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(850) 224-9115 FAX (850) 222-7560

April 1, 2005

HAND DELIVERED

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

Re: Tampa Electric Company's Ten-Year Site Plan

Dear Ms. Bayo:

Enclosed for filing on behalf of Tampa Electric Company are twenty-five (25) copies of the company's January 2005 to December 2014 Ten-Year Site Plan

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

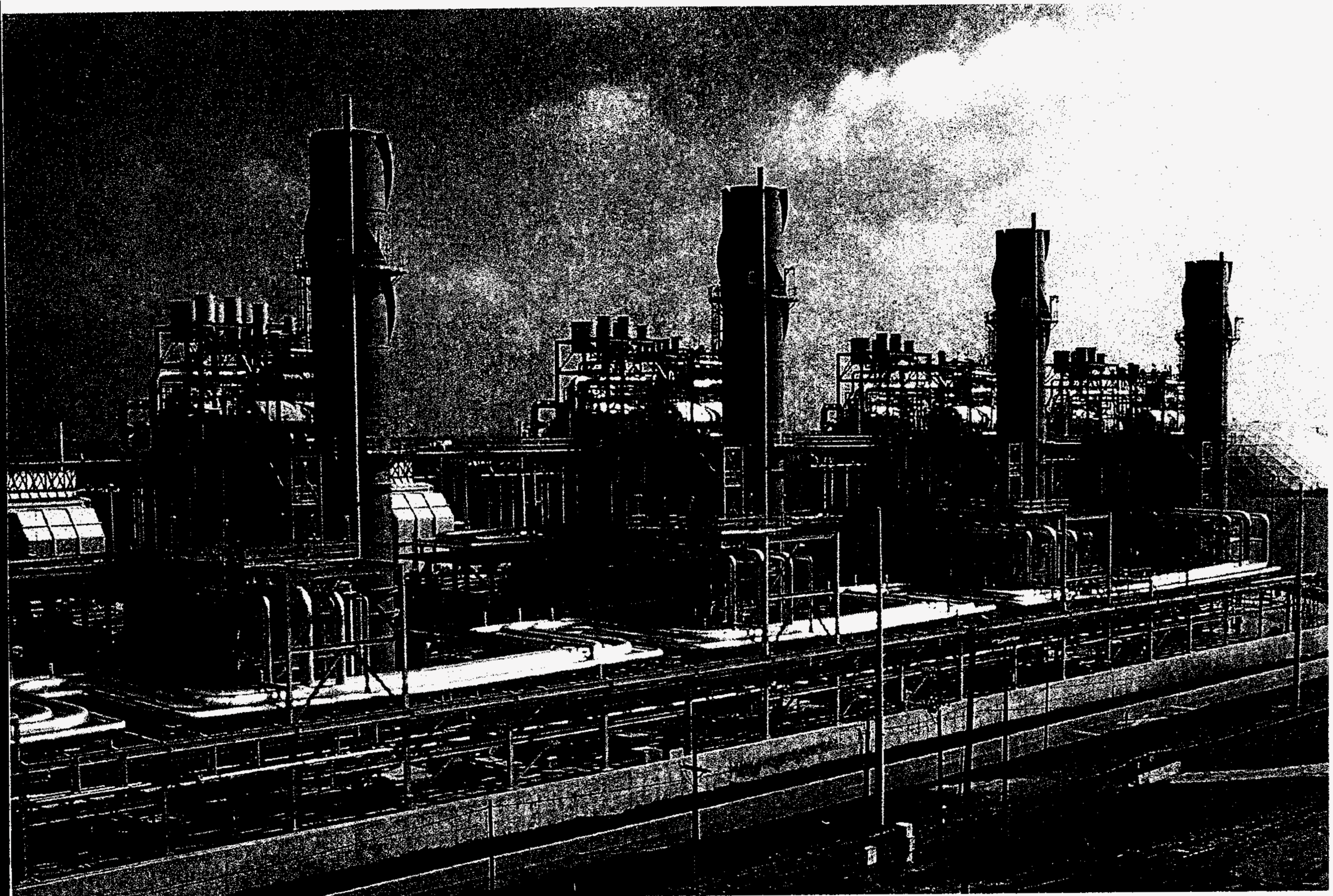
Thank you for your assistance in connection with this matter.

Sincerely,

James D. Beasley

JDB/pp
Enclosures

cc: Michael Haff (w/enc.)



H.L. Culbreath Bayside Power Station

TAMPA ELECTRIC

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

JANUARY 2005 TO DECEMBER 2014

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

January 2005 to December 2014

TAMPA ELECTRIC COMPANY
Tampa, Florida

April 1, 2005

TABLE OF CONTENTS

TABLE OF CONTENTS

TABLE OF CONTENTS

LIST OF SCHEDULES

SCHEDULES **PAGE**

SCHEDULES (continued) **PAGE**

CHAPTER IV

LIST OF FIGURES

TAMPA ELECTRIC COMPANY
CODE IDENTIFICATION SHEET

Unit Type:	CT	=	Combustion Turbine
	CC	=	Combined Cycle
	CG	=	Coal Gasifier
	D	=	Diesel
	FS	=	Fossil Steam
	HRSG	=	Heat Recovery Steam Generator
	IGCC	=	Integrated Gasification Combined Cycle
	ST	=	Steam Turbine
Unit Status:	P	=	Planned
	T	=	Regulatory Approval Received
	LTRS	=	Long Term Reserve Stand-by
	UC	=	Under Construction
Fuel Type:	BIT	=	Bituminous Coal
	C	=	Coal
	PC	=	Petroleum Coke
	HO	=	Heavy Oil (#6 Oil)
	LO	=	Light Oil (#2 Oil)
	NG	=	Natural Gas
	WH	=	Waste Heat
Environmental:	CL	=	Closed Loop Water Cooled
	CLT	=	Cooling Tower
	EP	=	Electrostatic Precipitator
	FQ	=	Fuel Quality
	LS	=	Low Sulfur
	FGD	=	Flue Gas Desulfurization
	OLS	=	Open Loop Cooling Water System
	OTS	=	Once-Through System
	NR	=	Not Required
Transportation:	PL	=	Pipeline
	TK	=	Truck
	RR	=	Railroad
	WA	=	Water
Other:	N	=	None

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CHAPTER I

DESCRIPTION OF EXISTING FACILITIES

Description of Electric Generating Facilities

Tampa Electric has five (5) generating stations that include 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 (4) pulverized coal fired steam units equipped with desulfurization scrubbers, electrostatic preciptators and three distillate fueled combustion turbines.

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

Polk: The station is presently comprised of three (3) 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 (2) residual or distillate oil fired diesel engines and one heat recovery steam generator with a steam turbine.

Partnership: The station is comprised of two (2) natural gas fired diesel engines.

Schedule 1

Existing Generating Facilities
As of December 31, 2004

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
								Alt	Commercial	Expected	Gen. Max.	Net Capability	
	Unit		Unit	Fuel		Fuel Transport		Fuel	In-Service	Retirement	Nameplate	Summer	Winter
Plant Name	No.	Location	Type	Pri	Alt	Pri	Alt	Days	Mo/Yr	Mo/Yr	KW	MW	MW
Big Bend		Hillsborough											
		Co. 14/31S/19E									1,998,000	1,838	1,912
	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	396	416
	3		FS	C	N	WA	N	0	05/76	"	445,500	423	433
	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	66	80
Bayside		Hillsborough											
		Co. 4/30S/19E									2,014,160	1,632	1,841
	1		CC	NG	N	PL	N	0	5/03	Unknown	809,060	702	793
	2		CC	NG	N	PL	N	0	1/04	Unknown	1,205,100	930	1,048
Phillips		Highland Co.											
		12-055									42,030	37	39
	1		D	HO	N	TK	N	0	06/83	Unknown	19,215	17	18
	2		D	HO	N	TK	N	0	06/83	Unknown	19,215	17	18
	3 (b)		HRSG	WH	N	N	N	0	06/83	Unknown	3,600	3	3
Polk		Polk Co.											
		2,3/32S/23E									677,839	580	628
	1		IGCC	C	LO	WA/TK	TK	0	09/96	Unknown	326,299	255	260
	2 (c)		CT	NG	LO	PL	TK	0	07/00	Unknown	175,770	160	184
	3 (c)		CT	NG	LO	PL	TK	0	5/02	Unknown	175,770	165	184
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	4,093	4,426

Notes: (a) Big Bend CT2 was placed on long term reserve standby in the fall of 2002 and returned to service in December 2004.

(b) Phillips Unit 3 was placed on long term reserve standby in February 1991.

