SACE 1st Response to Staff
020029

AUSLEY & MCMULLEN

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April 1, 2011

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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 2011 to December 2020 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

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TECO
TAMPA ELECTRIC

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

January 2011 to December 2020

Responsibly Serving Our Customers' Growing Needs

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

January 2011 to December 2020

TAMPA ELECTRIC COMPANY
Tampa, Florida

April 1, 2011

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List of Schedules & Tables

List of Schedules & Tables (continued)

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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

DESCRIPTION OF EXISTING FACILITIES

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

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 August 2009 and can be fired with natural gas or distilled 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) 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 unit (IGCC) 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 distilled 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 September 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.

Schedule 1

Existing Generating Facilities
As of December 31, 2010

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
								Alt	Commercial	Expected	Gen. Max.	Net Capability	
Plant	Unit		Unit	Fuel		Fuel Transport		Fuel	In-Service	Retirement	Nameplate	Summer	Winter
Name	No.	Location	Type	Pri	Alt	Pri	Alt	Days	Mo/Yr	Mo/Yr	KW	MW	MW
Big Bend		Hillsborough											
		Co. 14/31S/19E									1,892,485	1,608	1,643
	1		ST	BIT	N	WA	N	0	10/70	Unknown	445,500	385	395
	2		ST	BIT	N	WA	N	0	4/73	Unknown	445,500	385	395
	3		ST	BIT	N	WA	N	0	5/76	Unknown	445,500	365	365
	4		ST	BIT	N	WA	N	0	2/85	Unknown	486,000	417	427
	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 [2]	151	183
	3		GT	NG	LO	PL	TK	0	5/02	Unknown	175,770 [2]	151	183
	4		GT	NG	N	PL	N	0	3/07	Unknown	175,770 [2]	151	183
	5		GT	NG	N	PL	N	0	4/07	Unknown	175,770 [2]	151	183
Partnership		Hillsborough											
		Co. W30/29/19									5,800	6	6
	1		IC	NG	N	PL	N	0	4/01	Unknown	2,900	3	3
	2		IC	NG	N	PL	N	0	4/01	Unknown	2,900	3	3
											TOTAL	4,292	4,684

Notes:

[1] Phillips Units 1 & 2 were placed into long-term reserve standby (LTRS) on September 4, 2009, and net capacities are not included into the system total.

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

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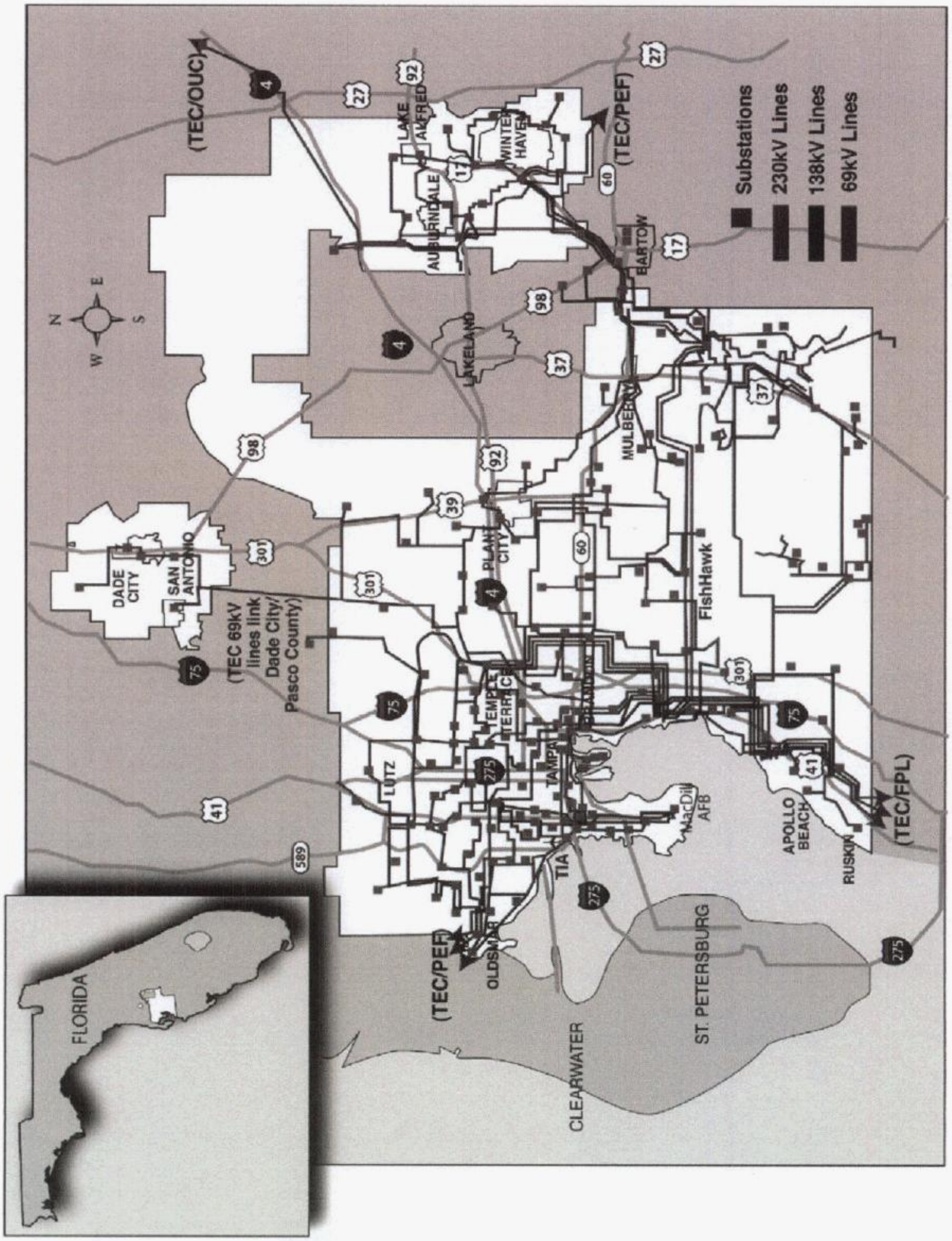
I.1 Tampa Electric Service Area Map

I.2 Tampa Electric Service Area Transmission Facility



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Chapter II

FORECAST OF ELECTRIC POWER, DEMAND, AND ENERGY CONSUMPTION

The Schedule 2 through 4 tables reflect three different levels of load forecasting: base case, high case and low case. The expansion plan is based on the base case of the 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)

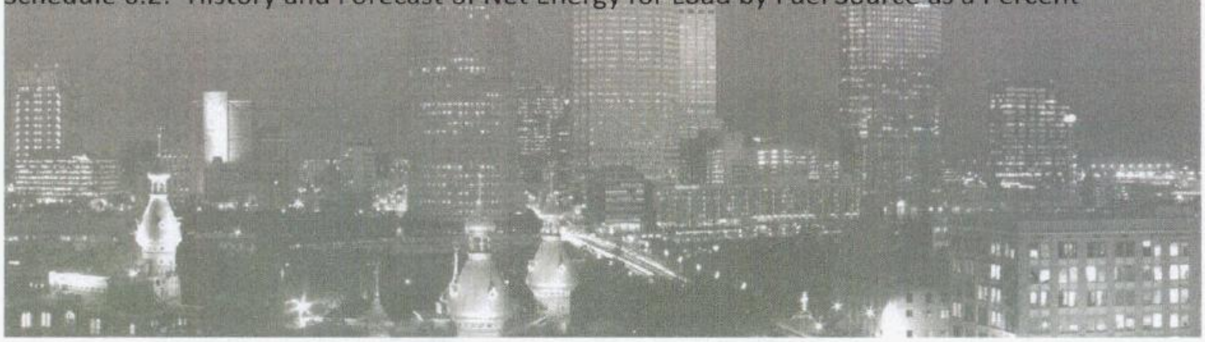
Schedule 3.3: History and Forecast of Annual Net Energy for Load (Base, High & Low)

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
2001	1,027,283	2.6	7,594	505,964	15,009	5,685	63,316	89,788
2002	1,055,617	2.6	8,046	518,554	15,516	5,832	64,665	90,188
2003	1,079,587	2.5	8,265	531,257	15,557	5,843	66,041	88,475
2004	1,108,435	2.5	8,293	544,313	15,236	5,988	67,488	88,727
2005	1,131,546	2.5	8,558	558,601	15,320	6,233	69,027	90,298
2006	1,164,425	2.5	8,721	575,111	15,164	6,357	70,205	90,549
2007	1,192,861	2.5	8,871	586,776	15,119	6,542	70,891	92,276
2008	1,200,541	2.5	8,546	587,602	14,545	6,399	70,770	90,415
2009	1,196,892	2.5	8,666	587,396	14,754	6,274	70,182	89,395
2010	1,199,400	2.6	9,185	591,554	15,526	6,221	70,176	88,655
2011	1,215,369	2.6	8,881	596,065	14,899	6,314	71,251	88,612
2012	1,231,551	2.6	8,979	602,379	14,906	6,380	72,269	88,287
2013	1,247,948	2.6	9,096	610,483	14,900	6,450	73,300	88,000
2014	1,264,563	2.6	9,207	619,169	14,870	6,521	74,340	87,717
2015	1,281,400	2.6	9,303	628,147	14,811	6,593	75,370	87,481
2016	1,301,687	2.6	9,416	637,849	14,763	6,676	76,490	87,279
2017	1,322,296	2.6	9,532	647,707	14,716	6,763	77,621	87,125
2018	1,343,231	2.6	9,653	657,616	14,679	6,851	78,750	87,001
2019	1,364,497	2.6	9,777	667,529	14,647	6,941	79,884	86,884
2020	1,386,100	2.6	9,899	677,149	14,619	7,025	80,996	86,729

December 31, 2010 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
2001	1,027,283	2.6	7,594	505,964	15,009	5,685	63,316	89,788
2002	1,055,617	2.6	8,046	518,554	15,516	5,832	64,665	90,188
2003	1,079,587	2.5	8,265	531,257	15,557	5,843	66,041	88,475
2004	1,108,435	2.5	8,293	544,313	15,236	5,988	67,488	88,727
2005	1,131,546	2.5	8,558	558,601	15,320	6,233	69,027	90,298
2006	1,164,425	2.5	8,721	575,111	15,164	6,357	70,205	90,549
2007	1,192,861	2.5	8,871	586,776	15,119	6,542	70,891	92,276
2008	1,200,541	2.5	8,546	587,602	14,545	6,399	70,770	90,415
2009	1,196,892	2.5	8,666	587,396	14,754	6,274	70,182	89,395
2010	1,199,400	2.6	9,185	591,554	15,526	6,221	70,176	88,655
2011	1,224,349	2.6	8,947	600,163	14,907	6,353	71,724	88,581
2012	1,245,006	2.6	9,117	610,174	14,941	6,470	73,205	88,376
2013	1,268,760	2.6	9,300	621,799	14,957	6,589	74,676	88,236
2014	1,293,537	2.6	9,479	633,948	14,952	6,709	76,149	88,108
2015	1,318,944	2.6	9,643	646,410	14,917	6,833	77,613	88,038
2016	1,345,994	2.6	9,825	659,679	14,894	6,969	79,178	88,012
2017	1,373,558	2.7	10,012	673,200	14,872	7,110	80,767	88,032
2018	1,401,449	2.7	10,208	686,882	14,861	7,253	82,368	88,061
2019	1,429,580	2.7	10,409	700,682	14,856	7,398	83,988	88,087
2020	1,457,320	2.7	10,611	714,290	14,855	7,539	85,601	88,070

