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130000-OT

April 1, 2013

HAND DELIVERED

Ms. Ann Cole, Director
Division of Commission Clerk
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, FL 32399-0850

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

Dear Ms. Cole:

Enclosed for filing on behalf of Tampa Electric Company are twenty-five (25) copies of the company's January 2013 to December 2022 Ten-Year Site Plan.

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

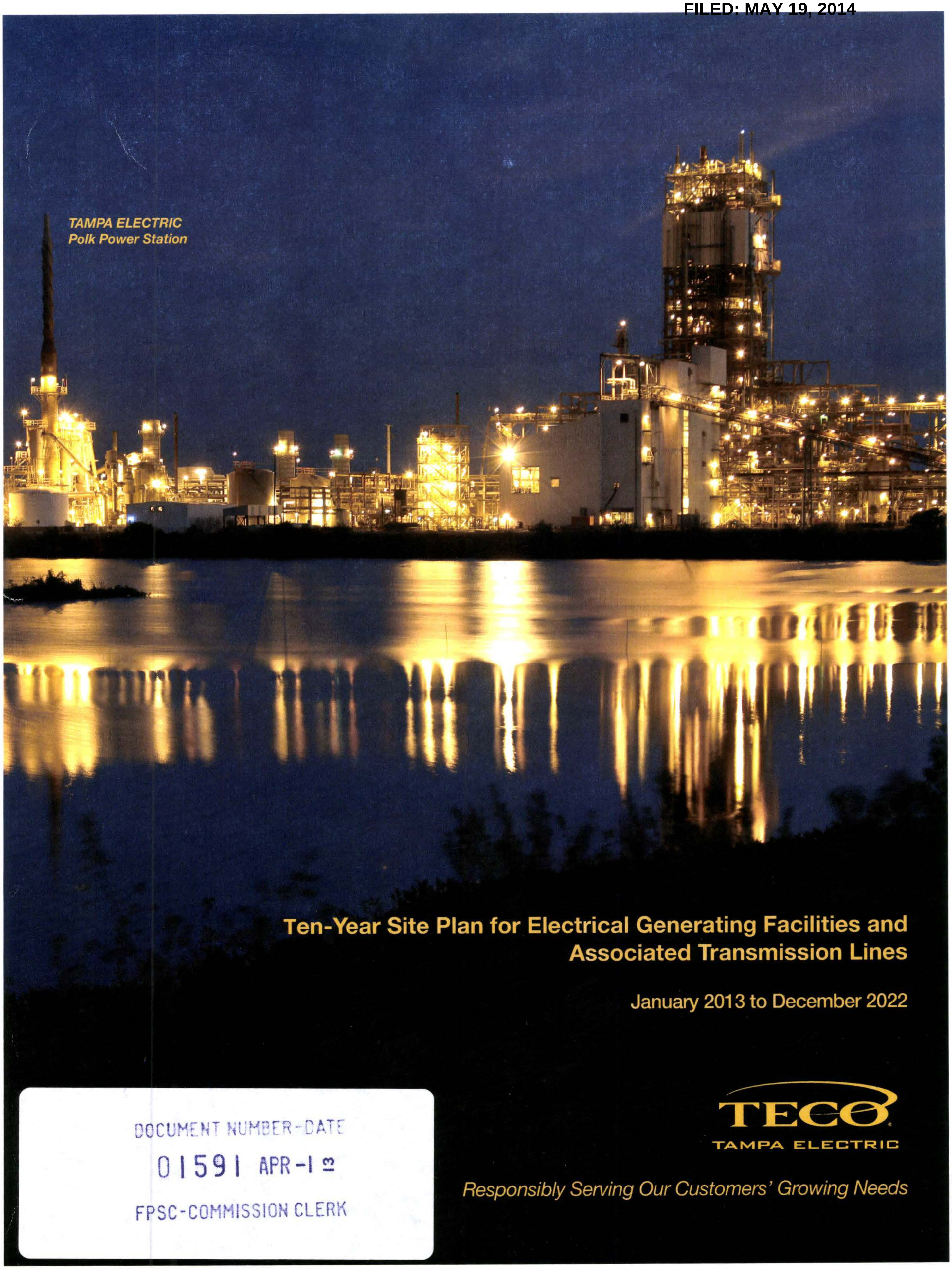
Thank you for your assistance in connection with this matter.

Sincerely,

James D. Beasley

JDB/pp
Enclosures

COM ____
AFD ____
APA ____
ECO ____
ENG 24
GCL 1
IDM ____
TEL ____
CLK ____



TAMPA ELECTRIC
Polk Power Station

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

January 2013 to December 2022

TECO
TAMPA ELECTRIC

Responsibly Serving Our Customers' Growing Needs

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

January 2013 to December 2022

TAMPA ELECTRIC COMPANY
Tampa, Florida

April 1, 2013

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Glossary of Terms

CODE IDENTIFICATION SHEET

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

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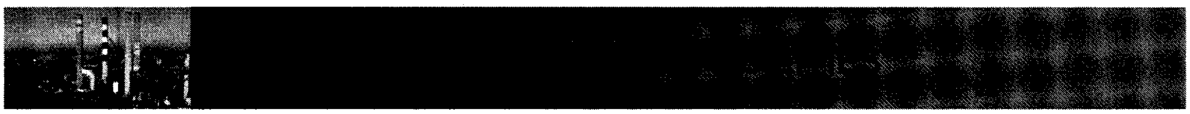
Chapter I



Tampa Electric has five (5) generating stations that include fossil steam units, combined cycle units, combustion turbine peaking units, an integrated coal gasification combined cycle unit, and internal combustion diesel units.

Big Bend Power Station

The station operates four (4) pulverized coal-fired steam units equipped with desulfurization scrubbers and electrostatic precipitators. The station's coal-fired units have recently undergone the addition of air pollution control systems called Selective Catalytic Reduction (SCR). The SCR installations occurred from 2007 to the spring of 2010. In addition, the station operates one (1) aero-derivative combustion turbine that entered into service in 2009 and can be fired with natural gas or distillate oil.

H.L. Culbreath Bayside Power Station

The station operates 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. In addition, the station operates four (4) natural gas fired aero-derivative combustion turbines that were placed into service in 2009.

Polk Power Station

The station operates five (5) generating units. Polk Unit 1 is an integrated gasification combined cycle (IGCC) unit fired with synthetic gas produced from gasified coal and other carbonaceous fuels. 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 fired primarily with natural gas. Units 1, 2 and 3 can also be fired with distillate oil.

J.H. Phillips Power Station

The station is comprised of two (2) residual or distillate oil-fired diesel engines. The units were placed into long-term reserve standby in 2009.

Partnership Power Station

The station is comprised of two (2) natural gas fired internal combustion engines. This project was developed in partnership with Tampa Electric and the City of Tampa. The units were placed into long-term reserve standby in July of 2012.

Schedule 1

Existing Generating Facilities
As of December 31, 2012

(1) Plant Name	(2) Unit No.	(3) Location	(4) Unit Type	(5) Fuel Pri	(6) Fuel Alt	(7) Fuel Transport Pri	(8) Fuel Transport Alt	(9) Alt Fuel Days	(10) Commercial In-Service Mo/Yr	(11) Expected Retirement Mo/Yr	(12) Gen. Max. Nameplate KW	(13) Net Capability Summer MW	(14) Net Capability Winter MW
Big Bend		Hillsborough Co. 14/31S/19E									1,892,485	1,598	1,633
	1		ST	BIT	N	WA/RR	N	0	10/70	Unknown	445,500	385	395
	2		ST	BIT	N	WA/RR	N	0	4/73	Unknown	445,500	385	395
	3		ST	BIT	N	WA/RR	N	0	5/76	Unknown	445,500	365	365
	4		ST	BIT	N	WA/RR	N	0	2/85	Unknown	486,000	407	417
	CT 4		GT	NG	LO	PL	TK	0	8/09	Unknown	69,985	56	61
Bayside		Hillsborough Co. 4/30S/19E									2,294,100	1,854	2,083
	1		CC	NG	N	PL	N	0	4/03	Unknown	809,060	701	792
	2		CC	NG	N	PL	N	0	1/04	Unknown	1,205,100	929	1,047
	3		GT	NG	N	PL	N	0	7/09	Unknown	69,985	56	61
	4		GT	NG	N	PL	N	0	7/09	Unknown	69,985	56	61
	5		GT	NG	N	PL	N	0	4/09	Unknown	69,985	56	61
	6		GT	NG	N	PL	N	0	4/09	Unknown	69,985	56	61
Phillips		Highland Co. 12-055									38,430	36 [1]	36 [1]
	1		IC	HO	LO	TK	N	0	6/83	LTRS 9/09	19,215	18 [1]	18 [1]
	2		IC	HO	LO	TK	N	0	6/83	LTRS 9/09	19,215	18 [1]	18 [1]
Polk		Polk Co. 2,3/32S/23E									1,029,379	824	952
	1		IGCC	BIT	LO	WA/TK	TK	0	9/96	Unknown	326,299	220	220
	2		GT	NG	LO	PL	TK	0	7/00	Unknown	175,770 [3]	151	183
	3		GT	NG	LO	PL	TK	0	5/02	Unknown	175,770 [3]	151	183
	4		GT	NG	N	PL	N	0	3/07	Unknown	175,770 [3]	151	183
	5		GT	NG	N	PL	N	0	4/07	Unknown	175,770 [3]	151	183
Partnership		Hillsborough Co. W30/29/19									5,800	6 [2]	6 [2]
	1		IC	NG	N	PL	N	0	4/01	LTRS 7/12	2,900	3 [2]	3 [2]
	2		IC	NG	N	PL	N	0	4/01	LTRS 7/12	2,900	3 [2]	3 [2]
											TOTAL	4,276	4,668

Notes:

[1] Phillips Station Units 1 & 2 were placed into LTRS on September 4, 2009, and net capacities are not included into the system total.

[2] Partnership Station Units 1 & 2 were placed into LTRS on July 1, 2012, and net capacities are not included into the system total.

[3] Polk Units 2-5 turbine name plate ratings are based on 59 °F. The net capacity of these units vary with ambient air temperature.

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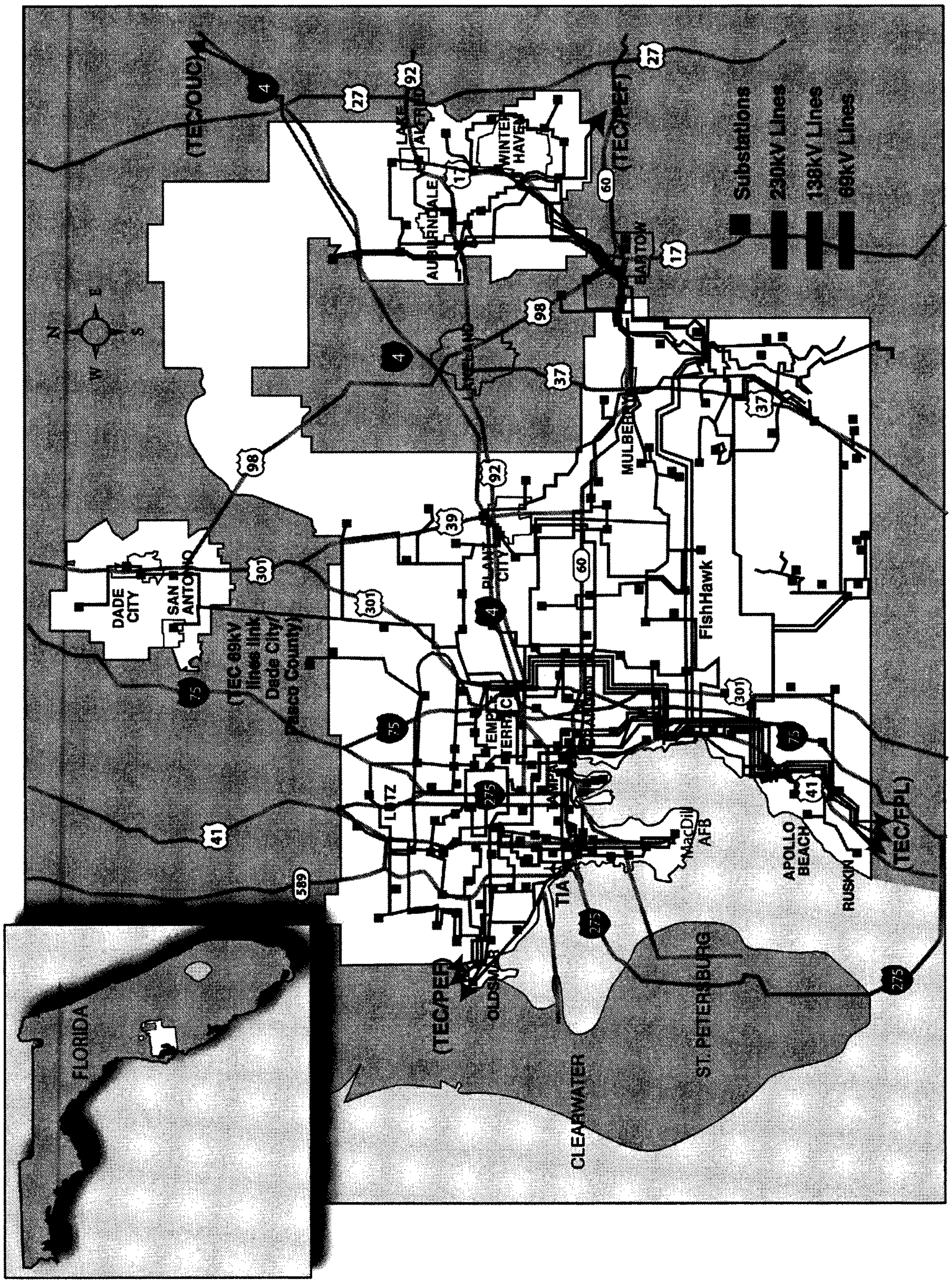
I.1 Tampa Electric Service Area Map

I.2 Tampa Electric Service Area Transmission Facility



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Chapter II

Tables in Schedules 2 through 4 reflect three different levels of load forecasting: base case, high case, and low case. The expansion plan is developed using the base case load forecast and is reflected in Schedules 5 through 9. This forecast band best represents the current economic conditions and the long-term impacts to Tampa Electric's service territory.