(c) 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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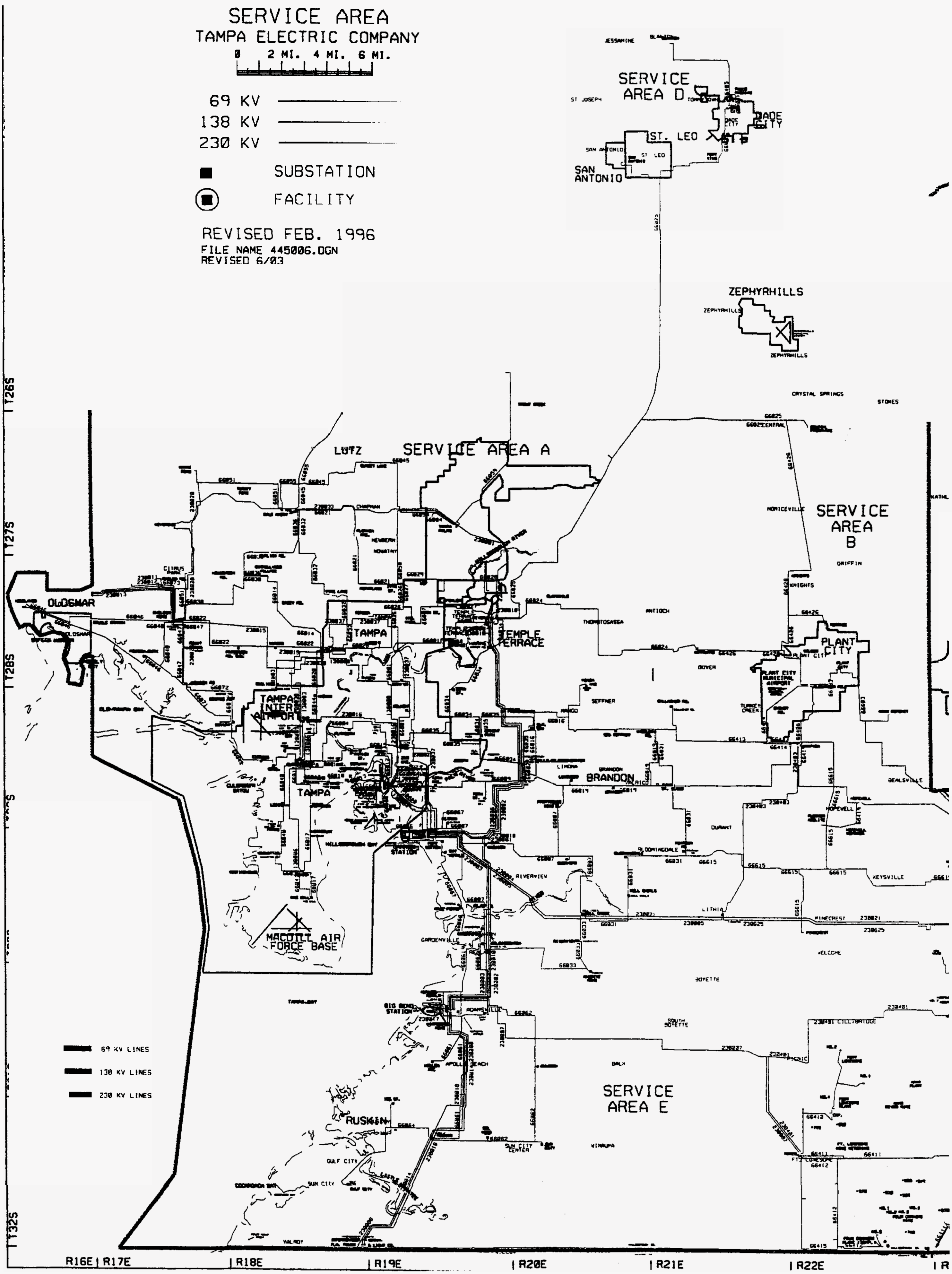
SERVICE AREA
TAMPA ELECTRIC COMPANY
0 2 MI. 4 MI. 6 MI.
69 KV
138 KV
230 KV
SUBSTATION
FACILITY
REVISED FEB. 1996
FILE NAME 445006.DGN
REVISED 6/03
SERVICE AREA D
DADE CITY
ST. LEO
SAN ANTONIO
ZEPHYRHILLS
SERVICE AREA A
LUTZ
SERVICE AREA B
PLANT CITY
OLDSMAR
TAMPA
TEMPLE TERRACE
TAMPA INTER. AIRPORT
BRANDON
MACDILL AIR FORCE BASE
SERVICE AREA E
RUSKIN
69 KV LINES
138 KV LINES
230 KV LINES
T26S
T27S
T28S
T32S
R16E
R17E
R18E
R19E
R20E
R21E
R22E

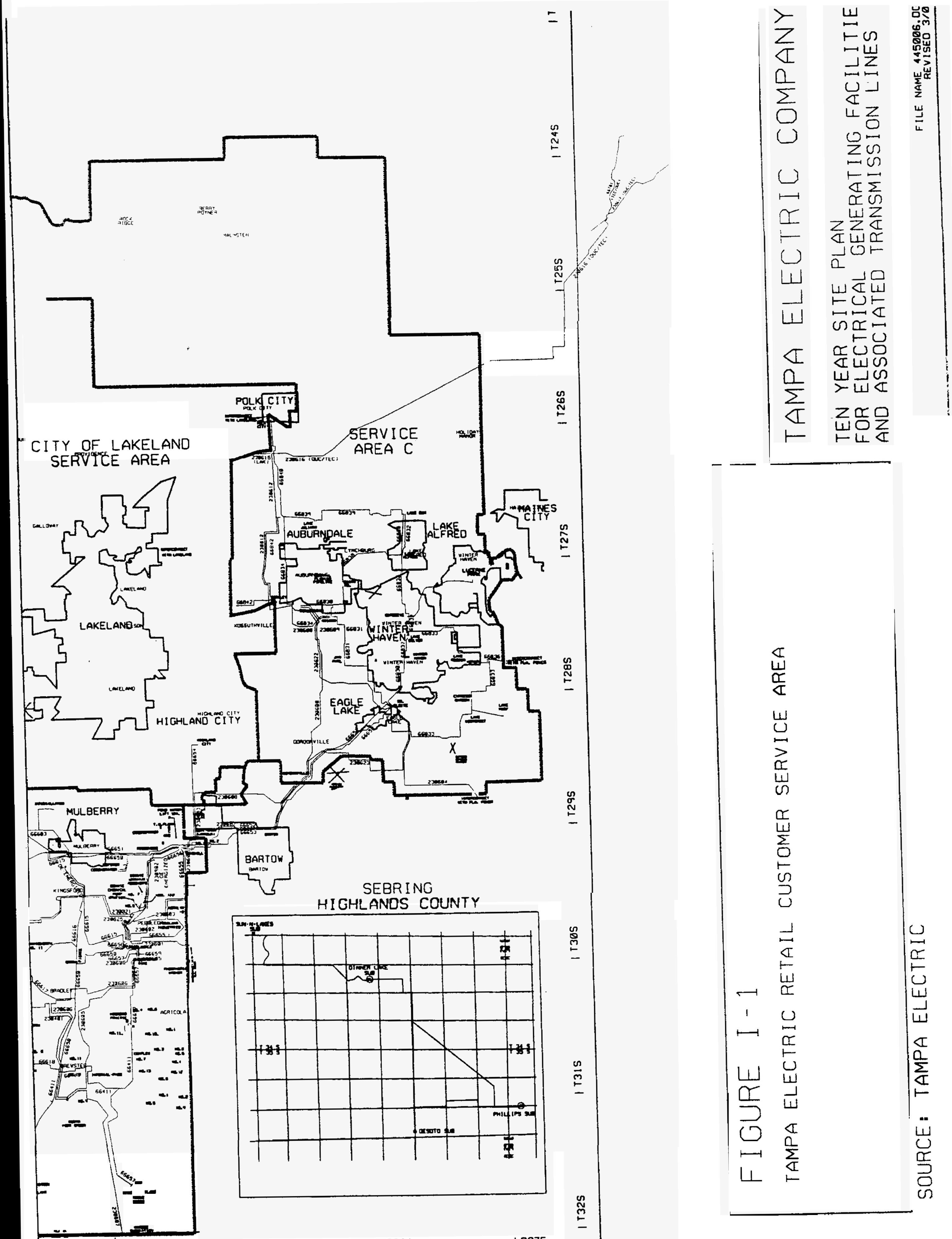

FIGURE I-1
TAMPA ELECTRIC RETAIL CUSTOMER SERVICE AREA

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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
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	1,084,198	2.5	8,265	531,257	15,557	5,843	66,041	88,475
2004	1,106,487	2.5	8,293	544,313	15,236	5,988	67,488	88,727
2005	1,127,449	2.5	8,824	558,217	15,807	6,197	68,606	90,327
2006	1,147,815	2.5	9,215	571,386	16,127	6,380	69,752	91,467
2007	1,168,494	2.5	9,547	583,878	16,351	6,547	70,983	92,233
2008	1,189,545	2.5	9,877	596,472	16,559	6,718	72,116	93,155
2009	1,210,976	2.5	10,243	610.379	16.781	6,901	73,287	94,164
2010	1,232,312	2.5	10,445	625,351	16,703	7,095	74,708	94,970
2011	1,252,646	2.5	10,836	640,734	16,912	7,291	76,168	95,723
2012	1,273,233	2.5	11,237	656,186	17,125	7,487	77,619	96,458
2013	1,295,036	2.4	11,609	669,200	17,348	7,661	78,889	97,111
2014	1,315,429	2.4	11,989	682.426	17.568	7,853	80,166	97,959

