State of Florida

Public Service Commission

CAPITAL CIRCLE OFFICE CENTER • 2540 SHUMARD OAK BOULEVARD
TALLAHASSEE, FLORIDA 32399-0850

-M-E-M-O-R-A-N-D-U-M-

110000-OT

DATE: May 4, 2011

TO: Ann Cole, Commission Clerk, Office of Commission Clerk

FROM: Phillip O. Ellis, Engineering Specialist II, Division of Regulatory Analysis
Traci L. Matthews, Government Analyst I, Division of Regulatory Analysis

RE: TECO's Response to 2011 Ten-Year Site Plan Supplemental Data Request #1

Attached is Tampa Electric Company's Response to 2011 Ten-Year Site Plan Supplemental Data Request #1, submitted by April 29, 2011. Please place this item in Docket No. 110000 – Undocketed Filings for 2011, as it relates to the annual undocketed staff Ten-Year Site Plan Review project.

If you have any additional questions, please contact me.

POE

Attachment

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TAMPA ELECTRIC COMPANY

2011 TEN-YEAR SITE PLAN

SUPPLEMENTAL DATA REQUEST

FILED: APRIL 29, 2011

TAMPA ELECTRIC COMPANY
INDEX TO SUPPLEMENTAL DATA REQUEST
TEN-YEAR SITE PLAN

GENERAL QUESTIONS

1. Please provide all data requested in the attached forms labeled 'Appendix A,' in electronic (Excel) and hard copy. If any of the requested data is already included in the Company's Ten-Year Site Plan, state so on the appropriate form.

A. The requested data is provided in the attached forms and in Excel on the enclosed CD.

History and Forecast of Summer Peak Demand
High Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Year	Total	Wholesale	Retail	Interruptible	Residential Load Management	Residential Conservation	C / I Load Management	C / I Conservation	Net Firm Demand
HISTORY:									
2001									
2002									
2003									
2004									
2005									
2006									
2007									
2008									
2009									
2010									
FORECAST:									
2011									
2012									
2013									
2014									
2015									
2016									
2017									
2018									
2019									
2020									

Please refer to 2011 TYSP Schedule 3.1 High

History and Forecast of Summer Peak Demand
Low Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Year	Total	Wholesale	Retail	Interruptible	Residential Load Management	Residential Conservation	C / I Load Management	C / I Conservation	Net Firm Demand
HISTORY:									
2001									
2002									
2003									
2004									
2005									
2006									
2007									
2008									
2009									
2010									
FORECAST:									
2011									
2012									
2013									
2014									
2015									
2016									
2017									
2018									
2019									
2020									

Please refer to 2011 TYSP Schedule 3.1 Low

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	C / I Load Management	C / I Conservation	Net Firm Demand
HISTORY:									
2000/01									
2001/02									
2002/03									
2003/04									
2004/05									
2005/06									
2006/07									
2007/08									
2008/09									
2009/10									
FORECAST:									
2010/11									
2011/12									
2012/13									
2013/14									
2014/15									
2015/16									
2016/17									
2017/18									
2018/19									
2019/20									

Please refer to 2011 TYSP Schedule 3.2 High

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	C / I Load Management	C / I Conservation	Net Firm Demand
HISTORY:									
2000/01									
2001/02									
2002/03									
2003/04									
2004/05									
2005/06									
2006/07									
2007/08									
2008/09									
2009/10									
FORECAST:									
2010/11									
2011/12									
2012/13									
2013/14									
2014/15									
2015/16									
2016/17									
2017/18									
2018/19									
2019/20									

Please refer to 2011 TYSP Schedule 3.2 Low

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Year	Total	Residential Conservation	C / I Conservation	Retail	Wholesale	Utility Use & Losses	Net Energy for Load	Load Factor (%)
HISTORY:								
2001								
2002								
2003			Please refer to 2011 TYSP Schedule 3.3 High					
2004								
2005								
2006								
2007								
2008								
2009								
2010								
FORECAST:								
2011								
2012								
2013								
2014								
2015								
2016								
2017								
2018								
2019								
2020								

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

(1) Year	(2) Total	(3) Residential Conservation	(4) C / I Conservation	(5) Retail	(6) Wholesale	(7) Utility Use & Losses	(8) Net Energy for Load	(9) Load Factor (%)
HISTORY:								
2001								
2002								
2003								
2004								
2005								
2006								
2007								
2008								
2009								
2010								
FORECAST:								
2011								
2012								
2013								
2014								
2015								
2016								
2017								
2018								
2019								
2020								

Please refer to 2011 TYSP Schedule 3.3 Low

Existing Generating Unit Operating Performance

(1)	(2)	(3)		(4)		(5)		(6)	
		Planned Outage Factor (POF)		Forced Outage Factor (FOF)		Equivalent Availability Factor (EAF)		Average Net Operating Heat Rate (ANOHR)	
Plant Name	Unit No.	Historical	Projected	Historical	Projected	Historical	Projected	Historical	Projected
Bayside	1	4.3	8.2	0.2	0.9	94.0	89.1	7,261	7,370
Bayside	2	10.0	7.8	0.4	0.9	88.4	89.5	7,367	7,435
Bayside[a]	3	0.3	1.9	0.6	0.8	94.4	96.7	11,390	10,808
Bayside[a]	4	0.3	1.9	2.2	0.8	90.5	96.7	11,276	10,799
Bayside[b]	5	0.3	1.9	1.7	0.8	94.0	96.7	11,128	10,835
Bayside[c]	6	0.3	1.9	0.9	0.8	94.6	96.7	11,008	10,837
Big Bend	1	14.5	8.6	9.0	7.4	63.9	77.3	10,603	10,322
Big Bend	2	14.1	9.9	18.2	7.4	58.8	76.7	10,388	10,341
Big Bend	3	15.3	10.0	9.3	7.4	67.7	76.6	10,638	10,550
Big Bend	4	9.0	8.9	9.6	6.3	72.9	80.3	10,564	10,526
Big Bend[d]	CT 4	0.1	2.5	3.8	0.5	89.1	97.0	11,266	10,434
Polk	1	7.3	6.4	1.8	6.0	83.2	81.1	10,383	10,604
Polk	2	0.3	1.8	11.5	0.5	87.1	97.2	12,371	11,768
Polk	3	2.0	1.3	0.6	0.5	96.3	97.6	12,948	12,001
Polk	4	1.1	1.1	2.0	0.3	95.6	98.3	12,365	11,356
Polk	5	0.7	1.3	1.9	0.3	95.4	98.2	11,938	11,432
Phillips[e]	1	2.7	0.0	0.4	0.0	94.2	0.0	10,643	0
Phillips[e]	2	4.5	0.0	0.1	0.0	95.0	0.0	10,595	0
Partnership Station	1 & 2	0.0	0.0	16.9	2.6	83.1	90.0	10,956	10,396

NOTE: Historical - average of past three years
Projected - average of next ten years

(a) The unit commercial operation date for Bayside 3 & 4 was July 13, 2009. Therefore, the historical data for this unit does not reflect a 3 year average.
(b) The unit commercial operation date for Bayside 5 was April 27, 2009. Therefore, the historical data for this unit does not reflect a 3 year average.
(c) The unit commercial operation date for Bayside 6 was April 20, 2009. Therefore, the historical data for this unit does not reflect a 3 year average.
(d) The unit commercial operation date for Big Bend CT 4 was August 26, 2009. Therefore, the historical data for this unit does not reflect a 3 year average.
(e) Phillips Units 1 & 2 were placed into long-term reserve standby (LTRS) on September 4, 2009, and projected values are not available.

Nominal, Delivered Residual Oil Prices
Base Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
	Residual Oil (By Sulfur Content)								
	Less Than 0.7%		Escalation	0.7 - 2.0%		Escalation	Greater Than 2.0%		Escalation
Year	$/BBL	c/MBTU	%	$/BBL	c/MBTU	%	$/BBL	c/MBTU	%
HISTORY:									
2008									
2009									
2010									
FORECAST:									
2011	NOTE: TAMPA ELECTRIC'S OIL FIRED UNITS DO NOT						$92.01	1,465	
2012	BURN RESIDUAL OIL LESS THAN 2.0% SULFUR CONTENT.						$113.42	1,806	23.3
2013							$119.08	1,897	5.0
2014							$124.74	1,987	4.7
2015							$130.44	2,077	4.6
2016							$134.25	2,138	2.9
2017							$140.73	2,241	4.8
2018							$142.82	2,275	1.5
2019							$145.12	2,311	1.6
2020							$146.64	2,335	1.1

ASSUMPTIONS: heat content, ash content
NOTE: 1. FUEL PRICES INCLUDE TRANSPORTATION COSTS.

Nominal, Delivered Residual Oil Prices
High Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
	Residual Oil (By Sulfur Content)								
	Less Than 0.7%		Escalation	0.7 - 2.0%		Escalation	Greater Than 2.0%		Escalation
Year	$/BBL	c/MBTU	%	$/BBL	c/MBTU	%	$/BBL	c/MBTU	%
HISTORY:									
2008									
2009									
2010									
FORECAST:									
2011	NOTE: TAMPA ELECTRIC'S OIL FIRED UNITS DO NOT						$124.21	1,978	
2012	BURN RESIDUAL OIL LESS THAN 2.0% SULFUR CONTENT.						$153.11	2,439	23.3
2013							$160.76	2,560	5.0
2014							$168.40	2,682	4.7
2015							$176.09	2,804	4.6
2016							$181.24	2,886	2.9
2017							$189.99	3,026	4.8
2018							$192.81	3,071	1.5
2019							$195.91	3,120	1.6
2020							$197.97	3,153	1.1

ASSUMPTIONS: heat content, ash content
NOTE: 1. FUEL PRICES INCLUDE TRANSPORTATION COSTS.

Nominal, Delivered Residual Oil Prices
Low Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
	Residual Oil (By Sulfur Content)								
	Less Than 0.7%		Escalation	0.7 - 2.0%		Escalation	Greater Than 2.0%		Escalation
Year	$/BBL	c/MBTU	%	$/BBL	c/MBTU	%	$/BBL	c/MBTU	%
HISTORY:									
2008									
2009									
2010									
FORECAST:									
2011	NOTE: TAMPA ELECTRIC'S OIL FIRED UNITS DO NOT						$59.81	952	
2012	BURN RESIDUAL OIL LESS THAN 2.0% SULFUR CONTENT.						$73.72	1,174	23.3
2013							$77.40	1,233	5.0
2014							$81.08	1,291	4.7
2015							$84.78	1,350	4.6
2016							$87.26	1,390	2.9
2017							$91.48	1,457	4.8
2018							$92.84	1,479	1.5
2019							$94.33	1,502	1.6
2020							$95.32	1,518	1.1

ASSUMPTIONS: heat content, ash content
NOTE: 1. FUEL PRICES INCLUDE TRANSPORTATION COSTS.

