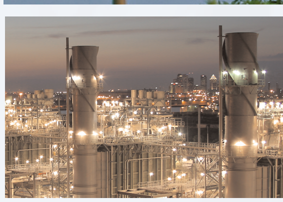
Ten -Year Site Plan for Electrical Generating Facilities and Associated Transmission Lines

January 2007 to December 2016

TAMPA ELECTRIC
Polk Power Station's Integrated Gasification Combined-Cycle (IGCC) Facility



Responsibly Serving Our Growing Customers' Needs.

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

January 2007 to December 2016

TAMPA ELECTRIC COMPANY
Tampa, Florida

April 1, 2007

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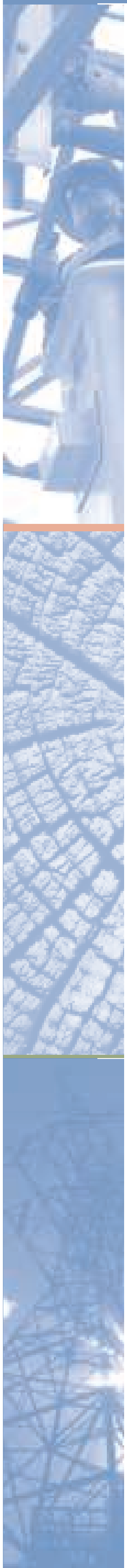

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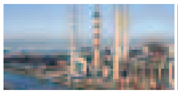
glossary of terms

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
	RFO	=	Residual Fuel Oil (#6 Oil)
	DFO	=	Distillate Fuel 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



Description of Existing 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.

Description of Electric Generating Facilities

Big Bend

The station contains four (4) pulverized coal fired steam units equipped with desulfurization scrubbers, electrostatic precipitators and three (3) distillate fueled combustion turbines. These coal units are currently undergoing the addition of air pollution control systems called Selective Catalytic Reduction (SCR), this work is scheduled to be completed by 2010.

H.L. Culbreath Bayside

The station contains two (2) natural gas fired combined cycle units. Bayside Unit 1 utilizes three (3) combustion turbines, three (3) heat recovery steam generators (HRSGs) and one (1) steam turbine. Bayside Unit 2 utilizes four (4) combustion turbines, four (4) HRSGs and one (1) steam turbine.

Polk Power Station

The station is presently comprised of four (4) generating units and one (1) unit under construction. 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 to create a clean fuel gas from a variety of feedstock with the efficiency benefits of combined cycle generation equipment. Polk Units 2 through 5 are combustion turbines. Units 2 and 3 are fueled primarily with natural gas with distillate backup. Unit 4 was placed in-service March 2007 and is fueled with natural gas. Unit 5 scheduled for in-service May 2007 is fueled with natural gas. Polk Units 4 and 5 each have a capacity rating of 180 MW winter and 160 MW summer.

Other Facilities

Phillips

The station is comprised of two (2) residual or distillate oil fired diesel engines.

Partnership

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

Schedule 1

Existing Generating Facilities
As of December 31, 2006

(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	1,760	1,815
	1		ST	BIT	N	WA	N	0	10/70	Unknown	445,500	391	401
	2		ST	BIT	N	WA	N	0	04/73	"	445,500	391	401
	3		ST	BIT	N	WA	N	0	05/76	"	445,500	414 (b)	423 (b)
	4		ST	BIT	N	WA	N	0	02/85	"	486,000	447	452
	CT 1		GT	DFO	N	WA	TK	0	02/69	01/15	18,000	12	13
	CT 2		GT	DFO	N	WA	TK	0	11/74	01/15	78,750	60	80
	CT 3		GT	DFO	N	WA	TK	0	11/74	01/15	78,750	45	45
Bayside		Hillsborough											
		Co. 4/30S/19E									2,014,160	1,632	1,841
	1		CC	NG	N	PL	N	0	4/03	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									38,430	34	36
	1		IC	RFO	N	TK	N	0	06/83	Unknown	19,215	17	18
	2		IC	RFO	N	TK	N	0	06/83	Unknown	19,215	17	18
Polk		Polk Co.											
		2,3/32S/23E									677,839	580	628
	1		IGCC	BIT	DFO	WA/TK	TK	0	09/96	Unknown	326,299	255	260
	2 (a)		GT	NG	DFO	PL	TK	0	07/00	Unknown	175,770	160	184
	3 (a)		GT	NG	DFO	PL	TK	0	5/02	Unknown	175,770	165	184
Partnership		Hillsborough											
		Co. W30/29/19									5,800	6	6
	1		IC	NG	N	PL	N	0	04/01	Unknown	2,900	3	3
	2		IC	NG	N	PL	N	0	04/01	Unknown	2,900	3	3
											TOTAL	4,012	4,326

Notes: (a) Polk Units 2 & 3 turbine name plate rating are based on 59 deg. F. The net capacity of these units vary with ambient air temperature.

(b) Big Bend Unit 3 derated (summer 50 MW/ winter 50 MW) until December 2007 outage.

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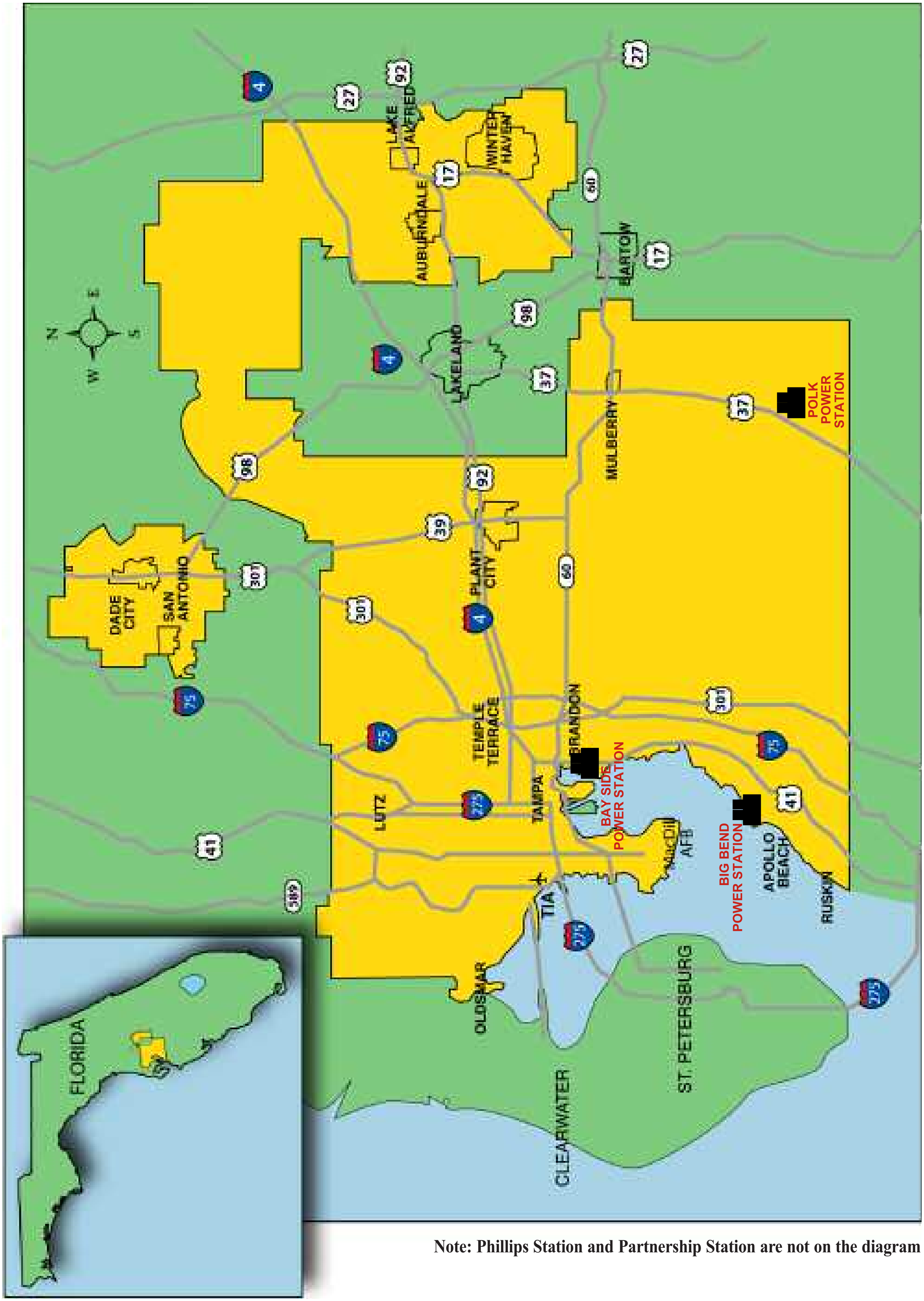
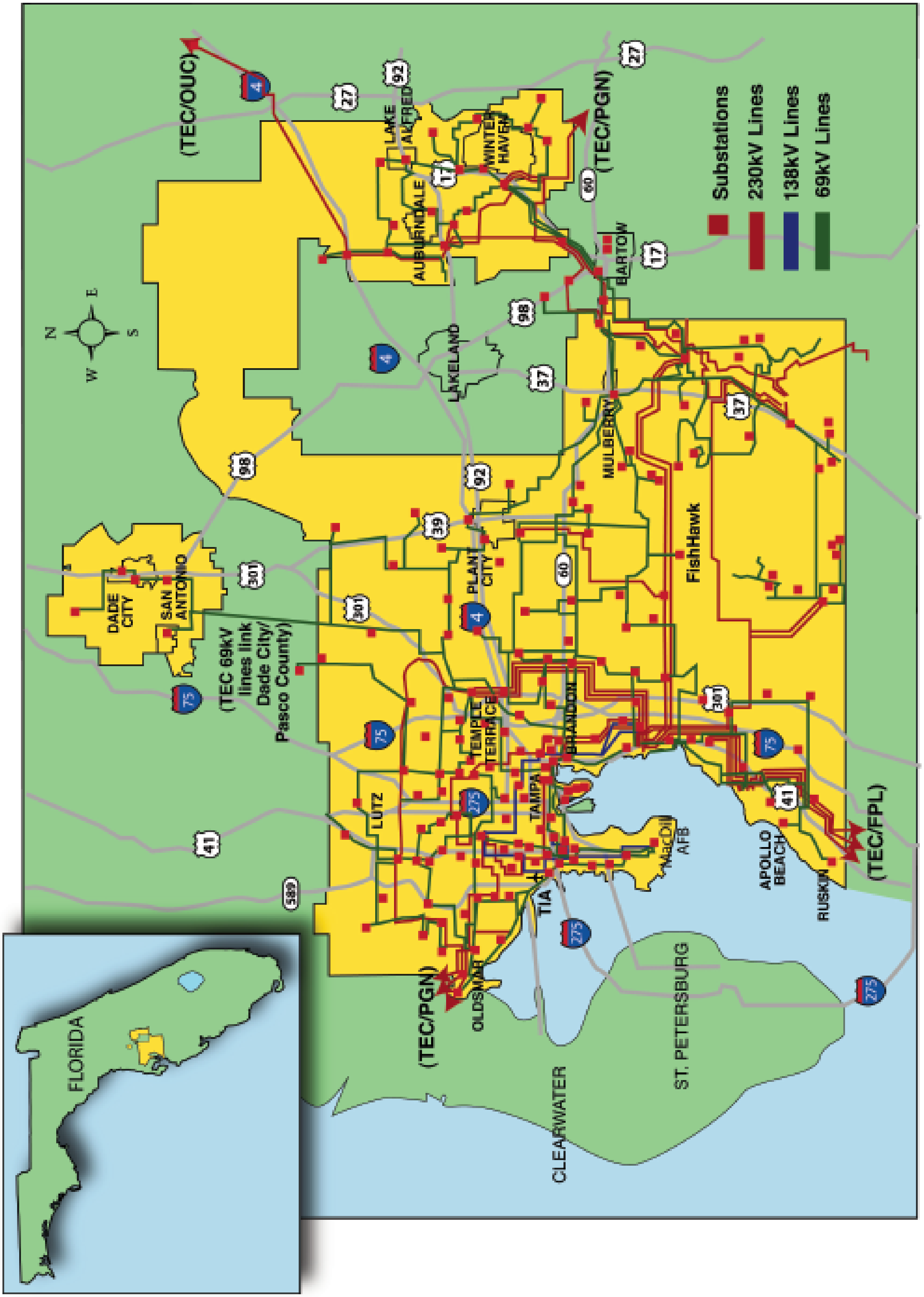
Tampa Electric Service Area & Generating Plant Map