December 31, 2004 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
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	2,556	1299	1,967,667	0	58	1,542	18.437
2005	2,453	1,384	1,772,399	0	62	1,649	19,185
2006	2,250	1,462	1,538,988	0	65	1,731	19,641
2007	2,302	1,529	1,505,559	0	67	1,778	20,241
2008	2,343	1,591	1,472,659	0	69	1,823	20,830
2009	2,397	1,656	1,447,464	0	70	1,872	21.483
2010	2,405	1,726	1,393,395	0	72	1,925	21,942
2011	2,495	1,798	1,387,653	0	74	1,980	22,676
2012	2,548	1,870	1,362,567	0	76	2,035	23,383
2013	2,605	1,948	1,337,269	0	78	2,090	24,043
2014	2,662	2,030	1,311,330	0	79	2.142	24,725

December 31, 2004 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
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	684	794	18,454	5,649	575,780
2002	502	935	19,362	6,032	590,199
2003	587	985	19,798	6,399	604,900
2004	589	945	19,971	6,435	619,535
2005	527	960	20,672	6,668	634,875
2006	528	982	21,151	6,850	649,450
2007	530	1,010	21,781	7,019	663,409
2008	531	1,039	22,400	7,185	677,364
2009	532	1,075	23,090	7,366	692,688
2010	533	1,096	23,571	7,558	709,343
2011	261	1,133	24,070	7,756	726,456
2012	239	1,168	24,790	7,954	743,629
2013	177	1,200	25,420	8,119	758,156
2014	63	1,236	26,024	8,288	772,910

December 31, 2004 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	
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	3,974	120	3,854	177	95	70	20	47	3,445	
2005	4,208	186	4,022	171	100	72	21	48	3,610	
2006	4,312	186	4,127	147	99	74	22	50	3,735	
2007	4,435	187	4,248	147	98	76	23	51	3,853	
2008	4,556	187	4,369	146	97	78	23	52	3,973	
2009	4,695	187	4,508	147	96	80	24	54	4,107	
2010	4,831	188	4,643	143	95	82	24	55	4,244	
2011	4,910	116	4,794	145	94	83	25	55	4,392	
2012	5,070	117	4,953	145	93	84	26	56	4,549	
2013	5,195	102	5,093	145	91	86	26	57	4,688	
2014	5,314	77	5,237	145	90	87	27	57	4,831	

December 31, 2004 Status

* Includes residential and commercial/industrial conservation.
** Includes sales to Progress Energy Florida, Wauchula, Ft. Meade, St. Cloud and Reedy Creek.
☑ 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
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	3,949	120	3,829	254	136	437	18	48	2,936
2004/05	4,885	190	4,697	175	226	441	19	48	3,788
2005/06	4,999	191	4,807	150	224	445	19	48	3,921
2006/07	5,137	191	4,946	151	221	448	20	49	4,057
2007/08	5,263	191	5,072	150	219	450	21	49	4,183
2008/09	5,403	192	5,211	151	217	453	21	50	4,319
2009/10	5,545	192	5,353	147	214	455	22	50	4,465
2010/11	5,699	192	5,507	149	212	457	22	50	4,617
2011/12	5,790	121	5,669	148	209	458	23	51	4,780
2012/13	5,925	106	5,819	149	207	460	23	51	4,929
2013/14	6,044	77	5,967	149	204	461	24	51	5,078

December 31, 2004 Status

* Includes cumulative conservation.

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

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 %
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	18,999	394	168	18,437	589	945	19,971	58.9
2005	19,749	397	167	19,185	527	960	20,672	53.7
2006	20,219	404	174	19,641	528	982	21,151	53.6
2007	20,831	410	180	20,241	530	1010	21,781	53.6
2008	21,430	415	185	20,830	531	1039	22,400	53.5
2009	22,093	420	190	21,483	532	1075	23,090	53.8
2010	22,562	425	195	21,942	533	1096	23,571	53.4
2011	23,303	429	198	22,676	261	1133	24,070	52.9
2012	24,017	432	202	23,383	239	1168	24,790	53.4
2013	24,683	436	204	24,043	177	1200	25,420	53.6
2014	25,369	438	206	24,725	63	1236	26,024	53.7

December 31, 2004 Status

* 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)
	2004 Actual		2005 Forecast		2006 Forecast	
	Peak Demand *	NEL **	Peak Demand *	NEL **	Peak Demand *	NEL **
Month	MW	GWH	MW	GWH	MW	GWH
January	3,464	1,540	4.396	1.541	4,506	1,581
February	3,171	1,357	3.608	1,367	3,705	1,402
March	2,673	1,447	3.385	1,525	3,474	1,560
April	3,284	1,452	3.341	1,491	3,428	1,526
May	3,623	1,801	3,793	1,831	3,888	1,874
June	3,857	1,937	3,962	1,902	4,064	1,951
July	3,736	1,946	4,084	2,064	4,187	2,116
August	3,771	1,946	4,088	2,071	4,188	2,121
September	3,671	1,784	3,947	1,917	4,046	1,962
October	3,508	1,748	3,690	1,795	3,782	1,833
November	3,160	1,447	3,388	1,534	3,474	1,562
December	3,406	1,565	3,629	1,634	3,719	1,663
TOTAL		19,971		20,672		21,151

December 31, 2004 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	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
(1)	Nuclear		Trillion BTU	0	0	0	0	0	0	0	0	0	0	0	0
(2)	Coal		1000 Ton	5,378	4,456	4,226	4,261	4,212	4,272	4,295	4,276	4,265	4,294	4,321	4,312
(3)	Residual	Total	1000 BBL	160	102	74	124	272	135	185	85	79	81	44	14
(4)		Steam	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(5)		CC	1000 BBL	160	102	74	124	272	135	185	85	79	81	44	14
(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	179	123	133	200	215	207	245	291	351	407	351	392
(9)		Steam	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(10)		CC	1000 BBL	131	110	100	147	151	151	148	151	150	148	151	151
(11)		CT	1000 BBL	48	14	33	53	64	56	97	140	201	259	201	241
(12)		Diesel	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(13)	Natural Gas	Total	1000 MCF	27,084	48,077	58,344	63,035	66,615	58,165	73,760	71,499	79,004	82,449	93,815	98,287
(14)		Steam	1000 MCF	0	0	0	0	0	0	0	0	0	0	0	0
(15)		CC	1000 MCF	22,337	46,535	56,901	59,762	61,777	53,705	68,046	64,980	70,440	72,605	86,165	89,571
(16)		CT	1000 MCF	4,747	1,542	1,443	3,273	4,838	4,460	5,714	6,520	8,563	9,844	7,649	8,716
(17)	Other (Specify)														
(18)	Petroleum Coke		1000 Ton	359	417	496	648	655	659	651	659	657	651	661	661

* Values shown may be affected due to rounding.