Schedule 2.1: History and Forecast of Energy Consumption and Number of Customers by Customer Class (Base, High & Low)

Schedule 2.2: History and Forecast of Energy Consumption and Number of Customers by Customer Class (Base, High & Low)

Schedule 2.3: History and Forecast of Energy Consumption and Number of Customers by Customer Class (Base, High & Low)

Schedule 3.1: History and Forecast of Summer Peak Demand (Base, High & Low)

Schedule 3.2: History and Forecast of Winter Peak Demand (Base, High & Low)

Schedule 3.3: History and Forecast of Annual Net Energy for Load (Base, High & Low)

Schedule 4: Previous Year and 2-Year Forecast of Peak Demand and Net Energy for Load by Month (Base, High & Low)

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 Percent

Schedule 2.1

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

(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
2003	1,079,491	2.5	8,265	531,257	15,557	5,848	66,041	88,551
2004	1,108,451	2.5	8,293	544,313	15,236	5,988	67,488	88,727
2005	1,138,786	2.5	8,562	558,728	15,324	6,233	69,027	90,298
2006	1,170,851	2.5	8,721	575,111	15,164	6,357	70,205	90,549
2007	1,194,436	2.5	8,871	586,776	15,119	6,542	70,891	92,276
2008	1,206,084	2.5	8,546	587,602	14,545	6,399	70,770	90,415
2009	1,215,216	2.5	8,666	587,396	14,754	6,274	70,182	89,395
2010	1,229,226	2.6	9,185	591,554	15,526	6,221	70,176	88,655
2011	1,238,951	2.6	8,718	595,914	14,630	6,207	70,522	88,009
2012	1,256,118	2.6	8,395	603,594	13,909	6,185	71,143	86,937
2013	1,269,277	2.6	8,492	610,685	13,905	6,197	71,930	86,148
2014	1,287,029	2.6	8,579	618,914	13,861	6,264	72,886	85,939
2015	1,308,007	2.6	8,661	628,730	13,775	6,344	74,033	85,694
2016	1,330,162	2.6	8,784	639,145	13,744	6,430	75,264	85,433
2017	1,351,291	2.6	8,910	649,098	13,727	6,525	76,388	85,424
2018	1,372,048	2.6	9,039	658,898	13,719	6,614	77,477	85,372
2019	1,392,821	2.6	9,165	668,727	13,705	6,704	78,567	85,327
2020	1,413,424	2.6	9,273	678,494	13,667	6,790	79,662	85,238
2021	1,432,744	2.6	9,392	687,661	13,658	6,864	80,690	85,063
2022	1,451,239	2.6	9,518	696,446	13,666	6,941	81,664	84,996

December 31, 2012 Status

* Average of end-of-month customers for the calendar year.
Note: Values shown may be affected due to rounding.

Schedule 2.1

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

(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
2003	1,079,491	2.5	8,265	531,257	15,557	5,848	66,041	88,551
2004	1,108,451	2.5	8,293	544,313	15,236	5,988	67,488	88,727
2005	1,138,786	2.5	8,562	558,728	15,324	6,233	69,027	90,298
2006	1,170,851	2.5	8,721	575,111	15,164	6,357	70,205	90,549
2007	1,194,436	2.5	8,871	586,776	15,119	6,542	70,891	92,276
2008	1,206,084	2.5	8,546	587,602	14,545	6,399	70,770	90,415
2009	1,215,216	2.5	8,666	587,396	14,754	6,274	70,182	89,395
2010	1,229,226	2.6	9,185	591,554	15,526	6,221	70,176	88,655
2011	1,238,951	2.6	8,718	595,914	14,630	6,207	70,522	88,009
2012	1,256,118	2.6	8,395	603,594	13,909	6,185	71,143	86,937
2013	1,275,557	2.6	8,552	613,697	13,935	6,223	72,262	86,113
2014	1,299,775	2.6	8,701	625,027	13,921	6,319	73,591	85,861
2015	1,327,459	2.6	8,847	638,059	13,866	6,429	75,125	85,578
2016	1,356,581	2.6	9,038	651,815	13,866	6,546	76,759	85,281
2017	1,384,912	2.7	9,234	665,221	13,882	6,674	78,298	85,239
2018	1,413,111	2.7	9,436	678,590	13,906	6,797	79,818	85,156
2019	1,441,570	2.7	9,637	692,105	13,925	6,922	81,350	85,084
2020	1,470,101	2.7	9,822	705,674	13,919	7,044	82,904	84,967
2021	1,497,547	2.7	10,022	718,738	13,944	7,155	84,403	84,767
2022	1,524,366	2.7	10,231	731,515	13,986	7,270	85,858	84,678

December 31, 2012 Status

* Average of end-of-month customers for the calendar year.
Note: Values shown may be affected due to rounding.

Schedule 2.1

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

(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
2003	1,079,491	2.5	8,265	531,257	15,557	5,848	66,041	88,551
2004	1,108,451	2.5	8,293	544,313	15,236	5,988	67,488	88,727
2005	1,138,786	2.5	8,562	558,728	15,324	6,233	69,027	90,298
2006	1,170,851	2.5	8,721	575,111	15,164	6,357	70,205	90,549
2007	1,194,436	2.5	8,871	586,776	15,119	6,542	70,891	92,276
2008	1,206,084	2.5	8,546	587,602	14,545	6,399	70,770	90,415
2009	1,215,216	2.5	8,666	587,396	14,754	6,274	70,182	89,395
2010	1,229,226	2.6	9,185	591,554	15,526	6,221	70,176	88,655
2011	1,238,951	2.6	8,718	595,914	14,630	6,207	70,522	88,009
2012	1,256,118	2.6	8,395	603,594	13,909	6,185	71,143	86,937
2013	1,262,992	2.6	8,431	607,674	13,875	6,171	71,597	86,184
2014	1,274,345	2.6	8,457	612,832	13,800	6,209	72,185	86,016
2015	1,288,743	2.6	8,477	619,493	13,683	6,260	72,952	85,811
2016	1,304,128	2.5	8,536	626,661	13,621	6,315	73,791	85,585
2017	1,318,323	2.5	8,596	633,289	13,574	6,379	74,514	85,609
2018	1,331,984	2.5	8,657	639,685	13,533	6,436	75,193	85,589
2019	1,345,489	2.5	8,713	646,029	13,487	6,492	75,863	85,572
2020	1,358,665	2.5	8,751	652,234	13,417	6,544	76,528	85,510
2021	1,370,445	2.5	8,798	657,785	13,375	6,583	77,120	85,357
2022	1,381,281	2.5	8,850	662,899	13,350	6,624	77,650	85,311

December 31, 2012 Status

* Average of end-of-month customers for the calendar year.
Note: Values shown may be affected due to rounding.

Schedule 2.2

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	Industrial						
Year	GWH	Customers*	Average KWH Consumption Per Customer	Railroads and Railways GWH	Street & Highway Lighting GWH	Other Sales to Public Authorities GWH	Total Sales to Ultimate Consumers GWH
2003	2,580	1203	2,144,638	0	57	1,481	18,231
2004	2,556	1299	1,967,667	0	58	1,542	18,437
2005	2,478	1337	1,853,403	0	60	1,582	18,915
2006	2,279	1,485	1,534,680	0	61	1,607	19,025
2007	2,366	1,494	1,583,695	0	63	1,692	19,533
2008	2,205	1,421	1,551,724	0	64	1,776	18,990
2009	1,995	1,424	1,401,219	0	68	1,771	18,774
2010	2,010	1,434	1,401,767	0	73	1,724	19,213
2011	1,804	1,493	1,207,838	0	74	1,761	18,564
2012	2,001	1,536	1,302,949	0	75	1,756	18,412
2013	1,687	1515	1,113,676	0	77	1,749	18,202
2014	1,687	1524	1,107,031	0	79	1,761	18,370
2015	1,684	1536	1,095,949	0	81	1,782	18,552
2016	1,686	1548	1,089,264	0	82	1,813	18,795
2017	1,671	1556	1,073,736	0	84	1,848	19,039
2018	1,665	1562	1,065,498	0	86	1,883	19,287
2019	1,656	1569	1,055,708	0	87	1,916	19,529
2020	1,648	1576	1,045,515	0	89	1,948	19,749
2021	1,640	1584	1,035,140	0	91	1,977	19,963
2022	1,631	1592	1,024,725	0	92	2,007	20,189

December 31, 2012 Status

* Average of end-of-month customers for the calendar year.
Note: Values shown may be affected due to rounding.

Schedule 2.2

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	Industrial						
Year	GWH	Customers*	Average KWH Consumption Per Customer	Railroads and Railways GWH	Street & Highway Lighting GWH	Other Sales to Public Authorities GWH	Total Sales to Ultimate Consumers GWH
2003	2,580	1,203	2,144,638	0	57	1,481	18,231
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	18,915
2006	2,279	1,485	1,534,680	0	61	1,607	19,025
2007	2,366	1,494	1,583,695	0	63	1,692	19,533
2008	2,205	1,421	1,551,724	0	64	1,776	18,990
2009	1,995	1,424	1,401,219	0	68	1,771	18,774
2010	2,010	1,434	1,401,767	0	73	1,724	19,213
2011	1,804	1,493	1,207,838	0	74	1,761	18,564
2012	2,001	1,536	1,302,949	0	75	1,756	18,412
2013	1,689	1,517	1,113,628	0	77	1,759	18,300
2014	1,691	1,528	1,106,980	0	79	1,780	18,570
2015	1,690	1,542	1,095,944	0	81	1,811	18,858
2016	1,694	1,556	1,088,852	0	82	1,851	19,212
2017	1,681	1,566	1,073,309	0	84	1,898	19,571
2018	1,677	1,575	1,064,469	0	86	1,943	19,939
2019	1,670	1,584	1,054,416	0	87	1,988	20,305
2020	1,664	1,594	1,043,685	0	89	2,033	20,652
2021	1,657	1,604	1,032,965	0	91	2,073	20,998
2022	1,650	1,614	1,022,250	0	92	2,116	21,360

December 31, 2012 Status

* Average of end-of-month customers for the calendar year.
Note: Values shown may be affected due to rounding.

Schedule 2.2

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	Industrial						
Year	GWH	Customers*	Average KWH Consumption Per Customer	Railroads and Railways GWH	Street & Highway Lighting GWH	Other Sales to Public Authorities GWH	Total Sales to Ultimate Consumers GWH
2003	2,580	1,203	2,144,638	0	57	1,481	18,231
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	18,915
2006	2,279	1,485	1,534,680	0	61	1,607	19,025
2007	2,366	1,494	1,583,695	0	63	1,692	19,533
2008	2,205	1,421	1,551,724	0	64	1,776	18,990
2009	1,995	1,424	1,401,219	0	68	1,771	18,774
2010	2,010	1,434	1,401,767	0	73	1,724	19,213
2011	1,804	1,493	1,207,838	0	74	1,761	18,564
2012	2,001	1,536	1,302,949	0	75	1,756	18,412
2013	1,685	1,513	1,113,902	0	77	1,740	18,104
2014	1,683	1,521	1,106,765	0	79	1,743	18,171
2015	1,678	1,531	1,095,922	0	81	1,754	18,250
2016	1,678	1,540	1,089,730	0	82	1,775	18,387
2017	1,661	1,546	1,074,328	0	84	1,800	18,520
2018	1,653	1,550	1,066,460	0	86	1,824	18,655
2019	1,643	1,555	1,056,687	0	87	1,846	18,782
2020	1,633	1,560	1,046,910	0	89	1,868	18,884
2021	1,623	1,565	1,037,142	0	91	1,885	18,979
2022	1,613	1,570	1,027,389	0	92	1,903	19,082

December 31, 2012 Status

* Average of end-of-month customers for the calendar year.
Note: Values shown may be affected due to rounding.