Note: Phillips Station and Partnership Station are not on the diagram

Tampa Electric Service Area Transmission Facility



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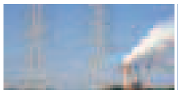
chapter 2



Forecast of Electric Power, Demand and Energy Consumption

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

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Schedule 3.1: History and Forecast of Summer Peak Demand

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Schedule 3.3: History and Forecast of Annual Net Energy for Load

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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
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	8,558	558,601	15,320	6,233	69,027	90,298
2006	1,161,959	2.5	8,721	575,111	15,164	6,357	70,205	90,549
2007	1,187,727	2.5	9,277	589,307	15,742	6,619	71,900	92,061
2008	1,214,066	2.5	9,570	603,394	15,861	6,800	73,327	92,737
2009	1,240,988	2.5	9,881	617,561	15,999	6,993	74,753	93,553
2010	1,267,305	2.5	10,192	631,430	16,142	7,189	76,153	94,408
2011	1,290,727	2.5	10,505	645,029	16,286	7,389	77,530	95,310
2012	1,314,377	2.5	10,829	659,079	16,431	7,592	78,927	96,186
2013	1,339,471	2.5	11,174	673,981	16,579	7,812	80,367	97,202
2014	1,362,985	2.5	11,525	689,615	16,713	8,040	81,842	98,238
2015	1,386,990	2.4	11,871	705,667	16,822	8,270	83,335	99,242
2016	1,408,645	2.4	12,240	721,830	16,957	8,504	84,830	100,253

December 31, 2006 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				Street &	Other Sales	Total Sales
			Average kWh	Railroads	Highway	to Public	to Ultimate
			Consumption	and Railways	Lighting	Authorities	Consumers
Year	GWH	Customers*	Per Customer	GWH	GWH	GWH	GWH
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	1,299	1,967,667	0	58	1,542	18,437
2005	2,478	1,337	1,853,403	0	60	1,582	18,911
2006	2,279	1,485	1,534,680	0	61	1,607	19,025
2007	2,323	1,441	1,612,337	0	63	1,690	19,972
2008	2,359	1,479	1,594,340	0	65	1,741	20,536
2009	2,394	1,532	1,562,794	0	67	1,795	21,130
2010	2,429	1,589	1,528,608	0	69	1,843	21,722
2011	2,461	1,647	1,494,129	0	70	1,888	22,313
2012	2,494	1,706	1,461,599	0	72	1,934	22,921
2013	2,525	1,768	1,428,175	0	74	1,983	23,568
2014	2,557	1,835	1,393,264	0	75	2,037	24,234
2015	2,589	1,907	1,357,578	0	77	2,093	24,900
2016	2,623	1,983	1,322,443	0	78	2,148	25,593

December 31, 2006 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
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	712	952	20,575	6,656	635,621
2006	700	1,000	20,725	6,905	653,706
2007	682	1,019	21,672	7,002	669,650
2008	665	1,047	22,248	7,166	685,366
2009	634	1,076	22,840	7,332	701,178
2010	616	1,107	23,445	7,494	716,666
2011	285	1,137	23,735	7,653	731,859
2012	222	1,167	24,310	7,816	747,528
2013	137	1,200	24,905	7,989	764,104
2014	78	1,234	25,547	8,169	781,462
2015	78	1,267	26,246	8,354	799,264
2016	79	1,302	26,974	8,540	817,184

December 31, 2006 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)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Year	Total *	Wholesale**	Retail *	Interruptible	Residential Load Management	Residential Conservation	Comm./Ind. Load Management	Comm./Ind. Conservation	Net Firm Demand
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	4,218	128	4,090	144	79	73	19	49	3,725
2006	4,265	128	4,137	146	77	77	18	50	3,769
2007	4,421	187	4,234	150	66	78	16	52	3,872
2008	4,542	187	4,355	150	63	80	17	53	3,991
2009	4,656	177	4,479	150	62	82	17	55	4,113
2010	4,780	177	4,603	150	61	84	18	56	4,235
2011	4,833	105	4,727	150	60	86	18	56	4,357
2012	4,962	105	4,856	150	59	87	19	57	4,484
2013	5,084	90	4,995	150	58	89	20	58	4,620
2014	5,217	77	5,141	150	58	90	20	58	4,765
2015	5,368	77	5,292	150	57	91	20	59	4,915
2016	5,522	77	5,445	150	56	92	20	59	5,068

December 31, 2006 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)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Year	Total *	Wholesale **	Retail *	Interruptible	Residential Load Management	Residential Conservation	Comm./Ind. Load Management	Comm./Ind. Conservation	Net Firm Demand
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	3,985	131	3,854	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	4,308	129	4,179	194	189	444	16	49	3,287
2005/06	4,404	171	4,233	51	144	447	18	50	3,523
2006/07	5,057	191	4,866	160	143	452	16	50	4,046
2007/08	5,185	191	4,994	160	134	455	16	51	4,178
2008/09	5,303	178	5,124	160	131	458	17	51	4,308
2009/10	5,436	178	5,257	160	128	461	17	52	4,440
2010/11	5,565	178	5,387	160	126	463	18	52	4,568
2011/12	5,627	107	5,520	160	124	465	18	52	4,700
2012/13	5,752	91	5,660	160	123	467	19	52	4,839
2013/14	5,887	77	5,810	160	121	469	19	53	4,988
2014/15	6,043	77	5,967	161	120	470	20	53	5,143
2015/16	6,203	77	6,126	160	118	471	20	53	5,304

December 31, 2006 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)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Year	Total	Residential Conservation	Comm./Ind. Conservation	Retail	Wholesale *	Utility Use & Losses	Net Energy for Load	Load ** Factor %
1997	15,430	279	61	15,090	507	731	16,328	57.5
1998	16,400	297	76	16,027	431	783	17,241	58.1
1999	16,212	315	92	15,805	533	900	17,238	55.1
2000	17,083	333	112	16,638	763	972	18,373	58.5
2001	17,444	346	122	16,976	684	794	18,454	53.3
2002	18,423	361	137	17,925	502	935	19,362	58.7
2003	18,756	378	152	18,226	587	985	19,799	56.4
2004	18,999	394	168	18,437	589	945	19,971	58.9
2005	19,491	404	176	18,911	712	952	20,575	57.3
2006	19,625	412	188	19,025	700	1000	20,725	57.2
2007	20,579	418	189	19,972	682	1019	21,672	54.3
2008	21,155	425	195	20,536	665	1047	22,248	54.1
2009	21,760	431	200	21,130	634	1076	22,840	54.4
2010	22,362	436	204	21,722	616	1107	23,445	54.4
2011	22,963	441	208	22,313	285	1137	23,735	53.7
2012	23,578	446	211	22,921	222	1167	24,310	54.2
2013	24,232	450	214	23,568	137	1200	24,905	54.3
2014	24,904	453	216	24,234	78	1234	25,547	54.4
2015	25,574	456	217	24,900	78	1267	26,246	54.3
2016	26,269	459	217	25,593	79	1302	26,974	54.1

December 31, 2006 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)
	2006 Actual		2007 Forecast		2008 Forecast	
Month	Peak Demand * MW	NEL ** GWH	Peak Demand * MW	NEL ** GWH	Peak Demand * MW	NEL ** GWH
January	3,204	1,546	4,555	1,629	4,679	1,691
February	3,906	1,410	3,746	1,443	3,852	1,483
March	2,952	1,518	3,528	1,600	3,626	1,630
April	3,587	1,639	3,496	1,584	3,591	1,621
May	3,753	1,831	3,982	1,922	4,088	1,971
June	3,951	1,967	4,174	2,022	4,285	2,070
July	4,046	2,040	4,300	2,178	4,416	2,227
August	4,138	2,135	4,291	2,205	4,408	2,246
September	3,840	1,915	4,141	2,036	4,254	2,082
October	3,665	1,732	3,866	1,869	3,974	1,920
November	3,128	1,468	3,504	1,550	3,605	1,600
December	2,799	1,526	3,748	1,634	3,855	1,707
TOTAL		20,725		21,673		22,248