** All values exclude ignition.

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 2003	Actual 2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
(1)	Annual Firm Interchange		GWH	699	208	205	184	179	174	200	181	186	291	0	0
(2)	Nuclear		GWH	0	0	0	0	0	0	0	0	0	0	0	0
(3)	Coal		GWH	11,454	9,554	8,951	8,959	8,857	8,958	9,010	8,961	8,938	9,002	9,059	9,038
(4)	Residual	Total	GWH	103	65	48	80	175	87	120	55	51	52	28	9
(5)		Steam	GWH	0	0	0	0	0	0	0	0	0	0	0	0
(6)		CC	GWH	103	65	48	80	175	87	120	55	51	52	28	9
(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	103	75	70	106	112	109	128	152	182	210	183	204
(10)		Steam	GWH	0	0	0	0	0	0	0	0	0	0	0	0
(11)		CC	GWH	85	69	55	82	84	84	82	84	83	82	84	84
(12)		CT	GWH	18	6	15	24	29	26	46	68	99	128	100	120
(13)		Diesel	GWH	0	0	0	0	0	0	0	0	0	0	0	0
(14)	Natural Gas	Total	GWH	3,561	6,652	7,973	8,530	8,948	7,793	9,907	9,547	10,493	10,911	12,830	13,404
(15)		Steam	GWH	0	0	0	0	0	0	0	0	0	0	0	0
(16)		CC	GWH	3,128	6,518	7,853	8,250	8,530	7,405	9,409	8,979	9,741	10,049	12,153	12,631
(17)		CT	GWH	433	134	120	280	418	388	498	568	752	862	677	774
(18)	Other (Specify)														
(19)	Petroleum Coke Generation		GWH	867	1,155	1,374	1,795	1,815	1,826	1,803	1,825	1,820	1,802	1,831	1,830
(20)	Net Interchange		GWH	2,494	1,751	1,595	1,043	1,239	2,998	1,467	2,396	1,944	2,066	1,030	1,083
(21)	Purchased Energy from														
(22)	Non-Utility Generators		GWH	516	510	456	456	456	456	456	456	456	456	456	456
(23)	Net Energy for Load*		GWH	19,798	19,970	20,671	21,151	21,782	22,402	23,089	23,571	24,070	24,790	25,418	26,024

* 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 2003	Actual 2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
(1)	Annual Firm Interchange		%	4	1	1	1	1	1	1	1	1	1	0	0
(2)	Nuclear		%	0	0	0	0	0	0	0	0	0	0	0	0
(3)	Coal		%	58	48	43	42	41	40	39	38	37	36	36	35
(4)	Residual	Total	%	1	0	0	0	1	0	1	0	0	0	0	0
(5)		Steam	%	0	0	0	0	0	0	0	0	0	0	0	0
(6)		CC	%	1	0	0	0	1	0	1	0	0	0	0	0
(7)		CT	%	0	0	0	0	0	0	0	0	0	0	0	0
(8)		Diesel	%	0	0	0	0	0	0	0	0	0	0	0	0
(9)	Distillate	Total	%	1	0	0	0	1	0	1	1	1	1	1	1
(10)		Steam	%	0	0	0	0	0	0	0	0	0	0	0	0
(11)		CC	%	0	0	0	0	0	0	0	0	0	0	0	0
(12)		CT	%	0	0	0	0	0	0	0	0	0	1	0	0
(13)		Diesel	%	0	0	0	0	0	0	0	0	0	0	0	0
(14)	Natural Gas	Total	%	18	33	39	40	41	35	43	41	44	44	50	52
(15)		Steam	%	0	0	0	0	0	0	0	0	0	0	0	0
(16)		CC	%	16	33	38	39	39	33	41	38	40	41	48	49
(17)		CT	%	2	1	1	1	2	2	2	2	3	3	3	3
(18)	Other (Specify)														
(19)	Petroleum Coke Generation		%	4	6	7	8	8	8	8	8	8	7	7	7
(20)	Net Interchange		%	13	9	8	5	6	13	6	10	8	8	4	4
(21)	Purchased Energy from														
(22)	Non-Utility Generators		%	3	3	2	2	2	2	2	2	2	2	2	2
(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 2005-2014 forecasts. The data tables in Chapter II outline the expected customer, demand, and energy values for the 2005-2014 time period.

Retail Load

MetrixND, an advanced statistics program for analysis and forecasting, was used to develop the 2005-2014 Customer, Demand and Energy forecasts. This software allows a platform for the development of more dynamic and fully integrated models.

In addition, Tampa Electric uses 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 an eight-equation model. The equations forecast the number of customers by eight major 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 correlation exists between historical changes in service area customers and historical changes in Florida's population, Florida population estimates for 2004-2024 were used to forecast the future growth patterns in residential customers.

2. **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:

    a. The Commercial Customer Model is a function of residential customers. 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.

    b. 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.

3. **Industrial Customer Model (Non-Phosphate):** Non-phosphate industrial customers include three rate classes that have been modeled individually: General Service, General Service Demand and General Service Large Demand.

   a. The General Service Customer Model is a function of Hillsborough County commercial employment.

   b. The General Service Demand Customer Model is a function of Hillsborough County 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.

   c. The General Service Large Demand Customer Model is simply based on a time trend variable.

4. **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.

5. **Street & Highway Lighting Customer Model**: As the number of commercial customers increases so does the need for infrastructure expansion, such as street and highway lighting. Therefore, the commercial customer forecast is the basis for the Street & Highway Lighting customer model.

3. Energy Multiregression Model

There are a total of eight energy models. All of these models represent average usage per customer (kWh/customer), except for the temporary services model which represents total kWh sales. The average usage models interact with the 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:

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

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

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

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.

2. 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.

   a. Commercial Energy 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.

b. Temporary Service Energy 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.

3. Industrial Energy Model (Non-Phosphate): Non-phosphate industrial energy includes three rate classes that have been modeled individually: General Service, General Service Demand and General Service Large Demand.

   a. The General Service Energy Model has 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.

   b. The General Service Demand Energy Model is modeled like the General Service Energy Model.

   c. The General Service Large Demand Customer Model is based on a time trend variable and a cooling degree day variable.

4. Public Authority Sector Model: Within this model, the equipment index is based on the same commercial equipment saturation and efficiency assumptions used in the commercial model. The economic component is based on government sector productivity and the price of electricity in this sector. Weather variables are consistent with the residential and commercial models.

5. 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 the number of billing days in the cycle, and the number of daylight hours in a day for each month.

The eight energy models described above plus an exogenous interruptible and 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 Models

After the total retail energy sales forecast is complete, it is integrated into the peak demand model as an independent variable along with weather variables. The energy variable represents the long-term economic and appliance trend impacts. To stabilize the peak demand data series and improve model accuracy, the volatility of the phosphate load is removed. To further stabilize the data, the peak demand models project on a per customer basis.

The weather variables provide the monthly seasonality to the peaks. The weather variables used are heating and cooling degree-days for both the temperature at the time of the peak and the 24-hour average on the day of the peak. By incorporating both temperatures, the model is accounting for the fact that cold/heat buildup contributes to determining the peak day.

The non-phosphate per customer kW forecast is multiplied by the final customer forecast. This result is then aggregated with a phosphate coincident peak forecast to arrive at the final projected peak demand.

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.

This department's familiarity with industry dynamics and their close working relationship with phosphate company representatives were used to form 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 demand equations and discussions with industry experts.

6. Conservation, Load Management and Cogeneration Programs

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

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

The company's current Demand Side Management (DSM) plan contains a mix of proven, mature programs that focus on the market place demand for their specific offerings. The following is a list that briefly describes the company's programs:

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

2. Load Management - Reduces weather-sensitive heating, cooling, water heating and pool pump loads through a radio signal control mechanism. This program is offered to residential(1) , commercial and industrial customers.

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.

(1) Per Commission Order No. 040033-EG issued February 16, 2005, the program is closed to new participants; however, existing participants are included in forecast.

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. 040033-EG, approved on August 19, 2004. The 2001 through 2004 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, 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, two equations have been developed for each municipality for forecasting energy: 1) customer forecast; 2) average usage forecast. The peak models for these two cities use sales forecast trend variables and heating and cooling degree variables as inputs.

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%
2004	62.6	70.7	88.5%	27.2	25.0	108.8%	70.8	45.3	156.3%

Commercial/Industrial

	Winter Peak MW Reduction			Summer Peak MW Reduction			GWH Energy Reduction		
Year	Total Achieved	Commission Approved Goal	% Variance	Total Achieved	Commission Approved Goal	% Variance	Total Achieved	Commission Approved Goal	% Variance
2000	1.8	1.5	120.0%	5.2	3.5	148.6%	19.0	12.9	147.3%
2001	3.7	3.0	123.3%	9.1	6.9	131.9%	27.3	25.7	106.2%
2002	6.3	4.5	140.0%	13.2	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%
2004	8.9	7.3	121.9%	18.2	16.7	109.0%	65.5	61.9	105.8%

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	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%
2004	71.5	78.0	91.7%	45.4	41.7	108.9%	136.3	107.2	127.1%

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 state population forecast is the starting point for developing the customer and energy projections. Both the University of Florida's Bureau of Economic and Business Research (BEBR) and Economy.com supply population projections for Hillsborough County and Florida. The short term population forecast is based upon Economy.com's projections while the long term forecast is based upon BEBR's projections. Over the next ten years (2005-2014) the average annual population growth rate in both Hillsborough County and Florida is expected to be 1.7%. In addition, Economy.com provides household data, an input to the residential average use model.