December 31, 2010 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
2001	1,027,283	2.6	7,594	505,964	15,009	5,685	63,316	89,788
2002	1,055,617	2.6	8,046	518,554	15,516	5,832	64,665	90,188
2003	1,079,587	2.5	8,265	531,257	15,557	5,843	66,041	88,475
2004	1,108,435	2.5	8,293	544,313	15,236	5,988	67,488	88,727
2005	1,131,546	2.5	8,558	558,601	15,320	6,233	69,027	90,298
2006	1,164,425	2.5	8,721	575,111	15,164	6,357	70,205	90,549
2007	1,192,861	2.5	8,871	586,776	15,119	6,542	70,891	92,276
2008	1,200,541	2.5	8,546	587,602	14,545	6,399	70,770	90,415
2009	1,196,892	2.5	8,666	587,396	14,754	6,274	70,182	89,395
2010	1,199,400	2.6	9,185	591,554	15,526	6,221	70,176	88,655
2011	1,200,250	2.5	8,848	594,093	14,893	6,285	71,018	88,502
2012	1,208,498	2.5	8,915	597,629	14,917	6,331	71,693	88,313
2013	1,219,470	2.5	8,992	602,588	14,922	6,379	72,333	88,186
2014	1,231,090	2.5	9,062	607,936	14,905	6,425	72,958	88,067
2015	1,242,960	2.5	9,116	613,464	14,859	6,473	73,558	88,005
2016	1,256,022	2.5	9,186	619,629	14,825	6,532	74,237	87,986
2017	1,269,183	2.5	9,258	625,885	14,792	6,594	74,918	88,012
2018	1,282,263	2.4	9,336	632,135	14,769	6,655	75,590	88,047
2019	1,295,179	2.4	9,417	638,334	14,752	6,717	76,259	88,078
2020	1,307,359	2.4	9,495	644,196	14,739	6,772	76,900	88,064

December 31, 2010 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
2001	2,329	851	2,736,780	0	54	1,314	16,976
2002	2,612	948	2,755,274	0	55	1,380	17,925
2003	2,580	1203	2,144,638	0	57	1,481	18,226
2004	2,556	1299	1,967,667	0	58	1,542	18,437
2005	2,478	1,337	1,853,403	0	60	1,582	18,911
2006	2,279	1,485	1,534,680	0	61	1,607	19,025
2007	2,366	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	1,867	1,437	1,299,173	0	69	1,796	18,927
2012	1,878	1,454	1,291,547	0	70	1,811	19,119
2013	1,892	1,471	1,286,826	0	71	1,827	19,336
2014	1,906	1,483	1,285,026	0	71	1,841	19,546
2015	1,915	1,494	1,281,443	0	72	1,859	19,743
2016	1,924	1,505	1,278,305	0	72	1,882	19,971
2017	1,934	1,516	1,275,240	0	73	1,905	20,206
2018	1,944	1,527	1,272,430	0	74	1,929	20,450
2019	1,953	1,539	1,269,656	0	74	1,953	20,698
2020	1,963	1,550	1,266,869	0	75	1,976	20,938

December 31, 2010 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				Street &	Other Sales	Total Sales
			Average KWH	Railroads	Highway	to Public	to Ultimate
			Consumption	and Railways	Lighting	Authorities	Consumers
Year	GWH	Customers*	Per Customer	GWH	GWH	GWH	GWH
2001	2,329	851	2,736,780	0	54	1,314	16,976
2002	2,612	948	2,755,274	0	55	1,380	17,925
2003	2,580	1,203	2,144,638	0	57	1,481	18,226
2004	2,556	1,299	1,967,667	0	58	1,542	18,437
2005	2,478	1,337	1,853,403	0	60	1,582	18,911
2006	2,279	1,485	1,534,680	0	61	1,607	19,025
2007	2,366	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	1,867	1,440	1,296,203	0	69	1,811	19,047
2012	1,879	1,458	1,288,587	0	70	1,836	19,371
2013	1,895	1,477	1,282,686	0	71	1,861	19,716
2014	1,909	1,491	1,280,547	0	71	1,885	20,054
2015	1,920	1,504	1,276,533	0	72	1,913	20,380
2016	1,931	1,517	1,272,788	0	72	1,947	20,744
2017	1,942	1,530	1,269,239	0	73	1,980	21,117
2018	1,953	1,543	1,265,816	0	74	2,015	21,503
2019	1,964	1,556	1,262,512	0	74	2,051	21,897
2020	1,976	1,570	1,258,383	0	75	2,086	22,286

December 31, 2010 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				Street &	Other Sales	Total Sales
Year	GWH	Customers*	Average KWH Consumption Per Customer	Railroads and Railways GWH	Highway Lighting GWH	to Public Authorities GWH	to Ultimate Consumers GWH
2001	2,329	851	2,736,780	0	54	1,314	16,976
2002	2,612	948	2,755,274	0	55	1,380	17,925
2003	2,580	1,203	2,144,638	0	57	1,481	18,226
2004	2,556	1,299	1,967,667	0	58	1,542	18,437
2005	2,478	1,337	1,853,403	0	60	1,582	18,911
2006	2,279	1,485	1,534,680	0	61	1,607	19,025
2007	2,366	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	1,866	1,434	1,301,513	0	69	1,781	18,849
2012	1,878	1,450	1,295,513	0	70	1,787	18,981
2013	1,894	1,465	1,292,937	0	71	1,793	19,128
2014	1,909	1,475	1,294,110	0	71	1,798	19,265
2015	1,919	1,485	1,292,464	0	72	1,807	19,387
2016	1,930	1,494	1,291,906	0	72	1,820	19,540
2017	1,941	1,503	1,291,486	0	73	1,833	19,699
2018	1,952	1,512	1,291,136	0	74	1,846	19,864
2019	1,963	1,521	1,290,851	0	74	1,860	20,031
2020	1,974	1,530	1,290,487	0	75	1,873	20,189

December 31, 2010 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
2001	684	794	18,454	5,649	575,780
2002	502	935	19,362	6,032	590,199
2003	587	985	19,798	6,399	604,900
2004	589	945	19,971	6,435	619,535
2005	712	952	20,575	6,656	635,621
2006	700	1,000	20,725	6,905	653,706
2007	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	105	980	20,012	7,818	676,571
2012	32	990	20,141	7,888	683,990
2013	0	1,002	20,339	7,971	693,225
2014	0	1,013	20,559	8,059	703,051
2015	0	1,024	20,766	8,148	713,160
2016	0	1,035	21,007	8,245	724,089
2017	0	1,048	21,254	8,342	735,186
2018	0	1,061	21,511	8,440	746,334
2019	0	1,074	21,772	8,538	757,489
2020	0	1,086	22,025	8,633	768,327

December 31, 2010 Status

* Includes sales to Progress Energy Florida, Wauchula, Ft. Meade, St. Cloud and Reedy Creek. Contract ended with Ft. Meade on 12/31/08 and Reedy Creek on 12/31/10.
** 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
2001	684	794	18,454	5,649	575,780
2002	502	935	19,362	6,032	590,199
2003	587	985	19,798	6,399	604,900
2004	589	945	19,971	6,435	619,535
2005	712	952	20,575	6,656	635,621
2006	700	1,000	20,725	6,905	653,706
2007	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	105	987	20,139	7,869	681,196
2012	32	1,003	20,407	7,969	692,806
2013	0	1,022	20,738	8,084	706,036
2014	0	1,040	21,093	8,205	719,793
2015	0	1,057	21,437	8,328	733,855
2016	0	1,076	21,819	8,459	748,833
2017	0	1,095	22,213	8,592	764,089
2018	0	1,116	22,619	8,728	779,521
2019	0	1,136	23,034	8,864	795,090
2020	0	1,157	23,443	8,999	810,460

December 31, 2010 Status

* Includes sales to Progress Energy Florida, Wauchula, Ft. Meade, St. Cloud and Reedy Creek. Contract ended with Ft. Meade on 12/31/08 and Reedy Creek on 12/31/10.
** 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
2001	684	794	18,454	5,649	575,780
2002	502	935	19,362	6,032	590,199
2003	587	985	19,798	6,399	604,900
2004	589	945	19,971	6,435	619,535
2005	712	952	20,575	6,656	635,621
2006	700	1,000	20,725	6,905	653,706
2007	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	105	976	19,931	7,768	674,313
2012	32	983	19,996	7,807	678,579
2013	0	991	20,120	7,861	684,247
2014	0	999	20,263	7,917	690,286
2015	0	1,005	20,392	7,974	696,481
2016	0	1,013	20,553	8,037	703,397
2017	0	1,022	20,720	8,101	710,407
2018	0	1,030	20,894	8,164	717,401
2019	0	1,039	21,071	8,227	724,341
2020	0	1,047	21,236	8,285	730,911

December 31, 2010 Status

* Includes sales to Progress Energy Florida, Wauchula, Ft. Meade, St. Cloud and Reedy Creek. Contract ended with Ft. Meade on 12/31/08 and Reedy Creek on 12/31/10.
** 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	
2001	3,730	178	3,552	181	90	55	21	40	3,165	
2002	3,869	122	3,747	206	99	60	21	43	3,318	***
2003	3,854	122	3,732	188	63	65	21	44	3,351	
2004	3,974	120	3,854	177	95	70	20	47	3,445	
2005	4,218	128	4,090	144	79	73	19	49	3,725	
2006	4,265	128	4,137	146	77	77	18	50	3,769	
2007	4,428	172	4,256	159	69	80	18	53	3,876	
2008	4,240	148	4,092	143	69	84	18	55	3,723	
2009	4,310	136	4,174	120	56	89	51	59	3,799	
2010	4,134	118	4,016	73	33	95	40	65	3,710	***
2011	4,162	28	4,134	127	55	98	70	65	3,719	
2012	4,207	15	4,192	126	56	104	71	69	3,766	
2013	4,257	0	4,257	127	57	111	73	73	3,817	
2014	4,318	0	4,318	127	57	117	75	77	3,864	
2015	4,378	0	4,378	127	59	124	77	81	3,909	
2016	4,443	0	4,443	127	60	131	80	86	3,959	
2017	4,510	0	4,510	127	62	138	82	90	4,011	
2018	4,579	0	4,579	128	64	146	84	94	4,063	
2019	4,649	0	4,649	128	66	154	86	98	4,117	
2020	4,716	0	4,716	128	69	161	88	102	4,169	