December 31, 2006 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		**Unit**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**
(1)	**Nuclear**		**Trillion BTU**	0	0	0	0	0	0	0	0	0	0	0	0
(2)	**Coal**		**1000 Ton**	4,072	4,637	4,344	4,241	4,220	4,175	4,358	4,349	4,754	4,630	4,652	4,718
(3)	**Residual**	**Total**	**1000 BBL**	110	47	28	9	2	1	5	5	1	2	3	3
(4)		**Steam**	**1000 BBL**	0	0	0	0	0	0	0	0	0	0	0	0
(5)		**CC**	**1000 BBL**	0	0	0	0	0	0	0	0	0	0	0	0
(6)		**CT**	**1000 BBL**	0	0	0	0	0	0	0	0	0	0	0	0
(7)		**Diesel** (A)	**1000 BBL**	110	47	28	9	2	1	5	5	1	2	3	3
(8)	**Distillate**	**Total**	**1000 BBL**	116	78	90	96	91	88	97	92	94	94	88	96
(9)		**Steam**	**1000 BBL**	0	0	0	0	0	0	0	0	0	0	0	0
(10)		**CC**	**1000 BBL**	75	71	87	91	89	86	91	85	91	91	86	91
(11)		**CT**	**1000 BBL**	42	7	3	6	2	2	6	7	3	3	3	4
(12)		**Diesel**	**1000 BBL**	0	0	0	0	0	0	0	0	0	0	0	0
(13)	**Natural Gas**	**Total**	**1000 MCF**	54,391	51,740	58,109	60,105	60,802	60,980	62,032	64,522	49,804	54,118	58,466	65,421
(14)		**Steam**	**1000 MCF**	0	0	0	0	0	0	0	0	0	0	0	0
(15)		**CC**	**1000 MCF**	53,166	49,823	57,179	58,255	60,089	59,636	58,662	60,383	47,988	51,354	54,247	58,660
(16)		**CT**	**1000 MCF**	1,225	1,917	931	1,850	714	1,344	3,370	4,139	1,817	2,764	4,219	6,761
(17)	**Other (Specify)**														
(18)	**Petroleum Coke**		**1000 Ton**	362	383	519	637	625	617	651	623	2010	2005	2037	1882

* Values shown may be affected due to rounding.
** All values exclude ignition.
(A) Phillips Unit 3 retired March 2006, data reported as diesel for Phillips Units 1 and 2.

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		Unit	Actual 2005	Actual 2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
(1)	Annual Firm Interchange		GWH	209	369	785	347	206	269	588	712	288	324	313	303
(2)	Nuclear		GWH	0	0	0	0	0	0	0	0	0	0	0	0
(3)	Coal		GWH	8,705	9,906	9,398	9,285	9,144	9,021	9,447	9,367	10,249	9,963	10,017	10,162
(4)	Residual	Total	GWH	71	29	18	6	1	1	3	3	1	1	2	2
(5)		Steam	GWH	0	0	0	0	0	0	0	0	0	0	0	0
(6)		CC	GWH	0	0	0	0	0	0	0	0	0	0	0	0
(7)		CT	GWH	0	0	0	0	0	0	0	0	0	0	0	0
(8)		Diesel (A)	GWH	71	29	18	6	1	1	3	3	1	1	2	2
(9)	Distillate	Total	GWH	64	45	49	52	49	48	53	49	51	51	48	52
(10)		Steam	GWH	0	0	0	0	0	0	0	0	0	0	0	0
(11)		CC	GWH	47	42	48	50	49	47	50	47	50	50	47	50
(12)		CT	GWH	18	2	1	2	1	1	3	3	1	2	1	2
(13)		Diesel	GWH	0	0	0	0	0	0	0	0	0	0	0	0
(14)	Natural Gas	Total	GWH	7,567	7,136	8,020	8,254	8,416	8,414	8,451	8,775	6,814	7,373	7,934	8,811
(15)		Steam	GWH	0	0	0	0	0	0	0	0	0	0	0	0
(16)		CC	GWH	7,461	6,971	7,942	8,098	8,357	8,294	8,157	8,411	6,662	7,130	7,530	8,153
(17)		CT	GWH	106	165	78	156	59	120	294	364	152	243	404	658
(18)	Other (Specify)														
(19)	Petroleum Coke Generation		GWH	955	1,011	1,368	1,681	1,651	1,631	1,720	1,644	5,807	5,794	5,899	5,422
(20)	Net Interchange		GWH	2,470	1,654	1,508	2,097	2,845	3,695	3,157	3,538	1,475	1,820	1,812	2,012
(21)	Purchased Energy from														
(22)	Non-Utility Generators		GWH	534	576	526	527	526	366	317	222	221	221	221	208
(23)	Net Energy for Load*		GWH	20,575	20,725	21,671	22,248	22,839	23,444	23,736	24,309	24,906	25,547	26,246	26,972

* Values shown may be affected due to rounding.
(A) Phillips Unit 3 retired March 2006, data reported as diesel for Phillips Units 1 and 2.

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)
					Actual	Actual										
	Energy Sources			Unit	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
(1)	Annual Firm Interchange			%	1.0	1.8	3.6	1.6	0.9	1.1	2.5	2.9	1.2	1.3	1.2	1.1
(2)	Nuclear			%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(3)	Coal			%	42.3	47.8	43.4	41.7	40.0	38.5	39.8	38.5	41.1	39.0	38.2	37.7
(4)	Residual	Total		%	0.3	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(5)		Steam		%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(6)		CC	(A)	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(7)		CT		%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(8)		Diesel		%	0.3	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(9)	Distillate	Total		%	0.3	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
(10)		Steam		%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(11)		CC		%	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
(12)		CT		%	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(13)		Diesel		%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(14)	Natural Gas	Total		%	36.8	34.4	37.0	37.1	36.8	35.9	35.6	36.1	27.4	28.9	30.2	32.7
(15)		Steam		%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(16)		CC		%	36.3	33.6	36.6	36.4	36.6	35.4	34.4	34.6	26.7	27.9	28.7	30.2
(17)		CT		%	0.5	0.8	0.4	0.7	0.3	0.5	1.2	1.5	0.6	1.0	1.5	2.4
(18)	Other (Specify)															
(19)	Petroleum Coke Generation			%	4.6	4.9	6.3	7.6	7.2	7.0	7.2	6.8	23.3	22.7	22.5	20.1
(20)	Net Interchange			%	12.0	8.0	7.0	9.4	12.5	15.8	13.3	14.6	5.9	7.1	6.9	7.5
(21)	Purchased Energy from															
(22)	Non-Utility Generators			%	2.6	2.8	2.4	2.4	2.3	1.6	1.3	0.9	0.9	0.9	0.8	0.8
(23)	Net Energy for Load*			%	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0

* Values shown may be affected due to rounding.
(A) Phillips Unit 3 retired March 2006, data reported as diesel for Phillips Units 1 and 2.

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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 2007-2016 forecasts. The data tables in Chapter II outline the expected customer, demand, and energy values for the 2007-2016 time period.

Retail Load

MetrixND, an advanced statistics program for analysis and forecasting, was used to develop the 2007-2016 Customer, Demand and Energy forecasts. This software provides 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. Demand Side Management 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 2007-2026 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 <u>Commercial Customer Model</u> 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 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 large scaled commercial customers.

c. The General Service Large Demand Customer Model is a function of Hillsborough County Manufacturing Employment.

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**.

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

Where:

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

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

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

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:

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

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

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

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

$$\text{HeatUse}_{y,m}$$

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

$$\text{CoolUse}_{y,m}$$

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

$$\text{OtherUse}_{y,m}$$

$$\left(\frac{\text{Price}_{y,m}}{\text{Price}_{\text{base } y,m}}\right)^{-.30} \times \left(\frac{\text{HH Income}_{y,m}}{\text{HH Income}_{\text{base } y,m}}\right)^{.30} \times \left(\frac{\text{HH Size}_{y,m}}{\text{HH Size}_{\text{base } y,m}}\right)^{.25} \times \left(\frac{\text{Billing Days}_{y,m}}{\text{Billing Days}_{\text{base } y,m}}\right)$$

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. <u>Commercial Energy Model</u>: 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 an Industrial Production Manufacturing Index 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. Demand Side 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. Commercial and industrial programs are offered. Although Tampa Electric's residential program is currently closed to new participants, the company had over 57,000 participating customers through December 31, 2006.
3. Energy Audits - The program is a "how to" information and analysis guide for customers. Five types of audits are available to Tampa Electric customers; three types are for residential class customers and two types for commercial/industrial customers.
4. Ceiling Insulation - An incentive program for existing residential structures which will help to supplement the cost of adding additional insulation.
5. Commercial Indoor Lighting - Encourages investment in more efficient lighting technologies within existing commercial facilities.
6. Standby Generator - A program designed to utilize the emergency generation capacity of commercial/industrial facilities in order to reduce weather sensitive peak demand.
7. Conservation Value - Encourages investments in measures that are not sanctioned by other commercial programs.
8. Duct Repair - An incentive program for existing homeowners which will help to supplement the cost of repairing leaky ductwork of central air–conditioning systems.
9. Cogeneration - A program whereby large industrial customers with waste heat or fuel resources may install electric generating equipment, meet their

own electrical requirements and/or sell their surplus to the company.

10. Commercial Cooling - Encourages the installation of high efficiency direct expansion commercial cooling equipment.
11. Energy Plus Homes - Encourages the construction of residential dwellings at efficiency levels greater than current Florida building code baseline practices.
12. Price Responsive Load Management (pilot) – A load management project designed to reduce weather sensitive peak loads by offering a multi-tiered rate structure as an incentive for participating customers to reduce their electric demand during high cost or critical periods of generation.

The programs listed above were developed to meet the FPSC demand and energy goals established in Docket No. 040033-EG, approved on August 9, 2004. The 2005 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.