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 2.7% 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 3.6% 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 2005 - 2014, real personal income per capita for Hillsborough County is expected to increase at a 3.9% 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 2005-2014, retail energy sales are projected to rise at a 2.9% annual rate. The major contributor to growth is the residential category, increasing at an annual rate of 3.5%.

Wholesale Energy

Wholesale energy sales to Progress Energy Florida, Wauchula, Ft. Meade, St. Cloud, and Reedy Creek of 527 GWH are expected in 2005. Sales are projected to increase at a 0.2% annual rate through 2010. In 2011, sales drop substantially to 261 GWH and continue to decline to 239 GWH in 2012, 177 in 2013, and fall below 100 in 2014.

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 2005-2014 period, Tampa Electric's base case retail firm peak demand for both winter and summer are expected to advance at annual rates of 3.3%.

CHAPTER IV

FORECAST OF FACILITIES REQUIREMENTS

The proposed generating facility additions and changes shown in Schedule 8 integrate DSM programs and generating resources to provide economical, reliable service to Tampa Electric's customers. Various energy resource plan alternatives comprised of a mixture of generating technologies, purchased power, and cost-effective DSM programs are developed to determine this plan. These alternatives are combined with existing supply resources and analyzed to determine the energy resource option which best meets 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 integrated resource planning process provide Tampa Electric with a plan that is cost-effective while maintaining system reliability and balancing engineering and other issues. The new capacity additions resulting from the analysis are shown in Schedule 8. To meet the expected system demand and energy requirements over the next ten years, combustion turbine additions are planned for 2006, 2007, 2009, two in 2010, 2012, 2013 and 2014. A combined cycle unit is planned for 2013.

Tampa Electric also plans on installing inlet cooling chillers to each of the Bayside CTs in 2008. This will provide 161 MW of increased summer system capacity. As the construction start dates for each scheduled unit approaches, TEC will continue to look for competitive purchase power agreements that may replace or delay the scheduled units. Such alternatives will be considered if better suited for achieving the overall objective of providing reliable power in the most cost-effective manner. 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 395 MW of cogeneration capacity operating in its service area in 2005. Self-service capacity of 226 MW (net) is used by cogenerators to serve internal load requirements, 63 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 101 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 Bayside Unit 1, a combined cycle unit burning natural gas in April 2003. In January 2004, Gannon Unit 6 was also repowered to Bayside Unit 2, a combined cycle unit burning natural gas. 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 2005 coal and pet coke will fuel 50% of net energy for load and natural gas will fuel 39%. Less than one percent of net energy for load will be fueled by 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

An agreement between the Florida Department of Environmental Protection (DEP) and Tampa Electric produced a comprehensive emissions reduction plan delineated in a 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) in a 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 the agreements. Tampa Electric has reduced annual sulfur dioxides (SO_2), nitrogen oxides (NO_x), and particulate matter (PM) emissions from our facilities by 161,642 tons, 39,006 tons, and 4,284 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 existing scrubber in 1995. 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 H.L. Culbreath 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.

The repowering of Gannon Station to H.L. Culbreath Bayside Power Station resulted in significant reduction in emissions of all pollutant types. Tampa Electric's decision to install additional NO_x emissions controls on all Big Bend Station Units by May of 2010 will result in the further reduction of emissions. Selective Catalytic Reduction (SCR) will be the control technology used to reduce Big Bend Station NO_x emissions. The first unit scheduled to have an SCR installed by June 1, 2007 is Unit 4. Subsequently, the other units will be compliant by May 1 of 2008, 2009 and 2010. By 2010, these projects are expected to result in 60,270 tons per year of additional NO_x reduction. In total, Tampa Electric's emission reduction initiatives will result in the reduction of SO_2, NO_x and PM emissions by 90%, 87%, and 72%, respectively, below 1998 levels. With these improvements in place, Tampa Electric's facilities will meet the same standards required of newer power generating facilities and significantly enhance the quality of the air in the 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. 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 (353 MW winter and 287 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 has an additional long-term purchase power contract with Invenergy for 88 MW winter and 69 MW summer of firm non-shared capacity. This contract began in May 2000 and expires on December 31, 2012.

In the 2005 planning process, Tampa Electric determined that it has a need for capacity in the summer of 2005, 2006, 2007 and the winter of 2008, 2009, and 2010 over and above its identified capacity additions. To address the 2005 requirements, the company entered into a firm purchase power agreement with New Hope Power Partnership for 50 MW for June through August of 2005. Due to the relatively small amount of capacity and the limited time it is needed, Tampa Electric will investigate purchase power options to satisfy the summer capacity need in 2006 of 40 MW and 2007 for 20 MW in the year each purchase is required.

The winter of 2008-2010 capacity needs are for 400 MW in each year. In order to complete the Selective Catalytic Reduction system installations (SCR) by the mandated Consent Decree (CD) date, one Big Bend unit will be down for the scheduled work from January through mid-April of each of the aforementioned years. Tampa Electric will seek to satisfy this winter capacity need by contracting power from one or more entities. Informal inquiries have begun to locate potential sources of capacity. Tampa Electric will look to sign agreement(s) that provide cost-effective alternative(s) to satisfy the projected requirements.

The 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
2005	4,090	406	0	63	4,559	3,797	762	20%	0	762	20%
2006	4,250	396	0	63	4,709	3,922	787	20%	0	787	20%
2007	4,410	376	0	63	4,849	4,040	809	20%	0	809	20%
2008	4,571	356	0	63	4,990	4,161	829	20%	0	829	20%
2009	4,731	356	0	63	5,150	4,295	855	20%	0	855	20%
2010	5,051	356	0	40	5,447	4,432	1,015	23%	0	1,015	23%
2011	5,051	356	0	40	5,447	4,508	939	21%	0	939	21%
2012	5,211	356	0	23	5,590	4,666	924	20%	0	924	20%
2013	5,816	0	0	23	5,839	4,790	1,049	22%	0	1,049	22%
2014	5,976	0	0	23	5,999	4,908	1,091	22%	0	1,091	22%

NOTE:
1. Capacity import includes firm purchase power agreement with Invenergy of 356 MW 2005 through 2012 and 50 MW from New Hope Power Partnership in 2005. Unspecified purchases are included in 2006 of 40 MW and 2007 of 20 MW.
2. The QF column accounts for cogeneration that will be purchased under firm contracts.
3. Chiller additions to Bayside units 1 and 2 in May 2008 will provide 23 MW per CT (161MW Total) of additional summer capacity.

* 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
2004-05	4,423	441	0	63	4,927	3,979	948	24%	0	948	24%
2005-06	4,423	441	0	63	4,927	4,112	815	20%	0	815	20%
2006-07	4,783	441	0	63	5,287	4,248	1,039	24%	0	1,039	24%
2007-08	4,783	841	0	63	5,687	4,374	1,313	30%	433	880	20%
2008-09	4,963	841	0	63	5,867	4,511	1,356	30%	416	940	21%
2009-10	5,143	841	0	63	6,047	4,657	1,390	30%	428	962	21%
2010-11	5,323	441	0	40	5,804	4,810	994	21%	0	994	21%
2011-12	5,503	441	0	23	5,967	4,901	1,066	22%	0	1,066	22%
2012-13	6,005	0	0	23	6,028	5,035	993	20%	0	993	20%
2013-14	6,185	0	0	23	6,208	5,155	1,053	20%	0	1,053	20%

NOTE:

1. Capacity import includes firm purchase power agreement with Invenergy of 441 MW for 2005 through 2012. Capacity imports also include 400 MW of unspecified purchase power expected to be needed for the installation of the Selective Catalytic Reduction (SCR) equipment on Big Bend 3 in 2008, Big Bend 2 in 2009 and Big Bend 1 in 2010. These SCR installations are part of the Consent Decree between Tampa Electric and the U.S. Environmental Protection Agency.
2. The QF column accounts for cogeneration that will be purchased under firm contracts.