Schedule 2.3

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

(1) Year	(2) Sales for * Resale GWH	(3) Utility Use ** & Losses GWH	(4) Net Energy *** for Load GWH	(5) Other **** Customers	(6) Total **** Customers
2003	587	985	19,803	6,399	604,900
2004	589	945	19,971	6,435	619,535
2005	712	952	20,579	6,656	635,748
2006	700	1,000	20,725	6,905	653,706
2007	829	916	21,278	7,193	666,354
2008	752	909	20,650	7,473	667,266
2009	191	978	19,943	7,748	666,750
2010	305	1,149	20,667	7,827	670,991
2011	93	642	19,298	7,869	675,799
2012	69	839	19,320	7,962	684,235
2013	0	964	19,166	7,994	692,125
2014	0	972	19,342	8,090	701,415
2015	0	982	19,534	8,204	712,504
2016	0	995	19,791	8,324	724,281
2017	0	1,008	20,047	8,439	735,481
2018	0	1,021	20,308	8,552	746,489
2019	0	1,034	20,563	8,666	757,528
2020	0	1,046	20,795	8,778	768,510
2021	0	1,058	21,021	8,883	778,819
2022	0	1,070	21,259	8,985	788,686

December 31, 2012 Status

* Includes sales to Progress Energy Florida, Wauchula, Ft. Meade, St. Cloud, Reedy Creek and Florida Power & Light. Contract ended with Ft. Meade on 12/31/08, Reedy Creek on 12/31/10, Progress Energy Florida on 2/31/11, Wachula on 9/31/11, St.Cloud on 12/31/2012 and Florida Power & Light on 12/31/12.

** 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.

Note: Values shown may be affected due to rounding.

Schedule 2.3

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

(1) Year	(2) Sales for * Resale GWH	(3) Utility Use ** & Losses GWH	(4) Net Energy *** for Load GWH	(5) Other **** Customers	(6) Total **** Customers
2003	587	985	19,803	6,399	604,900
2004	589	945	19,971	6,435	619,535
2005	712	952	20,579	6,656	635,748
2006	700	1,000	20,725	6,905	653,706
2007	829	916	21,278	7,193	666,354
2008	752	909	20,650	7,473	667,266
2009	191	978	19,943	7,748	666,750
2010	305	1,149	20,667	7,827	670,991
2011	93	642	19,298	7,869	675,799
2012	69	839	19,320	7,962	684,235
2013	0	969	19,269	8,027	695,503
2014	0	983	19,553	8,157	708,303
2015	0	998	19,856	8,306	723,032
2016	0	1,017	20,229	8,463	738,593
2017	0	1,036	20,607	8,615	753,700
2018	0	1,056	20,994	8,767	768,750
2019	0	1,075	21,380	8,920	783,959
2020	0	1,094	21,746	9,074	799,246
2021	0	1,113	22,110	9,223	813,968
2022	0	1,132	22,492	9,367	828,354

December 31, 2012 Status

* Includes sales to Progress Energy Florida, Wauchula, Ft. Meade, St. Cloud, Reedy Creek and Florida Power & Light. Contract ended with Ft. Meade on 12/31/08, Reedy Creek on 12/31/10, Progress Energy Florida on 2/31/11, Wachula on 9/31/11, St.Cloud on 12/31/2012 and Florida Power & Light on 12/31/12.
** 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.
Note: Values shown may be affected due to rounding.

Schedule 2.3

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

(1) Year	(2) Sales for * Resale GWH	(3) Utility Use ** & Losses GWH	(4) Net Energy *** for Load GWH	(5) Other **** Customers	(6) Total **** Customers
2003	587	985	19,803	6,399	604,900
2004	589	945	19,971	6,435	619,535
2005	712	952	20,579	6,656	635,748
2006	700	1,000	20,725	6,905	653,706
2007	829	916	21,278	7,193	666,354
2008	752	909	20,650	7,473	667,266
2009	191	978	19,943	7,748	666,750
2010	305	1,149	20,667	7,827	670,991
2011	93	642	19,298	7,869	675,799
2012	69	839	19,320	7,962	684,235
2013	0	958	19,063	7,961	688,745
2014	0	962	19,133	8,024	694,562
2015	0	966	19,216	8,104	702,080
2016	0	973	19,360	8,188	710,180
2017	0	981	19,501	8,266	717,615
2018	0	988	19,643	8,343	724,771
2019	0	995	19,777	8,418	731,865
2020	0	1,000	19,885	8,491	738,813
2021	0	1,006	19,985	8,558	745,028
2022	0	1,011	20,093	8,619	750,738

December 31, 2012 Status

* Includes sales to Progress Energy Florida, Wauchula, Ft. Meade, St. Cloud, Reedy Creek and Florida Power & Light. Contract ended with Ft. Meade on 12/31/08, Reedy Creek on 12/31/10, Progress Energy Florida on 2/31/11, Wachula on 9/31/11, St.Cloud on 12/31/2012 and Florida Power & Light on 12/31/12.
** 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.
Note: Values shown may be affected due to rounding.

Schedule 3.1

History and Forecast of Summer Peak Demand
Base Case

(1) Year	(2) Total *	(3) Wholesale**	(4) Retail *	(5) Interruptible	(6) Residential Load Management	(7) Residential Conservation	(8) Comm./Ind. Load Management	(9) Comm./Ind. Conservation	(10) Net Firm Demand
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	4,428	172	4,256	159	69	80	18	53	3,876
2008	4,275	148	4,127	143	69	84	53	55	3,723
2009	4,345	136	4,209	120	56	89	86	59	3,799
2010	4,169	118	4,051	73	33	95	75	65	3,710
2011	4,127	28	4,098	109	48	99	75	68	3,699
2012	4,084	15	4,069	133	45	106	86	71	3,627
2013	4,108	0	4,108	96	53	117	87	88	3,667
2014	4,161	0	4,161	97	54	125	90	95	3,701
2015	4,220	0	4,220	97	55	133	92	103	3,741
2016	4,287	0	4,287	97	56	141	95	111	3,788
2017	4,354	0	4,354	96	57	150	98	118	3,835
2018	4,420	0	4,420	96	59	158	100	126	3,881
2019	4,487	0	4,487	96	61	168	103	133	3,927
2020	4,550	0	4,550	96	63	177	104	140	3,971
2021	4,610	0	4,610	96	64	186	106	146	4,012
2022	4,671	0	4,671	96	66	195	107	153	4,054

December 31, 2012 Status

* Includes residential and commercial/industrial conservation.
** Includes sales to Progress Energy Florida, Wauchula, Ft. Meade, St. Cloud, Reedy Creek and Florida Power & Light. Contract ended with Ft. Meade on 12/31/08, Reed Creek on 12/31/10, Progress Energy Florida on 2/31/11, Wachula on 9/31/11, St.Cloud on 12/31/2012 and Florida Power & Light on 12/31/12.
*** Net Firm Demand is not coincident with system peak.
Note: Values shown may be affected due to rounding.

Schedule 3.1

History and Forecast of Summer Peak Demand
High Case

(1) Year	(2) Total *	(3) Wholesale**	(4) Retail *	(5) Interruptible	(6) Residential Load Management	(7) Residential Conservation	(8) Comm./Ind. Load Management	(9) Comm./Ind. Conservation	(10) Net Firm Demand	
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	4,428	172	4,256	159	69	80	18	53	3,876	
2008	4,275	148	4,127	143	69	84	53	55	3,723	
2009	4,345	136	4,209	120	56	89	86	59	3,799	
2010	4,169	118	4,051	73	33	95	75	65	3,710	***
2011	4,127	28	4,098	109	48	99	75	68	3,699	
2012	4,084	15	4,069	133	45	106	86	71	3,627	
2013	4,128	0	4,128	96	53	117	87	88	3,687	
2014	4,203	0	4,203	97	54	125	90	95	3,743	
2015	4,283	0	4,283	97	55	133	92	103	3,804	
2016	4,374	0	4,374	97	56	141	95	111	3,875	
2017	4,465	0	4,465	96	57	150	98	118	3,946	
2018	4,555	0	4,555	96	59	158	100	126	4,016	
2019	4,647	0	4,647	96	61	168	103	133	4,087	
2020	4,736	0	4,736	96	63	177	104	140	4,157	
2021	4,824	0	4,824	96	64	186	106	146	4,226	
2022	4,913	0	4,913	96	66	195	107	153	4,296	

December 31, 2012 Status

* Includes residential and commercial/industrial conservation.
** Includes sales to Progress Energy Florida, Wauchula, Ft. Meade, St. Cloud, Reedy Creek and Florida Power & Light. Contract ended with Ft. Meade on 12/31/08, Reedy Creek on 12/31/10, Progress Energy Florida on 2/31/11, Wachula on 9/31/11, St.Cloud on 12/31/2012 and Florida Power & Light on 12/31/12.
*** Net Firm Demand is not coincident with system peak.
Note: Values shown may be affected due to rounding.

Schedule 3.1

History and Forecast of Summer Peak Demand
Low Case

(1) Year	(2) Total *	(3) Wholesale**	(4) Retail *	(5) Interruptible	(6) Residential Load Management	(7) Residential Conservation	(8) Comm./Ind. Load Management	(9) Comm./Ind. Conservation	(10) Net Firm Demand	
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	4,428	172	4,256	159	69	80	18	53	3,876	
2008	4,275	148	4,127	143	69	84	53	55	3,723	
2009	4,345	136	4,209	120	56	89	86	59	3,799	
2010	4,169	118	4,051	73	33	95	75	65	3,710	***
2011	4,127	28	4,098	109	48	99	75	68	3,699	
2012	4,084	15	4,069	133	45	106	86	71	3,627	
2013	4,087	0	4,087	96	53	117	87	88	3,646	
2014	4,119	0	4,119	97	54	125	90	95	3,659	
2015	4,157	0	4,157	97	55	133	92	103	3,678	
2016	4,202	0	4,202	97	56	141	95	111	3,703	
2017	4,246	0	4,246	96	57	150	98	118	3,727	
2018	4,289	0	4,289	96	59	158	100	126	3,750	
2019	4,332	0	4,332	96	61	168	103	133	3,772	
2020	4,370	0	4,370	96	63	177	104	140	3,791	
2021	4,406	0	4,406	96	64	186	106	146	3,808	
2022	4,442	0	4,442	96	66	195	107	153	3,825	

December 31, 2012 Status

* Includes residential and commercial/industrial conservation.
** Includes sales to Progress Energy Florida, Wauchula, Ft. Meade, St. Cloud, Reedy Creek and Florida Power & Light. Contract ended with Ft. Meade on 12/31/08, Reedy Creek on 12/31/10, Progress Energy Florida on 2/31/11, Wachula on 9/31/11, St.Cloud on 12/31/2012 and Florida Power & Light on 12/31/12.
*** Net Firm Demand is not coincident with system peak.
Note: Values shown may be affected due to rounding.

Schedule 3.2

History and Forecast of Winter Peak Demand
Base Case

(1) Year	(2) Total *	(3) Wholesale **	(4) Retail *	(5) Interruptible	(6) Residential Load Management	(7) Residential Conservation	(8) Comm./Ind. Load Management	(9) Comm./Ind. Conservation	(10) Net Firm Demand	
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	4,063	162	3,900	157	96	452	18	51	3,127	
2007/08	4,405	152	4,253	120	130	456	53	52	3,443	
2008/09	4,722	67	4,655	181	120	461	87	52	3,754	
2009/10	5,195	122	5,073	117	111	468	75	56	4,246	
2010/11	4,729	120	4,609	174	92	475	75	58	3,735	
2011/12	4,075	15	4,060	103	68	481	83	58	3,267	***
2012/13	4,544	0	4,544	94	108	491	83	69	3,699	
2013/14	4,589	0	4,589	95	107	499	83	74	3,731	
2014/15	4,649	0	4,649	95	107	506	85	78	3,778	
2015/16	4,717	0	4,717	95	107	514	86	83	3,832	
2016/17	4,786	0	4,786	94	108	522	88	87	3,887	
2017/18	4,856	0	4,856	94	110	530	89	91	3,941	
2018/19	4,925	0	4,925	94	112	539	91	95	3,993	
2019/20	4,992	0	4,992	94	114	547	92	99	4,045	
2020/21	5,058	0	5,058	94	116	556	93	103	4,095	
2021/22	5,121	0	5,121	94	118	564	93	107	4,144	

December 31, 2012 Status

* Includes residential and commercial/industrial conservation.
** Includes sales to Progress Energy Florida, Wauchula, Ft. Meade, St. Cloud, Reedy Creek and Florida Power & Light. Contract ended with Ft. Meade on 12/31/08, Reedy Creek on 12/31/10, Progress Energy Florida on 2/31/11, Wachula on 9/31/11, St.Cloud on 12/31/2012 and Florida Power & Light on 12/31/12.
*** 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
High Case

(1) Year	(2) Total *	(3) Wholesale **	(4) Retail *	(5) Interruptible	(6) Residential Load Management	(7) Residential Conservation	(8) Comm./Ind. Load Management	(9) Comm./Ind. Conservation	(10) Net Firm Demand	
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	4,063	162	3,900	157	96	452	18	51	3,127	
2007/08	4,405	152	4,253	120	130	456	53	52	3,443	
2008/09	4,722	67	4,655	181	120	461	87	52	3,754	
2009/10	5,195	122	5,073	117	111	468	75	56	4,246	
2010/11	4,729	120	4,609	174	92	475	75	58	3,735	
2011/12	4,075	15	4,060	103	68	481	83	58	3,267	***
2012/13	4,562	0	4,562	94	108	491	83	69	3,717	
2013/14	4,627	0	4,627	95	107	499	83	74	3,769	
2014/15	4,709	0	4,709	95	107	506	85	78	3,838	
2015/16	4,800	0	4,800	95	107	514	86	83	3,915	
2016/17	4,892	0	4,892	94	108	522	88	87	3,993	
2017/18	4,986	0	4,986	94	110	530	89	91	4,071	
2018/19	5,080	0	5,080	94	112	539	91	95	4,148	
2019/20	5,174	0	5,174	94	114	547	92	99	4,227	
2020/21	5,266	0	5,266	94	116	556	93	103	4,303	
2021/22	5,356	0	5,356	94	118	564	93	107	4,379	

December 31, 2012 Status

* Includes residential and commercial/industrial conservation.