December 31, 2010 Status

* Includes residential and commercial/industrial conservation.
** Includes sales to Progress Energy Florida, Wauchula, Ft. Meade, St. Cloud and Reedy Creek. Contract ended with Ft. Meade on 12/31/08 and Reedy Creek on 12/31/10.
*** 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	
2001	3,730	178	3,552	181	90	55	21	40	3,165	
2002	3,869	122	3,747	206	99	60	21	43	3,318	***
2003	3,854	122	3,732	188	63	65	21	44	3,351	
2004	3,974	120	3,854	177	95	70	20	47	3,445	
2005	4,218	128	4,090	144	79	73	19	49	3,725	
2006	4,265	128	4,137	146	77	77	18	50	3,769	
2007	4,428	172	4,256	159	69	80	18	53	3,876	
2008	4,240	148	4,092	143	69	84	18	55	3,723	
2009	4,310	136	4,174	120	56	89	51	59	3,799	
2010	4,134	118	4,016	73	33	95	40	65	3,710	***
2011	4,191	28	4,163	127	55	98	70	65	3,748	
2012	4,258	15	4,243	126	56	104	71	69	3,817	
2013	4,331	0	4,331	127	57	111	73	73	3,891	
2014	4,414	0	4,414	127	57	117	75	77	3,960	
2015	4,497	0	4,497	127	59	124	77	81	4,028	
2016	4,585	0	4,585	127	60	131	80	86	4,101	
2017	4,675	0	4,675	127	62	138	82	90	4,176	
2018	4,769	0	4,769	128	64	146	84	94	4,253	
2019	4,864	0	4,864	128	66	154	86	98	4,332	
2020	4,957	0	4,957	128	69	161	88	102	4,410	

December 31, 2010 Status

* Includes residential and commercial/industrial conservation.

** Includes sales to Progress Energy Florida, Wauchula, Ft. Meade, St. Cloud and Reedy Creek. Contract ended with Ft. Meade on 12/31/08 and Reedy Creek on 12/31/10.

*** 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
2001	3,730	178	3,552	181	90	55	21	40	3,165
2002	3,869	122	3,747	206	99	60	21	43	3,318 ***
2003	3,854	122	3,732	188	63	65	21	44	3,351
2004	3,974	120	3,854	177	95	70	20	47	3,445
2005	4,218	128	4,090	144	79	73	19	49	3,725
2006	4,265	128	4,137	146	77	77	18	50	3,769
2007	4,428	172	4,256	159	69	80	18	53	3,876
2008	4,240	148	4,092	143	69	84	18	55	3,723
2009	4,310	136	4,174	120	56	89	51	59	3,799
2010	4,134	118	4,016	73	33	95	40	65	3,710 ***
2011	4,147	28	4,119	127	55	98	70	65	3,704
2012	4,173	15	4,158	126	56	104	71	69	3,732
2013	4,202	0	4,202	127	57	111	73	73	3,762
2014	4,242	0	4,242	127	57	117	75	77	3,788
2015	4,280	0	4,280	127	59	124	77	81	3,811
2016	4,323	0	4,323	127	60	131	80	86	3,839
2017	4,366	0	4,366	127	62	138	82	90	3,867
2018	4,411	0	4,411	128	64	146	84	94	3,895
2019	4,457	0	4,457	128	66	154	86	98	3,925
2020	4,500	0	4,500	128	69	161	88	102	3,953

December 31, 2010 Status

* Includes residential and commercial/industrial conservation.

** Includes sales to Progress Energy Florida, Wauchula, Ft. Meade, St. Cloud and Reedy Creek. Contract ended with Ft. Meade on 12/31/08 and Reedy Creek on 12/31/10.

*** 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
2000/01	4,405	136	4,269	191	196	410	21	44	3,407
2001/02	4,217	127	4,090	168	176	419	22	46	3,259
2002/03	4,484	129	4,355	195	210	428	21	46	3,455
2003/04	3,949	120	3,829	254	136	437	18	48	2,936
2004/05	4,308	129	4,179	194	189	444	16	49	3,287
2005/06	4,404	171	4,233	51	144	447	18	50	3,523
2006/07	4,063	162	3,900	157	96	452	18	51	3,127
2007/08	4,369	152	4,217	120	129	456	18	52	3,443
2008/09	4,687	67	4,620	181	120	461	52	52	3,754
2009/10	5,158	122	5,036	117	109	468	40	56	4,246
2010/11	4,766	99	4,667	136	113	472	70	55	3,820
2011/12	4,735	15	4,719	136	113	478	71	56	3,865
2012/13	4,789	0	4,788	136	113	485	72	58	3,923
2013/14	4,854	0	4,854	136	113	493	73	59	3,980
2014/15	4,918	0	4,918	136	114	500	75	61	4,032
2015/16	4,984	0	4,984	136	115	507	76	62	4,087
2016/17	5,055	0	5,055	137	117	515	78	64	4,145
2017/18	5,127	0	5,127	137	120	523	80	65	4,203
2018/19	5,202	0	5,202	137	123	531	81	67	4,263
2019/20	5,275	0	5,275	137	126	539	83	68	4,323

December 31, 2010 Status

* Includes residential and commercial/industrial conservation.

** Includes sales to Progress Energy Florida, Wauchula, Ft. Meade, St. Cloud and Reedy Creek. Contract ended with Ft. Meade on 12/31/08 and Reedy Creek on 12/31/1

Note: Values shown may be affected due to rounding.

Schedule 3.2

History and Forecast of Winter Peak Demand
High Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Year	Total *	Wholesale **	Retail *	Interruptible	Residential Load Management	Residential Conservation	Comm./Ind. Load Management	Comm./Ind. Conservation	Net Firm Demand
2000/01	4,405	136	4,269	191	196	410	21	44	3,407
2001/02	4,217	127	4,090	168	176	419	22	46	3,259
2002/03	4,484	129	4,355	195	210	428	21	46	3,455
2003/04	3,949	120	3,829	254	136	437	18	48	2,936
2004/05	4,308	129	4,179	194	189	444	16	49	3,287
2005/06	4,404	171	4,233	51	144	447	18	50	3,523
2006/07	4,063	162	3,900	157	96	452	18	51	3,127
2007/08	4,369	152	4,217	120	129	456	18	52	3,443
2008/09	4,687	67	4,620	181	120	461	52	52	3,754
2009/10	5,158	122	5,036	117	109	468	40	56	4,246
2010/11	4,788	99	4,689	136	113	472	70	55	3,843
2011/12	4,783	15	4,768	136	113	478	71	56	3,914
2012/13	4,860	0	4,860	136	113	485	72	58	3,995
2013/14	4,950	0	4,950	136	113	493	73	59	4,076
2014/15	5,037	0	5,037	136	114	500	75	61	4,151
2015/16	5,127	0	5,127	136	115	507	76	62	4,230
2016/17	5,223	0	5,223	137	117	515	78	64	4,313
2017/18	5,320	0	5,320	137	120	523	80	65	4,396
2018/19	5,420	0	5,420	137	123	531	81	67	4,481
2019/20	5,521	0	5,521	137	126	539	83	68	4,569

December 31, 2010 Status

* Includes residential and commercial/industrial conservation.

** Includes sales to Progress Energy Florida, Wauchula, Ft. Meade, St. Cloud and Reedy Creek. Contract ended with Ft. Meade on 12/31/08 and Reedy Creek on 12/31/1

Note: Values shown may be affected due to rounding.

Schedule 3.2

History and Forecast of Winter Peak Demand
Low Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Year	Total *	Wholesale **	Retail *	Interruptible	Residential Load Management	Residential Conservation	Comm./Ind. Load Management	Comm./Ind. Conservation	Net Firm Demand
2000/01	4,405	136	4,269	191	196	410	21	44	3,407
2001/02	4,217	127	4,090	168	176	419	22	46	3,259
2002/03	4,484	129	4,355	195	210	428	21	46	3,455
2003/04	3,949	120	3,829	254	136	437	18	48	2,936
2004/05	4,308	129	4,179	194	189	444	16	49	3,287
2005/06	4,404	171	4,233	51	144	447	18	50	3,523
2006/07	4,063	162	3,900	157	96	452	18	51	3,127
2007/08	4,369	152	4,217	120	129	456	18	52	3,443
2008/09	4,687	67	4,620	181	120	461	52	52	3,754
2009/10	5,158	122	5,036	117	109	468	40	56	4,246
2010/11	4,751	99	4,653	136	113	472	70	55	3,806
2011/12	4,703	15	4,688	136	113	478	71	56	3,834
2012/13	4,735	0	4,735	136	113	485	72	58	3,870
2013/14	4,780	0	4,780	136	113	493	73	59	3,906
2014/15	4,820	0	4,820	136	114	500	75	61	3,934
2015/16	4,863	0	4,863	136	115	507	76	62	3,966
2016/17	4,910	0	4,910	137	117	515	78	64	4,000
2017/18	4,958	0	4,958	137	120	523	80	65	4,034
2018/19	5,007	0	5,007	137	123	531	81	67	4,068
2019/20	5,055	0	5,055	137	126	539	83	68	4,103

December 31, 2010 Status

* Includes residential and commercial/industrial conservation.

** Includes sales to Progress Energy Florida, Wauchula, Ft. Meade, St. Cloud and Reedy Creek. Contract ended with Ft. Meade on 12/31/08 and Reedy Creek on 12/31/1

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 %
2001	17,443	346	122	16,976	684	794	18,454	53.3
2002	18,423	361	137	17,925	502	935	19,362	58.7
2003	18,756	378	152	18,226	587	985	19,798	56.4
2004	18,999	394	168	18,437	589	945	19,971	58.9
2005	19,491	404	176	18,911	712	952	20,575	57.3
2006	19,625	412	188	19,025	700	1,000	20,726	57.2
2007	20,153	421	200	19,533	829	916	21,278	56.6
2008	19,632	430	212	18,990	752	909	20,650	57.3
2009	19,449	443	231	18,774	191	978	19,943	54.6
2010	19,923	458	251	19,213	305	1,149	20,667	50.9
2011	19,659	473	259	18,927	105	980	20,012	53.9
2012	19,889	493	277	19,119	32	990	20,141	54.6
2013	20,142	509	296	19,336	0	1,002	20,339	54.7
2014	20,387	526	315	19,546	0	1,013	20,559	54.6
2015	20,620	544	334	19,743	0	1,024	20,766	54.4
2016	20,886	561	353	19,971	0	1,035	21,007	54.2
2017	21,158	580	372	20,206	0	1,048	21,254	54.2
2018	21,439	599	390	20,450	0	1,061	21,511	54.1
2019	21,723	618	407	20,698	0	1,074	21,772	54.0
2020	21,999	638	423	20,938	0	1,086	22,025	53.7