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.						Net Capability		
Plant Name	Unit No.	Location	Unit Type	Primary	Alternate	Primary	Alternate	Const. Start Mo/Yr	Commercial In-Service Mo/Yr	Expected Retirement Mo/Yr	Gen. Max. Nameplate kW	Summer MW	Winter MW	Status
Bayside	3A	Hills. Co.	CT	NG	NA	PL	NA	5/05	5/06	unknown	unknown	160	180	T
Bayside	3B	Hills. Co.	CT	NG	NA	PL	NA	1/06	1/07	unknown	unknown	160	180	T
Polk	4	Polk	CT	NG	LO	PL	TK	7/07	1/09	unknown	unknown	160	180	P
Polk	5	Polk	CT	NG	LO	PL	TK	7/08	1/10	unknown	unknown	160	180	P
Polk	6	Polk	CT	NG	LO	PL	TK	11/08	5/10	unknown	unknown	160	180	P
Future CT	1	unknown	CT	NG	LO	PL	TK	7/09	1/12	unknown	unknown	160	180	P
Future CC	1	unknown	CC	NG	LO	PL	TK	7/09	1/13	unknown	unknown	445	502	P
Future CT	2	unknown	CT	NG	LO	PL	TK	11/10	5/13	unknown	unknown	160	180	P
Future CT	3	unknown	CT	NG	LO	PL	TK	11/11	5/14	unknown	unknown	160	180	P

SCHEDULE 9

(Page 1 of 9)

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

(1)	PLANT NAME AND UNIT NUMBER	BAYSIDE UNIT 3A
(2)	CAPACITY	
	A. SUMMER	160
	B. WINTER	180
(3)	TECHNOLOGY TYPE	COMBUSTION TURBINE
(4)	ANTICIPATED CONSTRUCTION TIMING	
	A. FIELD CONSTRUCTION START DATE	MAY 2005
	B. COMMERCIAL IN-SERVICE DATE	MAY 2006
(5)	FUEL	
	A. PRIMARY FUEL	NATURAL GAS
	B. ALTERNATE FUEL	N/A
(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	REGULATORY APPROVAL
(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 (2006)	9.5%
	AVERAGE NET OPERATING HEAT RATE (ANOHR) [2]	11,540 Btu/kWh
(13)	PROJECTED UNIT FINANCIAL DATA	
	BOOK LIFE (YEARS)	26
	TOTAL INSTALLED COST (IN-SERVICE YEAR $/kW)	214.48
	DIRECT CONSTRUCTION COST ($/kW)	192.38
	AFUDC AMOUNT ($/kW)	15.42
	ESCALATION ($/kW)	6.69
	FIXED O&M ($/kW – Yr)	2.62
	VARIABLE O&M ($/MWH)	8.37
	K FACTOR	1.6926

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

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

(1)	PLANT NAME AND UNIT NUMBER	BAYSIDE UNIT 3B
(2)	CAPACITY	
	A. SUMMER	160
	B. WINTER	180
(3)	TECHNOLOGY TYPE	COMBUSTION TURBINE
(4)	ANTICIPATED CONSTRUCTION TIMING	
	A. FIELD CONSTRUCTION START DATE	JAN 2006
	B. COMMERCIAL IN-SERVICE DATE	JAN 2007
(5)	FUEL	
	A. PRIMARY FUEL	NATURAL GAS
	B. ALTERNATE FUEL	N/A
(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	REGULATORY APPROVAL
(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 (2007)	6.6%
	AVERAGE NET OPERATING HEAT RATE (ANOHR) [2]	11,402 Btu/kWh
(13)	PROJECTED UNIT FINANCIAL DATA	
	BOOK LIFE (YEARS)	26
	TOTAL INSTALLED COST (IN-SERVICE YEAR $/kW)	214.48
	DIRECT CONSTRUCTION COST ($/kW)	192.38
	AFUDC AMOUNT ($/kW)	15.42
	ESCALATION ($/kW)	6.69
	FIXED O&M ($/kW – Yr)	2.68
	VARIABLE O&M ($/MWH)	8.56
	K FACTOR	1.6926

[1] REPRESENTS TOTAL 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	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	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 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 (2009)	6.5%
	AVERAGE NET OPERATING HEAT RATE (ANOHR) [2]	11,421 Btu/kWh
(13)	PROJECTED UNIT FINANCIAL DATA	
	BOOK LIFE (YEARS)	26
	TOTAL INSTALLED COST (IN-SERVICE YEAR $/kW)	267.01
	DIRECT CONSTRUCTION COST ($/kW)	230.56
	AFUDC AMOUNT ($/kW)	16.49
	ESCALATION ($/kW)	19.97
	FIXED O&M ($/kW – Yr)	2.80
	VARIABLE O&M ($/MWH)	8.96
	K FACTOR	1.6926

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

SCHEDULE 9

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

(1)	PLANT NAME AND UNIT NUMBER	POLK UNIT 5
(2)	CAPACITY	
	A. SUMMER	160
	B. WINTER	180
(3)	TECHNOLOGY TYPE	COMBUSTION TURBINE
(4)	ANTICIPATED CONSTRUCTION TIMING	
	A. FIELD CONSTRUCTION START-DATE	JUL 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)	5.6%
	AVERAGE NET OPERATING HEAT RATE (ANOHR) [2]	11,420 Btu/kWh
(13)	PROJECTED UNIT FINANCIAL DATA	
	BOOK LIFE (YEARS)	26
	TOTAL INSTALLED COST (IN-SERVICE YEAR $/kW)	273.15
	DIRECT CONSTRUCTION COST ($/kW)	230.56
	AFUDC AMOUNT ($/kW)	16.87
	ESCALATION ($/kW)	25.73
	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 ENVIRONMENTALLY PERMITTED SITE.

SCHEDULE 9

(Page 5 of 9)

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

(1)	PLANT NAME AND UNIT NUMBER	POLK UNIT 6
(2)	CAPACITY	
	A. SUMMER	160
	B. WINTER	180
(3)	TECHNOLOGY TYPE	COMBUSTION TURBINE
(4)	ANTICIPATED CONSTRUCTION TIMING	
	A. FIELD CONSTRUCTION START DATE	NOV 2008
	B. COMMERCIAL IN-SERVICE DATE	MAY 2010
(5)	FUEL	
	A. PRIMARY FUEL	NATURAL GAS
	B. ALTERNATE FUEL	DISTILLATE OIL
(6)	AIR POLLUTION CONTROL STRATEGY	DRY LOW NO_x BURNER
(7)	COOLING METHOD	N/A
(8)	TOTAL SITE AREA [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)	5.6%
	AVERAGE NET OPERATING HEAT RATE (ANOHR) [2]	11,455 Btu/kWh
(13)	PROJECTED UNIT FINANCIAL DATA	
	BOOK LIFE (YEARS)	26
	TOTAL INSTALLED COST (IN-SERVICE YEAR $/kW)	283.62
	DIRECT CONSTRUCTION COST ($/kW)	230.56
	AFUDC AMOUNT ($/kW)	23.22
	ESCALATION ($/kW)	29.84
	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 ENVIRONMENTALLY PERMITTED SITE.

SCHEDULE 9

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

(1)	PLANT NAME AND UNIT NUMBER	FUTURE CT 1
(2)	CAPACITY	
	A. SUMMER	160
	B. WINTER	180
(3)	TECHNOLOGY TYPE	COMBUSTION TURBINE
(4)	ANTICIPATED CONSTRUCTION TIMING	
	A. FIELD CONSTRUCTION START DATE	JUL 2009
	B. COMMERCIAL IN-SERVICE DATE	JAN 2012
(5)	FUEL	
	A. PRIMARY FUEL	NATURAL GAS
	B. ALTERNATE FUEL	DISTILLATE OIL
(6)	AIR POLLUTION CONTROL STRATEGY	DRY LOW NO_x BURNER
(7)	COOLING METHOD	N/A
(8)	TOTAL SITE AREA	UNDETERMINED
(9)	CONSTRUCTION STATUS	PROPOSED
(10)	CERTIFICATION STATUS	UNDETERMINED
(11)	STATUS WITH FEDERAL AGENCIES	N/A
(12)	PROJECTED UNIT PERFORMANCE DATA	
	PLANNED OUTAGE FACTOR (POF)	1.9
	FORCED OUTAGE RATE (FOR)	4.8
	EQUIVALENT AVAILABILITY FACTOR (EAF)	93
	RESULTING CAPACITY FACTOR (2012)	7.4%
	AVERAGE NET OPERATING HEAT RATE (ANOHR) [1]	11,323 Btu/kWh
(13)	PROJECTED UNIT FINANCIAL DATA	
	BOOK LIFE (YEARS)	26
	TOTAL INSTALLED COST (IN-SERVICE YEAR $/kW)	285.86
	DIRECT CONSTRUCTION COST ($/kW)	230.56
	AFUDC AMOUNT ($/kW)	17.65
	ESCALATION ($/kW)	37.65
	FIXED O&M ($/kW – Yr)	3.00
	VARIABLE O&M ($/MWH)	9.60
	K FACTOR	1.6926

[1] BASED ON IN-SERVICE YEAR.

SCHEDULE 9

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

(1)	PLANT NAME AND UNIT NUMBER	FUTURE CC 1
(2)	CAPACITY	
	A. SUMMER	445
	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	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)	79.0%
	AVERAGE NET OPERATING HEAT RATE (ANOHR) [1]	6,910 Btu/kWh
(13)	PROJECTED UNIT FINANCIAL DATA	
	BOOK LIFE (YEARS)	26
	TOTAL INSTALLED COST (IN-SERVICE YEAR $/kW)	907.96
	DIRECT CONSTRUCTION COST ($/kW)	657.37
	AFUDC AMOUNT ($/kW)	131.65
	ESCALATION ($/kW)	118.94
	FIXED O&M ($/kW – Yr)	23.47
	VARIABLE O&M ($/MWH)	0.38
	K FACTOR	1.6926

[1] BASED ON IN-SERVICE YEAR.