** Includes sales to Progress Energy Florida, Wauchula, Ft. Meade, St. Cloud, Reedy Creek and Florida Power & Light. Contract ended with Ft. Meade on 12/31/08, Reedy Creek on 12/31/10, Progress Energy Florida on 2/31/11, Wachula on 9/31/11, St.Cloud on 12/31/2012 and Florida Power & Light on 12/31/12.

*** 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
Low Case

(1) Year	(2) Total *	(3) Wholesale **	(4) Retail *	(5) Interruptible	(6) Residential Load Management	(7) Residential Conservation	(8) Comm./Ind. Load Management	(9) Comm./Ind. Conservation	(10) Net Firm Demand
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	4,063	162	3,900	157	96	452	18	51	3,127
2007/08	4,405	152	4,253	120	130	456	53	52	3,443
2008/09	4,722	67	4,655	181	120	461	87	52	3,754
2009/10	5,195	122	5,073	117	111	468	75	56	4,246
2010/11	4,729	120	4,609	174	92	475	75	58	3,735
2011/12	4,075	15	4,060	103	68	481	83	58	3,267 ***
2012/13	4,527	0	4,527	94	108	491	83	69	3,682
2013/14	4,550	0	4,550	95	107	499	83	74	3,692
2014/15	4,589	0	4,589	95	107	506	85	78	3,718
2015/16	4,636	0	4,636	95	107	514	86	83	3,751
2016/17	4,682	0	4,682	94	108	522	88	87	3,783
2017/18	4,729	0	4,729	94	110	530	89	91	3,814
2018/19	4,774	0	4,774	94	112	539	91	95	3,842
2019/20	4,818	0	4,818	94	114	547	92	99	3,871
2020/21	4,859	0	4,859	94	116	556	93	103	3,896
2021/22	4,896	0	4,896	94	118	564	93	107	3,919

December 31, 2012 Status

* Includes residential and commercial/industrial conservation.
** Includes sales to Progress Energy Florida, Wauchula, Ft. Meade, St. Cloud, Reedy Creek and Florida Power & Light. Contract ended with Ft. Meade on 12/31/08, Reedy Creek on 12/31/10, Progress Energy Florida on 2/31/11, Wachula on 9/31/11, St.Cloud on 12/31/2012 and Florida Power & Light on 12/31/12.
*** Net Firm Demand is not coincident with system peak.
Note: Values shown may be affected due to rounding.

Schedule 3.3

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

(1) Year	(2) Total	(3) Residential Conservation	(4) Comm./Ind. Conservation	(5) Retail	(6) Wholesale *	(7) Utility Use & Losses	(8) Net Energy for Load	(9) Load ** Factor %
2003	18,760	378	152	18,231	587	985	19,803	56.4
2004	18,999	394	168	18,437	589	945	19,971	59.0
2005	19,495	404	176	18,915	712	952	20,579	57.4
2006	19,625	412	188	19,025	700	1,000	20,725	57.2
2007	20,154	421	200	19,533	829	916	21,278	56.6
2008	19,632	430	212	18,990	752	909	20,650	56.8
2009	19,449	443	231	18,774	191	978	19,943	54.1
2010	19,923	458	251	19,213	305	1,149	20,667	50.5
2011	19,295	472	259	18,564	93	642	19,298	53.7
2012	19,171	491	267	18,412	69	839	19,320	56.3
2013	19,068	515	351	18,202	0	964	19,166	54.9
2014	19,288	534	384	18,370	0	972	19,342	55.0
2015	19,521	553	417	18,552	0	982	19,534	54.9
2016	19,816	572	449	18,795	0	995	19,791	54.7
2017	20,111	592	480	19,039	0	1,008	20,047	54.8
2018	20,410	613	511	19,287	0	1,021	20,308	54.7
2019	20,703	634	541	19,529	0	1,034	20,563	54.7
2020	20,973	655	569	19,749	0	1,046	20,795	54.5
2021	21,238	676	598	19,963	0	1,058	21,021	54.6
2022	21,513	698	627	20,189	0	1,070	21,259	54.5

December 31, 2012 Status

* Includes residential and commercial/industrial conservation.
** Load Factor is the ratio of total system average load to peak demand.
Note: Values shown may be affected due to rounding.

Schedule 3.3

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

(1) Year	(2) Total	(3) Residential Conservation	(4) Comm./Ind. Conservation	(5) Retail	(6) Wholesale *	(7) Utility Use & Losses	(8) Net Energy for Load	(9) Load ** Factor %
2003	18,760	378	152	18,231	587	985	19,803	56.4
2004	18,999	394	168	18,437	589	945	19,971	59.0
2005	19,495	404	176	18,915	712	952	20,579	57.4
2006	19,625	412	188	19,025	700	1,000	20,725	57.2
2007	20,154	421	200	19,533	829	916	21,278	56.6
2008	19,632	430	212	18,990	752	909	20,650	56.8
2009	19,449	443	231	18,774	191	978	19,943	54.1
2010	19,923	458	251	19,213	305	1,149	20,667	50.5
2011	19,295	472	259	18,564	93	642	19,298	53.7
2012	19,171	491	267	18,412	69	839	19,320	56.3
2013	19,166	515	351	18,300	0	969	19,269	55.0
2014	19,488	534	384	18,570	0	983	19,553	55.1
2015	19,827	553	417	18,858	0	998	19,856	55.0
2016	20,233	572	449	19,212	0	1,017	20,229	54.8
2017	20,643	592	480	19,571	0	1,036	20,607	54.9
2018	21,062	613	511	19,939	0	1,056	20,994	54.9
2019	21,479	634	541	20,305	0	1,075	21,380	54.9
2020	21,876	655	569	20,652	0	1,094	21,746	54.7
2021	22,272	676	598	20,998	0	1,113	22,110	54.8
2022	22,684	698	627	21,360	0	1,132	22,492	54.8

December 31, 2012 Status

* Includes residential and commercial/industrial conservation.
** Load Factor is the ratio of total system average load to peak demand.
Note: Values shown may be affected due to rounding.

Schedule 3.3

History and Forecast of Annual Net Energy for Load - GWH
Low 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 %
2003	18,760	378	152	18,231	587	985	19,803	56.4
2004	18,999	394	168	18,437	589	945	19,971	59.0
2005	19,495	404	176	18,915	712	952	20,579	57.4
2006	19,625	412	188	19,025	700	1,000	20,725	57.2
2007	20,154	421	200	19,533	829	916	21,278	56.6
2008	19,632	430	212	18,990	752	909	20,650	56.8
2009	19,449	443	231	18,774	191	978	19,943	54.1
2010	19,923	458	251	19,213	305	1,149	20,667	50.5
2011	19,295	472	259	18,564	93	642	19,298	53.7
2012	19,171	491	267	18,412	69	839	19,320	56.3
2013	18,971	515	351	18,104	0	958	19,063	54.9
2014	19,089	534	384	18,171	0	962	19,133	54.9
2015	19,219	553	417	18,250	0	966	19,216	54.8
2016	19,407	572	449	18,387	0	973	19,360	54.6
2017	19,592	592	480	18,520	0	981	19,501	54.7
2018	19,779	613	511	18,655	0	988	19,643	54.6
2019	19,956	634	541	18,782	0	995	19,777	54.5
2020	20,109	655	569	18,884	0	1,000	19,885	54.3
2021	20,254	676	598	18,979	0	1,006	19,985	54.3
2022	20,407	698	627	19,082	0	1,011	20,093	54.3

December 31, 2012 Status

* Includes residential and commercial/industrial conservation.
** Load Factor is the ratio of total system average load to peak demand.
Note: Values shown may be affected due to rounding.

Schedule 4
Base Case

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	2012 Actual		2013 Forecast		2014 Forecast	
Month	Peak Demand * MW	NEL ** GWH	Peak Demand * MW	NEL ** GWH	Peak Demand * MW	NEL ** GWH
January	3,532	1,433	3,970	1,486	3,999	1,496
February	3,393	1,318	3,381	1,288	3,405	1,297
March	2,947	1,500	3,041	1,402	3,064	1,413
April	3,293	1,505	3,080	1,424	3,104	1,436
May	3,661	1,804	3,467	1,674	3,495	1,689
June	3,773	1,764	3,716	1,834	3,749	1,851
July	3,914	1,948	3,830	1,916	3,864	1,934
August	3,907	1,940	3,893	1,924	3,928	1,943
September	3,685	1,791	3,706	1,814	3,740	1,833
October	3,495	1,620	3,389	1,630	3,421	1,647
November	2,516	1,289	2,917	1,353	2,948	1,367
December	2,622	1,407	3,181	1,420	3,215	1,436
TOTAL		19,320		19,166		19,342

December 31, 2012 Status

* Peak demand represents total retail and wholesale demand, excluding conservation impacts.
** Values shown may be affected due to rounding.

Schedule 4
High Case

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	2012 Actual		2013 Forecast		2014 Forecast	
Month	Peak Demand * MW	NEL ** GWH	Peak Demand * MW	NEL ** GWH	Peak Demand * MW	NEL ** GWH
January	3,532	1,433	3,988	1,493	4,037	1,511
February	3,393	1,318	3,398	1,295	3,440	1,311
March	2,947	1,500	3,056	1,410	3,096	1,428
April	3,293	1,505	3,096	1,432	3,136	1,452
May	3,661	1,804	3,485	1,683	3,532	1,707
June	3,773	1,764	3,736	1,844	3,788	1,872
July	3,914	1,948	3,851	1,926	3,904	1,956
August	3,907	1,940	3,913	1,935	3,970	1,965
September	3,685	1,791	3,725	1,824	3,779	1,853
October	3,495	1,620	3,407	1,639	3,457	1,665
November	2,516	1,289	2,933	1,360	2,979	1,382
December	2,622	1,407	3,197	1,428	3,249	1,451
TOTAL		19,320		19,269		19,553

December 31, 2012 Status

* Peak demand represents total retail and wholesale demand, excluding conservation impacts.
* * Values shown may be affected due to rounding.

Schedule 4
Low Case

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	2012 Actual		2013 Forecast		2014 Forecast	
Month	Peak Demand * MW	NEL ** GWH	Peak Demand * MW	NEL ** GWH	Peak Demand * MW	NEL ** GWH
January	3,532	1,433	3,953	1,480	3,960	1,482
February	3,393	1,318	3,364	1,281	3,371	1,283
March	2,947	1,500	3,025	1,395	3,033	1,398
April	3,293	1,505	3,064	1,417	3,072	1,421
May	3,661	1,804	3,449	1,665	3,458	1,670
June	3,773	1,764	3,697	1,824	3,709	1,831
July	3,914	1,948	3,810	1,905	3,823	1,913
August	3,907	1,940	3,872	1,913	3,886	1,922
September	3,685	1,791	3,687	1,804	3,702	1,812
October	3,495	1,620	3,371	1,621	3,386	1,629
November	2,516	1,289	2,902	1,346	2,917	1,353
December	2,622	1,407	3,164	1,412	3,182	1,420
TOTAL		19,320		19,063		19,134

December 31, 2012 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
Base Case Forecast Basis

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
	Fuel Requirements		Unit	Actual 2011	Actual 2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
(1)	Nuclear		Trillion BTU	0	0	0	0	0	0	0	0	0	0	0	0
(2)	Coal		1000 Ton	4,261	4,325	4,386	4,212	4,414	4,449	4,558	4,562	4,574	4,599	4,563	4,569
(3)	Residual	Total	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(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	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(8)	Distillate	Total	1000 BBL	26	37	18	3	5	7	0	0	1	0	1	0
(9)		Steam	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(10)		CC	1000 BBL	26	36	18	2	3	4	0	0	0	0	0	0
(11)		CT	1000 BBL	0	1	0	1	2	3	0	0	1	0	1	0
(12)		Diesel	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(13)	Natural Gas	Total	1000 MCF	55,515	56,592	54,048	59,624	58,852	59,872	57,027	59,401	60,365	61,400	64,610	65,370
(14)		Steam	1000 MCF	0	0	0	0	0	0	0	0	0	0	0	0
(15)		CC	1000 MCF	49,542	50,662	52,332	56,231	54,177	54,160	57,001	59,328	60,150	61,088	63,758	65,125
(16)		CT	1000 MCF	5,973	5,930	1,716	3,393	4,675	5,712	26	73	215	312	852	245
(17)	Other (Specify)														
(18)	Petroleum Coke		1000 Ton	439	347	432	468	437	471	470	437	470	471	437	470

Notes: Values shown may be affected due to rounding.
All values exclude ignition.