December 31, 2010 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 %
2001	17,443	346	122	16,976	684	794	18,454	53.3
2002	18,423	361	137	17,925	502	935	19,362	58.7
2003	18,756	378	152	18,226	587	985	19,798	56.4
2004	18,999	394	168	18,437	589	945	19,971	58.9
2005	19,491	404	176	18,911	712	952	20,575	57.3
2006	19,625	412	188	19,025	700	1,000	20,726	57.2
2007	20,153	421	200	19,533	829	916	21,278	56.6
2008	19,632	430	212	18,990	752	909	20,650	57.3
2009	19,449	443	231	18,774	191	978	19,943	54.6
2010	19,923	458	251	19,213	305	1,149	20,667	50.9
2011	19,779	473	259	19,047	105	987	20,139	53.9
2012	20,141	493	277	19,371	32	1,003	20,407	54.7
2013	20,521	509	296	19,716	0	1,022	20,738	54.8
2014	20,895	526	315	20,054	0	1,040	21,093	54.7
2015	21,258	544	334	20,380	0	1,057	21,437	54.7
2016	21,658	561	353	20,744	0	1,076	21,819	54.5
2017	22,069	580	372	21,117	0	1,095	22,213	54.6
2018	22,492	599	390	21,503	0	1,116	22,619	54.6
2019	22,922	618	407	21,897	0	1,136	23,034	54.5
2020	23,347	638	423	22,286	0	1,157	23,443	54.3

December 31, 2010 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) 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 %
2001	17,443	346	122	16,976	684	794	18,454	53.3
2002	18,423	361	137	17,925	502	935	19,362	58.7
2003	18,756	378	152	18,226	587	985	19,798	56.4
2004	18,999	394	168	18,437	589	945	19,971	58.9
2005	19,491	404	176	18,911	712	952	20,575	57.3
2006	19,625	412	188	19,025	700	1,000	20,726	57.2
2007	20,153	421	200	19,533	829	916	21,278	56.6
2008	19,632	430	212	18,990	752	909	20,650	57.3
2009	19,449	443	231	18,774	191	978	19,943	54.6
2010	19,923	458	251	19,213	305	1,149	20,667	50.9
2011	19,582	473	259	18,849	105	976	19,931	53.9
2012	19,751	493	277	18,981	32	983	19,996	54.6
2013	19,934	509	296	19,128	0	991	20,120	54.8
2014	20,106	526	315	19,265	0	999	20,263	54.7
2015	20,265	544	334	19,387	0	1,005	20,392	54.7
2016	20,455	561	353	19,540	0	1,013	20,553	54.5
2017	20,651	580	372	19,699	0	1,022	20,720	54.6
2018	20,852	599	390	19,864	0	1,030	20,894	54.6
2019	21,056	618	407	20,031	0	1,039	21,071	54.6
2020	21,250	638	423	20,189	0	1,047	21,236	54.4

December 31, 2010 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)
	2010 Actual		2011 Forecast		2012 Forecast	
Month	Peak Demand * MW	NEL ** GWH	Peak Demand * MW	NEL ** GWH	Peak Demand * MW	NEL ** GWH
January	4,631	1,781	4,232	1,514	4,188	1,518
February	3,562	1,481	3,508	1,351	3,464	1,337
March	3,420	1,446	3,094	1,464	3,116	1,470
April	3,021	1,446	3,241	1,484	3,266	1,493
May	3,764	1,905	3,669	1,773	3,695	1,785
June	4,034	2,046	3,879	1,890	3,907	1,905
July	4,028	2,024	3,989	1,996	4,020	2,013
August	4,024	2,025	3,993	2,037	4,025	2,053
September	3,818	1,866	3,809	1,882	3,839	1,897
October	3,480	1,576	3,541	1,704	3,583	1,723
November	2,982	1,329	3,064	1,412	3,103	1,427
December	4,155	1,740	3,253	1,506	3,295	1,520
TOTAL		20,667		20,012		20,141

December 31, 2010 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)
	2010 Actual		2011 Forecast		2012 Forecast	
Month	Peak Demand * MW	NEL ** GWH	Peak Demand * MW	NEL ** GWH	Peak Demand * MW	NEL ** GWH
January	4,631	1,781	4,255	1,521	4,237	1,536
February	3,562	1,481	3,530	1,358	3,506	1,354
March	3,420	1,446	3,113	1,472	3,153	1,489
April	3,021	1,446	3,262	1,493	3,306	1,512
May	3,764	1,905	3,694	1,784	3,741	1,808
June	4,034	2,046	3,906	1,902	3,956	1,931
July	4,028	2,024	4,017	2,010	4,071	2,041
August	4,024	2,025	4,022	2,051	4,076	2,082
September	3,818	1,866	3,836	1,895	3,888	1,923
October	3,480	1,576	3,567	1,716	3,629	1,747
November	2,982	1,329	3,087	1,422	3,143	1,446
December	4,155	1,740	3,277	1,517	3,338	1,541
TOTAL		20,667		20,139		20,407

December 31, 2010 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)
	2010 Actual		2011 Forecast		2012 Forecast	
Month	Peak Demand * MW	NEL ** GWH	Peak Demand * MW	NEL ** GWH	Peak Demand * MW	NEL ** GWH
January	4,631	1,781	4,218	1,510	4,157	1,510
February	3,562	1,481	3,494	1,345	3,436	1,328
March	3,420	1,446	3,081	1,458	3,090	1,461
April	3,021	1,446	3,228	1,478	3,238	1,483
May	3,764	1,905	3,655	1,765	3,664	1,772
June	4,034	2,046	3,864	1,882	3,874	1,891
July	4,028	2,024	3,974	1,988	3,986	1,998
August	4,024	2,025	3,978	2,029	3,991	2,038
September	3,818	1,866	3,794	1,874	3,806	1,883
October	3,480	1,576	3,527	1,697	3,552	1,710
November	2,982	1,329	3,052	1,407	3,076	1,417
December	4,155	1,740	3,240	1,500	3,267	1,509
TOTAL		20,667		19,932		19,997

December 31, 2010 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)
				Actual	Actual										
	Fuel Requirements		**Unit**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
(1)	Nuclear		Trillion BTU	0	0	0	0	0	0	0	0	0	0	0	0
(2)	Coal		1000 Ton	3,818	3,962	4,593	4,695	4,683	4,632	4,721	4,745	4,710	4,725	4,762	4,806
(3)	Residual	Total	1000 BBL	40	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 (A)	1000 BBL	40	0	0	0	0	0	0	0	0	0	0	0
(8)	Distillate	Total	1000 BBL	61	82	95	91	92	92	93	98	96	92	90	85
(9)		Steam	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(10)		CC	1000 BBL	47	59	83	81	83	83	80	83	83	80	83	84
(11)		CT	1000 BBL	14	23	12	10	9	9	13	15	13	12	7	1
(12)		Diesel	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(13)	Natural Gas	Total	1000 MCF	62,686	61,924	55,480	55,518	58,945	61,591	62,279	63,962	66,434	68,438	68,004	67,480
(14)		Steam	1000 MCF	0	0	0	0	0	0	0	0	0	0	0	0
(15)		CC	1000 MCF	59,134	57,625	51,659	52,219	54,183	56,703	55,491	55,550	58,794	60,195	63,395	66,310
(16)		CT	1000 MCF	3,552	4,299	3,821	3,299	4,762	4,888	6,788	8,412	7,640	8,243	4,609	1,170
(17)	Other (Specify)														
(18)	Petroleum Coke		1000 Ton	420	481	460	450	462	462	443	461	459	444	462	466

(A) Data reported as diesel for Phillips Units 1 and 2.
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	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
(1)	Annual Firm Interchange			GWh	704	864	382	358	133	125	166	191	147	169	0	0
(2)	Nuclear			GWh	0	0	0	0	0	0	0	0	0	0	0	0
(3)	Coal			GWh	8,442	9,267	10,247	10,506	10,480	10,339	10,540	10,616	10,542	10,553	10,634	10,757
(4)	Residual	Total		GWh	24	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	(A)	GWh	24	0	0	0	0	0	0	0	0	0	0	0
(9)	Distillate	Total		GWh	35	49	53	49	51	50	51	53	52	50	50	47
(10)		Steam		GWh	0	0	0	0	0	0	0	0	0	0	0	0
(11)		CC		GWh	28	38	46	44	46	45	44	45	45	44	46	46
(12)		CT		GWh	6	12	7	5	5	5	7	8	7	6	4	1
(13)		Diesel		GWh	0	0	0	0	0	0	0	0	0	0	0	0
(14)	Natural Gas	Total		GWh	8,659	8,375	7,466	7,488	7,893	8,262	8,279	8,438	8,814	9,077	9,370	9,486
(15)		Steam		GWh	0	0	0	0	0	0	0	0	0	0	0	0
(16)		CC		GWh	8,268	8,004	7,123	7,192	7,462	7,818	7,660	7,668	8,113	8,320	8,949	9,381
(17)		CT		GWh	391	371	343	296	431	444	619	770	701	757	421	105
(18)	Other (Specify)															
(19)	Petroleum Coke Generation			GWh	1,177	1,346	1,178	1,149	1,178	1,177	1,126	1,170	1,165	1,127	1,177	1,189
(20)	Net Interchange			GWh	227	235	114	114	127	128	125	132	128	129	135	138
(21)	Purchased Energy from															
(22)	Non-Utility Generators		(B)	GWh	675	530	572	477	477	478	479	407	406	406	406	407
(23)	Net Energy for Load			GWh	19,943	20,667	20,012	20,141	20,339	20,559	20,766	21,007	21,254	21,511	21,772	22,025

(A) Data reported as diesel for Phillips Units 1 and 2.
(B) 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 2009	Actual 2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
(1)	Annual Firm Interchange			%	3.5	4.2	1.9	1.8	0.7	0.6	0.8	0.9	0.7	0.8	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			%	42.3	44.8	51.2	52.2	51.5	50.3	50.8	50.5	49.6	49.1	48.8	48.8
(4)	Residual	Total		%	0.1	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	(A)	%	0.1	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		%	0.2	0.2	0.3	0.2	0.3	0.2	0.2	0.3	0.2	0.2	0.2	0.2
(10)		Steam		%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(11)		CC		%	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
(12)		CT		%	0.0	0.1	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		%	43.4	40.5	37.3	37.2	38.8	40.2	39.9	40.2	41.5	42.2	43.0	43.1
(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		%	41.5	38.7	35.6	35.7	36.7	38.0	36.9	36.5	38.2	38.7	41.1	42.6
(17)		CT		%	2.0	1.8	1.7	1.5	2.1	2.2	3.0	3.7	3.3	3.5	1.9	0.5
(18)	Other (Specify)															
(19)	Petroleum Coke Generation			%	5.9	6.5	5.9	5.7	5.8	5.7	5.4	5.6	5.5	5.2	5.4	5.4
(20)	Net Interchange			%	1.1	1.1	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
(21)	Purchased Energy from															
(22)	Non-Utility Generators		(B)	%	3.4	2.6	2.9	2.4	2.3	2.3	2.3	1.9	1.9	1.9	1.9	1.8
(23)	Net Energy for Load			%	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0

(A) Data reported as diesel for Phillips Units 1 and 2.

(B) 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

TAMPA ELECTRIC COMPANY FORECASTING METHODOLOGY

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 2011-2020 forecasts. The data tables in Chapter II outline the expected customer, demand, and energy values for the 2011-2020 time period.