Nominal, Delivered Distillate Oil and Natural Gas Prices
Base Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Distillate Oil			Natural Gas		
			Escalation			Escalation
Year	$/BBL	c/MBTU	%	$/MCF	c/MBTU	%
HISTORY:						
2008						
2009						
2010						
FORECAST:						
2011	$105.53	1,821		$6.38	621.02	
2012	$110.49	1,906	4.7	$6.84	665.73	7.2
2013	$114.89	1,982	4.0	$7.10	690.56	3.7
2014	$119.29	2,058	3.8	$7.34	713.79	3.4
2015	$124.76	2,152	4.6	$7.64	742.84	4.1
2016	$131.33	2,266	5.3	$7.99	777.28	4.6
2017	$138.08	2,382	5.1	$8.35	812.32	4.5
2018	$141.13	2,435	2.2	$8.51	828.30	2.0
2019	$144.27	2,489	2.2	$8.68	844.82	2.0
2020	$147.47	2,544	2.2	$8.92	867.97	2.7

ASSUMPTIONS FOR DISTILLATE OIL: heat content, ash content, sulfur content

NOTE: 1. FUEL PRICES INCLUDE VARIABLE TRANSPORTATION COSTS AND PIPELINE RESERVATION COSTS AT 100% UTILIZATION.

Nominal, Delivered Distillate Oil and Natural Gas Prices
High Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Distillate Oil			Natural Gas		
Year	$/BBL	c/MBTU	Escalation %	$/MCF	c/MBTU	Escalation %
HISTORY:						
2008						
2009						
2010						
FORECAST:						
2011	$142.46	2,458		$8.33	810.06	
2012	$149.16	2,574	4.7	$8.93	868.87	7.3
2013	$155.10	2,676	4.0	$9.27	901.78	3.8
2014	$161.04	2,778	3.8	$9.59	933.09	3.5
2015	$168.42	2,906	4.6	$9.99	972.19	4.2
2016	$177.29	3,059	5.3	$10.47	1,018.69	4.8
2017	$186.41	3,216	5.1	$10.96	1,066.14	4.7
2018	$190.52	3,287	2.2	$11.18	1,087.73	2.0
2019	$194.77	3,360	2.2	$11.41	1,110.03	2.1
2020	$199.09	3,435	2.2	$11.71	1,139.06	2.6

ASSUMPTIONS FOR DISTILLATE OIL: heat content, ash content, sulfur content

NOTE: 1. FUEL PRICES INCLUDE VARIABLE TRANSPORTATION COSTS AND PIPELINE RESERVATION COSTS AT 100% UTILIZATION.

Nominal, Delivered Distillate Oil and Natural Gas Prices
Low Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Distillate Oil			Natural Gas		
Year	$/BBL	c/MBTU	Escalation %	$/MCF	c/MBTU	Escalation %
HISTORY:						
2008						
2009						
2010						
FORECAST:						
2011	$68.59	1,183		$4.44	431.98	
2012	$71.82	1,239	4.7	$4.76	462.60	7.1
2013	$74.68	1,288	4.0	$4.93	479.33	3.6
2014	$77.54	1,338	3.8	$5.08	494.49	3.2
2015	$81.09	1,399	4.6	$5.28	513.49	3.8
2016	$85.36	1,473	5.3	$5.51	535.88	4.4
2017	$89.75	1,549	5.1	$5.74	558.49	4.2
2018	$91.73	1,583	2.2	$5.85	568.88	1.9
2019	$93.78	1,618	2.2	$5.96	579.62	1.9
2020	$95.86	1,654	2.2	$6.14	596.89	3.0

ASSUMPTIONS FOR DISTILLATE OIL: heat content, ash content, sulfur content

NOTE: 1. FUEL PRICES INCLUDE VARIABLE TRANSPORTATION COSTS AND PIPELINE RESERVATION COSTS AT 100% UTILIZATION.

Nominal, Delivered Coal Prices
Base Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
	Low Sulfur Coal (< 1.0%)				Medium Sulfur Coal (1.0 - 2.0%)				High Sulfur Coal (> 2.0%)			
Year	$/Ton	c/MBTU	Escalation %	% Spot Purchase	$/Ton	c/MBTU	Escalation %	% Spot Purchase	$/Ton	c/MBTU	Escalation %	% Spot Purchase
HISTORY:												
2008												
2009												
2010												
FORECAST:												
2011	$92.04	407.27							$78.88	328.66		
2012	$99.12	438.57	7 7						$81.38	339 10	3.2	
2013	$103.57	458.26	4.5						$82.56	343.99	1 4	
2014	$114 29	505.72	10 4						$88 37	368.22	7 0	
2015	$116 18	514.07	1 7						$92.70	386.25	4.9	
2016	$116.67	516.25	0 4						$93.59	389.95	1.0	
2017	$116.96	517.52	0.2						$94.27	392 79	0.7	
2018	$120.57	533.51	3.1						$98.11	408.78	4.1	
2019	$124.31	550.03	3.1						$102 07	425.30	4.0	
2020	$128.10	566.83	3.1						$106.10	442.10	4.0	

ASSUMPTIONS: type of coal, heat content, ash content
NOTE 1. FUEL PRICES INCLUDE TRANSPORTATION COSTS.

Nominal, Delivered Coal Prices
High Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
	Low Sulfur Coal (< 1.0%)				Medium Sulfur Coal (1.0 - 2.0%)				High Sulfur Coal (> 2.0%)			
Year	$/Ton	c/MBTU	Escalation %	% Spot Purchase	$/Ton	c/MBTU	Escalation %	% Spot Purchase	$/Ton	c/MBTU	Escalation %	% Spot Purchase
HISTORY:												
2008												
2009												
2010												
FORECAST:												
2011	$92.04	407.27							$78.88	328.66		
2012	$99.12	438.57	7.7						$81.38	339.10	3.2	
2013	$103.57	458.26	4.5						$82.56	343.99	1.4	
2014	$114.29	505.72	10.4						$88.37	368.22	7.0	
2015	$116.18	514.07	1.7						$92.70	386.25	4.9	
2016	$116.67	516.25	0.4						$93.59	389.95	1.0	
2017	$116.96	517.52	0.2						$94.27	392.79	0.7	
2018	$120.57	533.51	3.1						$98.11	408.78	4.1	
2019	$124.31	550.03	3.1						$102.07	425.30	4.0	
2020	$128.10	566.83	3.1						$106.10	442.10	4.0	

ASSUMPTIONS: type of coal, heat content, ash content
NOTE 1. FUEL PRICES INCLUDE TRANSPORTATION COSTS

Nominal, Delivered Coal Prices
Low Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
	Low Sulfur Coal (< 1.0%)				Medium Sulfur Coal (1.0 - 2.0%)				High Sulfur Coal (> 2.0%)			
Year	$/Ton	c/MBTU	Escalation %	% Spot Purchase	$/Ton	c/MBTU	Escalation %	% Spot Purchase	$/Ton	c/MBTU	Escalation %	% Spot Purchase
HISTORY:												
2008												
2009												
2010												
FORECAST:												
2011	$92.04	407 27							$78.88	328.66		
2012	$99.12	438.57	7 7						$81 38	339 10	3.2	
2013	$103.57	458.26	4.5						$82.56	343.99	1.4	
2014	$114 29	505.72	10.4						$88.37	368.22	7 0	
2015	$116 18	514.07	1.7						$92.70	386.25	4 9	
2016	$116.67	516.25	0.4						$93.59	389.95	1.0	
2017	$116.96	517 52	0 2						$94.27	392.79	0.7	
2018	$120 57	533.51	3 1						$98 11	408 78	4.1	
2019	$124.31	550.03	3.1						$102.07	425.30	4 0	
2020	$128.10	566 83	3.1						$106.10	442.10	4.0	

ASSUMPTIONS: type of coal, heat content, ash content
NOTE: 1. FUEL PRICES INCLUDE TRANSPORTATION COSTS.

Nominal, Delivered Nuclear Fuel and Firm Purchases

(1)	(2)	(3)	(4)	(5)
	Nuclear		Firm Purchases	
Year	c/MBTU	Escalation %	$/MWh	Escalation %
HISTORY:				
2008	NOTE: TAMPA ELECTRIC COMPANY DOES NOT OWN OR PURCHASE			
2009	NUCLEAR POWER ON A FIRM BASIS, AND TAMPA ELECTRIC'S CURRENT			
2010	EXPANSION PLAN DOES NOT PROJECT A NUCLEAR GENERATING			
	FACILITY.			
FORECAST:				
2011			52.45	
2012			57.88	10.4
2013			50.14	-13.4
2014			50.45	0.6
2015			53.69	6.4
2016			64.10	19.4
2017			67.51	5.3
2018			69.11	2.4
2019				
2020	NOTE: TAMPA ELECTRIC DOES NOT HAVE ANY FIRM PURCHASES PAST 2018.			