Although Tampa Electric is exceeding its current DSM goals, the company is currently undertaking several steps to determine what, if any, additional conservation and load management offerings can be made available to its customers in an effort to further advance the five objectives previously stated. This effort is being driven by recent increased avoided generating unit and fuel costs. Specifically, Tampa Electric is systematically conducting the following evaluations:

1. Reviewing a full complement of residential and commercial DSM measures for cost-effectiveness and possible inclusion into a program offering to customers;
2. Utilizing M&E data to assist in the evaluation of all current programs to determine if incentive structures and program delivery mechanisms may be modified to secure additional customer participation;
3. Conducting an exhaustive review of DSM programs offered by other utilities in similar climate zones to determine their applicability in Tampa Electric's service area;
4. Exploring demand response as a viable commercial offering; and,
5. Gathering data from field personnel concerning energy consumption issues from the customer's perspective and determining the potential for cost-effective DSM solutions.

Tampa Electric's residential pilot program, Price Responsive Load Management, is a demand response program that has shown great promise for load shifting and energy conservation. The company is in the final phase of preparing to request Commission approval to offer the program on a permanent basis. It is anticipated the program offering will be available to customers by third quarter 2007.

Wholesale Load

Tampa Electric's firm long-term wholesale sales consist of five (5) 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 and 2) average usage forecast. The peak models for these two cities use sales forecast trend variables

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
2005	4.2	4.0	105.0%	2.8	2.4	116.7%	7.7	7.0	110.0%
2006	8.2	6.7	122.4%	6.1	4.4	138.6%	16.3	12.6	129.4%

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
2005	3.4	1.0	340.0%	4.3	2.1	204.8%	7.9	6.7	117.9%
2006	3.8	2.0	190.0%	5.8	4.4	131.8%	15.3	12.8	119.5%

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
2005	7.6	5.0	152.0%	7.1	4.5	157.8%	15.6	13.7	113.9%
2006	12.0	8.7	137.9%	11.9	8.8	135.2%	31.6	25.4	124.4%

and heating and cooling degree variables as inputs.

Florida Municipal Power Agency will commence serving City of Fort Meade's electric load on January 1, 2009 and will include the city's load in its 2007 Ten-Year Site Plan. Tampa Electric will continue to serve the City of Fort Meade's electric load through December 31, 2008.

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

Base Case Forecast Assumptions

Retail Load

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. Real Household 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 population forecast is based upon the projections of BEBR in the short term and is a blend in the long term of BEBR and Economy.com. Over the next ten years (2007-2016) the average annual population growth rate in both Hillsborough County and Florida is expected to be 2%. In addition, Economy.com provides household data as 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 3% average annual rate. Economy.com supplies employment projections.

3. Commercial, Industrial and Governmental Output

In addition to employment, output in terms of real gross domestic product by employment sector is utilized in computing energy in their respective sectors. Over the next ten years, output for the entire employment sector is assumed to rise at a 4.8% average annual rate. Economy.com supplies output projections.

4. Real Household Income

Economy.com supplies the assumptions for Hillsborough County's real household income growth. During 2007-2016, real household income for Hillsborough County is expected to increase at a 1.6% 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 Focus

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 2007-2016, retail energy sales are projected to rise at a 2.8% annual rate. The major contributor to growth is the residential category, increasing at an annual rate of 3.1%.

Wholesale Energy

Wholesale energy sales to Progress Energy Florida, Wauchula, Ft. Meade, St. Cloud, and Reedy Creek are expected to be 682 GWH in 2007. In 2011, sales drop substantially to 285 GWH and continue to decline to 137 GWH in 2013 and 78 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 2007-2016 period, Tampa Electric's base case retail firm peak demand for winter and summer are expected to advance at annual rates of 3.1% and 3.0% respectively.

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, balancing engineering concerns and other issues. To meet the expected system demand and energy requirements over the next ten years both peaking and base load capacity is needed. The peaking capacity need will be met by self-build and peaking power purchases throughout the ten year planning period. The base load capacity needs will be met by building one integrated coal gasification combined cycle unit planned for 2013. The operating and cost parameters associated with the capacity additions resulting from the analysis are shown in Schedule 8.

As the construction start dates for each scheduled unit approaches, Tampa Electric will continue to look for competitive purchased power agreements that may replace or delay the planned unit additions. Such alternatives will be considered, if they are better suited to 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 and in Chapter V.

In the fall of 2006 Tampa Electric solicited offers for peaking generation as an alternative to scheduled units through a Request for Proposal (RFP). The overriding objective of this RFP was to solicit bids for competitive resources that provide Tampa Electric with reliable and cost-effective capacity alternatives to satisfy its projected capacity requirements. The RFP was open to products within the Florida Reliability Coordinating Council (FRCC) North American Electric Reliability Council (NERC) Region as well as products originating outside of the FRCC given that the seller obtained the appropriate firm transmission service(s) to assure delivery. Tampa Electric requested proposals from all potential suppliers capable of satisfying the conditions of the RFP, including other electric utilities, power marketers, exempt wholesale generators, independent power producers, and qualifying facilities.

Through the RFP, Tampa Electric Company was seeking power supply proposals to meet its requirements for electric generating capacity and associated energy commencing on January 1, 2009, which provided the best value to its customers based on cost, reliability, and flexibility. In the RFP, Tampa Electric solicited proposals for peaking capacity and associated energy in the amounts, and during the time periods, described in the table below:

COMMENCEMENT DATE	REQUESTED CAPACITY AMOUNTS (MW)	CUMULATIVE CAPACITY AMOUNTS REQUESTED (MW)
January 1, 2009	Up to 150	150
January 1, 2010	Up to 175	325
May 1, 2011	Up to 235	560
May 1, 2012 and beyond	Up to 170	730

Tampa Electric received numerous offers for both existing and new generation. The offers were first prioritized based on their economic viability to offset or delay Tampa Electric self build generation. Factors used in determining this viability included capacity charge, fuel costs, variable and fixed operations and maintenance costs, startup costs and other charges associated with the offers. Several of the highest ranked offers were determined to be potentially cost effective alternatives to Tampa Electric self build options. Tampa Electric conducted a detailed cost analysis for each of these highest ranked offers using PROMOD, an economic dispatch model, in conjunction with an incremental capital revenue requirement calculation. Tampa Electric found several alternatives that demonstrated a benefit to Tampa Electric's customers through a combination of fuel savings and the offset or delay of Tampa Electric's next scheduled self build unit(s). Tampa Electric is currently in negotiation with these parties with the intent to complete purchased power agreements for the generation. The need expected to be filled as a result of this RFP is approximately 168 MW in the winter and 158 MW in the summer starting 2009 through 2011 and an additional 168 MW in the winter and 158 MW in the summer starting in May 1, 2011. Tampa Electric expects to complete negotiation of purchase power agreements during the second quarter of 2007.

IGCC Technology

In 1996, Tampa Electric began commercial operation of the Polk Power Station, originally a 260-megawatt Integrated Gasification Combined Cycle power plant. Operational improvements developed by Tampa Electric and the cost of fuel make the Polk IGCC Unit the most economical unit on Tampa Electric's system. Polk Unit 1 has inherently low environmental emissions due to the IGCC technology. Polk Unit 6 will have even lower emissions than Polk 1 and will also be designed to be carbon capture ready. Because Polk Unit 1 has established IGCC as a clean, economical and reliable technology, IGCC technology is the logical candidate for future baseload needs. In addition to these factors, fuel diversity is also an important consideration for future baseload generation. Tampa Electric has recognized and responded to federal and state fuel diversity concerns. Both the federal government through the Energy Policy Act of 2005 and the state of Florida through the 2006 Florida Energy Plan have recognized the benefits of fuel diversity and advancing electric generation technology. One method by which the federal government has addressed concerns regarding fuel diversity has been to encourage the development of advanced clean-coal technologies. In 2006, the Internal Revenue Service and U. S. Department of Energy awarded Tampa Electric $133 million in tax credits for a proposed 630 megawatt IGCC project to be built at the company's Polk Power Station.

Tampa Electric's 2006 fuel mix on a capacity basis was 53% Coal/Pet Coke, 44% Natural Gas related resources, and 0.3% Oil. If Tampa Electric future generation needs were met with only natural gas fuel generation the fuel mix in 2013 would be 45% Coal/Pet Coke, 54% Natural Gas related resources, and 0.3% Oil. This would represent an increasing reliance on natural gas for the production of electricity. Although natural gas generation offers relatively low capital cost, high efficiency and good environmental performance, continued capacity expansion relying only on this technology would put Tampa Electric's electric generation at significant exposure to those risks inherent with the natural gas commodity. Some of the risks include price volatility, delivery disruptions and long term price exposure. In contrast, Tampa Electric's 2013 proposed expansion plan fuel mix is 64% Coal/Pet Coke, 35% Natural Gas related resources, and 0.2% Oil. This mix reflects a more balanced fuel mix and will result in reduced exposure and less reliance on a single commodity.

Cogeneration

Tampa Electric plans for 427 MW of cogeneration capacity operating in its service area in 2007. Self-service capacity of 212 MW is used by cogenerators to serve internal load requirements, 65 MW are purchased by Tampa Electric on a firm contract basis, and 14 MW are purchased on a non-firm, as-available basis. The remaining 136 MW of cogeneration capacity is forecasted 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 has a generation portfolio consisting of coal and natural gas for its generating requirements. Tampa Electric has firm transportation contracts with the Florida Gas Transmission Company (FGT) and Gulfstream Natural Gas System LLC for delivery of natural gas to the Bayside and Polk Units. As shown in Schedule 6.2, in 2007 coal and pet coke will fuel 50% of net energy for load and natural gas will fuel 37%. 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 met by purchases from 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 February 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. Since 1998, Tampa Electric has to date reduced annual sulfur dioxides (SO_2), nitrogen oxides (NOx), and particulate matter (PM) emissions from our facilities by 161,000 tons, 41,000 tons, and 4,000 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 NOx 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.

Reductions in particulate matter were accomplished through the use of electrostatic precipitators, which remove 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 NOx 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 NOx 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 62,000 tons per year of additional NOx reduction. In total, Tampa Electric's emission reduction initiatives will result in the reduction of SO_2, NOx and PM emissions by 89%, 90%, 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. As a result of all its already completed emission reduction actions and upon completion of planned controls, Tampa Electric will have achieved emission reduction levels contained in the Clean Air Interstate Rule (CAIR) Phase I requirements, the Clean Air Mercury Rule (CAMR) Phase I requirements and be positioned for other potential future emission control requirements.