Schedule 6.1

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
				Actual	Actual										
	Energy Sources		Unit	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
(1)	Annual Firm Interchange		GWh	461	689	76	128	136	150	3	3	0	0	0	0
(2)	Nuclear		GWh	0	0	0	0	0	0	0	0	0	0	0	0
(3)	Coal		GWh	9,657	9,720	10,049	9,658	10,099	10,198	10,473	10,477	10,486	10,566	10,488	10,493
(4)	Residual	Total	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(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	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(9)	Distillate	Total	GWh	13	20	10	0	0	0	0	0	0	0	0	0
(10)		Steam	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(11)		CC	GWh	13	20	10	0	0	0	0	0	0	0	0	0
(12)		CT	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(13)		Diesel	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(14)	Natural Gas	Total	GWh	7,392	7,568	7,347	8,065	7,891	7,993	8,149	8,496	8,649	8,780	9,186	9,342
(15)		Steam	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(16)		CC	GWh	6,860	7,042	7,197	7,764	7,478	7,482	8,147	8,489	8,629	8,751	9,107	9,319
(17)		CT	GWh	532	526	150	301	413	511	2	7	20	29	79	23
(18)	Other (Specify)														
(19)	Petroleum Coke Generation		GWh	1,231	971	1,184	1,295	1,210	1,305	1,302	1,211	1,302	1,306	1,211	1,302
(20)	Net Interchange		GWh	150	81	306	3	5	24	(1)	1	5	22	15	1
(21)	Purchased Energy from														
(22)	Non-Utility Generators	(A)	GWh	393	271	194	194	194	121	121	121	121	121	121	121
(23)	Net Energy for Load		GWh	19,298	19,320	19,166	19,342	19,534	19,791	20,047	20,308	20,563	20,795	21,021	21,259

(A) Line (22) includes energy purchased from Non-Renewable and Renewable resources.
Notes: Values shown may be affected due to rounding.

Schedule 6.2

History and Forecast of Net Energy for Load by Fuel Source as a Percent
Base Case Forecast Basis

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
	Energy Sources		Unit	Actual 2011	Actual 2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
(1)	Annual Firm Interchange		%	2.4	3.6	0.4	0.7	0.7	0.8	0.0	0.0	0.0	0.0	0.0	0.0
(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		%	50.0	50.3	52.4	49.9	51.7	51.5	52.2	51.6	51.0	50.8	49.9	49.4
(4)	Residual	Total	%	0.0	0.0	0.0	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	%	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	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(9)	Distillate	Total	%	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(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	%	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(12)		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
(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	%	38.3	39.2	38.3	41.7	40.4	40.4	40.6	41.8	42.1	42.2	43.7	43.9
(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	%	35.5	36.4	37.6	40.1	38.3	37.8	40.6	41.8	42.0	42.1	43.3	43.8
(17)		CT	%	2.8	2.7	0.8	1.6	2.1	2.6	0.0	0.0	0.1	0.1	0.4	0.1
(18)	Other (Specify)														
(19)	Petroleum Coke Generation		%	6.4	5.0	6.2	6.7	6.2	6.6	6.5	6.0	6.3	6.3	5.8	6.1
(20)	Net Interchange		%	0.8	0.4	1.6	0.0	0.0	0.1	(0.0)	0.0	0.0	0.1	0.1	0.0
(21)	Purchased Energy from														
(22)	Non-Utility Generators	(A)	%	2.0	1.4	1.0	1.0	1.0	0.6	0.6	0.6	0.6	0.6	0.6	0.6
(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

(A) Line (22) includes energy purchased from Non-Renewable and Renewable resources.
Notes: Values shown may be affected due to rounding.

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Chapter III

The Customer, Demand and Energy Forecasts are 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 2013-2022 forecasts. The data tables in Chapter II outline the expected customer, demand, and energy values for the 2013-2022 time period.

RETAIL LOAD

MetrixND, an advanced statistics program for analysis and forecasting, was used to develop the 2013-2022 Customer, Demand and Energy forecasts. This software allows a platform for the development of more dynamic and fully integrated models.

In addition, Tampa Electric uses MetrixLT, which integrates with MetrixND to develop multiple-year forecasts of energy usage at the hourly level. This tool allows the annual or monthly forecasts in MetrixND to be combined with hourly load shape data to develop a long-term "bottom-up" forecast that 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 Multiregression Model
3. Energy Multiregression Model
4. Peak Demand Multiregression Model
5. Phosphate Demand and Energy Analysis
6. Conservation, Load Management and Cogeneration Programs

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 Moody's Analytics and the University of Florida's Bureau of Economic and Business Research (BEBR).

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

2. CUSTOMER MULTIREGRESSION MODEL

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

1. *Residential Customer Model:* Customer projections are a function of Hillsborough County's population. Since a strong correlation exists between historical changes in service area customers and historical changes in Hillsborough County, the County's population estimates for 2013-2022 were used to forecast the future growth patterns in residential customers.
2. *Commercial Customer Model:* Total commercial customers include commercial customers plus temporary service customers (temporary poles on construction sites); therefore, two models are used to forecast total commercial customers:
    a. The Commercial Customer Model is a function of residential customers. An increase in the number of households provides the need for additional services, restaurants, and retail establishments. The amount of residential activity also plays a part in the attractiveness of the Tampa Bay area as a place to relocate or start a new business.
    b. Projections of employment in the construction sector are a good indicator of expected increases and decreases in local construction activity. Therefore, the Temporary Service Model projects the number of customers as a function of construction employment.
3. *Industrial Customer Model (Non-Phosphate):* Non-phosphate industrial customers include two rate classes that have been modeled individually: General Service and General Service Demand.
    a. The General Service Customer Model is a function of Hillsborough County commercial employment.

    b. The General Service Demand Customer Model is based on the recent growth trend in the sector.

4. *Public Authority Customer Model:* Customer projections are a function of Hillsborough County's population. The need for public services will depend on the number of people in the region; therefore, consistent with the residential customer model, Hillsborough's population projections are used to determine future growth in the public authorities sector.
5. *Street & Highway Lighting Customer Model:* Customer projections are based on the recent growth trend in the sector.

3. ENERGY MULTIREGRESSION MODEL

There are a total of seven 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) end-use equipment index variables, which capture the long-term net effect of equipment saturation and equipment efficiency improvements; (2) changes in the economy such as household income, household size, and the price of electricity; and, (3) 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:

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

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

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

Next, the monthly usage multiplier or utilization variables (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.

$$\textbf{HeatUse}_{y,m} =$$
$$\left(\frac{\text{Price}_{y,m}}{\text{Price}_{\text{base } y,m}} \right)^{-.10} \text{x} \left(\frac{\text{HH Income}_{y,m}}{\text{HH Income}_{\text{base } y,m}} \right)^{.20} \text{x} \left(\frac{\text{HH Size}_{y,m}}{\text{HH Size}_{\text{base } y,m}} \right)^{.20} \text{x} \left(\frac{\text{HDD}_{y,m}}{\text{Normal HDD}} \right)$$

$$\textbf{CoolUse}_{y,m} =$$
$$\left(\frac{\text{Price}_{y,m}}{\text{Price}_{\text{base } y,m}} \right)^{-.10} \text{x} \left(\frac{\text{HH Income}_{y,m}}{\text{HH Income}_{\text{base } y,m}} \right)^{.20} \text{x} \left(\frac{\text{HH Size}_{y,m}}{\text{HH Size}_{\text{base } y,m}} \right)^{.20} \text{x} \left(\frac{\text{CDD}_{y,m}}{\text{Normal CDD}} \right)$$

$$\textbf{OtherUse}_{y,m} =$$
$$\left(\frac{\text{Price}_{y,m}}{\text{Price}_{\text{base } y,m}} \right)^{-.10} \text{x} \left(\frac{\text{HH Income}_{y,m}}{\text{HH Income}_{\text{base } y,m}} \right)^{.20} \text{x} \left(\frac{\text{HH Size}_{y,m}}{\text{HH Size}_{\text{base } y,m}} \right)^{.20} \text{x} \left(\frac{\text{Billing Days}_{y,m}}{\text{Billing Days}_{\text{base } y,m}} \right)$$

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

2. *Commercial Energy Models:* total commercial energy sales include commercial sales plus temporary service sales (temporary poles on construction sites); therefore, two models are used to forecast total commercial energy sales.
   a. Commercial Energy Model: The model framework for the commercial sector is the same as the residential model. It also has three major components and utilizes the SAE model framework. The differences lie in the type of end-use equipment and in the economic variables used. The end-use equipment variables are based on commercial appliance/equipment saturation and efficiency assumptions. The

economic drivers in the commercial model are commercial productivity measured in terms of dollar output and the price of electricity for the commercial sector. The third component, weather variables, is the same as in the residential model.

b. Temporary Service Energy Model: This 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 driver being temporary service customer growth.

3. *Industrial Energy Model (Non-Phosphate):* Nonphosphate industrial energy includes two rate classes that have been modeled individually: General Service and General Service Demand.
   a. The General Service Energy Model utilizes the same SAE model framework as the commercial energy model. The weather component is consistent with the residential and commercial models.
   b. The General Service Demand Energy Model is based on industrial employment, the price of electricity in the industrial sector, cooling degree-days and number of days billed. Unlike the previous models discussed, heating load does not impact this sector.

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 and 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 seven 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. PEAK DEMAND MULTIREGRESSION MODEL

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 and day prior to 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

Tampa Electric's phosphate customers are relatively few in number, which has allowed the company's Sales and Marketing Department to obtain 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 individual customer trend analysis and discussions with industry experts.

6. CONSERVATION, LOAD MANAGEMENT AND COGENERATION PROGRAMS

Conservation and Load Management demand and energy savings are forecasted for each individual program. The savings is based on a forecast of the annual number of new participants, estimated annual average energy savings per participant and estimated summer and winter average demand savings per participant. The individual forecasts are aggregated and represent the cumulative amount of Demand Side Management (DSM) savings throughout the forecast horizon.

Tampa Electric's retail demand and energy forecasts are adjusted downward to reflect the incremental demand and energy savings of these DSM 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 energy efficiency and conservation plan contains a mix of proven, mature programs along with several newly developed 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 – Encourages residential, commercial and industrial programs to reduce weather-sensitive heating, cooling and water heating through a radio signal control mechanism. However, the residential program is closed to new participation.

3. Energy Audits - a "how to" information and analysis guide for customers. Six types of audits are available to Tampa Electric customers; four types are for residential class customers and two types are for commercial/industrial customers.

4. Residential Building Envelope - An incentive program for existing residential structures which will help to supplement the cost of adding additional ceiling and wall insulation, window film and window upgrades.

5. Commercial 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. Residential 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 and packaged terminal air conditioning cooling equipment.

11. Commercial Chillers - Encourages the installation of high efficiency chiller equipment.

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

13. Low Income Weatherization - Provides for the installation of energy efficient measures for qualified low-income customers.

14. Energy Planner - Reduces weather-sensitive loads through an innovative rate used to encourage residential customers to make behavioral or equipment usages changes by pre-programming HVAC, water heating and pool pumps.

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

16. Commercial Building Envelope - An incentive program for existing commercial structures which will help to supplement the cost of adding additional ceiling and wall insulation and window film.

17. Energy Efficient Motors - Encourages the installation of high-efficiency motors.

18. Commercial Lighting Occupancy Sensors – Encourages the installation of occupancy sensors for load control in commercial facilities.

19. Commercial Refrigeration (Anti-condensate) – A program to encourage the installation of anti-condensate equipment sensors for load control in commercial facilities.

20. Commercial Water Heating - Encourages the installation of high efficiency water heating systems.

21. Commercial Demand Response - A turn-key program to incent commercial/industrial customers to reduce their demand for electricity in response to market signals.

22. Residential Electronically Commutated Motor - An incentive program designed to help residential customers improve the overall efficiency of their existing HVAC equipment by replacing the existing motor in the air-handler with an Electronically Commutated Motor.

23. Residential HVAC Re-commissioning - An incentive program designed to help residential customers ensure HVAC equipment is operating at optimal efficiency through maintenance and equipment tune-up.

24. Energy Education Outreach - A program designed to establish opportunities for engaging groups of customers and students, in energy-efficiency related discussions in an organized setting. Participants will be provided with energy saving devices and supporting information appropriate for the audience.

25. Commercial Electronically Commutated Motor - An incentive program designed to help commercial customers improve the overall efficiency of their existing HVAC equipment by replacing the existing HVAC motors with an Electronically Commutated Motor.

26. Commercial HVAC Re-commissioning - An incentive program designed to help commercial customers ensure HVAC equipment is operating at optimal efficiency through maintenance and equipment tune-up.

27. Cool Roof - An incentive program designed to encourage commercial/industrial customers to install a cool roof system above conditioned spaces.