SCHEDULE 9

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

(1)	PLANT NAME AND UNIT NUMBER	FUTURE CT 2
(2)	CAPACITY	
	A. SUMMER	160
	B. WINTER	180
(3)	TECHNOLOGY TYPE	COMBUSTION TURBINE
(4)	ANTICIPATED CONSTRUCTION TIMING	
	A. FIELD CONSTRUCTION START DATE	NOV 2010
	B. COMMERCIAL IN-SERVICE DATE	MAY 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	UNDETERMINED
(9)	CONSTRUCTION STATUS	PROPOSED
(10)	CERTIFICATION STATUS	UNDETERMINED
(11)	STATUS WITH FEDERAL AGENCIES	N/A
(12)	PROJECTED UNIT PERFORMANCE DATA	
	PLANNED OUTAGE FACTOR (POF)	1.9
	FORCED OUTAGE RATE (FOR)	4.8
	EQUIVALENT AVAILABILITY FACTOR (EAF)	93
	RESULTING CAPACITY FACTOR (2013)	5.9%
	AVERAGE NET OPERATING HEAT RATE (ANOHR) [1]	11,420 Btu/kWh
(13)	PROJECTED UNIT FINANCIAL DATA	
	BOOK LIFE (YEARS)	26
	TOTAL INSTALLED COST (IN-SERVICE YEAR $/kW)	303.64
	DIRECT CONSTRUCTION COST ($/kW)	230.56
	AFUDC AMOUNT ($/kW)	24.86
	ESCALATION ($/kW)	48.23
	FIXED O&M ($/kW – Yr)	3.07
	VARIABLE O&M ($/MWH)	9.82
	K FACTOR	1.6926

[1] BASED ON IN-SERVICE YEAR.

SCHEDULE 9

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

(1)	PLANT NAME AND UNIT NUMBER	FUTURE CT 3
(2)	CAPACITY	
	A. SUMMER	160
	B. WINTER	180
(3)	TECHNOLOGY TYPE	COMBUSTION TURBINE
(4)	ANTICIPATED CONSTRUCTION TIMING	
	A. FIELD CONSTRUCTION START DATE	NOV 2011
	B. COMMERCIAL IN-SERVICE DATE	MAY 2014
(5)	FUEL	
	A. PRIMARY FUEL	NATURAL GAS
	B. ALTERNATE FUEL	DISTILLATE OIL
(6)	AIR POLLUTION CONTROL STRATEGY	DRY LOW NO_X BURNER
(7)	COOLING METHOD	N/A
(8)	TOTAL SITE AREA	UNDETERMINED
(9)	CONSTRUCTION STATUS	PROPOSED
(10)	CERTIFICATION STATUS	UNDETERMINED
(11)	STATUS WITH FEDERAL AGENCIES	N/A
(12)	PROJECTED UNIT PERFORMANCE DATA	
	PLANNED OUTAGE FACTOR (POF)	1.9
	FORCED OUTAGE RATE (FOR)	4.8
	EQUIVALENT AVAILABILITY FACTOR (EAF)	93
	RESULTING CAPACITY FACTOR (2014)	6.1%
	AVERAGE NET OPERATING HEAT RATE (ANOHR) [1]	11,435 Btu/kWh
(13)	PROJECTED UNIT FINANCIAL DATA	
	BOOK LIFE (YEARS)	26
	TOTAL INSTALLED COST (IN-SERVICE YEAR $/kW)	310.63
	DIRECT CONSTRUCTION COST ($/kW)	230.56
	AFUDC AMOUNT ($/kW)	25.43
	ESCALATION ($/kW)	54.64
	FIXED O&M ($/kW – Yr)	3.14
	VARIABLE O&M ($/MWH)	10.04
	K FACTOR	1.6926

[1] BASED ON IN-SERVICE YEAR.

Schedule 10

Status Report and Specifications of Proposed Directly Associated Transmission Lines

Point of Origin and Termination	Number of Circuits	Right-of-Way	Circuit Length	Voltage	Anticipated In-Service Date	Anticipated Capital Investment	Substations	Participation with Other Utilities
Gannon/SR 60	1	No new ROW required	2.3 mi	230 kV	Summer 2006	$3.4 million	No new substations	None
Pebbledale to English Creek	1	Possible road ROW required	12.0 mi	230 kV	Summer 2007	$16.0 million	New 230/69 kV Substation at English Creek	None
English Creek to Hampton	1	Possible road ROW required	8.0 mi	230 kV	Summer 2008	$8.2 million	Hampton – New 230 kV Ring Bus	None
Davis to Wilderness	1	Possible road ROW required	12.6 mi	230 kV	Summer 2009	$8.0 million	Wilderness –new 230/69 kV Substation	None
Hampton to Wheeler	1	Possible road ROW required	10.2 mi	230 kV	Summer 2009	$11.0 million	Wheeler – new 230 kV Ring Bus and 230/69 kV Transformer	None
Davis to Chapman	2	No new right of way required	8.4 mi	230 kV	Summer 2010	$15.0 million	Davis - new 230 kV switching station Chapman – complete 230 kV ring bus	None
Wheeler/Davis	1	No new right of way required	13.0 mi	230 kV	Summer 2011	$13.0 million	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 2004 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 using Tampa Electric's Integrated Resource Planning process. As part of this process, Tampa Electric evaluated various planning and operating alternatives to current operations, with objectives including meeting compliance requirements in the most cost-effective and reliable manner, maximizing operational flexibility and minimizing total costs.

Early in the study process, many alternatives were screened on a qualitative and quantitative basis to determine those alternatives that were the most feasible 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 a more detailed economic analysis.

Fuel commodity price forecasting for base, high and low forecasts 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, Hill & Associates, PIRA Energy Group, Coal Daily, and oil, natural gas, and propane pricing publications and periodicals which include: *Inside FERC* and *Platt's Oilgram*. Additionally, NYMEX forward pricing curves are utilized in conjunction with the forecasted data to derive forecast pricing.

High and low fuel price projections represent alternative forecasts to the company's base case outlook. The high and low price projections are defined by natural gas prices varying 35% above or below the base case. The high and low price projections represent 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 Assumptions

Tampa Electric's generating unit performance assumptions are used to evaluate long-range system operating costs associated with particular generation expansion plans. Generating units 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 are based on historical data trends, engineering judgement, time since last planned outage, and recent equipment performance. 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 forecasted outage schedule is based on unit-specific maintenance needs, material lead-time, labor availability, 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 status 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 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.

Tampa Electric uses the PROVIEW module of STRATEGIST, a computer model developed by New Energy Associates, to evaluate the supply side resources. PROVIEW uses a dynamic programming approach to develop an estimate of the 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 of STRATEGIST and the PROMOD economic dispatch model. 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. 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.

In the 2005 planning process, Tampa Electric determined that it has a need for capacity in the summer of 2005, 2006, 2007 and the winter of 2008, 2009, and 2010 over and above its identified capacity additions. To address the 2005 requirements, the company entered into a firm purchase power agreement with New Hope Power Partnership for 50 MW for June through August of 2005. Due to the relatively small amount of capacity and the limited time it is needed, Tampa Electric will investigate purchase power options to satisfy the summer capacity need in 2006 of 40 MW and 2007 for 20 MW. The winter of 2008, 2009, 2010 capacity needs are for 400 MW in each year. One Big Bend unit in each of these years will be taken out from for January through mid April. In order to complete the Selective Catalytic Reduction system installations (SCR) by the mandated Consent Decree (CD) date. Tampa Electric will seek to satisfy this winter capacity need by contracting power from one or more entities. Informal inquiries have begun to locate potential sources of capacity. Tampa Electric will look to sign agreement(s) that provide the most cost-effective peaking capacity alternative to satisfy the projected requirements.

As the construction start dates for each scheduled unit approaches, TEC will continue to look for competitive purchase power agreements that may replace or delay the scheduled units. Such alternatives would be considered if better suited to the overall objective of providing reliable power in the most cost effective manner.

Generation and Transmission Reliability Criteria

Generation

Tampa Electric currently uses two criteria to measure the reliability of its generating system. The company utilizes a 20% reserve margin criteria and a 7% minimum summer supply side reserve margin criteria. Tampa Electric's approach to calculating percent reserves are consistent with that outlined in the settlement agreement. 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 purchase power contract with Invenergy for 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%
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.