RETAIL LOAD

MetrixND, an advanced statistics program for analysis and forecasting, was used to develop the 2011-2020 Customer, Demand and Energy forecasts. This software allows a platform for the development of more dynamic and fully integrated models.

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

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

1. Economic Analysis;
2. Customer 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 Economy.com and the University of Florida's Bureau of Economic and Business Research (BEBR).

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

2. CUSTOMER MULTIREGRESSION MODEL

The customer multiregression forecasting model is an seven-equation model. The equations forecast the number of customers by eight 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 2011-2020 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:* As the number of commercial customers increases so does the need for infrastructure expansion, such as street and highway lighting. Therefore, the commercial customer forecast is the basis for the Street & Highway Lighting customer model.

3. ENERGY MULTIREGRESSION MODEL

There are a total of 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) The end-use equipment index variables, which capture the long-term net effect of equipment saturation and equipment efficiency improvements; (2) The second component serves to capture changes in the economy such as household income, household size, and the price of electricity; and, (3) The third component is made up of weather variables, which serve to allocate the seasonal impacts of weather throughout the year. The SAE model framework begins by defining energy use for an average customer in year (y) and month (m) as the sum of energy used by heating equipment (XHeat y,m), cooling equipment (XCool y,m), and other equipment (XOther y,m). The XHeat, XCool, and XOther variables are defined as a product of an annual equipment index and a monthly usage multiplier.

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

   Where:

   $$\text{XHeat}_{y,m} = \text{HeatEquipIndex}_{y} \times \text{HeatUse}_{y,m}$$
   $$\text{XCool}_{y,m} = \text{CoolEquipIndex}_{y} \times \text{CoolUse}_{y,m}$$
   $$\text{XOtherUse}_{y,m} = \text{OtherEquipIndex}_{y} \times \text{OtherUse}_{y,m}$$

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

Where:

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

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

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

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

HeatUse $_{y,m}$ =

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

CoolUse $_{y,m}$ =

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

OtherUse $_{y,m}$ =

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

The SAE approach to modeling provides a powerful framework for developing short-term and long-term energy forecasts. This approach reflects changes in equipment saturation and efficiency levels and gives estimates of weather 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: The model is a subset of the total commercial sector and is a rather small percentage of the total commercial sector. Although small in nature, it is still a component that needs to be included. A simple regression model is used with the primary 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 recent trends in consumption, the price of electricity in the industrial sector and a cooling degree-day variable. 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 five 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. By incorporating both temperatures, the model is accounting for the fact that cold/heat buildup contributes to determining the peak day.

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

5. PHOSPHATE DEMAND AND ENERGY ANALYSIS

Because Tampa Electric's phosphate customers are relatively few in number, the company's Commercial/Industrial Customer Service Department has obtained detailed knowledge of industry developments including:

1. knowledge of expansion and close-out plans;
2. familiarity with historical and projected trends;
3. personal contact with industry personnel;
4. governmental legislation;
5. familiarity with worldwide demand for phosphate products.

This department's familiarity with industry dynamics and their close working relationship with phosphate company representatives were used to form the basis for a survey of the phosphate customers to determine their future energy and demand requirements. This survey is the foundation upon which the phosphate forecast is based. Further inputs are provided by 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 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. <u>Heating and Cooling</u> - Encourages the installation high-efficiency residential heating and cooling equipment.

2. <u>Load Management</u> - Residential, commercial and industrial programs reduce weather-sensitive heating, cooling and water heating through a radio signal control mechanism. However, the residential program is closed to new participation.

3. <u>Energy Audits</u> - The program is 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 for commercial/industrial customers.

4. <u>Residential Building Envelope</u> - 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. <u>Commercial Lighting</u> - Encourages investment in more efficient lighting technologies within existing commercial facilities.

6. <u>Standby Generator</u> - A program designed to utilize the emergency generation capacity of commercial/industrial facilities in order to reduce weather sensitive peak demand.

7. <u>Conservation Value</u> - Encourages investments in measures that are not sanctioned by other commercial programs.

8. <u>Residential Duct Repair</u> - An incentive program for existing homeowners which will help to supplement the cost of repairing leaky ductwork of central air-conditioning systems.

9. <u>Cogeneration</u> - 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 - The program is 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 2010 demand and energy savings achieved by conservation and load management programs are listed in Table III-1.

Tampa Electric developed a Monitoring and Evaluation (M&E) plan in response to requirements filed in Docket No. 941173-EG. The M&E plan was designed to effectively accomplish the required objective with prudent application of resources.

The M&E plan has as its focus two distinct areas: process evaluation and impact evaluation. Process evaluation examines how well a program has been implemented including the efficiency of delivery and customer satisfaction regarding the usefulness and quality of the services delivered. Impact evaluation is an evaluation of the change in demand and energy consumption achieved through program participation. The results of these evaluations give Tampa Electric insight into the direction that should be taken to refine delivery processes, program standards, and overall program cost-effectiveness.

WHOLESALE LOAD

Tampa Electric's firm long-term wholesale sales consist of contracts with Progress Energy Florida and the cities of Wauchula and St. Cloud.

Since Tampa Electric's sales to Wauchula will vary over time based on the strength of the local economies, a multiple regression approach similar to that used for forecasting Tampa Electric's retail load has been utilized. An energy and peak demand equation have been developed for the municipality. The peak model uses sales forecast trend variables and heating and cooling degree variables as inputs.

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

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

Residential

	Winter Peak MW Reduction			Summer Peak MW Reduction			GWh Energy Reduction		
Year	Total Achieved	Commission Approved Goal	% Variance	Total Achieved	Commission Approved Goal	% Variance	Total Achieved	Commission Approved Goal	% Variance
2010	10.6	6.4	165.6%	7.6	4.6	165.2%	16.3	9.8	166.3%

Commercial/Industrial

	Winter Peak MW Reduction			Summer Peak MW Reduction			GWh Energy Reduction		
Year	Total Achieved	Commission Approved Goal	% Variance	Total Achieved	Commission Approved Goal	% Variance	Total Achieved	Commission Approved Goal	% Variance
2010	6.8	0.9	755.6%	10.4	2.5	416.0%	17.3	6.5	266.2%

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	17.4	7.3	238.4%	18.0	7.1	253.5%	33.6	16.3	206.1%

BASE CASE FORECAST ASSUMPTIONS

RETAIL LOAD

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

1. Population and Households
2. Commercial, Industrial and Governmental Employment
3. Commercial, Industrial and Governmental Output
4. 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 Economy.com supply population projections for Hillsborough County and Florida. The population forecast is based upon the projections of BEBR in the short term and is a blend in the long term of BEBR and Economy.com. Over the next ten years (2011-2020) the average annual population growth rate in Hillsborough County is expected to be 1.5%. In addition, Economy.com provides household data as an input to the residential average use model.

2. COMMERCIAL, INDUSTRIAL AND GOVERNMENTAL EMPLOYMENT

Commercial and industrial employment assumptions are utilized in computing the number of customers in their respective sectors. It is imperative that employment growth be consistent with the expected population expansion and unemployment levels. Over the next ten years, employment is assumed to rise at a 2.3% average annual rate. Economy.com supplies employment projections.

3. COMMERCIAL, INDUSTRIAL AND GOVERNMENTAL OUTPUT

In addition to employment, output in terms of real gross domestic product by employment sector is utilized in computing energy in their respective sectors. Over the next ten years, output for the entire employment sector is assumed to rise at a 3.7% average annual rate. Economy.com supplies output projections.

4. REAL HOUSEHOLD INCOME

Economy.com supplies the assumptions for Hillsborough County's real household income growth. During 2011-2020, real household income for Hillsborough County is expected to increase at a 2.8% 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 2011-2020, retail energy sales are projected to rise at a 1.1% annual rate. The major contributor to growth is the residential category, increasing at an annual rate of 1.2%.

2. WHOLESALE ENERGY

Wholesale energy sales to Progress Energy Florida, Wauchula and St. Cloud are expected to be 105 GWH in 2011. In 2012, sales drop to 32 GWH and decline to zero in 2013.

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 2011-2020 period, Tampa Electric's base retail firm peak demand is expected to advance in the winter at an average annual rate of 1.4% and at rate of 1.3% in the summer.

Chapter IV

FORECAST OF FACILITIES REQUIREMENTS

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 peaking and intermediate resources are needed. The peaking capacity need will be met by building combustion turbine additions in 2013 to 2018 and/or future purchase power agreements. Beyond 2018, Tampa Electric currently expects to meet its intermediate load needs by either converting Polk Power Station's simple cycle combustion turbines (Polk units 2 - 5) to a natural gas combined cycle (NGCC) unit in 2019 or by entering into additional purchase power agreements. The operating and cost parameters associated with the capacity additions resulting from the analysis are shown in Schedule 9.

Tampa Electric will compare viable purchase power options as an alternative and/or enhancement to planned unit additions. The purchase power must have firm transmission service 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 42 MW of firm cogeneration capacity, which includes the 19 MW (through July 2011) of firm cogeneration inside its service area and 23 MW (through December 2015) of firm cogeneration imported from outside its service area. In 2011 Tampa Electric plans for 453 MW of cogeneration capacity operating in its service area.

Cogeneration in Service Area	Capacity (MW)
Self-service	242
Firm to Tampa Electric	19
As-available to Tampa Electric	23
Export to other systems	169
Total	453

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 2011 coal and petcoke will fuel 57% of net energy for load and natural gas will fuel 37%. Less than one percent of net energy for load will be fueled by oil. The remaining net energy for load is served by non-utility generators and net interchange purchases.

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 (NOx) by 91%, particulate matter (PM) by 87% and mercury emissions by 85%. 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:

- installation of flue gas desulfurization (scrubber) systems on Big Bend Units 1 and 2 in 1999
- intergration of Big Bend Unit 3 into Big Bend Unit 4's existing scrubber in 1995
- installation and operation of selective catalytic reduction systems, combustion tuning and optimization projects at Big Bend Station
- repowering of Gannon Station to H.L. Culbreath Bayside Power Station from coal to natural gas optimization
- improvement of the Big Bend electrostatic precipitators

In January 2008, the Chicago Climate Exchange (CCX) applauded Tampa Electric for meeting the program's Phase I greenhouse gas commitment of a 4% carbon dioxide (CO2) reduction. With an actual reduction of more than 20%, the company far surpassed the CCX target. The CCX

Phase II commitment of an additional 2% reduction (for a 6% total reduction commitment) is anticipated to be achieved after certification of 2010 emissions in early 2011.