28. Energy Recovery Ventilation - An incentive program designed to help commercial/industrial customers reduce humidity and HVAC loads in buildings.

The programs listed above were developed to meet the FPSC demand and energy goals established in Docket No. 080409-EG, approved on December 30, 2009. The 2012 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 its focus on 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.

TABLE III-1
Comparison of Achieved MW and GWh Reductions With Florida Public Service Commission Goals
Savings at the Generator

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
2010	11.3	6.4	176.6%	8.1	4.6	176.1%	17.3	9.8	176.5%
2011	21.5	14.9	144.3%	16.7	11.2	149.1%	36.5	23.8	153.4%
2012	32.4	25.1	129.1%	26.4	19.6	134.7%	57.5	41.5	138.6%

Commercial/Industrial

	Winter Peak MW Reduction			Summer Peak MW Reduction			GWh Energy Reduction		
Year	Total Achieved	Commission Approved Goal	% Variance	Total Achieved	Commission Approved Goal	% Variance	Total Achieved	Commission Approved Goal	% Variance
2010[1]	6.6	0.9	733.3%	9.8	2.5	392.0%	16.4	6.5	252.3%
2011	18.4	2.0	920.0%	25.1	6.1	411.5%	49.4	17.1	288.9%
2012	22.0	3.4	647.1%	31.4	10.4	301.9%	59.9	32.5	184.3%

Combined Total

	Winter Peak MW Reduction			Summer Peak MW Reduction			GWh Energy Reduction		
Year	Total Achieved	Commission Approved Goal	% Variance	Total Achieved	Commission Approved Goal	% Variance	Total Achieved	Commission Approved Goal	% Variance
2010	17.9	7.3	245.2%	17.9	7.1	252.1%	33.7	16.3	206.7%
2011	39.9	16.9	236.1%	41.8	17.3	241.6%	85.9	40.9	210.0%
2012	54.4	28.5	190.9%	57.8	30.0	192.7%	117.4	74.0	158.6%

[1] 2010 Commercial/Industrial Reductions corrected in 2012

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
7. Weather

1. POPULATION AND HOUSEHOLDS

Florida and Hillsborough County population forecasts are the starting point for developing the customer and energy projections. Both the University of Florida's Bureau of Economic and Business Research (BEBR) and Moody's Analytics supply population projections for Hillsborough County and Florida. The population forecast is based upon a blend of BEBR and Moody's Analytics projections. Over the next ten years (2013-2022) the average annual population growth rate in Hillsborough County is expected to be 1.5%. In addition, Moody's Analytics 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 1.8% average annual rate. Moody's Analytics supplies employment projections.

3. COMMERCIAL, INDUSTRIAL AND GOVERNMENTAL OUTPUT

In addition to employment, output in terms of real gross domestic product by employment sector is utilized in computing energy in their respective sectors. Over the next ten years, output for the entire employment sector is assumed to rise at a 3.0% average annual rate. Moody's Analytics supplies output projections.

4. REAL HOUSEHOLD INCOME

Moody's Analytics supplies the assumptions for Hillsborough County's real household income growth. During 2013-2022, real household income for Hillsborough County is expected to increase at a 1.9% average annual rate.

5. PRICE OF ELECTRICITY

Forecasts for the price of electricity by customer class are supplied by Tampa Electric's Regulatory Affairs 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.

HIGH AND LOW SCENARIO FOCUS ASSUMPTIONS

The base case scenario is tested for sensitivity to varying economic conditions and customer growth rates. The high and low peak demand and energy scenarios represent alternatives to the company's base case outlook. Compared to the base case, the expected 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.

1. RETAIL ENERGY

For 2013-2022, retail energy sales are projected to rise at a 1.2% annual rate. The major contributor to growth is the residential category, increasing at an annual rate of 1.3%.

2. WHOLESALE ENERGY

Tampa Electric does not currently have any contracts for firm wholesale sales.

HISTORY AND FORECAST OF PEAK LOADS

Historical, base, high, and low scenario forecasts of peak loads for the summer and winter seasons are presented in Schedules 3.1 and 3.2, respectively. For the 2013-2022 period, Tampa Electric's base retail firm peak demand is expected to advance in the winter at an average annual rate of 1.3% and at rate of 1.1% in the summer.

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Chapter IV

The proposed generating facility additions and changes shown in Schedule 8.1 integrate energy efficiency and conservation 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 energy efficiency and conservation 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 cost-effective plan that maintains system reliability and environmental requirements while considering technology availability and lead times for construction. To meet the expected system demand and energy requirements over the next ten years, both peaking and intermediate resources are needed. The peaking capacity need will be met by purchased power agreements for peaking capacity secured through 2016. In 2017, Tampa Electric currently expects to meet its intermediate load needs by converting Polk Power Station's simple cycle combustion turbines (Polk Units 2-5) to a natural gas combined cycle (NGCC) unit. The operating and cost parameters associated with the capacity additions resulting from the analysis are shown in Schedule 9. Beyond 2017, the company foresees the future needs being that of additional peaking capacity, which it will meet by combustion turbine additions and/or future purchased power agreements.

Tampa Electric will compare viable purchased power options as an alternative and/or enhancement to planned unit additions. At a minimum, the purchased power must have firm transmission service and firm fuel transportation to support firm reserve margin criteria for reliability. Assumptions and information that impact the plan are discussed in the following sections and in Chapter V.

COGENERATION

Tampa Electric plans for a total of 23 MW of firm cogeneration capacity, of which all 23 MW (through December 2015) are imported from outside its service area. In 2013 Tampa Electric plans for 626 MW of cogeneration capacity operating in its service area. The as-available cogen to Tampa Electric in 2013 is subject to change due to a contract ending of 131 MW later this year.

Cogeneration in Service Area	Capacity (MW)
Self-service	266
Firm to Tampa Electric	23
As-available to Tampa Electric	155
Export to other systems	182
Total	626

Self-service is the capacity and energy cogenerators use to serve their internal load requirements.

FUEL REQUIREMENTS

A forecast of fuel requirements and energy sources is shown in Schedule 5, Schedule 6.1 and Schedule 6.2. Tampa Electric currently uses a 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 Big Bend Aero, Bayside, and Polk Units. As shown in Schedule 6.2, in 2013 coal and petcoke will fuel 59% of net energy for load and natural gas will fuel 38%. Less than one percent of net energy for load will be fueled by oil. The remaining net energy for load is served by non-utility generators and net interchange purchases. Some of the company's natural gas generating units also have dual-fuel (i.e., natural gas or oil) capability, which adds to system reliability.

ENVIRONMENTAL CONSIDERATIONS

Tampa Electric has always strived to reduce emissions from its generating facilities. Since 1998, Tampa Electric has reduced annual sulfur dioxides (SO_2) by 94%, nitrogen oxides (NO_x) by 91%, particulate matter (PM) by 87% and mercury emissions by 90%. These reductions were the result of a December 1999 agreement between the Florida Department of Environmental Protection (DEP) and Tampa Electric. In February 2000, Tampa Electric reached a similar agreement with the U.S. Environmental Protection Agency (EPA) in a Consent Decree (CD).

Tampa Electric's major activities to increase pollution control and decrease emissions include:

- Integration of Big Bend Unit 3 into Big Bend Unit 4's existing flue gas desulfurization (scrubber) system in 1995
- Installation of a scrubber on Big Bend Units 1 and 2 in 1999
- Installation and operation of selective catalytic reduction systems, at Big Bend Station from 2007 to 2010
- Installation and operation of combustion tuning and optimization projects at Big Bend Station from 2000 to 2004

- Repowering of Gannon Station to H.L. Culbreath Bayside Power Station from coal to natural gas optimization from 2003 to 2004
- Improvement of the Big Bend electrostatic precipitators

Through a proactive approach, Tampa Electric has achieved significant levels of emission reduction. However, the company recognizes that environmental regulations continue to change. As these regulations evolve, they will impact both cost and operations.

INTERCHANGE SALES AND PURCHASES

Currently, Tampa Electric has no long-term firm sales agreements; however, the company does have the following long-term purchased power contracts for capacity and energy.

- 117 MW from Calpine Energy Services for the period November 2011 through December 2016
- 160 MW from Southern Power Company for the period January 2013 through December 2015
- 121 MW from Pasco Cogen for the period January 2009 through December 2018

There is a 30 MW need for the summer of 2016 to meet the reserve margin planning criteria of 20%. Tampa Electric will address this need from among multiple resources, including economic purchases.

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
2013	4,276	398	0	23	4,697	3,667	1,030	28%	0	1,030	28%
2014	4,276	398	0	23	4,697	3,701	996	27%	0	996	27%
2015	4,276	398	0	23	4,697	3,741	956	26%	0	956	26%
2016	4,276	268	0	0	4,544	3,788	756	20%	0	756	20%
2017	4,735	121	0	0	4,856	3,835	1,021	27%	0	1,021	27%
2018	4,735	121	0	0	4,856	3,881	975	25%	0	975	25%
2019	4,735	0	0	0	4,735	3,927	808	21%	0	808	21%
2020	4,925	0	0	0	4,925	3,971	954	24%	0	954	24%
2021	4,925	0	0	0	4,925	4,012	913	23%	0	913	23%
2022	4,925	0	0	0	4,925	4,054	871	21%	0	871	21%

NOTE:

1. Capacity import includes firm purchase power agreements (PPA) with Calpine of 117 MW through 2016, Southern of 160 MW through 2015, and Pasco Cogen of 121 MW through 2018
2. A 30 MW need for the summer of 2016 to be identified among multiple resources.
3. The QF column accounts for cogeneration that will be purchased under firm contracts, and excludes non-firm purchases.

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
2012-13	4,668	398	0	23	5,089	3,699	1,390	38%	0	1,390	38%
2013-14	4,668	398	0	23	5,089	3,731	1,358	36%	0	1,358	36%
2014-15	4,668	398	0	23	5,089	3,778	1,311	35%	0	1,311	35%
2015-16	4,668	238	0	0	4,906	3,832	1,074	28%	0	1,074	28%
2016-17	5,131	121	0	0	5,252	3,887	1,365	35%	0	1,365	35%
2017-18	5,131	121	0	0	5,252	3,941	1,311	33%	0	1,311	33%
2018-19	5,131	0	0	0	5,131	3,993	1,138	28%	0	1,138	28%
2019-20	5,131	0	0	0	5,131	4,045	1,086	27%	0	1,086	27%
2020-21	5,351	0	0	0	5,351	4,095	1,256	31%	0	1,256	31%
2021-22	5,351	0	0	0	5,351	4,144	1,207	29%	0	1,207	29%

NOTE:

1. Capacity import includes firm purchase power agreements (PPA) with Calpine of 117 MW through 2016, Southern of 160 MW through 2015, and Pasco Cogen of 121 MW through 2018
2. The QF column accounts for cogeneration that will be purchased under firm contracts, and excludes non-firm purchases.

Schedule 8.1

Planned and Prospective Generating Facility Additions

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
				Fuel		Fuel Trans.						Net Capability		
Plant Name	Unit No.	Location	Unit Type	Primary	Alternate	Primary	Alternate	Const. Start Mo/Yr	Commercial In-Service Mo/Yr	Expected Retirement Mo/Yr	Gen. Max. Nameplate kW	Summer MW	Winter MW	Status
Polk 2-5 CC	1	Polk	CC	NG	LO*	PL	N/A	10/14	1/17	unknown	unknown	1063**	1195**	P
Future CT	1	unknown	CT	NG	N/A	PL	N/A	9/19	5/20	unknown	unknown	190	220	P

Notes:
* Net capability associated with the Polk 2-5 CC on LO is approximately 473 MW Summer and 540 MW Winter.
** Net capability values shown for the Polk 2-5 CC reflect the conversion of Polk Units 2-5 CTs to a natural gas CC unit in 2017. Incremental capacity gain from the conversion is 459 MW summer and 463 MW winter.

SCHEDULE 9
(Page 1 of 2)
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
UTILITY: TAMPA ELECTRIC COMPANY

(1)	PLANT NAME AND UNIT NUMBER	POLK 2-5 CC CONVERSION
(2)	CAPACITY	
	A. SUMMER	1063
	B. WINTER	1195
(3)	TECHNOLOGY TYPE	COMBINED CYCLE
(4)	ANTICIPATED CONSTRUCTION TIMING	
	A. FIELD CONSTRUCTION START DATE	OCT 2014
	B. COMMERCIAL IN-SERVICE DATE	JAN 2017
(5)	FUEL	
	A. PRIMARY FUEL	NATURAL GAS
	B. ALTERNATE FUEL*	LIGHT OIL
(6)	AIR POLLUTION CONTROL STRATEGY	SCR, DLN BURNERS
(7)	COOLING METHOD	COOLING RESERVOIR
(8)	TOTAL SITE AREA	UNDETERMINED
(9)	CONSTRUCTION STATUS	PROPOSED
(10)	CERTIFICATION STATUS	IN PROGRESS
(11)	STATUS WITH FEDERAL AGENCIES	IN PROGRESS
(12)	PROJECTED UNIT PERFORMANCE DATA	
	PLANNED OUTAGE FACTOR (POF)	3.2
	FORCED OUTAGE RATE (FOR)	0.7
	EQUIVALENT AVAILABILITY FACTOR (EAF)	96.1
	RESULTING CAPACITY FACTOR (2017)	48.5%
	AVERAGE NET OPERATING HEAT RATE (ANOHR) [1]	7,009 Btu/kWh
(13)	PROJECTED UNIT FINANCIAL DATA	
	BOOK LIFE (YEARS)	30
	TOTAL INSTALLED COST (IN-SERVICE YEAR $/kW)	449.02
	DIRECT CONSTRUCTION COST ($/kW)	368.12
	AFUDC AMOUNT ($/kW)	61.60
	ESCALATION ($/kW)	19.29
	FIXED O&M ($/kW – Yr)	1.27
	VARIABLE O&M ($/MWH)	2.43
	K FACTOR	1.5383

[1] BASED ON IN-SERVICE YEAR.
* NET CAPABILITY ASSOCIATED WITH POLK 2-5 CC ON LIGHT OIL IS APPROXIMATELY 473 MW SUMMER AND 540 MW WINTER.