Interchange Sales and Purchases

Tampa Electric's long-term firm sale agreements include Progress Energy Florida for 70 MW and Reedy Creek Improvement District for 75 MW as well as the cities of Ft. Meade for 12 MW, St. Cloud for 15 MW and Wauchula for 15 MW. Tampa Electric also has a firm sales agreement to New Smyrna Beach of 10 MW for January 2006 through December 31, 2007.

Tampa Electric has a long-term purchased power contract for capacity and energy from the Hardee Power Station owned by 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. Under the existing contract Tampa Electric also has the right to purchase an additional 88 MW winter and 69 MW summer of firm non-shared capacity from the Hardee Power Station.

Tampa Electric also entered into a firm purchased power agreement with Progress Energy Florida for 50 MW from January 1, 2006 through March 31, 2007; the contract was extended through November 31, 2007 at an increase of 25 MW for a total of 75 MW. For the winter of 2007, Tampa Electric has purchased power agreements of 50 MW and 40 MW with Cargill Power Markets and New Hope Power Partnership, respectively. In addition, Tampa Electric has an agreement with Calpine Energy Services for 170 MW from May 1, 2006 through April 30, 2011. Tampa Electric has completed a term sheet for the purchase of 115 MW from Pasco Cogen for the period January 1, 2009 to December 31, 2018.

As a result of an existing purchased power agreement ending in 2011, Tampa Electric has a 170 MW need extending through 2016. Additionally, in the summer of 2011 through 2016 Tampa Electric has a need of 160 MW as well as spot purchases of 70 MW and 25 MW during the summers of 2012 and 2016, respectively. In the winters of 2012 and 2013, Tampa Electric has a need of 180 MW and 172 MW extending throughout the study period.

Tampa Electric determined that it has a capacity need during the winters of 2008, 2009 and 2010. The capacity need is 135 MW for 2008, 155 MW for 2009 and 170 MW for 2010. This capacity need is for the completion of the SCR system installations by the required Consent Decree. Big Bend units 1, 2, and 3 will be down in consecutive years for the scheduled work from January through mid-April in 2008, 2009 and 2010.

As discussed earlier in this section, Tampa Electric will seek to satisfy these capacity needs for the given years by contracting power from one or more entities. 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
2007	4,281	601	10	65	4,937	4,057	880	22%	0	880	22%
2008	4,332	684	0	65	5,081	4,176	905	22%	0	905	22%
2009	4,332	799	0	65	5,196	4,299	897	21%	0	897	21%
2010	4,461	799	0	42	5,302	4,421	881	20%	0	881	20%
2011	4,461	959	0	42	5,462	4,472	990	22%	0	990	22%
2012	4,461	1,026	0	23	5,510	4,599	911	20%	0	911	20%
2013	5,066	600	0	23	5,689	4,720	969	21%	0	969	21%
2014	5,242	600	0	23	5,865	4,841	1,024	21%	0	1,024	21%
2015	5,389	600	0	23	6,012	4,991	1,021	20%	0	1,021	20%
2016	5,565	625	0	0	6,190	5,144	1,046	20%	0	1,046	20%

NOTE:

1. Capacity import includes firm purchase power agreements with Invenergy of 356 MW from 2006 through 2012, 50 MW through March,2007 increasing to 75 MW through November,2007 from Progress Energy Florida and 170 MW from Calpine from May 2006 through April 2011. Pasco Cogen for 115 MW from 2009 through 2018. TEC has issued a Request for Proposal(RFP) for peaking power from 2008 through 2011 for 158 MW in the summer. Unspecified purchased power of 160 MW is needed beginning in the summer of 2011 through 2016 as well as a purchase of 155 MW beginning in the summer of 2012 through 2016. Unspecified purchased power of 170 MW is needed beginning in the summer of 2011 through 2016 as well as spot market purchases of 70 MW and 25 MW for the summers of 2012 and 2016.
2. The QF column accounts for cogeneration that will be purchased under firm contracts.
3. Big Bend CT 1, 2, and 3 will be retired January 1, 2015.

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
2006-07	4,276	844	10	65	5,175	4,233	942	22%	0	942	22%
2007-08	4,686	914	0	65	5,665	4,365	1,300	30%	423	867	20%
2008-09	4,686	1,049	0	65	5,800	4,496	1,304	29%	401	913	20%
2009-10	4,827	1,064	0	65	5,956	4,628	1,328	29%	401	917	20%
2010-11	4,827	894	0	42	5,763	4,756	1,007	21%	0	1,007	21%
2011-12	4,827	1,074	0	23	5,924	4,817	1,107	23%	0	1,107	23%
2012-13	5,457	637	0	23	6,117	4,941	1,176	24%	0	1,176	24%
2013-14	5,457	637	0	23	6,117	5,064	1,053	21%	0	1,053	21%
2014-15	5,610	637	0	23	6,270	5,220	1,050	20%	0	1,050	20%
2015-16	5,804	637	0	0	6,441	5,380	1,061	20%	0	1,061	20%

NOTE:

1. Capacity import includes firm purchase power agreements with Invenergy of 441 MW from 2006 through 2012, Progress Energy Florida of 50 MW through March, 2007 increasing to 75 MW through November,2007 and Calpine of 170 MW from May 2006 through April 2011. Winter of 2007 purchases of 50 MW and 40 MW from Cargill and New Hope Power Partnership. Unspecified purchased power of 135 MW is expected to be needed for the installation of the Selective Catalytic Reduction (SCR) equipment on Big Bend 3 in 2008, a purchase of 155 MW in 2009 for Big Bend 2 and a purchase of 170 MW for Big Bend 1 in 2010. Pasco Cogen for 115 MW from 2009 through 2018. TEC has issued a Request for Proposal(RFP) for peaking power from 2008 through 2012 for 168 MW in the winter. Unspecified purchase power of 180 MW is needed in the winter of 2012 through 2016. Unspecified purchase power of 172 MW is needed in the winter of 2013 through 2016.
2. The QF column accounts for cogeneration that will be purchased under firm contracts.
3. Big Bend CT 1, 2, and 3 will be retired January 1, 2015.

* Values may be affected due to rounding.

Schedule 8

Planned and Prospective Generating Facility Additions

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
				Fuel		Fuel Trans.		Const. Start	Commercial In-Service	Expected Retirement	Gen. Max. Nameplate	Net Capability		
Plant Name	Unit No.	Location	Unit Type	Primary	Alternate	Primary	Alternate	Mo/Yr	Mo/Yr	Mo/Yr	kW	Summer MW	Winter MW	Status
Future CT*	1	unknown	GT	NG	DFO	PL	TK	1/09	1/10	unknown	unknown	43	47	P
Future CT*	2	unknown	GT	NG	NA	PL	NA	1/09	1/10	unknown	unknown	43	47	P
Future CT*	3	unknown	GT	NG	NA	PL	NA	1/09	1/10	unknown	unknown	43	47	P
Polk IGCC	6	Polk	IGCC	BIT	NG	WA	PL	1/09	1/13	unknown	unknown	605	630	P
Future CT	4	unknown	GT	NG	NA	PL	NA	1/13	5/14	unknown	unknown	88	97	P
Future CT	5	unknown	GT	NG	NA	PL	NA	1/13	5/14	unknown	unknown	88	97	P
Future CT	6	unknown	GT	NG	NA	PL	NA	5/13	1/15	unknown	unknown	88	97	P
Future CT	7	unknown	GT	NG	NA	PL	NA	1/14	5/15	unknown	unknown	88	97	P
Future CT	8	unknown	GT	NG	NA	PL	NA	1/14	5/15	unknown	unknown	88	97	P
Future CT	9	unknown	GT	NG	NA	PL	NA	1/15	5/16	unknown	unknown	88	97	P
Future CT	10	unknown	GT	NG	NA	PL	NA	1/15	5/16	unknown	unknown	88	97	P

* The future CT additions slated for 2010 are GE LM6000 technology all other future CT expansion are GE LMS 100 technology.

SCHEDULE 9
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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	43
	B. WINTER	47
(3)	TECHNOLOGY TYPE	COMBUSTION TURBINE
(4)	ANTICIPATED CONSTRUCTION TIMING	
	A. FIELD CONSTRUCTION START DATE	JAN 2009
	B. COMMERCIAL IN-SERVICE DATE	JAN 2010
(5)	FUEL	
	A. PRIMARY FUEL	NATURAL GAS
	B. ALTERNATE FUEL	DISTILLATE FUEL OIL
(6)	AIR POLLUTION CONTROL STRATEGY	DRY LOW NOX 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)	0.8
	FORCED OUTAGE RATE (FOR)	4.0
	EQUIVALENT AVAILABILITY FACTOR (EAF)	94.0
	RESULTING CAPACITY FACTOR (2010)	4.8%
	AVERAGE NET OPERATING HEAT RATE (ANOHR) 1	9,792 Btu/kWh
(13)	PROJECTED UNIT FINANCIAL DATA	
	BOOK LIFE (YEARS)	26
	TOTAL INSTALLED COST (IN-SERVICE YEAR $/kW)	760.51
	DIRECT CONSTRUCTION COST ($/kW)	674.12
	AFUDC AMOUNT ($/kW)	63.49
	ESCALATION ($/kW)	22.90
	FIXED O&M ($/kW – Yr)	9.50
	VARIABLE O&M ($/MWH)	2.91
	K FACTOR	1.5983

1 BASED ON IN-SERVICE YEAR.

SCHEDULE 9
(Page 2 of 11)
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	43
	B. WINTER	47
(3)	TECHNOLOGY TYPE	COMBUSTION TURBINE
(4)	ANTICIPATED CONSTRUCTION TIMING	
	A. FIELD CONSTRUCTION START DATE	JAN 2009
	B. COMMERCIAL IN-SERVICE DATE	JAN 2010
(5)	FUEL	
	A. PRIMARY FUEL	NATURAL GAS
	B. ALTERNATE FUEL	N/A
(6)	AIR POLLUTION CONTROL STRATEGY	DRY LOW NOX 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)	0.8
	FORCED OUTAGE RATE (FOR)	4.0
	EQUIVALENT AVAILABILITY FACTOR (EAF)	94.0
	RESULTING CAPACITY FACTOR (2010)	4.8%
	AVERAGE NET OPERATING HEAT RATE (ANOHR) 1	9,792 Btu/kWh
(13)	PROJECTED UNIT FINANCIAL DATA	
	BOOK LIFE (YEARS)	26
	TOTAL INSTALLED COST (IN-SERVICE YEAR $/kW)	760.51
	DIRECT CONSTRUCTION COST ($/kW)	674.12
	AFUDC AMOUNT ($/kW)	63.49
	ESCALATION ($/kW)	22.90
	FIXED O&M ($/kW – Yr)	9.50
	VARIABLE O&M ($/MWH)	2.91
	K FACTOR	1.5983