Financial Assumptions
Base Case

AFUDC RATE	7.79	%
CAPITALIZATION RATIOS:		
DEBT	46.04	%
PREFERRED	0	%
EQUITY	53.96	%
RATE OF RETURN		
DEBT	6.9	%
PREFERRED	N/A	%
EQUITY	11.25	%
INCOME TAX RATE:		
STATE	3.575	%
FEDERAL	35	%
EFFECTIVE	38.575	%
OTHER TAX RATE:	2.25	%
DISCOUNT RATE:	8.02	%
TAX DEPRECIATION RATE:	MACRS	%

Financial Escalation Assumptions

(1)	(2)	(3)	(4)	(5)
Year	General Inflation %	Plant Construction Cost %	Fixed O&M Cost %	Variable O&M Cost %
2011	2.1	3.2	2.1	2.1
2012	2.8	1.7	2.8	2.8
2013	2.2	1.9	2.2	2.2
2014	2.2	1.9	2.2	2.2
2015	2.2	1.9	2.2	2.2
2016	2.2	1.9	2.2	2.2
2017	2.2	1.9	2.2	2.2
2018	2.2	1.9	2.2	2.2
2019	2.2	1.9	2.2	2.2
2020	2.2	1.9	2.2	2.2

Loss of Load Probability, Reserve Margin, and Expected Unserved Energy
Base Case Load Forecast

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Annual Isolated			Annual Assisted		
Year	Loss of Load Probability (Days/Yr)	Reserve Margin (%) (Including Firm Purchases)	Expected Unserved Energy (MWh)	Loss of Load Probability (Days/Yr)	Reserve Margin (%) (Including Firm Purchases)	Expected Unserved Energy (MWh)
2011	NA	NA	NA	NA	32.6%	0
2012	NA	NA	NA	NA	26.7%	0
2013	NA	NA	NA	NA	20.6%	890
2014	NA	NA	NA	NA	20.6%	0
2015	NA	NA	NA	NA	20.6%	460
2016	NA	NA	NA	NA	19.9%	1220
2017	NA	NA	NA	NA	19.8%	720
2018	NA	NA	NA	NA	19.6%	80
2019	NA	NA	NA	NA	24.0%	8000
2020	NA	NA	NA	NA	22.5%	8730

Note: Tampa Electric Co. does not use Loss of Load Probability.
Reserve Margins are based on summer peaks.
Ten Year Site Plan EUE analysis were run in the annual assisted mode only.

2. Please provide all data requested in the attached forms labeled 'Appendix B,' which consist of Schedules 1 through 10 from the Company's Ten-Year Site Plan, in an electronic copy in Excel (.xls file format).

A. The requested data is provided in the attached forms and in Excel on the enclosed CD.

Schedule 1
Existing Generating Facilities
As of December 31, 2009

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Plant Name	Unit No.	Location	Unit Type	Fuel Pri	Fuel Alt	Fuel Transport Pri	Fuel Transport Alt	Alt. Fuel Days Use	Commercial In-Service Month/Year	Expected Retirement Month/Year	Gen. Max. Nameplate KW	Net Capability Summer MW	Net Capability Winter MW
Big Bend		Hillsborough Co. 14/31S/19E									**1892485**	**1608**	**1643**
	1		ST	BIT	N	WA	N	0	10/70	Unknown	445500	385	395
	2		ST	BIT	N	WA	N	0	4/73	Unknown	445500	385	395
	3		ST	BIT	N	WA	N	0	5/76	Unknown	445500	365	365
	4		ST	BIT	N	WA	N	0	2/85	Unknown	486000	417	427
	CT4		GT	NG	LO	PL	TK	0	8/09	Unknown	69985	56	61
Bayside		Hillsborough Co. 4/30S/19E									**2294100**	**1854**	**2083**
	1		CC	NG	N	PL	N	0	4/03	Unknown	809060	701	792
	2		CC	NG	N	PL	N	0	1/04	Unknown	1205100	929	1047
	3		GT	NG	N	PL	N	0	7/09	Unknown	69985	56	61
	4		GT	NG	N	PL	N	0	7/09	Unknown	69985	56	61
	5		GT	NG	N	PL	N	0	4/09	Unknown	69985	56	61
	6		GT	NG	N	PL	N	0	4/09	Unknown	69985	56	61
Phillips		Highland Co. 12-055									**38430**	**36** [1]	**36** [1]
	1		IC	HO	LO	TK	N	0	6/83	LTRS 9/09	19215	18 [1]	18 [1]
	2		IC	HO	LO	TK	N	0	6/83	LTRS 9/09	19215	18 [1]	18 [1]
Polk											**1029379**	**824**	**952**
	1		IGCC	BIT	LO	WA/TK	TK	0	9/96	Unknown	326299	220	220
	2		GT	NG	LO	PL	TK	0	7/00	Unknown	175770 [2]	151	183
	3		GT	NG	LO	PL	TK	0	5/02	Unknown	175770 [2]	151	183
	4		GT	NG	N	PL	N	0	3/07	Unknown	175770 [2]	151	183
	5		GT	NG	N	PL	N	0	4/07	Unknown	175770 [2]	151	183
Partnership											**5800**	**5.8**	**5.8**
	1		IC	NG	N	PL	N	0	4/01	Unknown	2900	2.9	2.9
	2		IC	NG	N	PL	N	0	4/01	Unknown	2900	2.9	2.9
											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.

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 2.2
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 2.3
History and Forecast of Energy Consumption and Number of Customers by Customer Class
Base Case

(1)	(2)	(3)	(4)	(5)	(6)
Year	Sales for * Resale GWH	Utility Use ** & Losses GWH	Net Energy *** for Load GWH	Other **** Customers	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 3.1
History and Forecast of Summer Peak Demand
Base Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	
Year	Total *	Wholesale**	Retail *	Interruptible	Residential Load Management	Residential Conservation	Comm./Ind. Load Management	Comm./Ind. Conservation	Net Firm Demand	
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 3.2
History and Forecast of Winter Peak Demand
Base Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Year	Total *	Wholesale **	Retail *	Interruptible	Residential Load Management	Residential Conservation	Comm./Ind. Load Management	Comm./Ind. Conservation	Net Firm Demand
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 3.3
History and Forecast of Annual Net Energy for Load - GWH
Base Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Year	Total	Residential Conservation	Comm./Ind. Conservation	Retail	Wholesale *	Utility Use & Losses	Net Energy for Load	Load ** Factor %
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 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 5
Fuel Requirements

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
	Fuel Requirements		Units	Actual 2009	Actual 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	4,025	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)		Other	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)		Other	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
Energy Sources

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
	Energy Sources		Units	Actual 2009	Actual 2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
(1)	Firm Inter-Region 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)		Other	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)		Other	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)	NUG		GWH	85	88	73	73	73	73	73	0	0	0	0	0
(19)	Renewables	Total	GWH	590	594	499	404	404	405	406	407	406	406	406	407
(20)		Biofuels	GWH	0	0	0	0	0	0	0	0	0	0	0	0
(21)		Biomass	GWH	0	152	0	0	0	0	0	0	0	0	0	0
(22)		Hydro	GWH	0	0	0	0	0	0	0	0	0	0	0	0
(23)		Landfill Gas	GWH	0	0	0	0	0	0	0	0	0	0	0	0
(24)		MSW	GWH	347	195	97	0	0	0	0	0	0	0	0	0
(25)		Solar	GWH	0.036	0.075	0.075	0.075	0.075	0.075	0.075	0.075	0.075	0.075	0.075	0.075
(26)		Wind	GWH	0	0	0	0	0	0	0	0	0	0	0	0
(27)		Other	GWH	243	246	402	404	404	405	406	407	406	406	406	407
(28)	Other - Petroleum Coke		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
(29)	Other - Net Interchange		GWH	227	83	114	114	127	128	125	132	128	129	135	138
(30)	Net Energy for Load		GWH	19,943	20,667	20,012	20,141	20,340	20,559	20,766	21,007	21,255	21,511	21,772	22,025

Schedule 6.2
Energy Sources

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
	Energy Sources		Units	Actual 2009	Actual 2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
(1)	Firm Inter-Region 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)		Other	%	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)		Other	%	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)	NUG		%	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.0	0.0	0.0	0.0	0.0
(19)	Renewables	Total	%	3.0	2.9	2.5	2.0	2.0	2.0	2.0	1.9	1.9	1.9	1.9	1.8
(20)		Biofuels	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(21)		Biomass	%	0.0	0.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(22)		Hydro	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(23)		Landfill Gas	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(24)		MSW	%	1.7	0.9	0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(25)		Solar	%	0.0002	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0003	0.0003	0.0003
(26)		Wind	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(27)		Other	%	1.2	1.2	2.0	2.0	2.0	2.0	2.0	1.9	1.9	1.9	1.9	1.8
(28)	Other - Petroleum Coke		%	5.9	6.5	5.9	5.7	5.8	5.7	5.4	5.6	5.5	5.2	5.4	5.4
(29)	Other - Net Interchange		%	1.1	0.4	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
(30)	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

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)
Year	Total Installed Capacity MW	Firm Capacity Import MW	Firm Capacity Export MW	QF MW	Total Capacity Available MW	System Firm Summer Peak Demand MW	Reserve Margin before Maintenance MW	% of Peak	Scheduled Maintenance MW	Reserve Margin after Maintenance MW	% of Peak
HISTORY:											
2001											
2002											
2003											
2004											
2005											
2006											
2007											
2008											
2009											
2010											
FORECAST:											
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%

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)
Year	Total Installed Capacity MW	Firm Capacity Import MW	Firm Capacity Export MW	QF MW	Total Capacity Available MW	System Firm Winter Peak Demand MW	Reserve Margin before Maintenance MW	Reserve Margin before Maintenance % of Peak	Scheduled Maintenance MW	Reserve Margin after Maintenance MW	Reserve Margin after Maintenance % of Peak
HISTORY:											
2000/01											
2001/02											
2002/03											
2003/04											
2004/05											
2005/06											
2006/07											
2007/08											
2008/09											
2009/10											
FORECAST:											
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%

Schedule 8.1
Planned and Prospective Generating Facility Additions

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
Plant Name	Unit No.	Location	Unit Type	Fuel		Fuel Trans.		Const. Start Mo/Yr	Commercial In-Service Mo/Yr	Expected Retirement Mo/Yr	Gen. Max. Nameplate kW	Net Capability		Status
				Primary	Alternate	Primary	Alternate					Summer MW	Winter MW	
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
Status Report and Specifications of Proposed Generating Facilities

(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 Perfomance Data		
	Planned Outage Factor (POF):		2.6
	Forced Outage Factor (FOF):		1.0
	Equivalent Availability Factor (EAF):		95.4
	Resulting Capacity Factor (%):		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):		19.21
	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
Status Report and Specifications of Proposed Generating Facilities

(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 Perfomance Data		
	Planned Outage Factor (POF):		2.6
	Forced Outage Factor (FOF):		1.0
	Equivalent Availability Factor (EAF):		95.4
	Resulting Capacity Factor (%):		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
Status Report and Specifications of Proposed Generating Facilities

(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. Altemate 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 Perfomance Data		
	Planned Outage Factor (POF):		2.6
	Forced Outage Factor (FOF):		1.0
	Equivalent Availability Factor (EAF):		95.4
	Resulting Capacity Factor (%):		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
Status Report and Specifications of Proposed Generating Facilities