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

Tampa Electric has the following long-term firm sale agreements:

- 12 MW to the City of Wauchula through September 2011
- 15 MW to the City of St. Cloud through December 2012
- 70 MW to Progress Energy Florida through February 2011

Tampa Electric has the following long-term purchase power contracts for capacity and energy:

- 441 MW winter and 356 MW summer from the Hardee Power Station for the period January 1993 through December 2012

- 170 MW from Calpine Energy Services for the period May 2006 through April 2011

- 158 MW from RRI Energy (previously Reliant Energy Services) for the period January 2008 through May 2012

- 121 MW from Pasco Cogen for the period January 2009 through December 2018

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
2011	4,292	635	0	42	4,969	3,747	1,222	33%	0	1,222	33%
2012	4,292	477	0	23	4,792	3,781	1,011	27%	0	1,011	27%
2013	4,460	121	0	23	4,604	3,817	788	21%	0	788	21%
2014	4,516	121	0	23	4,660	3,864	796	21%	0	796	21%
2015	4,572	121	0	23	4,716	3,909	807	21%	0	807	21%
2016	4,628	121	0	0	4,749	3,959	790	20%	0	790	20%
2017	4,684	121	0	0	4,805	4,011	794	20%	0	794	20%
2018	4,740	121	0	0	4,861	4,063	798	20%	0	798	20%
2019	5,106	0	0	0	5,106	4,117	989	24%	0	989	24%
2020	5,106	0	0	0	5,106	4,169	937	22%	0	937	22%

NOTE:
1. Capacity import includes firm purchase power agreements (PPA) with Invenergy of 356 MW through 2012, Calpine of 170 MW through April 2011, Reliant of 158 MW through May 2012, 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 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
2010-11	4,684	890	0	42	5,616	3,919	1,697	43%	0	1,697	43%
2011-12	4,684	720	0	23	5,427	3,881	1,546	40%	0	1,546	40%
2012-13	4,684	121	0	23	4,828	3,923	905	23%	0	905	23%
2013-14	4,867	121	0	23	5,011	3,980	1,031	26%	0	1,031	26%
2014-15	4,928	121	0	23	5,072	4,032	1,040	26%	0	1,040	26%
2015-16	4,989	121	0	0	5,110	4,087	1,023	25%	0	1,023	25%
2016-17	5,050	121	0	0	5,171	4,145	1,026	25%	0	1,026	25%
2017-18	5,111	121	0	0	5,232	4,203	1,030	24%	0	1,030	24%
2018-19	5,172	0	0	0	5,172	4,263	909	21%	0	909	21%
2019-20	5,503	0	0	0	5,503	4,323	1,180	27%	0	1,180	27%

NOTE:
1. Capacity import includes firm purchase power agreements (PPA) with Invenergy of 441 MW through 2012, Calpine of 170 MW through April 2011, Reliant of 158 MW through May 2012, 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.		Const.	Commercial	Expected	Gen. Max.	Net Capability		
Plant Name	Unit No.	Location	Unit Type	Primary	Alternate	Primary	Alternate	Start Mo/Yr	In-Service Mo/Yr	Retirement Mo/Yr	Nameplate kW	Summer MW	Winter MW	Status
Future CT	1	Bayside	CT	NG	N/A	PL	N/A	9/12	5/13	unknown	unknown	56	61	P
Future CT	2	Bayside	CT	NG	N/A	PL	N/A	9/12	5/13	unknown	unknown	56	61	P
Future CT	3	Big Bend	CT	NG	N/A	PL	N/A	9/12	5/13	unknown	unknown	56	61	P
Future CT	4	Big Bend	CT	NG	N/A	PL	N/A	9/13	5/14	unknown	unknown	56	61	P
Future CT	5	unknown	CT	NG	N/A	PL	N/A	9/14	5/15	unknown	unknown	56	61	P
Future CT	6	unknown	CT	NG	N/A	PL	N/A	9/15	5/16	unknown	unknown	56	61	P
Future CT	7	unknown	CT	NG	N/A	PL	N/A	9/16	5/17	unknown	unknown	56	61	P
Future CT	8	unknown	CT	NG	N/A	PL	N/A	9/17	5/18	unknown	unknown	56	61	P
Polk 2-5 CC	1	Polk	CC	NG	N/A	PL	N/A	1/15	5/19	unknown	unknown	970	1063	P

Notes:
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 2019. Incremental capacity gain from the conversion is 366 MW summer and 331 MW winter.

SCHEDULE 9
(Page 1 of 7)

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

(1)	PLANT NAME AND UNIT NUMBER	FUTURE CT 1, 2, & 3
(2)	CAPACITY	
	A. SUMMER	56
	B. WINTER	61
(3)	TECHNOLOGY TYPE	COMBUSTION TURBINE
(4)	ANTICIPATED CONSTRUCTION TIMING	
	A. FIELD CONSTRUCTION START DATE	SEP 2012
	B. COMMERCIAL IN-SERVICE DATE	MAY 2013
(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 (2013)	6.7%
	AVERAGE NET OPERATING HEAT RATE (ANOHR) [1]	10,781 Btu/kWh
(13)	PROJECTED UNIT FINANCIAL DATA	
	BOOK LIFE (YEARS)	25
	TOTAL INSTALLED COST (IN-SERVICE YEAR $/kW)	698.28
	DIRECT CONSTRUCTION COST ($/kW)	665.96
	AFUDC AMOUNT ($/kW)	13.21
	ESCALATION ($/kW)	19.10
	FIXED O&M ($/kW – Yr)	21.53
	VARIABLE O&M ($/MWH)	4.01
	K FACTOR	1.5964

[1] BASED ON IN-SERVICE YEAR.

SCHEDULE 9
(Page 2 of 7)

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

(1)	PLANT NAME AND UNIT NUMBER	FUTURE CT 4
(2)	CAPACITY	
	A. SUMMER	56
	B. WINTER	61
(3)	TECHNOLOGY TYPE	COMBUSTION TURBINE
(4)	ANTICIPATED CONSTRUCTION TIMING	
	A. FIELD CONSTRUCTION START DATE	SEP 2013
	B. COMMERCIAL IN-SERVICE DATE	MAY 2014
(5)	FUEL	
	A. PRIMARY FUEL	NATURAL GAS
	B. ALTERNATE FUEL	N/A
(6)	AIR POLLUTION CONTROL STRATEGY	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 (2014)	3.8%
	AVERAGE NET OPERATING HEAT RATE (ANOHR) [1]	10,798 Btu/kWh
(13)	PROJECTED UNIT FINANCIAL DATA	
	BOOK LIFE (YEARS)	25
	TOTAL INSTALLED COST (IN-SERVICE YEAR $/kW)	711.56
	DIRECT CONSTRUCTION COST ($/kW)	665.96
	AFUDC AMOUNT ($/kW)	13.48
	ESCALATION ($/kW)	32.12
	FIXED O&M ($/kW – Yr)	21.94
	VARIABLE O&M ($/MWH)	4.09
	K FACTOR	1.5964

[1] BASED ON IN-SERVICE YEAR.

SCHEDULE 9
(Page 3 of 7)

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

(1)	PLANT NAME AND UNIT NUMBER	FUTURE CT 5
(2)	CAPACITY	
	A. SUMMER	56
	B. WINTER	61
(3)	TECHNOLOGY TYPE	COMBUSTION TURBINE
(4)	ANTICIPATED CONSTRUCTION TIMING	
	A. FIELD CONSTRUCTION START DATE	SEP 2014
	B. COMMERCIAL IN-SERVICE DATE	MAY 2015
(5)	FUEL	
	A. PRIMARY FUEL	NATURAL GAS
	B. ALTERNATE FUEL	N/A
(6)	AIR POLLUTION CONTROL STRATEGY	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 (2015)	3.5%
	AVERAGE NET OPERATING HEAT RATE (ANOHR) [1]	10,809 Btu/kWh
(13)	PROJECTED UNIT FINANCIAL DATA	
	BOOK LIFE (YEARS)	25
	TOTAL INSTALLED COST (IN-SERVICE YEAR $/kW)	725.07
	DIRECT CONSTRUCTION COST ($/kW)	665.96
	AFUDC AMOUNT ($/kW)	13.72
	ESCALATION ($/kW)	45.38
	FIXED O&M ($/kW – Yr)	22.35
	VARIABLE O&M ($/MWH)	4.07
	K FACTOR	1.5964

[1] BASED ON IN-SERVICE YEAR.

SCHEDULE 9
(Page 4 of 7)

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

(1)	PLANT NAME AND UNIT NUMBER	FUTURE CT 6
(2)	CAPACITY	
	A. SUMMER	56
	B. WINTER	61
(3)	TECHNOLOGY TYPE	COMBUSTION TURBINE
(4)	ANTICIPATED CONSTRUCTION TIMING	
	A. FIELD CONSTRUCTION START DATE	SEP 2015
	B. COMMERCIAL IN-SERVICE DATE	MAY 2016
(5)	FUEL	
	A. PRIMARY FUEL	NATURAL GAS
	B. ALTERNATE FUEL	N/A
(6)	AIR POLLUTION CONTROL STRATEGY	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 (2016)	4.0%
	AVERAGE NET OPERATING HEAT RATE (ANOHR) [1]	10,842 Btu/kWh
(13)	PROJECTED UNIT FINANCIAL DATA	
	BOOK LIFE (YEARS)	25
	TOTAL INSTALLED COST (IN-SERVICE YEAR $/kW)	738.85
	DIRECT CONSTRUCTION COST ($/kW)	665.96
	AFUDC AMOUNT ($/kW)	13.98
	ESCALATION ($/kW)	58.90
	FIXED O&M ($/kW – Yr)	22.78
	VARIABLE O&M ($/MWH)	4.25
	K FACTOR	1.5964

[1] BASED ON IN-SERVICE YEAR.

SCHEDULE 9
(Page 5 of 7)

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

(1)	PLANT NAME AND UNIT NUMBER	FUTURE CT 7
(2)	CAPACITY	
	A. SUMMER	56
	B. WINTER	61
(3)	TECHNOLOGY TYPE	COMBUSTION TURBINE
(4)	ANTICIPATED CONSTRUCTION TIMING	
	A. FIELD CONSTRUCTION START DATE	SEP 2016
	B. COMMERCIAL IN-SERVICE DATE	MAY 2017
(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 (2017)	4.2%
	AVERAGE NET OPERATING HEAT RATE (ANOHR) [1]	10,830 Btu/kWh
(13)	PROJECTED UNIT FINANCIAL DATA	
	BOOK LIFE (YEARS)	25
	TOTAL INSTALLED COST (IN-SERVICE YEAR $/kW)	752.89
	DIRECT CONSTRUCTION COST ($/kW)	665.96
	AFUDC AMOUNT ($/kW)	14.25
	ESCALATION ($/kW)	72.67
	FIXED O&M ($/kW – Yr)	23.21
	VARIABLE O&M ($/MWH)	4.33
	K FACTOR	1.5964

[1] BASED ON IN-SERVICE YEAR.