1 BASED ON IN-SERVICE YEAR.

SCHEDULE 9
(Page 3 of 11)
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	43
	B. WINTER	47
(3)	TECHNOLOGY TYPE	COMBUSTION TURBINE
(4)	ANTICIPATED CONSTRUCTION TIMING	
	A. FIELD CONSTRUCTION START-DATE	JAN 2009
	B. COMMERCIAL IN-SERVICE DATE	JAN 2010
(5)	FUEL	
	A. PRIMARY FUEL	NATURAL GAS
	B. ALTERNATE FUEL	UNDETERMINED
(6)	AIR POLLUTION CONTROL STRATEGY	DRY LOW NOX 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)	0.8
	FORCED OUTAGE RATE (FOR)	4.0
	EQUIVALENT AVAILABILITY FACTOR (EAF)	94.0
	RESULTING CAPACITY FACTOR (2010)	4.8%
	AVERAGE NET OPERATING HEAT RATE (ANOHR) 1	9,792 Btu/kWh
(13)	PROJECTED UNIT FINANCIAL DATA	
	BOOK LIFE (YEARS)	26
	TOTAL INSTALLED COST (IN-SERVICE YEAR $/kW)	760.51
	DIRECT CONSTRUCTION COST ($/kW)	674.12
	AFUDC AMOUNT ($/kW)	63.49
	ESCALATION ($/kW)	22.90
	FIXED O&M ($/kW – Yr)	9.50
	VARIABLE O&M ($/MWH)	2.91
	K FACTOR	1.5983

1 BASED ON IN-SERVICE YEAR.

SCHEDULE 9
(Page 4 of 11)
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
UTILITY: TAMPA ELECTRIC COMPANY

(1)	PLANT NAME AND UNIT NUMBER	FUTURE IGCC
(2)	CAPACITY	
	A. SUMMER	605
	B. WINTER	630
(3)	TECHNOLOGY TYPE	INTERGRATED COAL GASIFICATION COMBINED CYCLE
(4)	ANTICIPATED CONSTRUCTION TIMING	
	A. FIELD CONSTRUCTION START DATE	JAN 2009
	B. COMMERCIAL IN-SERVICE DATE	JAN 2013
(5)	FUEL	
	A. PRIMARY FUEL	COAL / PETCOKE
	B. ALTERNATE FUEL	NATURAL GAS
(6)	AIR POLLUTION CONTROL STRATEGY	SYNGAS SATURATION DILUENT NITROGEN
(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)	7.4
	FORCED OUTAGE RATE (FOR)	5.0
	EQUIVALENT AVAILABILITY FACTOR (EAF)	85.1
	RESULTING CAPACITY FACTOR (2013)	88.5%
	AVERAGE NET OPERATING HEAT RATE (ANOHR) 1	9,304 Btu/kWh
(13)	PROJECTED UNIT FINANCIAL DATA	
	BOOK LIFE (YEARS)	26
	TOTAL INSTALLED COST (IN-SERVICE YEAR $/kW)[2]	3,180.30
	DIRECT CONSTRUCTION COST ($/kW)[2]	2,555.56
	AFUDC AMOUNT ($/kW)[2]	375.41
	ESCALATION ($/kW)	249.34
	FIXED O&M ($/kW – Yr)	37.68
	VARIABLE O&M ($/MWH)	0.83
	K FACTOR	1.5983

1 BASED ON IN-SERVICE YEAR.

2 PRELIMINARY COST ESTIMATE SUBJECT TO CHANGE BASED ON OVERNIGHT CONSTRUCTION COST $1.6 BILLION

SCHEDULE 9
(Page 5 of 11)
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
UTILITY: TAMPA ELECTRIC COMPANY

(1)	PLANT NAME AND UNIT NUMBER	FUTURE CT 4
(2)	CAPACITY	
	A. SUMMER	88
	B. WINTER	97
(3)	TECHNOLOGY TYPE	COMBUSTION TURBINE
(4)	ANTICIPATED CONSTRUCTION TIMING	
	A. FIELD CONSTRUCTION START DATE	JAN 2013
	B. COMMERCIAL IN-SERVICE DATE	MAY 2014
(5)	FUEL	
	A. PRIMARY FUEL	NATURAL GAS
	B. ALTERNATE FUEL	N/A
(6)	AIR POLLUTION CONTROL STRATEGY	DRY LOW NOX 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)	1.1
	FORCED OUTAGE RATE (FOR)	1.0
	EQUIVALENT AVAILABILITY FACTOR (EAF)	96.9
	RESULTING CAPACITY FACTOR (2014)	7.2%
	AVERAGE NET OPERATING HEAT RATE (ANOHR) 1	9,164 Btu/kWh
(13)	PROJECTED UNIT FINANCIAL DATA	
	BOOK LIFE (YEARS)	26
	TOTAL INSTALLED COST (IN-SERVICE YEAR $/kW)	770.27
	DIRECT CONSTRUCTION COST ($/kW)	618.55
	AFUDC AMOUNT ($/kW)	64.31
	ESCALATION ($/kW)	87.40
	FIXED O&M ($/kW – Yr)	4.34
	VARIABLE O&M ($/MWH)	3.18
	K FACTOR	1.5983

1 BASED ON IN-SERVICE YEAR.

SCHEDULE 9
(Page 6 of 11)
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
UTILITY: TAMPA ELECTRIC COMPANY

((1)	PLANT NAME AND UNIT NUMBER	FUTURE CT 5
(2)	CAPACITY	
	A. SUMMER	88
	B. WINTER	97
(3)	TECHNOLOGY TYPE	COMBUSTION TURBINE
(4)	ANTICIPATED CONSTRUCTION TIMING	
	A. FIELD CONSTRUCTION START DATE	JAN 2013
	B. COMMERCIAL IN-SERVICE DATE	MAY 2014
(5)	FUEL	
	A. PRIMARY FUEL	NATURAL GAS
	B. ALTERNATE FUEL	N/A
(6)	AIR POLLUTION CONTROL STRATEGY	DRY LOW NOX 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)	1.1
	FORCED OUTAGE RATE (FOR)	1.0
	EQUIVALENT AVAILABILITY FACTOR (EAF)	96.9
	RESULTING CAPACITY FACTOR (2014)	7.2%
	AVERAGE NET OPERATING HEAT RATE (ANOHR) 1	9,164 Btu/kWh
(13)	PROJECTED UNIT FINANCIAL DATA	
	BOOK LIFE (YEARS)	26
	TOTAL INSTALLED COST (IN-SERVICE YEAR $/kW)	770.27
	DIRECT CONSTRUCTION COST ($/kW)	618.55
	AFUDC AMOUNT ($/kW)	64.31
	ESCALATION ($/kW)	87.40
	FIXED O&M ($/kW – Yr)	4.34
	VARIABLE O&M ($/MWH)	3.18
	K FACTOR	1.5983

1 BASED ON IN-SERVICE YEAR.

SCHEDULE 9
(Page 7 of 11)
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
UTILITY: TAMPA ELECTRIC COMPANY

(1)	PLANT NAME AND UNIT NUMBER	FUTURE CT 6
(2)	CAPACITY	
	A. SUMMER	88
	B. WINTER	97
(3)	TECHNOLOGY TYPE	COMBUSTION TURBINE
(4)	ANTICIPATED CONSTRUCTION TIMING	
	A. FIELD CONSTRUCTION START DATE	MAY 2013
	B. COMMERCIAL IN-SERVICE DATE	JAN 2015
(5)	FUEL	
	A. PRIMARY FUEL	NATURAL GAS
	B. ALTERNATE FUEL	N/A
(6)	AIR POLLUTION CONTROL STRATEGY	DRY LOW NOX 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)	1.1
	FORCED OUTAGE RATE (FOR)	1.0
	EQUIVALENT AVAILABILITY FACTOR (EAF)	96.9
	RESULTING CAPACITY FACTOR (2015)	6.5%
	AVERAGE NET OPERATING HEAT RATE (ANOHR) 1	9,164 Btu/kWh
(13)	PROJECTED UNIT FINANCIAL DATA	
	BOOK LIFE (YEARS)	26
	TOTAL INSTALLED COST (IN-SERVICE YEAR $/kW)	789.53
	DIRECT CONSTRUCTION COST ($/kW)	618.55
	AFUDC AMOUNT ($/kW)	65.92
	ESCALATION ($/kW)	105.05
	FIXED O&M ($/kW – Yr)	4.44
	VARIABLE O&M ($/MWH)	3.26
	K FACTOR	1.5983

1 BASED ON IN-SERVICE YEAR

SCHEDULE 9
(Page 8 of 11)
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
UTILITY: TAMPA ELECTRIC COMPANY

(1)	PLANT NAME AND UNIT NUMBER	FUTURE CT 7
(2)	CAPACITY	
	A. SUMMER	88
	B. WINTER	97
(3)	TECHNOLOGY TYPE	COMBUSTION TURBINE
(4)	ANTICIPATED CONSTRUCTION TIMING	
	A. FIELD CONSTRUCTION START DATE	JAN 2014
	B. COMMERCIAL IN-SERVICE DATE	MAY 2015
(5)	FUEL	
	A. PRIMARY FUEL	NATURAL GAS
	B. ALTERNATE FUEL	N/A
(6)	AIR POLLUTION CONTROL STRATEGY	DRY LOW NOX 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)	1.1
	FORCED OUTAGE RATE (FOR)	1.0
	EQUIVALENT AVAILABILITY FACTOR (EAF)	96.9
	RESULTING CAPACITY FACTOR (2015)	6.0%
	AVERAGE NET OPERATING HEAT RATE (ANOHR) 1	9,164 Btu/kWh
(13)	PROJECTED UNIT FINANCIAL DATA	
	BOOK LIFE (YEARS)	26
	TOTAL INSTALLED COST (IN-SERVICE YEAR $/kW)	789.53
	DIRECT CONSTRUCTION COST ($/kW)	618.55
	AFUDC AMOUNT ($/kW)	65.92
	ESCALATION ($/kW)	105.05
	FIXED O&M ($/kW – Yr)	4.44
	VARIABLE O&M ($/MWH)	3.26
	K FACTOR	1.5983