(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 Perfomance Data		
	Planned Outage Factor (POF):		2.6
	Forced Outage Factor (FOF):		1.0
	Equivalent Availability Factor (EAF):		95.4
	Resulting Capacity Factor (%):		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
Status Report and Specifications of Proposed Generating Facilities

(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 Perfomance Data	
	Planned Outage Factor (POF):	2.6
	Forced Outage Factor (FOF):	1.0
	Equivalent Availability Factor (EAF):	95.4
	Resulting Capacity Factor (%):	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
Status Report and Specifications of Proposed Generating Facilities

(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 Perfomance Data		
	Planned Outage Factor (POF):		2.6
	Forced Outage Factor (FOF):		1.0
	Equivalent Availability Factor (EAF):		95.4
	Resulting Capacity Factor (%):		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
Status Report and Specifications of Proposed Generating Facilities

(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 2016
	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 Perfomance Data	
	Planned Outage Factor (POF):	3.8
	Forced Outage Factor (FOF):	3.0
	Equivalent Availability Factor (EAF):	93.1
	Resulting Capacity Factor (%):	66.3%
	Average Net Operating Heat Rate (ANOHR): [1]	7,0121 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

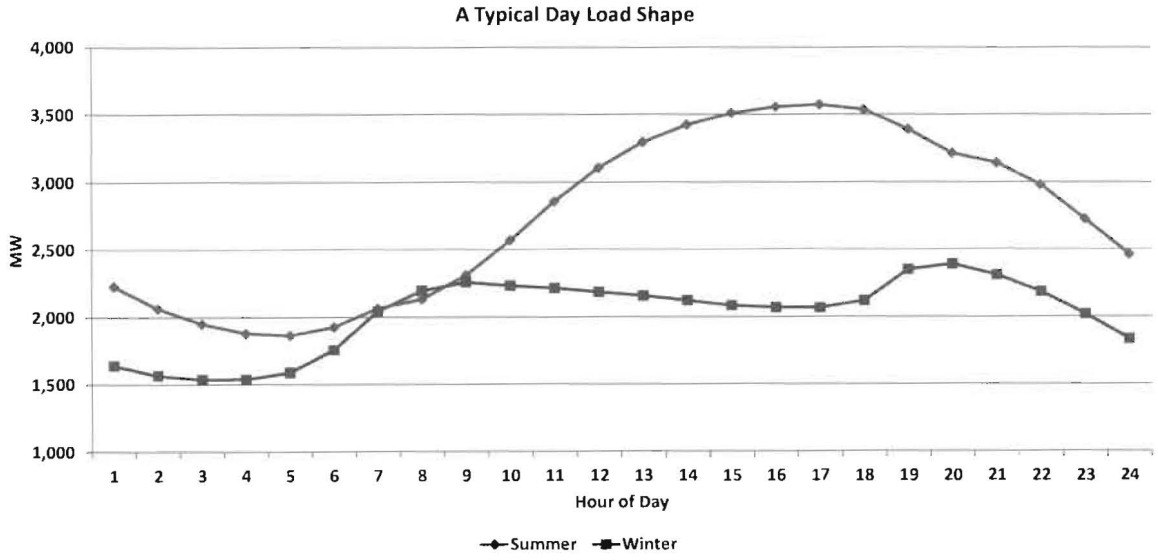
Units	Point of Origin and Termination	Number of Circuits	Right-of-Way	Circuit Length	Voltage	Anticipated In-Service Date	Anticipated Capital Investment	Substations	Participation with Other Utilities
Future CT 1 and 2	Bayside	2	No new ROW required	0.7 mi	138kV	Spring 2013	$2 million	No new substations	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.

LOAD & DEMAND FORECASTING

3. Please provide, on a system-wide basis, an average month of observed peak capacity values for Summer and Winter. From this data, excluding weekends and holidays, generate an average seasonal Daily Loading Curve. Please complete the table below and provide an electronic copy in Excel (.xls file format) and hard copy.

A. The requested data is provided in the attached forms and in Excel on the enclosed CD. The data reflects Tampa Electric's typical weekday, non-holiday loading data and curves for the summer and winter on a system-wide basis.



Typical Summer Month

Year	Month	Day	Day of Week	Observed Hourly Peak Capacity (MW) 1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	MAX (MW)	MIN (MW)
2011	Aug	1	Mon	2240	2065	1947	1876	1859	1924	2068	2140	2319	2584	2890	3162	3366	3507	3608	3663	3682	3639	3488	3291	3213	3037	2768	2492	3682	1859
2011	Aug	2	Tue	2157	1995	1878	1809	1794	1853	1993	2064	2253	2514	2804	3051	3235	3357	3440	3485	3481	3370	3300	3140	3079	2920	2665	2404	3485	1794
2011	Aug	3	Wed	2250	2076	1960	1887	1873	1939	2084	2155	2323	2590	2894	3172	3384	3531	3634	3692	3717	3693	3516	3318	3232	3049	2777	2502	3717	1873
2011	Aug	4	Thu	2196	2035	1924	1854	1838	1896	2032	2101	2289	2526	2796	3038	3216	3330	3402	3443	3461	3483	3293	3130	3067	2912	2669	2421	3483	1838
2011	Aug	5	Fri	2194	2033	1922	1856	1838	1896	2030	2093	2263	2524	2807	3056	3237	3361	3442	3485	3499	3468	3319	3150	3082	2921	2673	2419	3499	1838
2011	Aug	8	Mon	2245	2072	1955	1884	1869	1932	2080	2148	2336	2596	2889	3140	3326	3450	3537	3584	3592	3479	3408	3242	3171	3007	2745	2483	3592	1869
2011	Aug	9	Tue	2331	2154	2035	1961	1947	2015	2165	2224	2391	2667	2973	3252	3463	3608	3711	3770	3794	3757	3605	3410	3312	3120	2845	2568	3794	1947
2011	Aug	10	Wed	2406	2227	2100	2026	2008	2084	2243	2309	2481	2755	3067	3340	3546	3694	3791	3852	3882	3853	3701	3503	3399	3203	2922	2642	3882	2008
2011	Aug	11	Thu	2474	2303	2179	2105	2089	2166	2334	2394	2564	2819	3129	3403	3613	3754	3846	3904	3937	3900	3764	3570	3462	3265	2984	2705	3937	2089
2011	Aug	15	Mon	2312	2132	2011	1939	1922	1993	2145	2220	2392	2641	2967	3261	3492	3649	3758	3823	3853	3853	3649	3428	3339	3146	2863	2576	3853	1922
2011	Aug	16	Tue	2355	2182	2060	1989	1975	2043	2197	2259	2425	2698	2997	3266	3473	3618	3703	3760	3786	3794	3600	3403	3323	3140	2868	2592	3794	1975
2011	Aug	18	Thu	2373	2211	2089	2018	2002	2073	2225	2286	2438	2714	3019	3296	3506	3650	3745	3803	3830	3782	3635	3437	3351	3167	2893	2619	3830	2002
2011	Aug	19	Fri	2435	2270	2145	2070	2051	2121	2277	2339	2518	2782	3073	3333	3523	3650	3733	3784	3814	3770	3639	3455	3372	3196	2929	2663	3814	2051
2011	Aug	22	Mon	2077	1942	1852	1795	1782	1831	1943	2004	2178	2386	2575	2711	2785	2817	2822	2812	2809	2771	2729	2655	2640	2549	2376	2194	2822	1782
2011	Aug	23	Tue	2065	1901	1792	1724	1709	1759	1883	1949	2125	2390	2685	2943	3137	3280	3370	3416	3398	3249	3201	3043	2979	2822	2571	2314	3416	1709
2011	Aug	24	Wed	2130	1968	1852	1786	1771	1828	1965	2034	2224	2475	2754	2999	3178	3294	3376	3413	3413	3324	3236	3082	3019	2865	2616	2363	3413	1771
2011	Aug	25	Thu	2133	1965	1854	1787	1768	1825	1952	2025	2201	2466	2764	3031	3239	3380	3479	3534	3553	3573	3346	3150	3088	2923	2665	2398	3573	1768
2011	Aug	26	Fri	2140	1967	1853	1781	1765	1822	1952	2025	2196	2480	2791	3065	3277	3431	3539	3600	3622	3623	3395	3190	3128	2956	2690	2412	3623	1765
2011	Aug	29	Mon	2226	2056	1937	1864	1850	1909	2045	2110	2281	2551	2861	3137	3353	3507	3604	3663	3688	3675	3482	3281	3202	3020	2753	2476	3688	1850
2011	Aug	30	Tue	2121	1953	1841	1773	1753	1811	1942	2018	2221	2463	2741	2969	3132	3238	3309	3344	3352	3339	3189	3028	2982	2836	2594	2343	3352	1753
2011	Aug	31	Wed	1979	1839	1749	1695	1680	1725	1838	1917	2096	2286	2492	2648	2744	2782	2803	2804	2808	2832	2697	2601	2596	2505	2322	2126	2832	1680
		AVG		2230	2064	1949	1880	1864	1926	2066	2134	2310	2567	2856	3108	3296	3423	3507	3554	3570	3535	3390	3215	3144	2979	2723	2462	3570	1864
		MAX		2474	2303	2179	2105	2089	2166	2334	2394	2564	2819	3129	3403	3613	3754	3846	3904	3937	3900	3764	3570	3462	3265	2984	2705	3937	2089
		MIN		1979	1839	1749	1695	1680	1725	1838	1917	2096	2286	2492	2648	2744	2782	2803	2804	2808	2771	2697	2601	2596	2505	2322	2126	2808	1680