SCHEDULE 9
(Page 6 of 7)

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

(1)	PLANT NAME AND UNIT NUMBER	FUTURE CT 8
(2)	CAPACITY	
	A. SUMMER	56
	B. WINTER	61
(3)	TECHNOLOGY TYPE	COMBUSTION TURBINE
(4)	ANTICIPATED CONSTRUCTION TIMING	
	A. FIELD CONSTRUCTION START DATE	SEP 2017
	B. COMMERCIAL IN-SERVICE DATE	MAY 2018
(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 (2018)	3.9%
	AVERAGE NET OPERATING HEAT RATE (ANOHR) [1]	10,785 Btu/kWh
(13)	PROJECTED UNIT FINANCIAL DATA	
	BOOK LIFE (YEARS)	25
	TOTAL INSTALLED COST (IN-SERVICE YEAR $/kW)	767.20
	DIRECT CONSTRUCTION COST ($/kW)	665.96
	AFUDC AMOUNT ($/kW)	14.52
	ESCALATION ($/kW)	86.71
	FIXED O&M ($/kW – Yr)	23.65
	VARIABLE O&M ($/MWH)	4.41
	K FACTOR	1.5964

[1] BASED ON IN-SERVICE YEAR.

SCHEDULE 9
(Page 7 of 7)

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	970
	B. WINTER	1063
(3)	TECHNOLOGY TYPE	COMBINED CYCLE
(4)	ANTICIPATED CONSTRUCTION TIMING	
	A. FIELD CONSTRUCTION START DATE	JAN 2015
	B. COMMERCIAL IN-SERVICE DATE	MAY 2019
(5)	FUEL	
	A. PRIMARY FUEL	NATURAL GAS
	B. ALTERNATE FUEL	N/A
(6)	AIR POLLUTION CONTROL STRATEGY	SCR, DLN BURNERS
(7)	COOLING METHOD	N/A
(8)	TOTAL SITE AREA	UNDETERMINED
(9)	CONSTRUCTION STATUS	PROPOSED
(10)	CERTIFICATION STATUS	UNDETERMINED
(11)	STATUS WITH FEDERAL AGENCIES	N/A
(12)	PROJECTED UNIT PERFORMANCE DATA	
	PLANNED OUTAGE FACTOR (POF)	3.8
	FORCED OUTAGE RATE (FOR)	3.0
	EQUIVALENT AVAILABILITY FACTOR (EAF)	93.1
	RESULTING CAPACITY FACTOR (2019)	66.3%
	AVERAGE NET OPERATING HEAT RATE (ANOHR) [1]	7,012 Btu/kWh
(13)	PROJECTED UNIT FINANCIAL DATA	
	BOOK LIFE (YEARS)	25
	TOTAL INSTALLED COST (IN-SERVICE YEAR $/kW)	663.93
	DIRECT CONSTRUCTION COST ($/kW)	549.56
	AFUDC AMOUNT ($/kW)	39.27
	ESCALATION ($/kW)	75.10
	FIXED O&M ($/kW – Yr)	8.96
	VARIABLE O&M ($/MWH)	3.42
	K FACTOR	1.6482

[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	Circuit Length	Voltage	Anticipated In-Service Date	Anticipated Capital Investment	Substations	Participation with Other Utilities
Future CT 1 and 2	Bayside	2	No new ROW required	0.7 mi	138kV	Spring 2013	$2 million	No new substations	None
Future CT 3	Big Bend	1	No new ROW required	0.2 mi	230kV	Spring 2013	$1 million	No new substations	None
Future CT 4	Big Bend	1	No new ROW required	0.2 mi	230kV	Spring 2014	$1 million	No new substations	None
Future CT 5	Unsited[1]	1	No new ROW required	0.0 mi	kV	Spring 2015	$ million	No new substations	None
Future CT 6	Unsited[1]	1	No new ROW required	0.0 mi	kV	Spring 2016	$ million	No new substations	None
Future CT 7	Unsited[1]	1	No new ROW required	0.0 mi	kV	Spring 2017	$ million	No new substations	None
Future CT 8	Unsited[1]	1	No new ROW required	0.0 mi	kV	Spring 2018	$ million	No new substations	None
Future CC 1	Polk to Pebbledale - 1	1	No new ROW required	13.5 mi	230kV	Spring 2019	$6 million	No new substations	None
Future CC 1	Polk to Pebbledale - 2	1	No new ROW required	9.9 mi	230kV	Spring 2019	$10 million	No new substations	None
Future CC 1	Polk to Fishhawk	1	No new ROW required	30.5mi	230kV	Spring 2019	$80 million	No new substations	None
Future CC 1	Polk	1	No new ROW required	.3 mi	230kV	Spring 2019	$4 million	No new substations	None
Future CC 1	Pebbledale to Willow Oak to Wheeler Road	1	ROW issues under-review	25.9 mi	230kV	Spring 2019	$75 million	New 230/69kV substation at Willow Oak	None

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

Chapter V

OTHER PLANNING ASSUMPTIONS AND INFORMATION

TRANSMISSION CONSTRAINTS AND IMPACTS

Based on a variety of assessments and sensitivity studies of the Tampa Electric transmission system using year 2010 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 those alternatives that were the most feasible overall. Those alternatives that failed to meet the qualitative and quantitative considerations were eliminated. This phase of the study resulted in a set of feasible alternatives that were considered in a more detailed economic analysis.

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 weeks, 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 PROVIEW module of STRATEGIST, a computer model developed by Ventyx, to evaluate the supply side resources. PROVIEW uses a dynamic programming approach to develop an estimate of the timing and type of capacity additions which would most economically meet the system demand and energy requirements. Dynamic programming compares all feasible combinations of generating unit additions, which satisfy the specified reliability criteria, and determines the schedule of additions that have the lowest revenue requirements. The model uses production costing analysis and incremental capital and O&M expenses to project the revenue requirements and rank each plan.

A detailed cost analysis for each of the top ranked resource plans is performed using the Capital Expenditure and Recovery module of STRATEGIST and the PLANNING & RISK (PAR) production cost model. PAR, a computer model developed by Ventyx, 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 addition of combustion turbines and a conversion of Polk Units 2-5 to a natural gas combined cycle.

Tampa Electric will continue to look for competitive purchase power agreements that may replace or delay the scheduled new units. Such alternatives would be considered if better suited to the overall objective of providing reliable power in the most cost effective manner.

GENERATION AND TRANSMISSION RELIABILITY CRITERIA

GENERATION

Tampa Electric currently uses two criteria to measure the reliability of its generating system. The company utilizes a 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%. Since the reserve margin calculation assumes no forced outages, Tampa Electric includes the purchased power contract with Invenergy for the Hardee Power Station in its available capacity. Contractually, Hardee Power Station is planned to be available to Tampa Electric at the time of system peak. Also, the capacity dedicated to any firm unit or station power sales at the time of system peak is subtracted from Tampa Electric's available capacity.

Tampa Electric's summer supply-side reserve margin is calculated by dividing the difference of projected supply-side resources and projected total peak demand by the forecasted firm peak demand. The total peak demand includes the summer firm peak demand, and interruptible and load management loads.

TRANSMISSION

The following criteria are used as guidelines for proposing system expansion and/or improvement projects. A detailed engineering study must be performed prior to making a prudent decision to initiate a project.

Tampa Electric follows Florida Reliability Coordinating Council (FRCC) planning criteria as contained in the FRCC Regional Transmission Planning Process document. 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, Tampa Electric utilizes specific criteria for normal system operation and single contingency operation are listed in the Generation and Transmission Reliability Criteria section of this document.

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 activity schedules the unit dispatch so that the total generation cost required to meet the projected load is minimized. This is the generation scenario contained in the power flow cases submitted to fulfill the requirements of FERC Form 715 and the FRCC.

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

TRANSMISSION SYSTEM PLANNING LOADING LIMITS CRITERIA

Tampa Electric follows the FRCC planning criteria as contained in the FRCC Standards Handbook and NERC Standards. In addition to FRCC criteria, Tampa Electric utilizes company-specific planning criteria.

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

TRANSMISION SYSTEM LOADING LIMITS	
Transmission System Conditions	**Maximum Acceptable Loading Limit for Transformers and Transmission Lines**
All elements in service	100%
Single Contingency (pre-switching)	120%
Single Contingency (post-switching)	100%
Bus Outages (pre-switching)	120%
Bus Outages (post-switching)	100%

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

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

AVAILABLE TRANSMISSION TRANSFER CAPABILITY (ATC) CRITERIA

Tampa Electric adheres to the FRCC ATC calculation methodology described in the *FRCC ATC Calculation and Coordination Procedures* document, as well as the principles contained in the NERC Reliability Standards relating to ATC calculations.

TRANSMISSION PLANNING ASSESSMENT PRACTICES

BASE CASE OPERATING CONDITIONS

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

SINGLE CONTINGENCY PLANNING CRITERIA

The Tampa Electric Company transmission system is designed such that any single branch (transmission line or autotransformer) can be removed from service up to the forecasted peak load level without any violations of the criteria stated in the Generation and Transmission Reliability Criteria section of this document.

MULTIPLE CONTINGENCY PLANNING CRITERIA

Double contingencies (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 Tampa Electric Company transmission system is designed such that these double contingencies do not cause violation of FRCC 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 transmission construction related to the generation expansion plan available. However, due to the timing of this document in relationship to our internal planning schedule, this plan may change in the near future.

SUPPLY SIDE RESOURCES PROCUREMENT PROCESS

Tampa Electric will manage the procurement process in accordance with established policies and procedures. Prospective suppliers of supply side resources as well as suppliers of equipment and services will be identified using various data base resources and competitive bid evaluations, and will be used in developing award recommendations to management.

This process will allow for future supply side resources to be supplied from self-build, purchase power, or competitively bid third parties. Consistent with company practice, bidders will be encouraged to propose incentive arrangements that promote development and implementation of cost savings and process improvement recommendations.

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) 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; and

5. In commercial programs such as Standby Generator and Commercial Load Management and Commercial Demand Response, the reductions are verified through metering of loads under control to determine the demand and energy savings.

Second, the programs are designed to promote the use of high efficiency equipment having permanent installation characteristics. Specifically, those programs that promote the installation of energy efficient measures or equipment (heat pumps, hard-wired lighting fixtures, ceiling insulation, 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 2010, Tampa Electric's Renewable Energy Program has over 2,500 customers purchasing over 3,600 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.

Tampa Electric is one of the few electric utilities in the state that uses renewable generation produced in the State of Florida. The company's renewable generation portfolio is a mix of various technologies and renewable fuel sources, including six company owned photovoltaic (PV) arrays totaling 81.7 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 2010, participating customers have utilized over 39 GWH of renewable energy since the program inception.