1 BASED ON IN-SERVICE YEAR

SCHEDULE 9

(Page 9 of 11)

STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES

UTILITY: TAMPA ELECTRIC COMPANY

(1)	PLANT NAME AND UNIT NUMBER	FUTURE CT 8
(2)	CAPACITY	
	A. SUMMER	88
	B. WINTER	97
(3)	TECHNOLOGY TYPE	COMBUSTION TURBINE
(4)	ANTICIPATED CONSTRUCTION TIMING	
	A. FIELD CONSTRUCTION START DATE	JAN 2014
	B. COMMERCIAL IN-SERVICE DATE	MAY 2015
(5)	FUEL	
	A. PRIMARY FUEL	NATURAL GAS
	B. ALTERNATE FUEL	N/A
(6)	AIR POLLUTION CONTROL STRATEGY	DRY LOW NOX 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)	1.1
	FORCED OUTAGE RATE (FOR)	1.0
	EQUIVALENT AVAILABILITY FACTOR (EAF)	96.9
	RESULTING CAPACITY FACTOR (2015)	6.0%
	AVERAGE NET OPERATING HEAT RATE (ANOHR) 1	9,164 Btu/kWh
(13)	PROJECTED UNIT FINANCIAL DATA	
	BOOK LIFE (YEARS)	26
	TOTAL INSTALLED COST (IN-SERVICE YEAR $/kW)	789.53
	DIRECT CONSTRUCTION COST ($/kW)	618.55
	AFUDC AMOUNT ($/kW)	65.92
	ESCALATION ($/kW)	105.05
	FIXED O&M ($/kW – Yr)	4.44
	VARIABLE O&M ($/MWH)	3.26
	K FACTOR	1.5983

1 BASED ON IN-SERVICE YEAR

SCHEDULE 9
(Page 10 of 11)
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
UTILITY: TAMPA ELECTRIC COMPANY

(1)	PLANT NAME AND UNIT NUMBER	FUTURE CT 9
(2)	CAPACITY	
	A. SUMMER	88
	B. WINTER	97
(3)	TECHNOLOGY TYPE	COMBUSTION TURBINE
(4)	ANTICIPATED CONSTRUCTION TIMING	
	A. FIELD CONSTRUCTION START DATE	JAN 2015
	B. COMMERCIAL IN-SERVICE DATE	MAY 2016
(5)	FUEL	
	A. PRIMARY FUEL	NATURAL GAS
	B. ALTERNATE FUEL	N/A
(6)	AIR POLLUTION CONTROL STRATEGY	DRY LOW NOX 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)	1.1
	FORCED OUTAGE RATE (FOR)	1.0
	EQUIVALENT AVAILABILITY FACTOR (EAF)	96.9
	RESULTING CAPACITY FACTOR (2016)	5.6%
	AVERAGE NET OPERATING HEAT RATE (ANOHR) 1	9,164 Btu/kWh
(13)	PROJECTED UNIT FINANCIAL DATA	
	BOOK LIFE (YEARS)	26
	TOTAL INSTALLED COST (IN-SERVICE YEAR $/kW)	809.27
	DIRECT CONSTRUCTION COST ($/kW)	618.55
	AFUDC AMOUNT ($/kW)	67.57
	ESCALATION ($/kW)	123.15
	FIXED O&M ($/kW – Yr)	4.54
	VARIABLE O&M ($/MWH)	3.33
	K FACTOR	1.5983

1 BASED ON IN-SERVICE YEAR

SCHEDULE 9
(Page 11 of 11)
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
UTILITY: TAMPA ELECTRIC COMPANY

(1)	PLANT NAME AND UNIT NUMBER	FUTURE CT 10
(2)	CAPACITY	
	A. SUMMER	88
	B. WINTER	97
(3)	TECHNOLOGY TYPE	COMBUSTION TURBINE
(4)	ANTICIPATED CONSTRUCTION TIMING	
	A. FIELD CONSTRUCTION START DATE	JAN 2015
	B. COMMERCIAL IN-SERVICE DATE	MAY 2016
(5)	FUEL	
	A. PRIMARY FUEL	NATURAL GAS
	B. ALTERNATE FUEL	N/A
(6)	AIR POLLUTION CONTROL STRATEGY	DRY LOW NOX 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)	1.1
	FORCED OUTAGE RATE (FOR)	1.0
	EQUIVALENT AVAILABILITY FACTOR (EAF)	96.9
	RESULTING CAPACITY FACTOR (2016)	5.6%
	AVERAGE NET OPERATING HEAT RATE (ANOHR) 1	9,164 Btu/kWh
(13)	PROJECTED UNIT FINANCIAL DATA	
	BOOK LIFE (YEARS)	26
	TOTAL INSTALLED COST (IN-SERVICE YEAR $/kW)	809.27
	DIRECT CONSTRUCTION COST ($/kW)	618.55
	AFUDC AMOUNT ($/kW)	67.57
	ESCALATION ($/kW)	123.15
	FIXED O&M ($/kW – Yr)	4.54
	VARIABLE O&M ($/MWH)	3.33
	K FACTOR	1.5983

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	1	No new ROW required	0.1 mi	230kV	Summer 2009	$6.8 million	New 230/69kV transformer at Gannon	None
Pebbledale to Willow Oak	1	Possible road ROW required	9.0 mi	230kV	Summer 2009	$20 million	New 230/69kV Substation at Willow Oak	None
Davis to Wheeler	1	Possible ROW required	12.3 mi	230kV	Summer 2010	$30 million	Davis - new 230kV switching station & 230/69kV transformer at Wheeler	None
Lake Tarpon/Sheldon to Double Branch	1	Possible road ROW required	1.4 mi	230kV	Summer 2011	$4.5 million	New 230/69kV transformer at Double Branch	PEF
Lake Agnes to Gifford	1	New ROW required.	13.1 mi.	230kV	Summer 2011	$23.5 million	No new Tampa Electric substations	PEF
Clearview to Himes	1	Possible road ROW required	6.1 mi.	138kV	Summer 2012	$10 million	New 138kV ring-bus and 2nd 138/69kV transformer at Himes	None
Willow Oak to Wheeler Road	1	Possible road ROW required	17.1 mi	230kV	Summer 2012	$30 million	Wheeler Road – complete 230kV Ring Bus	None
Polk to Hardee (2)	1	No new right of way required	9.4 mi	230kV	Summer 2012	$7.1 million	No new substations	SEC
Davis to Dale Mabry	1	No new right of way required	14.0 mi	230kV	Summer 2012	$26 million	Dale Mabry 230kV Ring Bus	None
Dale Mabry to Denham East	1	Possible road ROW required	5.7 mi	230kV	Summer 2012	$10 million	No new substations	PEF

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Other Planning Assumptions and Information

Transmission Constraints and Impacts

Based on a variety of assessments and sensitivity studies of the Tampa Electric transmission system using year 2006 Florida Reliability Coordinating Council (FRCC) databank models, no transmission constraints that violate the criteria stated in the Generation and Transmission Reliability Criteria section of this document were identified in these studies.

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 the base case is derived through analysis of historical and current prices combined with price forecasts obtained from various consultants and agencies. These sources include the New York Mercantile Exchange, Energy Information Administration, Hill & Associates, PIRA Energy Group, Coal Daily, Inside FERC and Platt's Oilgram.

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

Only base case forecasts are prepared for coal fuels because of the fuels' relatively low price volatility. Only a base case forecast for oil is utilized because oil comprises a very small component of total system generation.

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 incremental 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 PROMOD economic dispatch model in conjunction with an incremental capital revenue requirement calculation. 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.

The results of the Integrated Resource Planning process provide Tampa Electric with a plan that is cost-effective while maintaining flexibility and adaptability to a dynamic regulatory and competitive environment. The new capacity additions are shown in Schedule 8. To meet the expected system demand and energy requirements over the next ten years and cost-effectively maintain system reliability, Tampa Electric is planning the addition of combustion turbines, Polk Unit 6 IGCC, and economical market purchases. For the purposes of this study, Big Bend CT Units 1 through 3 are assumed to be retired in January 2015.

As the scheduled SCR outages and construction outages for the new units approach, Tampa Electric will continue to look for competitive purchase power agreements that may replace or delay the scheduled new 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 purchased 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 must be performed prior to making a prudent decision to initiate a project.

Tampa Electric follows FRCC planning criteria as contained in its Principles and Guides for Planning Reliable Bulk Electric Systems. The FRCC planning guide is based on NERC Planning Reliability Standards, which are used to measure system adequacy. In general the NERC standards state that the transmission system will remain stable, within the applicable thermal and voltage rating limits, without cascading outages, under normal, single and multiple contingency conditions.

Generation Dispatch Modeled

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

Since varying load levels and 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 of the FRCC Standards Handbook and NERC Standards. In addition to FRCC criteria, Tampa Electric utilizes company-specific planning criteria. The following table summarizes the thresholds, which alert planners to problematic transmission lines and transformers.

Transmission System Loading Units

TRANSMISSION SYSTEMS CONDITIONS	MAXIMUM ACCEPTABLE LOADING UNIT FOR TRANSFORMERS AND TRANSMISSION LINES
All elements in service	100%
Single Contingency (pre-switching)	115%
Single Contingency (post-switching)	100%
Bus Outages (pre-switching)	115%
Bus Outages (post-switching)	100%

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

Transmission System Voltage Units

TRANSMISSION SYSTEMS CONDITIONS	INDUSTRIAL SUBSTATION BUSES AT POINT-OF-SERVICE	69 KV BUSES	138KV 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 Standards relating to ATC.

Transmission Planning Assessment Practices

Base Case Operating Conditions

The System 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 100% of peak load level. The Tampa Electric Company transmission system is designed such that these double contingencies do not cause violation of NERC criteria.