Typical Winter Month

Year	Month	Day	Day of Week	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	MAX (MW)	MIN (MW)
				Observed Hourly Peak Capacity (MW)																									
2011	Jan	3	mon	1632	1513	1440	1397	1393	1471	1648	1753	1894	1998	2160	2308	2434	2526	2584	2626	2623	2504	2693	2623	2470	2286	2073	1850	2693	1393
2011	Jan	4	tue	1509	1409	1350	1321	1323	1411	1602	1719	1884	1959	2028	2069	2104	2125	2121	2123	2111	2062	2274	2269	2172	2042	1879	1700	2274	1321
2011	Jan	5	wed	1453	1362	1314	1296	1320	1435	1660	1797	1940	1976	2011	2031	2040	2037	2020	2012	1996	1975	2212	2229	2140	2013	1847	1661	2229	1296
2011	Jan	6	thu	1449	1355	1312	1301	1329	1465	1721	1869	1987	2007	2029	2028	2024	2005	1979	1965	1960	1980	2202	2234	2144	2015	1846	1654	2234	1301
2011	Jan	7	fri	1427	1340	1304	1297	1340	1502	1797	1972	2073	2064	2057	2028	1999	1958	1918	1897	1890	1940	2185	2236	2153	2024	1848	1648	2236	1297
2011	Jan	10	mon	1526	1432	1378	1351	1358	1445	1626	1738	1853	1921	2010	2079	2129	2157	2171	2182	2184	2149	2312	2292	2186	2048	1880	1699	2312	1351
2011	Jan	11	tue	1497	1400	1347	1324	1334	1430	1620	1736	1854	1931	2006	2054	2094	2112	2116	2121	2116	2091	2268	2260	2161	2026	1861	1679	2268	1324
2011	Jan	12	wed	1950	1898	1890	1907	1973	2170	2481	2645	2762	2610	2448	2284	2147	2026	1932	1890	1901	2132	2294	2397	2395	2346	2247	2125	2762	1890
2011	Jan	13	thu	2659	2653	2690	2758	2889	3212	3676	3855	3711	3454	3212	2999	2831	2686	2556	2518	2561	2919	3079	3184	3186	3114	2991	2850	3855	2518
2011	Jan	17	mon	2017	1985	1992	2023	2089	2245	2467	2639	2744	2593	2449	2305	2181	2088	2008	1966	1952	2081	2238	2311	2310	2261	2165	2027	2744	1952
2011	Jan	18	tue	1996	1969	1981	2026	2131	2399	2800	2963	2878	2715	2575	2442	2331	2226	2137	2102	2112	2273	2523	2614	2594	2509	2362	2189	2963	1969
2011	Jan	19	wed	1811	1768	1771	1807	1909	2181	2609	2797	2729	2605	2475	2352	2245	2154	2062	2026	2037	2200	2492	2586	2512	2387	2214	2018	2797	1768
2011	Jan	20	thu	1483	1408	1384	1393	1457	1655	1991	2158	2146	2138	2137	2127	2111	2082	2046	2029	2019	1987	2333	2382	2269	2114	1915	1692	2382	1384
2011	Jan	21	fri	1468	1384	1341	1327	1343	1445	1646	1755	1821	1899	1973	2016	2054	2075	2074	2076	2062	1997	2229	2229	2119	1983	1816	1636	2229	1327
2011	Jan	24	mon	1477	1381	1327	1301	1311	1408	1605	1735	1909	1948	1997	2026	2047	2050	2041	2037	2026	1982	2207	2223	2127	2004	1846	1672	2223	1301
2011	Jan	25	tue	1560	1481	1448	1453	1510	1701	2037	2227	2380	2278	2198	2105	2012	1927	1856	1821	1829	1974	2201	2286	2223	2123	1967	1787	2380	1448
2011	Jan	26	wed	1513	1438	1424	1449	1548	1835	2304	2529	2530	2412	2322	2224	2146	2055	1965	1929	1930	2064	2419	2515	2416	2251	2030	1778	2530	1424
2011	Jan	27	thu	1458	1377	1348	1363	1435	1659	2039	2232	2257	2212	2188	2136	2089	2033	1978	1953	1948	2017	2317	2385	2289	2142	1934	1702	2385	1348
2011	Jan	28	fri	1454	1373	1334	1324	1345	1456	1663	1776	1812	1893	1968	2012	2051	2072	2069	2071	2057	2001	2227	2223	2118	1982	1811	1624	2227	1324
2011	Jan	31	mon	1460	1389	1361	1367	1423	1603	1908	2063	2012	2048	2083	2094	2090	2073	2056	2052	2055	2090	2325	2341	2230	2072	1870	1647	2341	1361
		AVG		1640	1566	1537	1539	1588	1756	2045	2198	2259	2233	2216	2186	2158	2123	2084	2070	2068	2121	2351	2391	2311	2187	2020	1832	2391	1537
		MAX		2659	2653	2690	2758	2889	3212	3676	3855	3711	3454	3212	2999	2831	2686	2584	2626	2623	2919	3079	3184	3186	3114	2991	2850	3855	2584
		MIN		1427	1340	1304	1296	1311	1408	1602	1719	1812	1893	1968	2012	1999	1927	1856	1821	1829	1940	2185	2223	2118	1982	1811	1624	2223	1296

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4. Please provide, on a system-wide basis, historical annual heating degree day (HDD) and cooling degree day (CDD) data for the period 2001 through 2010 and forecasted annual HDD and CDD data for the period 2011 through 2020. Describe how the Company derives system-wide temperature if more than one weather station is used. Please complete the table below and provide an electronic copy in Excel (.xls file format) and hard copy.

Year		HDD	CDD
Actual	2001		
	2002		
	2003		
	2004		
	2005		
	2006		
	2007		
	2008		
	2009		
	2010		
Projected	2011		
	2012		
	2013		
	2014		
	2015		
	2016		
	2017		
	2018		
	2019		
	2020		

A. Listed below are the historical and forecasted annual heating degree-days. Tampa Electric uses one weather station for historical and forecasted HDD data. The following table is in Excel format on the enclosed CD.

Year		HDD	CDD
Actual	2001	572	3613
	2002	447	3982
	2003	605	3736
	2004	547	3490
	2005	534	3469
	2006	499	3513
	2007	381	3849
	2008	420	3523
	2009	457	3823
	2010	1003	3643
Projected	2011	501	3655
	2012	501	3655
	2013	501	3655
	2014	501	3655
	2015	501	3655
	2016	501	3655
	2017	501	3655
	2018	501	3655
	2019	501	3655
	2020	501	3655

5. Please provide the following data to support Schedule 4 of the Company's Ten-Year Site Plan: the 12 monthly peak demands for the years 2008, 2009, and 2010; the date when these monthly peaks occurred; and, the temperature at the time of these monthly peaks. Describe how the Company derives system-wide temperature if more than one weather station is used. Please complete the table below and provide an electronic copy in Excel (.xls file format) and hard copy.

Year	Month	Peak Demand (MW)	Date	Day of Week	Hour	Temperature (F)
2008	1					
	2					
	3					
	4					
	5					
	6					
	7					
	8					
	9					
	10					
	11					
	12					
2009	1					
	2					
	3					
	4					
	5					
	6					
	7					
	8					
	9					
	10					
	11					
	12					
2010	1					
	2					
	3					
	4					
	5					
	6					
	7					
	8					
	9					
	10					
	11					
	12					

A. The requested data is provided in the attached table and in Excel on the enclosed CD. Tampa Electric is presently using one weather station for historical temperature data.

Year	Month	Peak Demand (MW)	Date	Day of Week	Hour	Temperature (F)
2008	1	3862	3	Thu	800	31
	2	3136	28	Thu	800	43
	3	2971	16	Sun	1800	78
	4	3325	3	Thu	1700	81
	5	3823	31	Sat	1700	90
	6	4101	6	Fri	1700	96
	7	4052	21	Mon	1600	92
	8	4063	27	Wed	1700	89
	9	3946	11	Thu	1600	88
	10	3565	10	Fri	1700	83
	11	3119	13	Thu	1600	84
	12	3313	3	Wed	800	44
2009	1	4080	22	Thu	800	35
	2	3973	6	Fri	800	38
	3	3058	3	Tue	800	44
	4	3133	1	Wed	1800	80
	5	3545	11	Mon	1700	89
	6	4015	22	Mon	1600	93
	7	3796	29	Wed	1700	88
	8	3810	20	Thu	1700	89
	9	3708	21	Mon	1700	92
	10	3741	9	Fri	1700	89
	11	2920	1	Sun	1500	80
	12	2795	14	Mon	1900	75
2010	1	4512	11	Mon	800	32
	2	3447	26	Fri	800	43
	3	3305	5	Fri	800	45
	4	2909	23	Fri	1700	81
	5	3649	3	Mon	1700	85
	6	3917	14	Mon	1700	91
	7	3912	28	Wed	1500	92
	8	3908	19	Thu	1700	90
	9	3702	13	Mon	1700	85
	10	3366	28	Thu	1600	87
	11	2956	3	Wed	1800	80
	12	4010	15	Wed	800	36

6. Please discuss any recent trends in customer growth, by customer type (residential, industrial & commercial, etc), and as a whole. Please explain the nature or reason for these trends, and identify what types of customers are most affected by these trends. (For example, is a decline in customers a loss of temporary construction meters or a decline in population?)

A. **RESIDENTIAL:**
After several consecutive years of flat customer growth, customers increased by 0.7% in 2010. Customer growth is projected to increase by 0.8% in 2011. The main drivers of customer growth in this sector are net migration and population.

COMMERCIAL:
Commercial customer growth was 0.2% in 2010 and is projected to increase by 0.5% in 2011. Commercial growth depends heavily on the recovery of the residential sector and the employment opportunities within Tampa Electric's service territory.

TEMPORARY CONSTRUCTION SERVICE (COMMERCIAL SUB-SECTOR):
In 2010, Temporary Service accounts decreased by 147 (10%). Although an increase in accounts was projected for 2011, current counts remain slightly below 2010 levels. The primary driver of customer growth in this sector is building permits and construction employment.

GOVERNMENTAL:
Growth in the governmental sector was 1.2% in 2010. This increase includes accounts that migrated from the street and highway lighting sector. 2011 is projected to increase by 0.7%. Population growth and residential customer growth are drivers in this sector.

INDUSTRIAL:
The number of industrial accounts increased by 0.7% in 2010 and is anticipated to remain relatively flat (0.2%) during 2011. Manufacturing firms were hit hardest by the recession and many long-time customers in the area were forced to close permanently given the duration of the recession.

TOTAL:
Residential customers are approximately 85% of total customers and are therefore the primary driver behind total customer growth. Total customers increased by 0.6% in 2010 and are expected to increase by 0.8% in 2011.

7. Please discuss any impacts of "smart" or digital meter installations on forecasting sales and net energy for load. Please explain the nature or reason for these trends, and identify what types of customers are most affected by these trends. (For example, are increased sales due to more accurate measurement of low-load conditions?)