SCHEDULE 9
(Page 2 of 2)
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	190
	B. WINTER	220
(3)	TECHNOLOGY TYPE	COMBUSTION TURBINE
(4)	ANTICIPATED CONSTRUCTION TIMING	
	A. FIELD CONSTRUCTION START DATE	SEP 2019
	B. COMMERCIAL IN-SERVICE DATE	MAY 2020
(5)	FUEL	
	A. PRIMARY FUEL	NATURAL GAS
	B. ALTERNATE FUEL	N/A
(6)	AIR POLLUTION CONTROL STRATEGY	WET LOW EMISSION
(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)	2.6
	FORCED OUTAGE RATE (FOR)	1.0
	EQUIVALENT AVAILABILITY FACTOR (EAF)	95.4
	RESULTING CAPACITY FACTOR (2019)	0.5%
	AVERAGE NET OPERATING HEAT RATE (ANOHR) [1]	11,983 Btu/kWh
(13)	PROJECTED UNIT FINANCIAL DATA	
	BOOK LIFE (YEARS)	25
	TOTAL INSTALLED COST (IN-SERVICE YEAR $/kW)	757.64
	DIRECT CONSTRUCTION COST ($/kW)	571.47
	AFUDC AMOUNT ($/kW)	70.36
	ESCALATION ($/kW)	115.81
	FIXED O&M ($/kW – Yr)	14.01
	VARIABLE O&M ($/MWH)	2.22
	K FACTOR	1.4763

[1] BASED ON IN-SERVICE YEAR.

Schedule 10

Status Report and Specifications of Proposed Directly Associated Transmission Lines

Units	Point of Origin and Termination	Number of Circuits	Right-of-Way (ROW)	Circuit Length	Voltage	Anticipated In-Service Date	Anticipated Capital Investment	Substations	Participation with Other Utilities
Polk 2-5 CC	Polk-Aspen-FishHawk	5	ROW issues under-review	62.5 mi	230kV	January 2017	$140 million	Switching Station	None
Polk 2-5 CC	Davis Substation Switched Reactor	0	ROW issues under-review	0 mi	230kV	January 2017	$2 million	No new substations	None
Polk 2-5 CC	Polk Steam Turbine Interconnect & Upgrade	1	ROW issues under-review	0 mi	230kV	January 2017	$5 million	No new substations	None
Future CT 1	Unsited[1]	1	No new ROW required	0 mi	kV	May 2020	$ million	No new substations	None

[1]**Note: Specific information related to "Unsited" units unknown at this time.**

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Chapter V

TRANSMISSION CONSTRAINTS AND IMPACTS

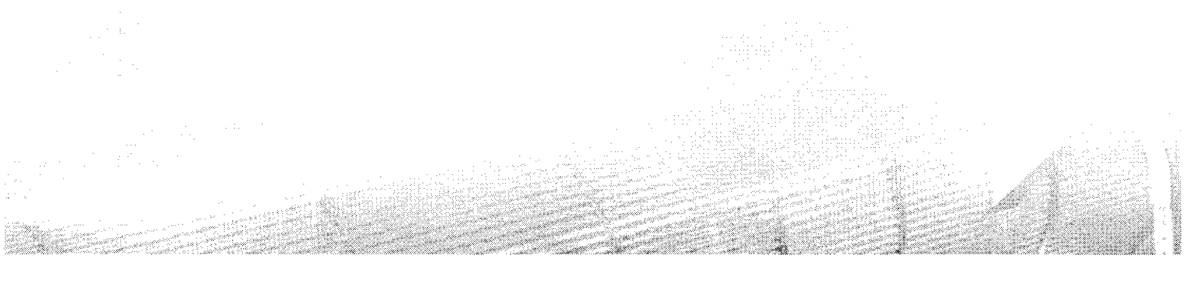
Based on a variety of assessments and sensitivity studies of the Tampa Electric transmission system using year 2012 Florida Reliability Coordinating Council (FRCC) databank models, no transmission constraints, that violate the criteria stated in the Generation and Transmission Reliability Criteria section 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 against expected operations, with the objective to: meet compliance requirements in the most cost-effective and reliable manner, maximize operational flexibility, and minimize total costs.

Early in the study process, many alternatives were screened on a qualitative and quantitative basis to determine the options 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.

Tampa Electric forecasts base case natural gas, coal, and oil fuel commodity prices by analyzing current market prices and price forecasts obtained from various consultants and agencies. These sources include the New York Mercantile Exchange, Wood Mackenzie Energy Group, Coal Daily, Inside FERC, and Platt's Oilgram. For the more volatile natural gas and oil prices, the company produces both high- and low- fuel price projections, which represent alternative forecasts to the company's base case outlook. The high and low price projections are defined by varying natural gas and oil prices by 35% relative to the base case.



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 days, and unplanned outage rates.

The unit performance projections are based on historical data trends, engineering judgment, 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 approved 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 energy efficiency and conservation programs, is developed. Then a supply plan based on the system requirements, which excludes incremental energy efficiency and conservation, is developed. This interim supply plan becomes the basis for potential avoided unit(s) in a comprehensive cost-effective analysis of the energy efficiency and conservation programs. Once the cost-effective energy efficiency and conservation 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 energy efficiency and conservation programs and supply-side resources.

The cost-effectiveness of energy efficiency and demand-response 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 energy efficiency and demand response 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 energy efficiency and demand response measures using a spreadsheet that comports with Rule 25-17.008, F.A.C., 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 System Optimizer (SO), a computer model developed by Ventyx, to evaluate supply side resources. SO utilizes a mixed integer linear program (MILP) to develop an estimate of the timing and type of supply side resources for capacity additions which would most economically meet the system demand and energy requirements. The MILP's objective function is to compare all feasible combinations of generating unit additions, which satisfy the specified reliability criteria and determine the schedule and addition with the lowest revenue requirement.

A detailed cost analysis for each of the top ranked resource plan is performed using the Planning & Risk (PAR) production cost model, also developed by Ventyx. PAR replaced ProMod as Tampa Electric's production cost model in 2009. 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 8.1. 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 conversion of Polk Units 2-5 to a natural gas combined cycle unit with the addition of a combustion turbine in 2017.

Tampa Electric will continue to assess competitive purchased 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 minimum 20% reserve margin criteria with a minimum contribution of 7% supply side resources. 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. 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, however they are not absolute. The listed criteria are used to alert planners of potential transmission system capacity limitations. Engineering analysis is used in all stages of the planning process to weigh the impact of system deficiencies, the likelihood of the triggering contingency, and the viability of any operating options. Only by carefully researching each planning criteria violation can a final evaluation of available transmission capacity be made.

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 load flow 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 planned and unplanned unit outages can result in a system dispatch that varies from a base plan (economic dispatch), bulk transmission planners also investigate several non-economic scenarios that may stress TEC's transmission system. These additional generation sensitivities are performed to ensure the integrity of the bulk electric system (BES) under maximized bulk power flows.

TRANSMISSION SYSTEM PLANNING LOADING LIMITS CRITERIA

TEC follows the FRCC planning criteria, as contained in the *FRCC Regional Transmission Planning Process.* The FRCC planning guide is based on the North American Electric Reliability Council (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.

In addition to FRCC criteria, TEC utilizes company-specific planning criteria for normal system operation and single-contingency operation.

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

TRANSMISSION SYSTEM LOADING LIMITS	
Transmission System Conditions	**Maximum Acceptable Loading Limit for Transformers and Transmission Lines**
All elements in service	100%
Single Contingency (pre-switching)	Emergency Rating*
Single Contingency (post-switching)	100%
Bus Outages (pre-switching)	Emergency Rating*
Bus Outages (post-switching)	100%

* As determined by FAC-009.

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, these criteria can be approximated by the following transmission system voltage limits.

TRANSMISION SYSTEM VOLTAGE LIMITS				
Transmission System Conditions	**Industrial Substation Buses at point-of-service**	**69 kV Buses**	**138 kV Buses**	**230 kV Buses**
Single Contingency (pre-switching)	0.925 - 1.050 p.u.	0.925 - 1.050 p.u.	0.950 – 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 – 1.050 p.u.	0.950 - 1.060 p.u.
Bus Outages	0.925 - 1.050 p.u.	0.925 - 1.050 p.u.	0.950 – 1.050 p.u.	0.950 - 1.060 p.u.

AVAILABLE TRANSMISSION TRANSFER CAPABILITY (ATC) CRITERIA

TEC adheres to the ATC calculation methodology described in the *Attachment C of TEC Open Access Transmission Tariff FERC Electric Tariff, Fourth Revised Volume No. 4* document, as well as the principles contained in the NERC Reliability Standards relating to ATC calculations.

Members of the FRCC, including TEC, have formed the Florida Transmission Capability Determination Group in an effort to provide ATC values to the regional electric market that are transparent, coordinated, timely and accurate.

TRANSMISSION PLANNING ASSESSMENT PRACTICES

BASE CASE OPERATING CONDITIONS

The Transmission Planning department ensures the TEC 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 TEC 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 (including FRCC studies of C2, C3, C3Gens, C3Lines, and C5 events) involving two branches or more out of service simultaneously are analyzed at a variety of load levels. The TEC transmission system is designed such that double contingencies do not cause violation of FRCC and NERC Reliability Standards criteria.

TRANSMISSION CONSTRUCTION AND UPGRADE PLANS

A specific list of the construction projects can be found in Chapter IV, Schedule 10. This list represents the latest BES transmission construction related to the generation 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 database 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, purchased 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.

ENERGY EFFICIENCY AND CONSERVATION AND 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 and Energy Planner) to confirm the accuracy of Tampa Electric's load reduction estimation formulas;

2. Billing analysis of various program participants (Energy Planner), compared to control groups to minimize the impact of weather abnormalities;

3. Periodic DOE2 modeling of various program participants such as the Residential and Commercial Building Envelope programs to evaluate savings achieved in residential programs involving building components; components;

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

5. Metering of loads under control to determine the demand and energy savings in commercial programs such as Standby Generator and Commercial Load Management and Commercial Demand Response

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, wall insulation, window replacements, air distribution system repairs, DX commercial cooling units, chiller replacements, water heating replacements, and motor upgrades) 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 offered a pilot Renewable Energy Program for several years. Due to its success, permanent program status was requested by the company and approved by the Commission in Docket No. 060678-EG, Order No. PSC-06-1063-TRF-EG, issued December 26, 2006.

Through December 2012, Tampa Electric's Renewable Energy Program has over 2,200 customers purchasing over 3,200 blocks of renewable energy each month. With the permanent program status effective December 2006, the company doubled the renewable energy block size from 100 to 200 kWh per month. Furthermore, in 2009, Tampa Electric began offering the ability to purchase one-time blocks of renewable energy to power specific events, starting with Super Bowl XLIII.

The company's renewable-generation portfolio is a mix of various technologies and renewable fuel sources, including six company owned photovoltaic (PV) arrays totaling 101.5 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. Most recently, systems were installed at Tampa's Lowry Park Zoo and the Florida Aquarium to further educate the public on the benefits of renewable energy. To complement the installations at these facilities throughout the community, interactive displays were built to provide a hands-on experience to engage visitors' interest in solar technology. Program participation has reached a level where it is necessary to supplement the company's renewable resources with incremental purchases from a biomass facility in south Florida. Through December 2012, participating customers have utilized over 56 GWh of renewable energy since the program inception.

In 2011, Tampa Electric also initiated a five-year renewable energy pilot that utilizes rebates and incentives to encourage the following installations:

1. Solar PV and solar water heating (SWH) technologies on existing and new residential and commercial premises

2. PV on emergency shelter schools, coupled with an educational component for teachers and students

3. SWH on low-income housing done in partnership with local non-profit building organizations

This pilot has annual funding capped at $1.53 million. Through this initiative Tampa Electric expects an additional 510 kW of customer owned PV to be installed along with 155 residential SWH systems to be added each year of the pilot. Tampa Electric continually analyzes renewable energy alternatives with the objective to integrate them into our resource portfolio. Specific renewable options for the future are the integration of a 60 MW biomass boiler at Bayside 2 and a possible fuel conversion of Phillips Power Station to bio-diesel as its primary fuel resulting in 32 MW. Solar thermal integration of the new combined cycle conversion at Polk Power Station could result in a 30 MW renewable energy alternative for our customers. The addition of 20 kW of solar PV arrays to our existing 23.8 kW at our Manatee Viewing Center occurred in October of 2012. As market conditions continue to change and technology improves in this sector, renewable alternatives, such as solar, become more cost effective to our customers.