Tl			
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

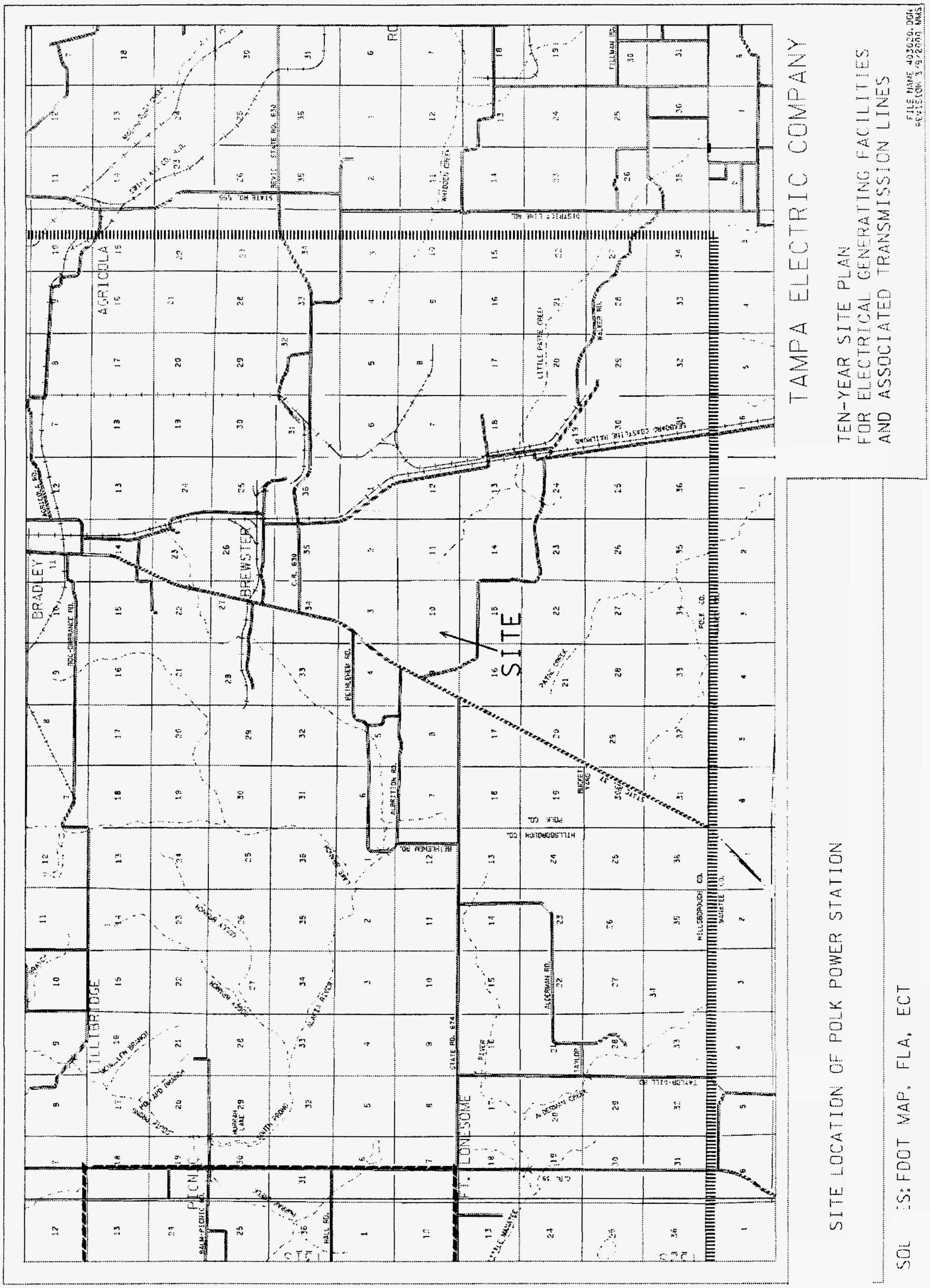
The renewable generation mix consists of an 18 kW photovoltaic array installed at the Museum of Science and Industry (MOSI) and a 30 kW Capstone micro turbine that operates on methane at a Hillsborough County landfill. In May 2004, a 4 kW photovoltaic system was installed at a local middle school in a partnership with the Hillsborough County School District.

CHAPTER VI

ENVIRONMENTAL AND LAND USE INFORMATION

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

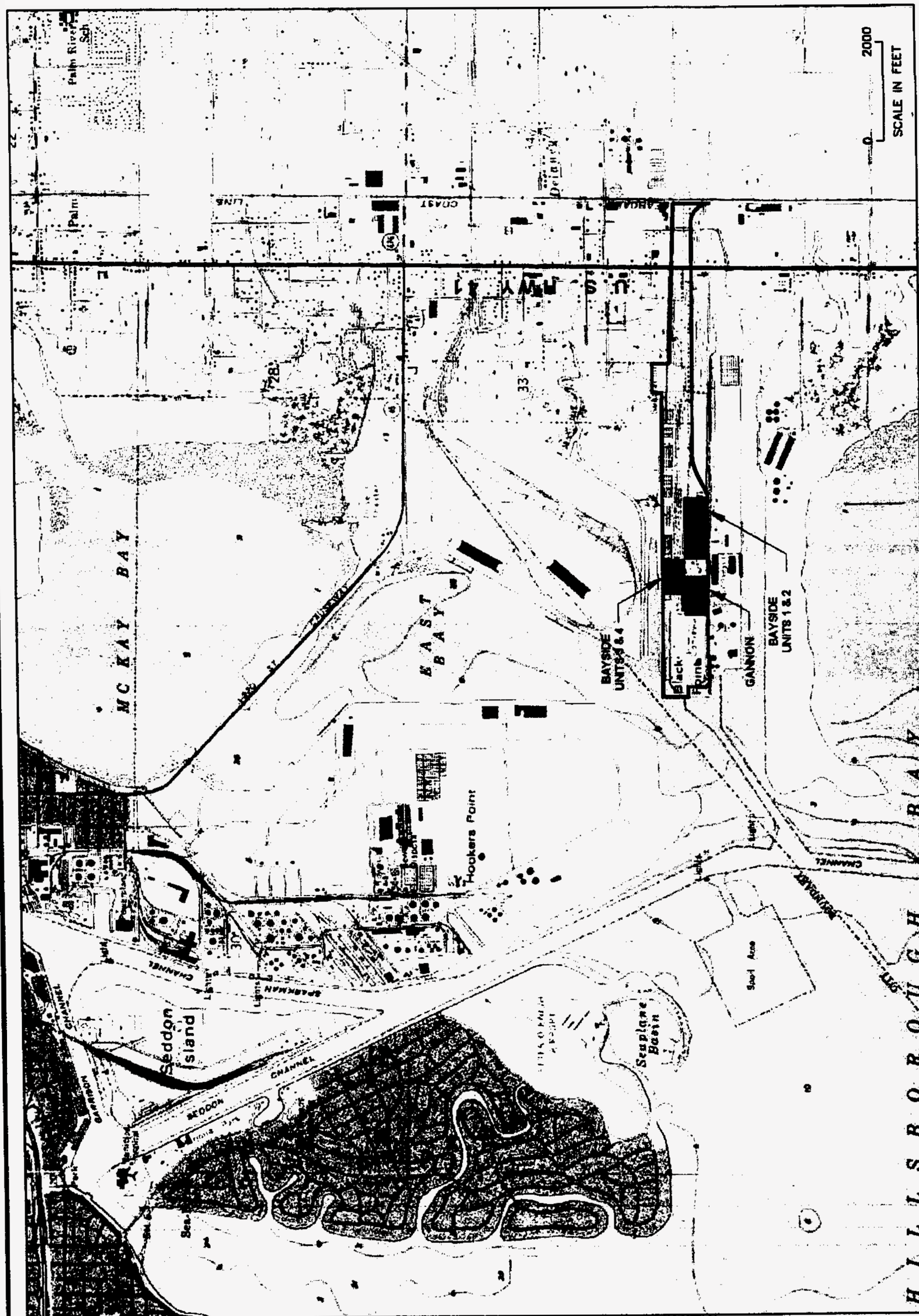
Figure VI-1



TAMPA ELECTRIC COMPANY
TEN-YEAR SITE PLAN
FOR ELECTRICAL GENERATING FACILITIES
AND ASSOCIATED TRANSMISSION LINES
SITE LOCATION OF POLK POWER STATION
SITE
BRADLEY
AGRICOLA
BREWSTER
LONESOME

FIGURE VI-2

[redacted]



F.J. GANNON / BAYSIDE LOCATION MAP

SOURCE: USGS QUAD, TAMPA, FL 1981