A. Tampa Electric Company has digital meters installed in approximately 82 percent of its meter locations and no "smart" meters at this time. The company anticipates improvements in its ability to accurately forecast sales and net energy for load given the utilization of digital meters to accurately account for the energy consumed by customers and the company.

RENEWABLE GENERATION

8. Please provide the estimated total capacity of all renewable resources the utility owns or purchases as of January 1, 2011. Include in this value the sum of all utility-owned, and purchased power contracts (firm and non-firm), and purchases from as-available energy producers (net-metering, self-generators, etc.). Please also include the estimated total capacity of all renewable resources (firm and non-firm) the utility is anticipated to own or purchase as of the end of the planning period in 2020.

Fuel Type	Renewable Resource Capacity (MW)	
	Existing	Planned
Solar		
Wind		
Biomass		
Municipal Solid Waste		
Waste Heat		
Landfill Gas		
Hydro		
Total		

A. Tampa Electric plans to install an additional 20 kW of PV in the community each year with funding provided by the Company's voluntary renewable energy program. The locations of these systems and their capacities have not yet been determined, but installations will continue through 2020, with a chance to increase, dependent on the success of the renewable program.

The most recent PV projects that have been constructed and placed into service include a 15 kW PV system at Tampa's Lowry Park Zoo (in service December 2009), a 10 kW PV system at the Florida Aquarium in Tampa (in services March 2010), and an additional 16.8 kW at the Manatee Viewing Center (in service October 2010). All projects include an interactive educational display, showcasing renewable technologies.

Fuel Type	Renewable Resource Capacity (MW)	
	Existing	Planned
Solar	0.0817	0.2817
Wind	0	0
Biomass	0	0
Municipal Solid Waste	57.0	57.0
Waste Heat	22.9	22.9
Landfill Gas	0	0
Hydro	0	0
Total	79.982	80.182

9. Please provide a description of each existing utility-owned renewable generation resource and each renewable purchased power agreement as of January 1, 2011. For both utility-owned and purchased resources, please divide them into Firm and Non-Firm categories as shown below. Please also include those renewable resources which provide fuel to conventional facilities, if applicable, with estimates of their capacity and energy contributions. As part of this response, please include the description of the unit's generator type, fuel type, commercial in-service date, seasonal net capacity (even if not considered firm capacity), annual energy generation. For purchased power agreements, also provide the contract start and end dates. Please complete the tables below and provide an electronic copy in Excel format and hardcopy.

Existing Renewables as of January 1, 2011
Utility-Owned Firm Renewable Resources

Facility Name	Unit Type	Fuel Type	Commercial In-Service Date	Net Capacity (kW)		Annual Generation	Capacity Factor
-	-	-	(MM/YYYY)	Sum	Win	(MWh)	(%)

Utility-Owned Non-Firm Renewable Resources

Facility Name	Unit Type	Fuel Type	Commercial In-Service Date	Net Capacity (kW)		Annual Generation	Capacity Factor
-	-	-	(MM/YYYY)	Sum	Win	(MWh)	(%)

Firm Renewable Purchased Power Agreements

Facility Name	Unit Type	Fuel Type	Unit Commercial In-Service Date	Net Capacity (kW)		Annual Generation	Capacity Factor	Contract Start Date	Contract End Date
-	-	-	(MM/YYYY)	Sum	Win	(MWh)			(%)

Non-Firm Renewable Purchased Power Agreements

Facility Name	Unit Type	Fuel Type	Unit Commercial In-Service Date	Net Capacity (kW)		Annual Generation	Capacity Factor	Contract Start Date	Contract End Date
-	-	-	(MM/YYYY)	Sum	Win	(MWh)		(%)	(%)

A. The requested data is provided in the attached forms and in Excel on the enclosed CD.

Existing Renewables as of January 1, 2011
Utility-Owned Firm Renewable Resources

Facility Name	Unit Type	Fuel Type	Commercial In-Service Date	Net Capacity (kW)		Annual Generation	Capacity Factor
-	-	-	(MM/YYYY)	Sum	Win	(MWh)	(%)
N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

Utility-Owned Non-Firm Renewable Resources

Facility Name	Unit Type	Fuel Type	Commercial In-Service Date	Net Capacity (kW)		Annual Generation	Capacity Factor
-	-	-	(MM/YYYY)	Sum	Win	(MWh)	(%)
Museum of Science & Industry	PV	Solar	12/1999	18	18	19.419	12.29%
Walker Middle School	PV	Solar	05/2004	4.3	4.3	4.629	12.32%
Manatee Viewing Center	PV	Solar	11/2006 & 10/2010*	23.8	23.8	14.156	18.12%*
Middleton High School	PV	Solar	05/2007	10.5	10.5	9.602	10.44%
Tampa's Lowry Park Zoo	PV	Solar	12/2009	15	15	17.055	12.98%
Florida Aquarium	PV	Solar	03/2010	10.12	10.12	9.673	16.28%**

* An additional 16.8 kW were added to the Manatee Viewing Center in Oct. 2010. The capacity factor was calculated using two full months of generation to represent generation from existing and additional panels. Total generation is actual generation.

** The Aquarium capacity factor was calculated using 5 months of complete data once the system was fully operating.

Firm Renewable Purchased Power Agreements

Facility Name	Unit Type	Fuel Type	Unit Commercial In-Service Date	Net Capacity (kW)		Annual Generation	Capacity Factor	Contract Start Date	Contract End Date
-	-	-	(MM/YYYY)	Sum	Win	(MWh)			(%)
City of Tampa WTE	Steam	MSW	10/1985	19,000	19,000	146,779	88%	8/26/1982	8/31/2011

Non-Firm Renewable Purchased Power Agreements

Facility Name	Unit Type	Fuel Type	Unit Commercial In-Service Date	Net Capacity (kW)		Annual Generation	Capacity Factor	Contract Start Date	Contract End Date
-	-	-	(MM/YYYY)	Sum	Win	(MWh)		(%)	(%)
N/A									

10. Please provide a description of each existing utility-owned renewable generation resource and each renewable purchased power agreement planned during the 2011 through 2020 period. For both utility-owned and purchased resources, please divide them into Firm and Non-Firm categories as shown below. Please also include those renewable resources which provide fuel to conventional facilities, if applicable, with estimates of their capacity and energy contributions. As part of this response, please include the description of the unit's generator type, fuel type, commercial in-service date, seasonal net capacity (even if not considered firm capacity), annual energy generation. For purchased power agreements, also provide the contract start and end dates. Please complete the tables below and provide an electronic copy in Excel format and hardcopy.

Planned Renewables for 2011 through 2020
Utility-Owned Firm Renewable Resources

Facility Name	Unit Type	Fuel Type	Commercial In-Service Date	Net Capacity (kW)		Annual Generation	Capacity Factor
-	-	-	(MM/YYYY)	Sum	Win	(MWh)	(%)

Utility-Owned Non-Firm Renewable Resources

Facility Name	Unit Type	Fuel Type	Commercial In-Service Date	Net Capacity (kW)		Annual Generation	Capacity Factor
-	-	-	(MM/YYYY)	Sum	Win	(MWh)	(%)

Firm Renewable Purchased Power Agreements

Facility Name	Unit Type	Fuel Type	Unit Commercial In-Service Date	Net Capacity (kW)		Annual Generation	Capacity Factor	Contract Start Date	Contract End Date
-	-	-	(MM/YYYY)	Sum	Win	(MWh)			(%)

Non-Firm Renewable Purchased Power Agreements

Facility Name	Unit Type	Fuel Type	Unit Commercial In-Service Date	Net Capacity (kW)		Annual Generation	Capacity Factor	Contract Start Date	Contract End Date
-	-	-	(MM/YYYY)	Sum	Win	(MWh)		(%)	(%)

A. The requested data is provided in the attached forms and in Excel on the enclosed CD.

Planned Renewables for 2011 through 2020
Utility-Owned Firm Renewable Resources

Facility Name	Unit Type	Fuel Type	Commercial In-Service Date	Net Capacity (kW)		Annual Generation	Capacity Factor
-	-	-	(MM/YYYY)	Sum	Win	(MWh)	(%)
N/A							

Utility-Owned Non-Firm Renewable Resources

Facility Name	Unit Type	Fuel Type	Commercial In-Service Date	Net Capacity (kW)		Annual Generation	Capacity Factor
-	-	-	(MM/YYYY)	Sum	Win	(MWh)	(%)
TBD*							

*Tampa Electric plans to install an additional 20 kW of PV in the community each year with funding provided by the Company's voluntary renewable energy program. The locations of these systems and their capacities have not yet been determined, but installations will continue through 2020, with a chance to increase, dependent on the success of the renewable program.

Firm Renewable Purchased Power Agreements

Facility Name	Unit Type	Fuel Type	Unit Commercial In-Service Date	Net Capacity (kW)		Annual Generation	Capacity Factor	Contract Start Date	Contract End Date
-	-	-	(MM/YYYY)	Sum	Win	(MWh)			(%)
N/A									

Non-Firm Renewable Purchased Power Agreements

Facility Name	Unit Type	Fuel Type	Unit Commercial In-Service Date	Net Capacity (kW)		Annual Generation	Capacity Factor	Contract Start Date	Contract End Date
-	-	-	(MM/YYYY)	Sum	Win	(MWh)		(%)	(%)
N/A									

11. Please refer to the list of planned utility-owned renewable resource additions with an in-service date for the renewable generator during the 2011 through 2020 period outlined above. Please discuss the current status of each project.

A. Tampa Electric plans to install an additional 20 kW of PV in the community each year with funding provided by the Company's voluntary renewable energy program. The locations of these systems and their capacities have not yet been determined, but installations will continue through 2020, with a chance to increase, dependent on the success of the renewable program.

12. Please refer to the list of existing or planned renewable PPAs with an in-service date for the renewable generator during the 2011 through 2020 period outlined above. Please discuss the current status of each project.

A. Tampa Electric does not have any planned renewable PPAs with in-service dates of 2011 through 2020. Tampa Electric will continue to evaluate renewable PPAs on a project by project basis as valid, economically viable opportunities present themselves.

13. Please provide a description of each renewable facility in the company's service territory that it does not currently have a PPA with, including self-service facilities. As part of this response, please include the description of the unit's location, generator type, fuel type, commercial in-service date, seasonal net capacity (even if not considered firm capacity), annual energy generation. Please exclude from this response small customer-owned renewable resources, such as rooftop PV, which are more appropriately included in the following question. Please complete the tables below and provide an electronic copy in Excel format and hardcopy.