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Chapter VI

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.

Figure VI-1

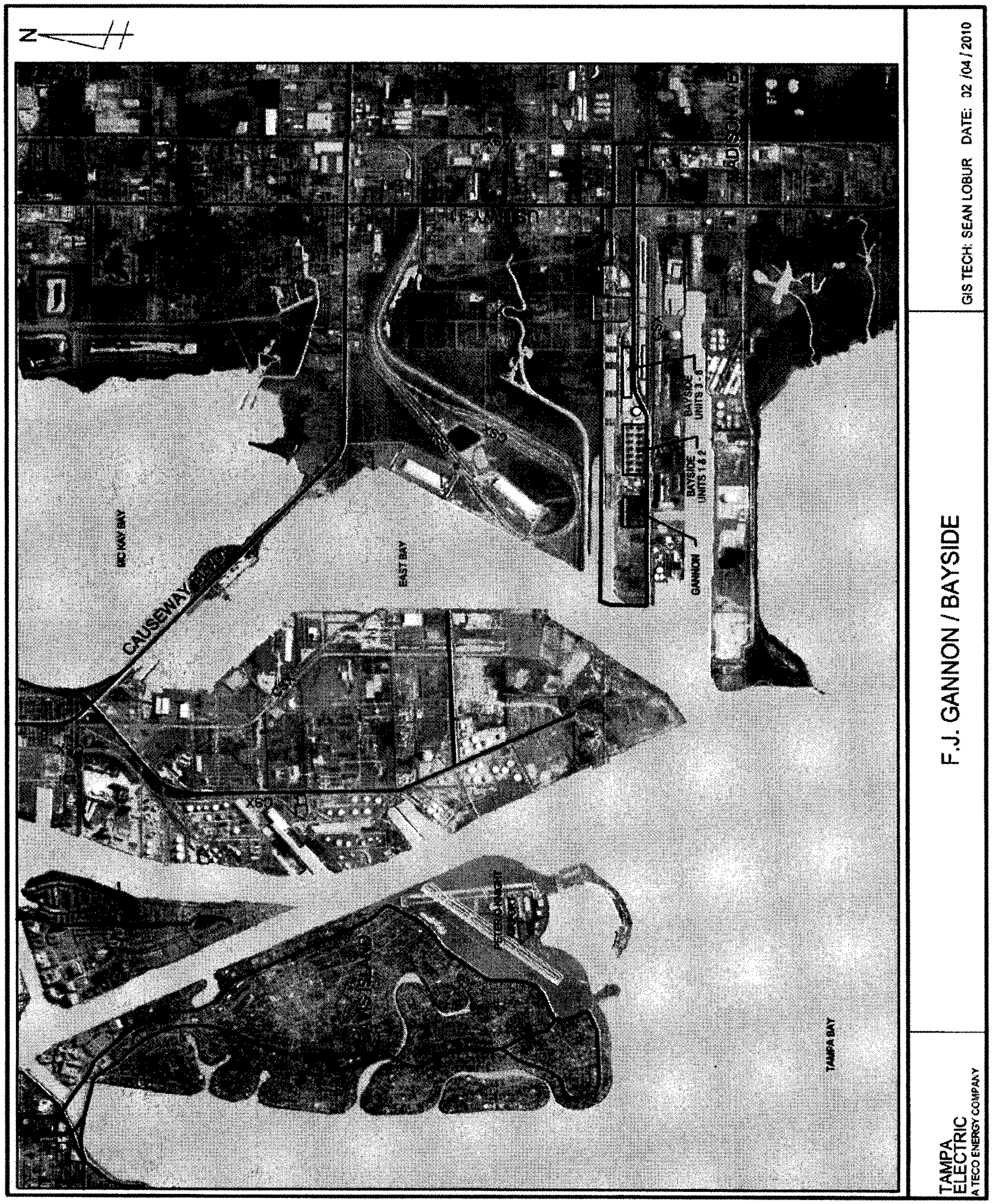

F.J. GANNON / BAYSIDE
GIS TECH: SEAN LOBUR DATE: 02/04/2010
TAMPA ELECTRIC
A TECO ENERGY COMPANY
CAUSEWAY
MC KAY BAY
EAST BAY
TAMPA BAY
BAYSIDE UNITS 3 - 6
BAYSIDE UNITS 1 & 2
GANNON

Figure VI-2

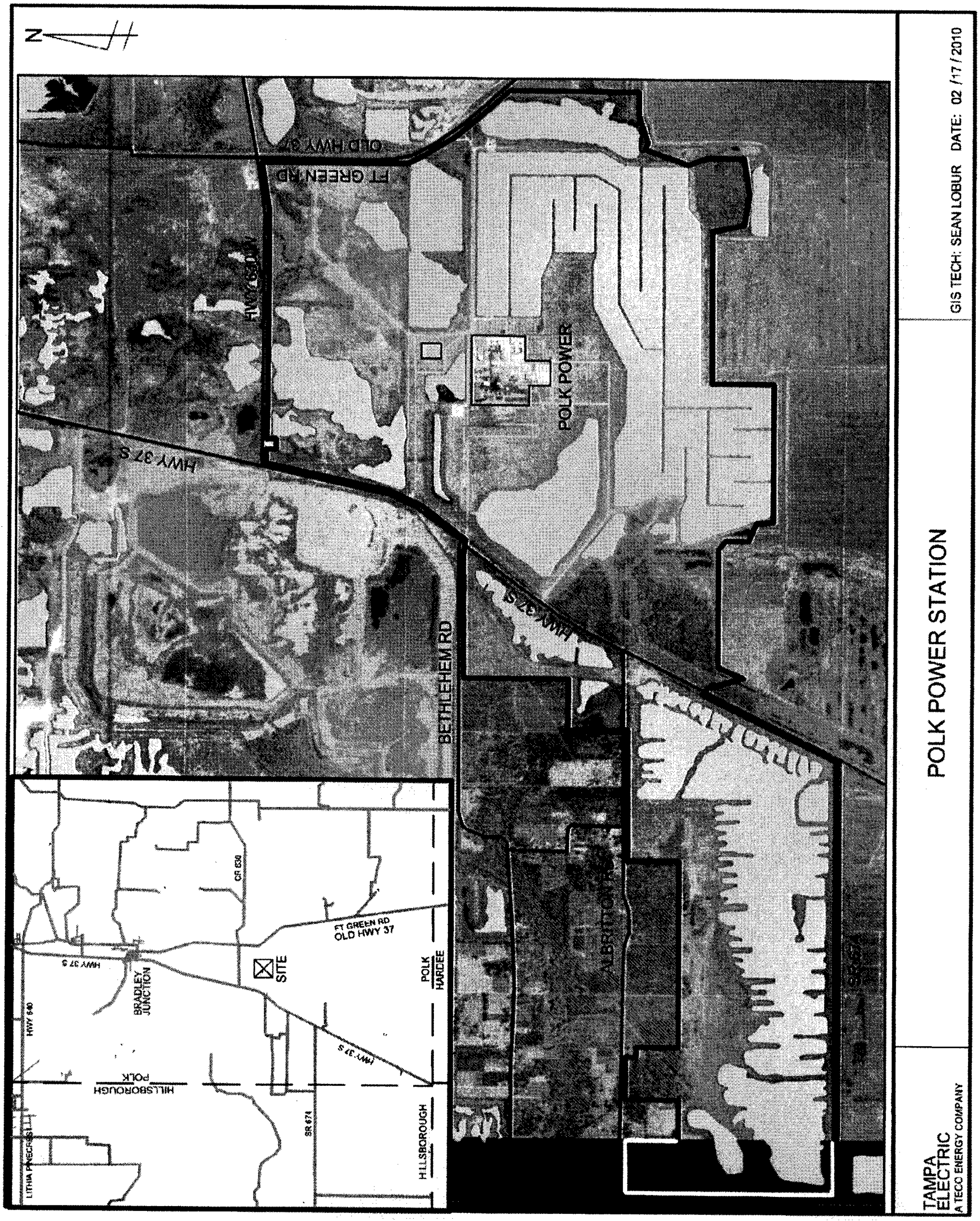
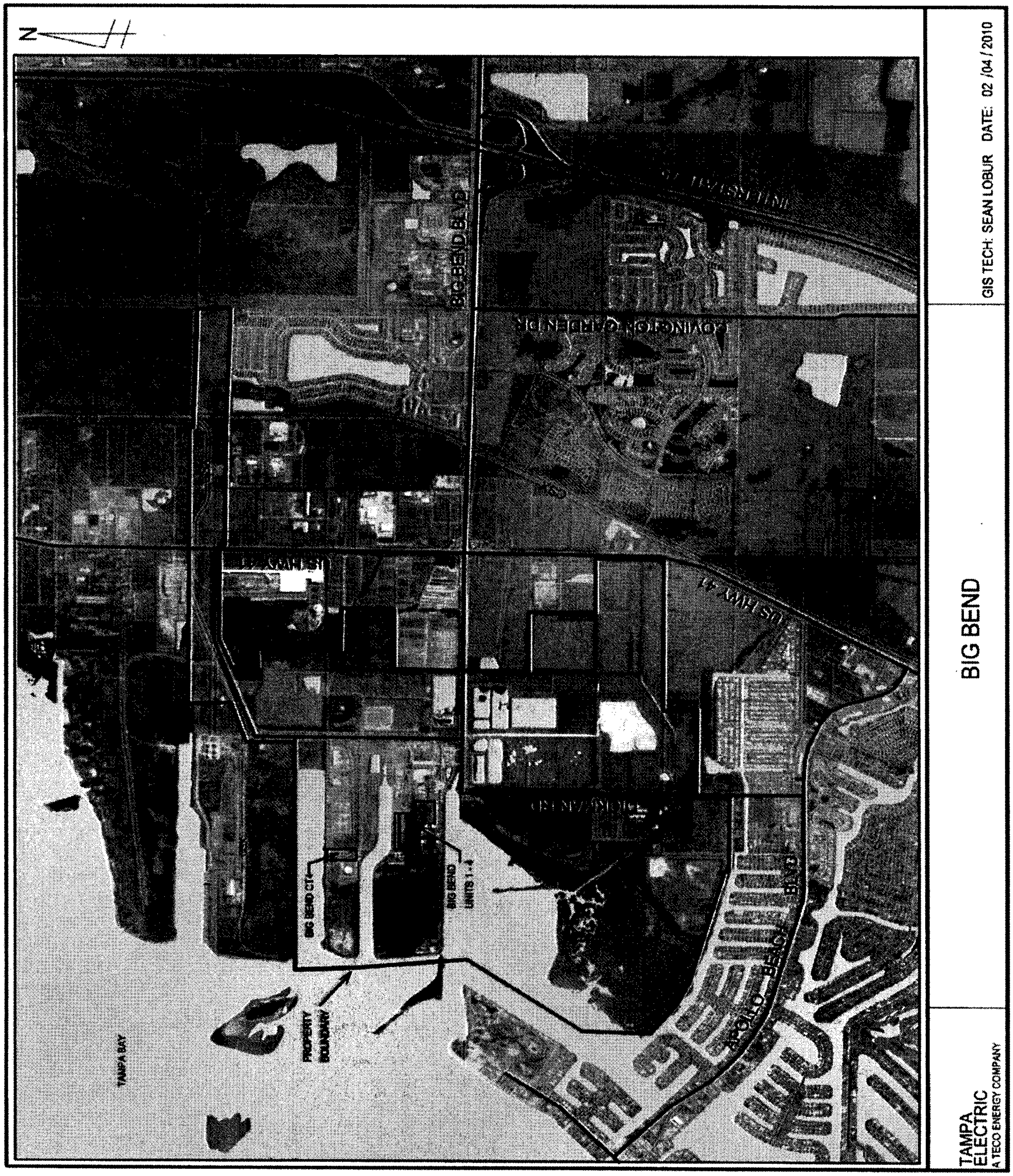

POLK POWER STATION
GIS TECH: SEAN LOBUR DATE: 02 / 17 / 2010
TAMPA ELECTRIC
A TECO ENERGY COMPANY
N
OLD HWY 37
FT GREEN RD
POLK POWER
HWY 37 S
BETHLEHEM RD
SITE
BRADLEY JUNCTION
FT GREEN RD
OLD HWY 37
CR 630
POLK
HARDEE
HILLSBOROUGH
POLK
SR 674
HWY 640
HWY 37 S

Figure VI-3


BIG BEND
TAMPA ELECTRIC
A TECO ENERGY COMPANY
GIS TECH: SEAN LOBUR DATE: 02 /04 / 2010
BIG BEND BLVD
US HWY 41
PROPERTY BOUNDARY
BIG BEND CT4
BIG BEND UNITS 1-4
TAMPA BAY