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 the company's 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 Programs

Tampa Electric has offered a pilot Renewable Energy Program for several years. Due to the recent success of the pilot, permanent program status was requested by the company and approved by the Commission in Order No. PSC-07-0052-CO-EG, Docket No. 06078-EG, issued January 19, 2007.

Through December 2006, Tampa Electric's Renewable Energy Program has approximately 1,500 customers purchasing over 2,000 blocks of renewable energy each month. Participation for 2006 alone increased the total number of participants in the program by over 52 percent since inception. In addition, with the permanent program status effective January 2007, the company doubled the renewable energy block size from 100 to 200 kWh per month.

Tampa Electric is one of the few electric utilities in the state that uses renewable generation produced in the State of Florida. The company's renewable generation portfolio consists of four photovoltaic (PV) arrays totaling 40 kW. The PV arrays are installed at the Museum of Science and Industry, Walker Middle and Middleton High schools and Tampa Electric's Manatee Viewing Center. Additionally, Tampa Electric is evaluating a methodology to utilize captured methane gas emanating from a Hillsborough County landfill.

Program growth has now reached a point where it has become necessary to supplement the company's renewable resources with incremental purchases from a biomass facility in south Florida. Through December 2006, participating customers have utilized over 4.5 GWH of renewable energy since the program inception.

Tampa Electric recognizes the need and value of renewable generation for the future, and to that end, the company continues to investigate and obtain the most cost-effective methods of system generation and available off-system incremental purchases.

chapter 6

Environmental and Land Use Information

The future generating capacity additions identified in Chapter IV could occur at H.L. Culbreath Bayside Power station, Polk Power Station, or Big Bend Power Station. The H.L. Culbreath Bayside Power Station site is located in Hillsborough County on Port Sutton Road (See Figure VI-1), Polk Power station site is located in southwest Polk County close to the Hillsborough and Hardee County lines (See Figure VI-2) and Big Bend Power Station is located in Hillsborough County on Big Bend Road (See Figure VI-3). All facilities are currently permitted as existing power plant sites. Additional land use requirements and/or alternative site locations are not currently under consideration.

F.J. GANNON / BAYSIDE LOCATION MAP
SOURCE: USGS QUAD, TAMPA, FL 1981

Figure VI-2

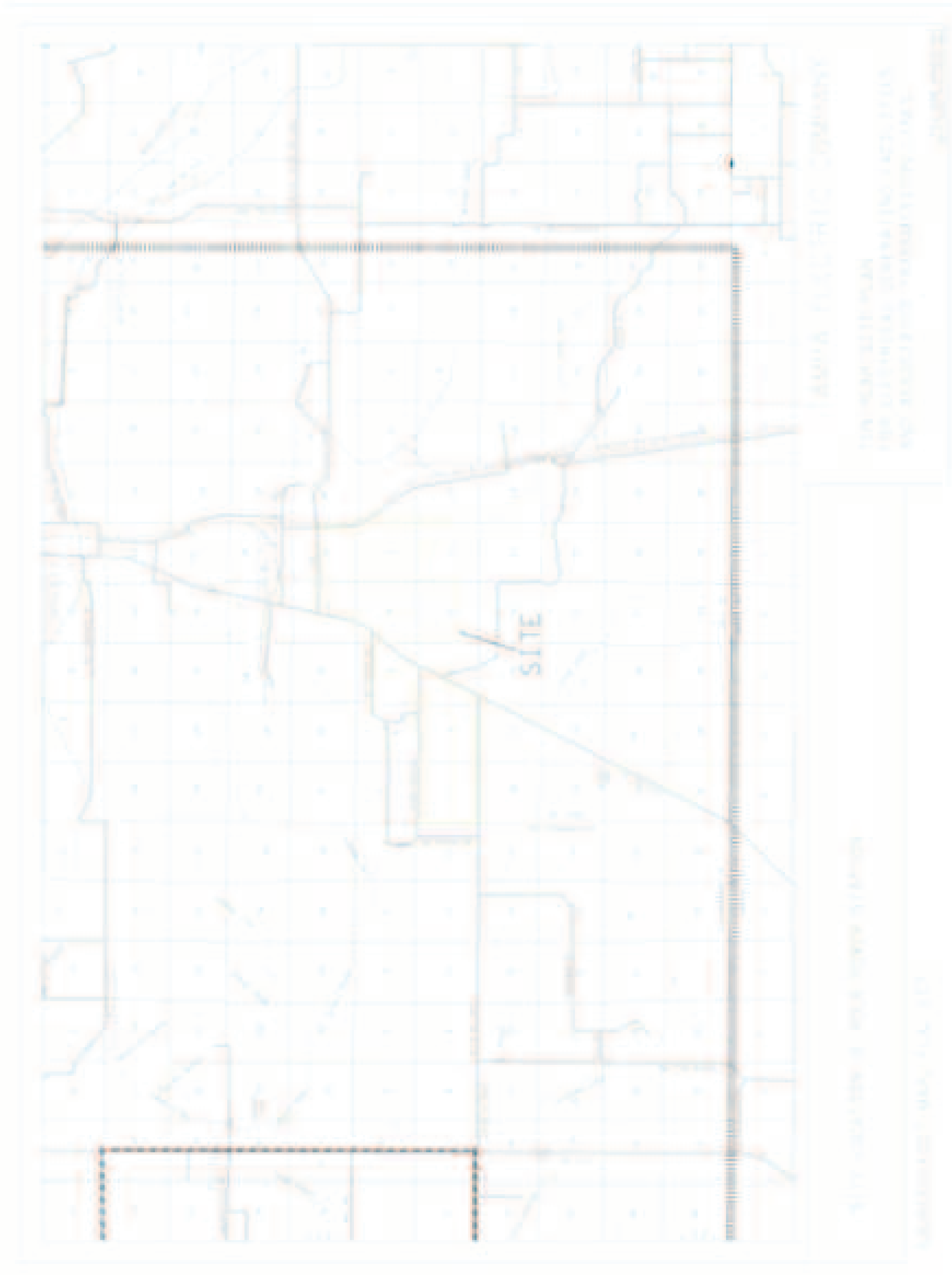
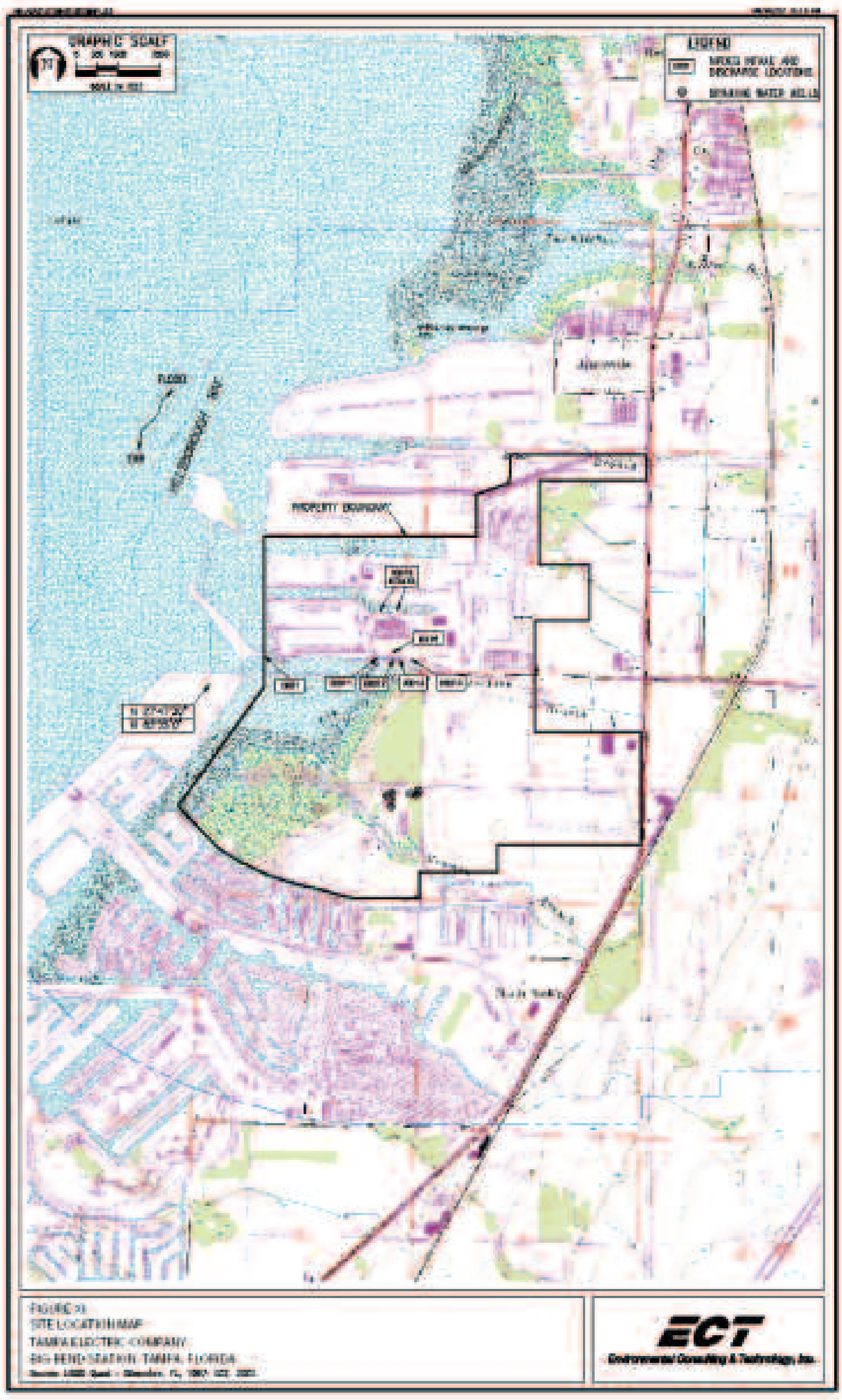


Figure VI-3


GRAPHIC SCALE
LEGEND
PROPERTY BOUNDARY
SITE LOCATION MAP
TAMPA ELECTRIC COMPANY
BIG BEND STATION, TAMPA, FLORIDA
ECT
Environmental Consulting & Technology, Inc.