Facility Name	Unit Type	Fuel Type	Commercial In-Service Date	Net Capacity (kW)		Annual Generation	Capacity Factor
-	-	-	(MM/YYYY)	Sum	Win	(MWh)	(%)

A. Listed below are the renewable facilities in the company's service territory that Tampa Electric does not have a purchase power agreement (PPA) with. The requested data is also provided in Excel on the enclosed CD.

Facility Name	Unit Type	Fuel Type	Commercial In-Service	Net Capacity (kW)		Annual Generation	Capacity Factor
-	-	-	(MM/YYYY)	Sum	Win	(MWh)	(%)
Mosaic Millpoint	Steam	Waste Heat	12/1995	7,000	7,000	Varies	Varies
Mosaic Ridgewood	Steam	Waste Heat	10/1992	6,000	6,000	Varies	Varies
CF Industries	Steam	Waste Heat	12/1988	3,400	3,400	Varies	Varies
Mosaic New Wales	Steam	Waste Heat	12/1984	5,000	5,000	Varies	Varies
Mosaic So. Pierce	Steam	Waste Heat	09/1969	1,500	1,500	Varies	Varies
Hillsborough Co. WTE	Steam	Municipal Solid Waste	04/1987	38,000	38,000	Varies	Varies

14. Please provide the number of customer-owned renewable resources within the Company's service territory. Please organize by resource type, and include total estimated installed capacity and annual output. Please exclude from this response any customer-owned renewable resources already accounted for under PPAs or other sources. If renewable energy types beyond those listed were utilized, please include an additional row and a description of the renewable fuel and generator. For non-electricity generating renewable energy systems, such as geothermal cooling and solar hot water heaters, please use kilowatt-equivalent and kilowatt-hour-equivalent units. Please complete the tables below and provide an electronic copy in Excel (.xls file format) and hard copy.

Customer Class	Renewable Type	# of Connections	Installed Capacity (kW)	Annual Output (kWh)
Residential	Solar Photovoltaic			
Residential	Solar Thermal Water Heating			
Residential	Geothermal Heat Pump			
Residential	Wind Turbine			
Residential	Other (Describe)			
Commercial	Solar Photovoltaic			
Commercial	Solar Thermal Water Heating			
Commercial	Geothermal Heat Pump			
Commercial	Wind Turbine			
Commercial	Other (Describe)			

A. Tampa Electric does not track customer-owned solar water heaters or geothermal devices. The solar PV sources below are not included in the purchase power agreements listed in response to previous questions. Actual annual output for customer owned solar PV is not metered. Provided in the chart below is an estimate based on expected generation from PV installed in Tampa Electric's territory. Tampa Electric's one small wind generator customer removed the wind turbine in 2009.

The following table provides the number of customer-owned renewable resources within the Company's service territory in 2010. The requested data is also provided in Excel on the enclosed CD.

Customer Class	Renewable Type	# of Connections	Installed Capacity (kW)	Annual Output (kWh)
Residential	Solar Photovoltaic	110	510.335	804,696
Residential	Solar Thermal Water Heating	Unknown		
Residential	Geothermal Heat Pump	Unknown		
Residential	Wind Turbine	0		
Residential	Other (Describe)	Unknown		
Commercial	Solar Photovoltaic	26	760.5	1,199,161
Commercial	Solar Thermal Water Heating	Unknown		
Commercial	Geothermal Heat Pump	Unknown		
Commercial	Wind Turbine	0		
Commercial	Other (Describe)	Unknown		

15. Please provide the annual output for the company's renewable resources (owned and purchased through PPA), retail sales, and the net energy for load for the period 2010 through 2020. Please complete the tables below and provide an electronic copy in Excel (.xls file format) and hard copy.

Annual Output (GWh)		Actual	Projected									
		2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Renewable Generation	Utility											
	PPA											
	Total											
Retail Sales												
Net Energy for Load												

A. The requested data is provided in the table below and in Excel on the enclosed CD.

Annual Output (GWh)		Actual	Projected									
		2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Renewable Generation	Utility	0.0745	0.0745	0.0745	0.0745	0.0745	0.0745	0.0745	0.0745	0.0745	0.0745	0.0745
	PPA	195	97	0	0	0	0	0	0	0	0	0
	Non-PPA*	398	402	404	404	405	406	407	406	406	406	407
	Total	594	499	404	404	405	406	407	406	406	406	407
Retail Sales		19,213	18,927	19,119	19,336	19,546	19,743	19,971	20,206	20,450	20,698	20,938
Net Energy for Load		20,667	20,012	20,141	20,339	20,559	20,766	21,007	21,254	21,511	21,772	22,025

*Note: Non-PPA renewable energy captures as-available cogen energy.

16. Provide, on a system-wide basis, the historical annual average as-available energy rate in the Company's service territory for the period 2001 through 2010. Also, provide the forecasted annual average as-available energy rate in the Company's service territory for the period 2011 through 2020. Please use the Consumer Price Index to calculate real as-available energy rates. Please complete the table below and provide an electronic copy in Excel (.xls file format) and hard copy.

Year	As-Available Energy ($/MWh)		CPI
	Real	Nominal	
2010			
2011			
2012			
2013			
2014			
2015			
2016			
2017			
2018			
2019			
2020			

A. Listed below are Tampa Electric's as-available energy prices for the period 2000 through 2010 and forecasted prices for the period 2011 through 2020. The Consumer Price Index was used to calculate the real as-available energy prices (CPI Index 1982-1984 =100). The tables are in Excel format on the enclosed CD.

Year	Historical As-Available Energy ($/MWh)		CPI
	Real	Nominal	
2001	$17.43	$30.86	177.1
2002	$18.40	$33.10	179.9
2003	$21.89	$40.27	184.0
2004	$22.11	$41.76	188.9
2005	$32.10	$62.69	195.3
2006	$25.35	$51.10	201.6
2007	$25.00	$51.83	207.3
2008	$28.68	$61.74	215.3
2009	$14.85	$31.85	214.5
2010	$16.89	$36.83	218.1

Year	Forecast As-Available Energy ($/MWh)		CPI
	Real	Nominal	
2011	$19.90	$44.30	222.6
2012	$20.66	$47.28	228.9
2013	$20.68	$48.38	233.9
2014	$20.40	$48.76	239.0
2015	$21.92	$53.56	244.3
2016	$22.96	$57.32	249.7
2017	$23.55	$60.09	255.2
2018	$22.96	$59.86	260.8
2019	$21.40	$57.04	266.5
2020	$21.18	$57.70	272.4

17. Please discuss any studies conducted or planned regarding the use combinations of renewable and fossil fuels in existing or future fossil units. What potential does the Company identify in this area?

A. Tampa Electric is committed to staying current with the latest developments and viability of renewable technologies in the southeast region. Over the past two years, Tampa Electric has engaged a consultant to study and characterize supply side technologies, including renewables, for the Florida peninsula.

A second study was conducted in 2010 to specifically investigate the possibility of Integrating Solar Thermal technology into a combined cycle facility.

Tampa Electric has conducted preliminary investigations of biomass co-firing at Big Bend Station and gasification at Polk Unit 1. Preliminary investigation of biodiesel firing at the Sebring station was also conducted.

Tampa Electric is presently investigating the feasibility of integrating a biomass fired steam generator at the Bayside combined cycle facility.

18. Please discuss any planned renewable generation or renewable purchased power agreements within the past 5 years that did not materialize. What was the primary reason these generation plans or purchased power contracts were not realized? What, if any, were the secondary reasons?

A. Tampa Electric signed and subsequently submitted for approval a 25 MW contract for solar renewable purchased power from Energy 5.0 LLC. On May 7, 2010 Tampa Electric filed a Notice of Voluntary Dismissal with Prejudice of its March 9, 2009 Petition for Approval as concerns about the Agreement's cost exceeding projected avoided cost continued to be raised by intervenors and the Commission.

Similarly, Tampa Electric signed and subsequently submitted for approval a 19 MW contract for energy from a municipal solid waste facility owned by the City of Tampa. The FPSC expressed concern over certain terms and conditions proposed in the agreement and requested that Tampa Electric and the city renegotiate those terms. Unwilling to make the FPSC's prescribed modifications, the City of Tampa supported Tampa Electric's notice of withdrawal of its petition without prejudice. Subsequently the City of Tampa decided to sell its energy to Seminole Electric Cooperative.

19. Please discuss whether the company purchases or sells Renewable Energy Credits. As part of this response, please discuss whether the company offers the sale of Renewable Energy Credits to its customers through a green pricing or similar program.

A. Currently, Tampa Electric does not purchase or sell Renewable Energy Credits.

TRADITIONAL GENERATION

20. Please provide the cumulative present worth revenue requirement of the Company's Base Case for the 2011 Ten-Year Site Plan. If available, please provide the cumulative present worth revenue requirement for any sensitivities conducted of the Company's generation expansion plan.

A. Listed below is the cumulative present worth revenue requirements for the Company's base expansion plan along with four (4) sensitivities: high fuel, low fuel, high load and low load.

	CPWRR ($ 000)
Base Expansion Plan	$8,045,568
High Fuel Expansion Plan	$9,795,430
Low Fuel Expansion Plan	$6,351,373
High Load Expansion Plan	$8,504,569
Low Load Expansion Plan	$7,733,259

21. Please illustrate what the Company's generation expansion plan would be as a result of sensitivities to the base case demand. Include impacts on unit in-service dates for any possible delays, cancellations, accelerated completion, or new additions as a result.

A. Illustrated below is the Company's generation expansion plan as a result of sensitivities to the base case demand.

Year	Base Expansion Plan	High Load Expansion Plan	Low Load Expansion Plan
2011	_	_	_
2012	_	_	_
2013	(3) Aero CT 183/168 MW - S	(4) Aero CT 244/224 MW - S	(2) Aero CT 122/112 MW - S
2014	(1) Aero CT 61/56 MW - S	(1) Polk 2-5 CC Conversion 1063/970 MW - S	_
2015	(1) Aero CT 61/56 MW - S	_	(1) Aero CT 61/56 MW - S
2016	(1) Aero CT 61/56 MW - S	_	(1) Aero CT 61/56 MW - S
2017	(1) Aero CT 61/56 MW - S	_	_
2018	(1) Aero CT 61/56 MW - S	(2) Aero CT 122/112 MW - S	(1) Aero CT 61/56 MW - S
2019	(1) Polk 2-5 CC Conversion 1063/970 MW - S	(4) Aero CT 244/224 MW - S	(3) Aero CT 183/168 MW - S
2020	_	(1) 7FA CT 177/149 MW - S	_
CPWRR ($000)	8,045,568	8,504,596	7,733,259

22. Please complete the following table detailing planned unit additions, including information on capacity and in-service dates. Please include only planned conventional units with an in-service date past January 1, 2011, and including nuclear units, nuclear unit uprates, combustion turbines, and combined-cycle units. For each planned unit, provide the date of the Commission's Determination of Need and Power Plant Siting Act certification (if applicable), and the anticipated in-service date.