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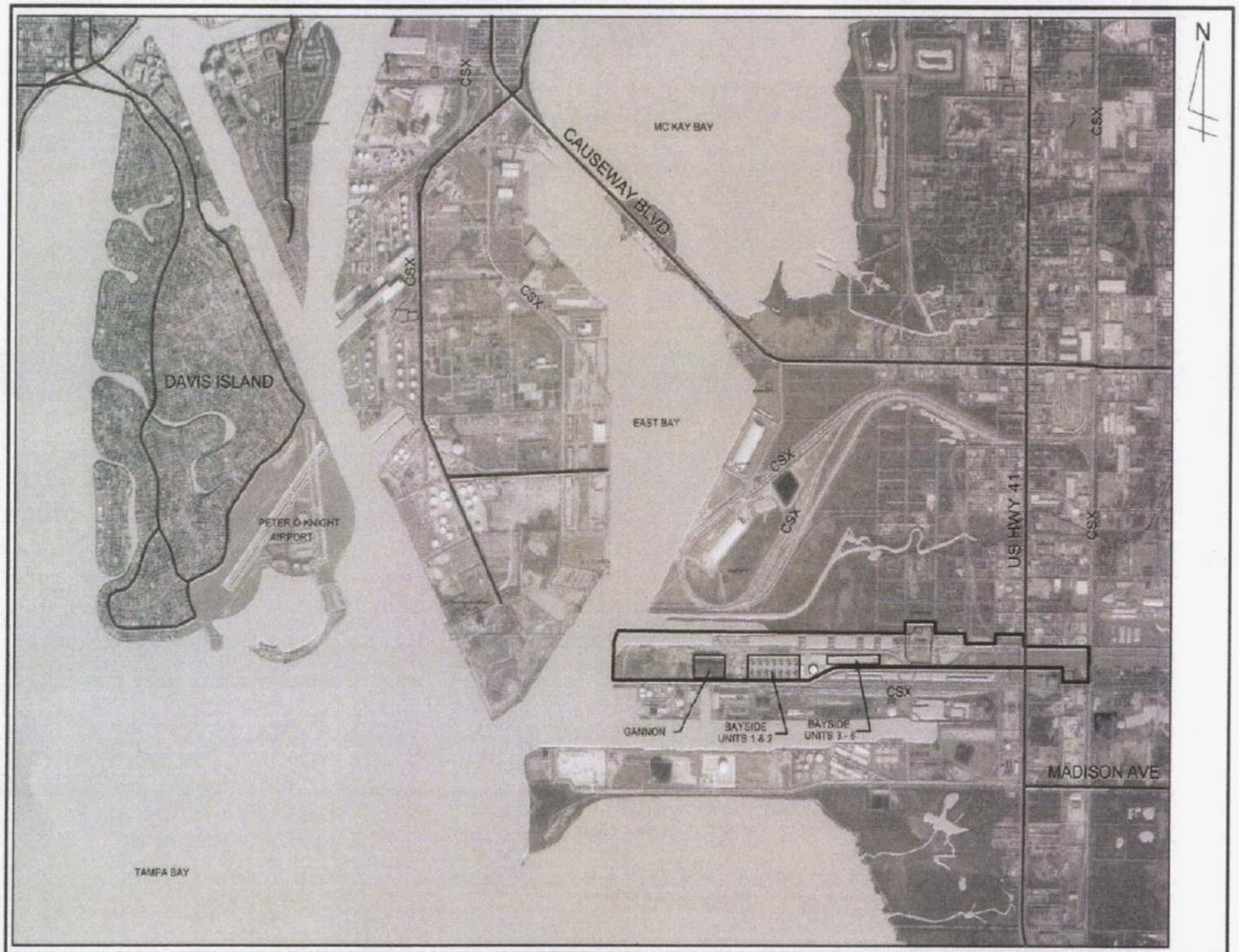
Chapter VI

ENVIRONMENTAL AND LAND USE INFORMATION

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

Figure VI-1



TAMPA ELECTRIC A TECO ENERGY COMPANY	F.J. GANNON / BAYSIDE	GIS TECH: SEAN LOBUR DATE: 02 /04 / 2010

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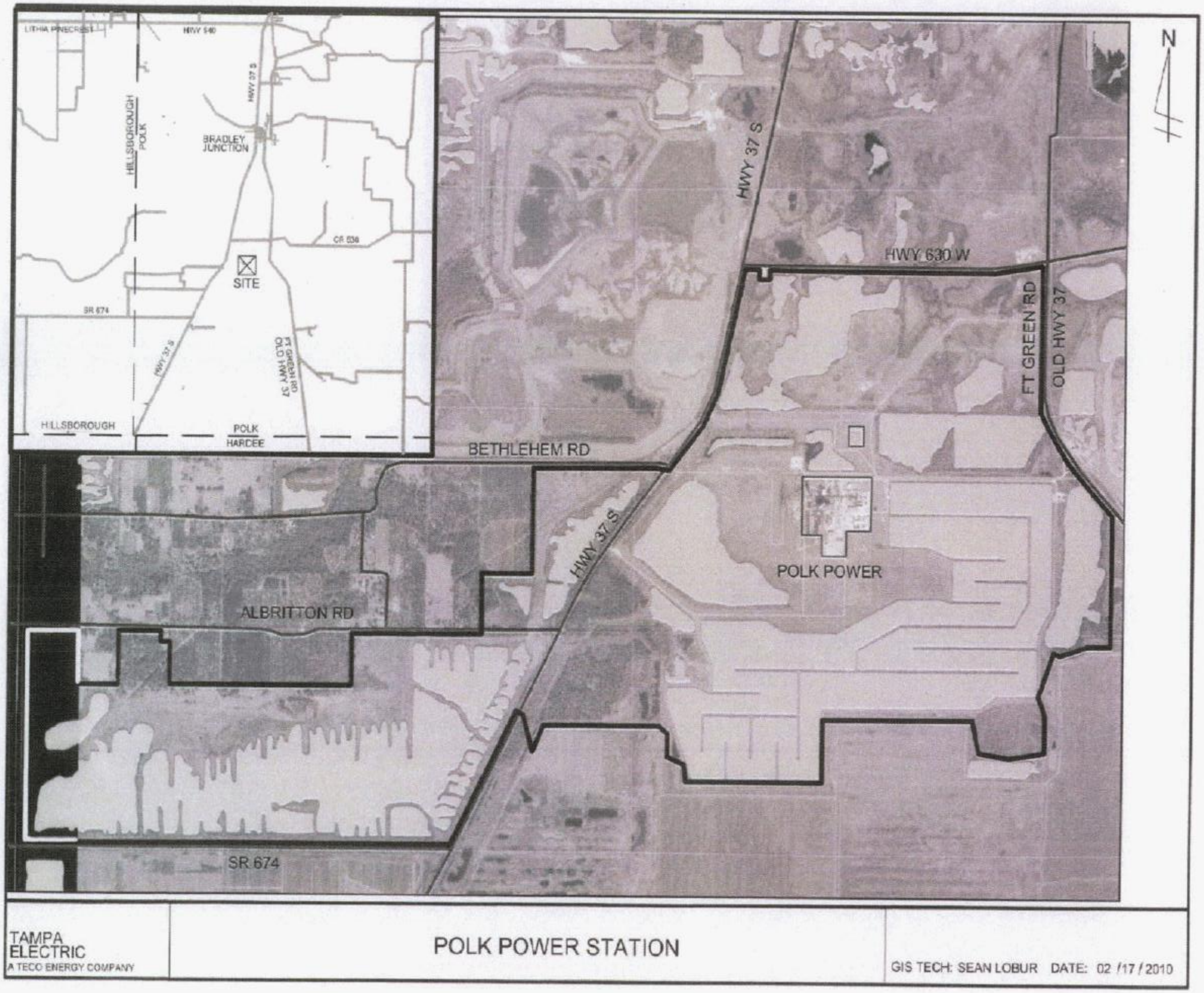

Figure VI-2

SACE 1st Response to Staff
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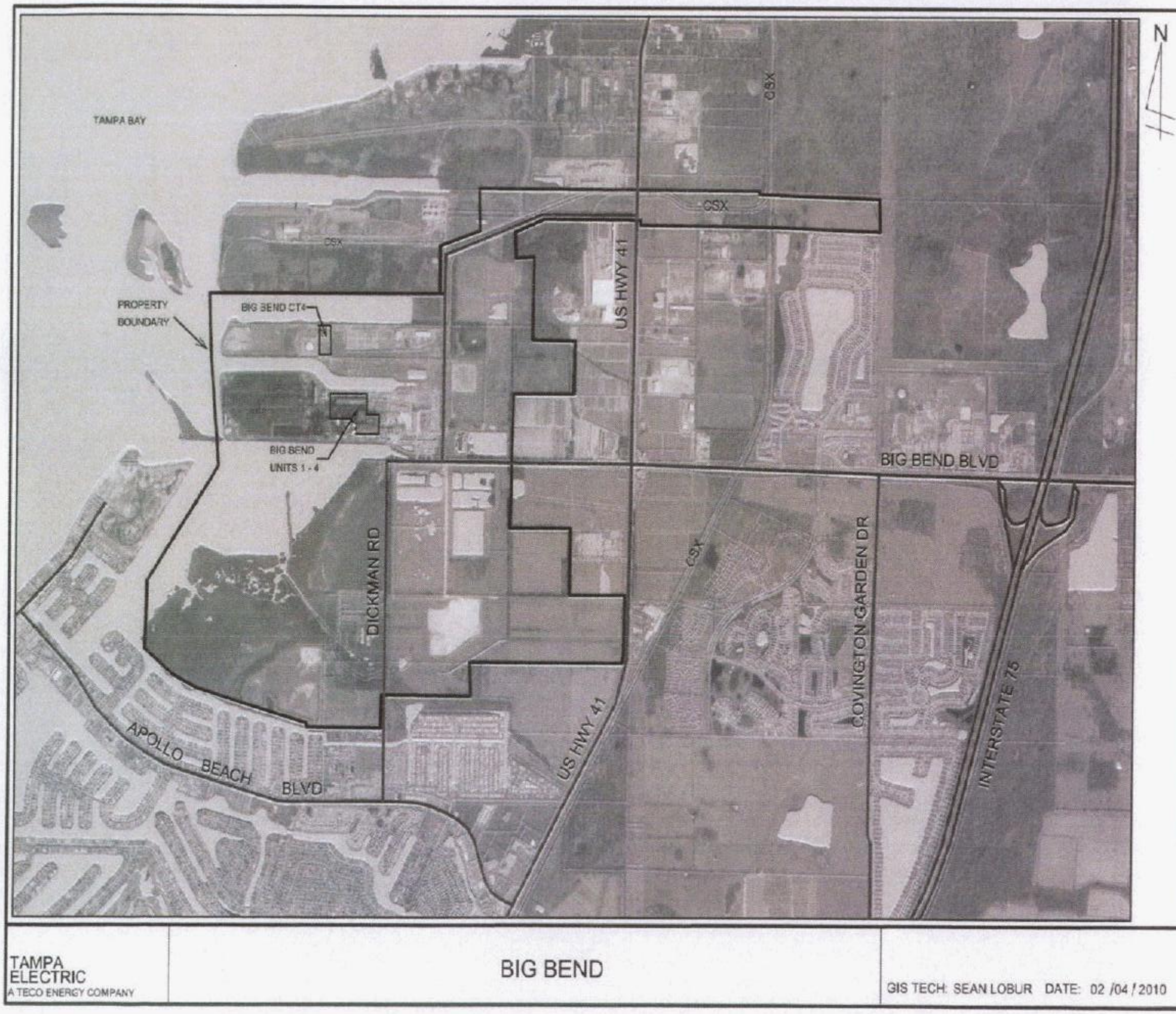

Figure VI-3