Planned Unit Additions for 2011 through 2020

Generating Unit Name	Summer Capacity (MW)	Certification Dates (if Applicable)		In-Service Date
		Need Approved (Commission)	PPSA Certified	
Nuclear Unit Additions / Uprates				
Combustion Turbine Unit Additions				
Combined Cycle Unit Additions				
Steam Turbine Unit Additions				

A. Detailed below are the planned unit additions for 2011 through 2020. 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.

Planned Unit Additions for 2011 through 2020

Generating Unit Name	Summer Capacity (MW)	Certification Dates (if Applicable)		In-Service Date
		Need Approved (Commission)	PPSA Certified	
Nuclear Unit Additions / Uprates				
N/A	N/A	N/A	N/A	N/A
Combustion Turbine Unit Additions				
Future CT 1	56	N/A	N/A	5/2013
Future CT 2	56	N/A	N/A	5/2013
Future CT 3	56	N/A	N/A	5/2013
Future CT 4	56	N/A	N/A	5/2014
Future CT 5	56	N/A	N/A	5/2015
Future CT 6	56	N/A	N/A	5/2016
Future CT 7	56	N/A	N/A	5/2017
Future CT 8	56	N/A	N/A	5/2018
Combined Cycle Unit Additions				
Polk 2-5 CC 1	970	*	*	5/2019
Steam Turbine Unit Additions				
N/A	N/A	N/A	N/A	N/A

* Tampa Electric does not have an active Determination of Need nor a Power Plant Siting Act Certification for the Polk 2-5 CC repower. Working backwards from the construction schedule, a Determination of Need would have to be finalized around the end of 2014 for the Polk 2-5 CC repower. This time estimate may be improved upon or delayed based upon major equipment availability and site permitting.

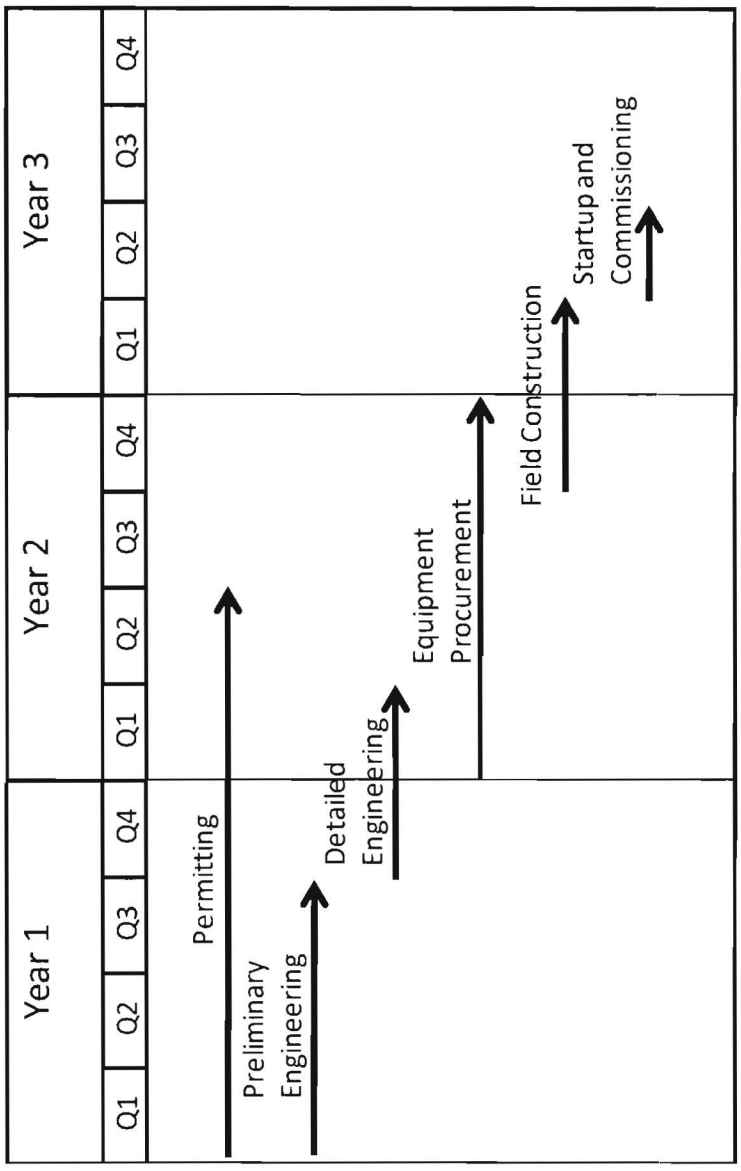
23. For each of the generating units contained in the Company's Ten-Year Site Plan, please discuss the drop dead date for a decision on whether or not to construct each unit. Provide a time line for the construction of each unit, including regulatory approval, and final decision point.

A. Tampa Electric estimates a final decision point for procuring and constructing a typical combustion turbine (CT) unit to be approximately 30 months prior to the expected in-service date. The 30 months is comprised of 21 months for engineering, procurement and permitting, which could vary depending on whether the unit is placed at a green field site or an existing site, and nine months for construction. The 30 month time estimate may be improved or delayed based upon major equipment availability and site permitting.

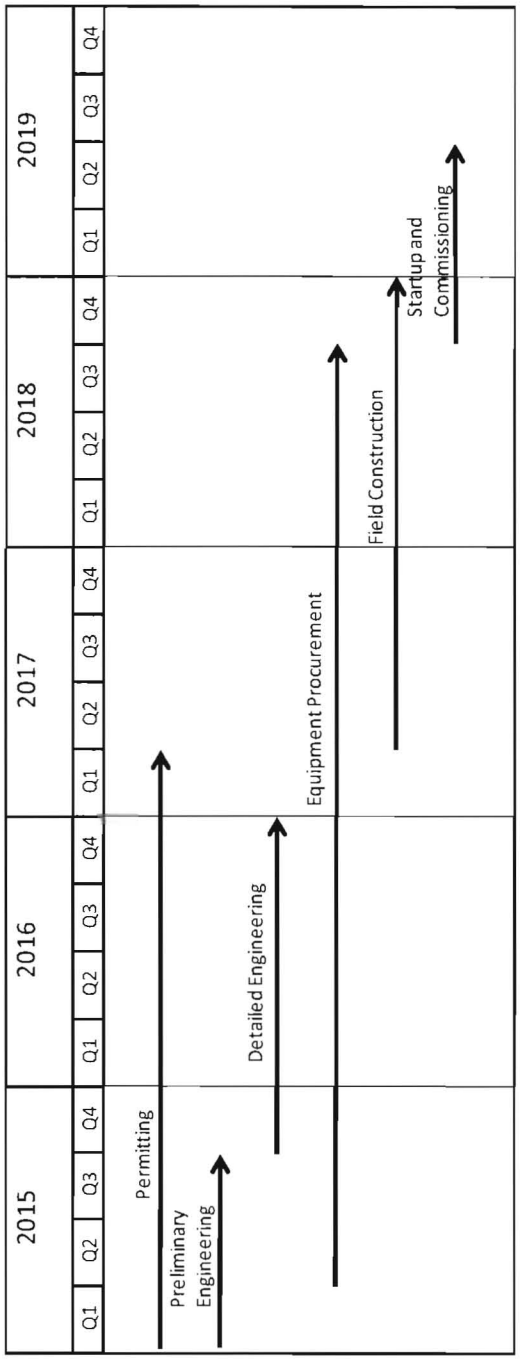
The final decision point for the 2019 combined-cycle (CC) conversion unit is estimated to be approximately 51 months prior to the expected in-service date. The 51 months is primarily due to major equipment procurement. The 51 month time estimate may be improved or delayed based upon on major equipment availability and site permitting.

Attached are the following schedules for Tampa Electric's construction time lines.

Future Aero CT Project Execution Plan



Future CC Project Execution Plan



24. Please complete the following table detailing unit specific information on capacity and fuel consumption for 2010. For each unit on the Company's system, provide the following data based upon historic data from 2010: the unit's capacity; annual generation; resulting capacity factor; estimated annual availability factor; unit average heat rate; quantity of fuel burned; average cost of fuel; and resulting average energy cost for the unit's production. Please complete the table below and provide an electronic copy in Excel (.xls file format) and hard copy.

Plant	Unit #	Unit Type	Fuel Type	Nameplate Capacity	Net Capacity (MW)		Annual Generation	Capacity Factor	Availability Factor	In-Service Date
				(MW)	Sum	Win	(MWh)	(%)	(%)	

Plant	Unit #	Fuel Type	Heat Rate	Total Fuel Burned	Total Fuel Cost	Unit Fuel Cost	
			(BTU/kWh)	(MMBTU)	($000)	($/MMBTU)	(¢/kWh)

A. The table below includes unit specific information on capacity, fuel consumption, capacity factor, availability factor, heat rate and fuel cost for 2010. The tables below are also in Excel on the enclosed CD.

Plant	Unit #	Unit Type	Fuel Type	Nameplate Capacity	Net Capacity (MW)		Annual Generation	Capacity Factor	Availability Factor	In-Service Date
				(MW)	Sum	Win	(MWh)	(%)	(%)	
Big Bend	1	ST	BIT	446	385	395	1,978,198	58.2	60.5	10/70
Big Bend	2	ST	BIT	446	385	395	2,197,115	64.6	68.4	4/73
Big Bend	3	ST	BIT	446	365	365	2,434,151	76.1	79.8	5/76
Big Bend	4	ST	BIT	486	417	427	2,376,875	64.2	66.5	2/85
Big Bend	CT4	GT	NG/LO	70	56	61	46,560	9.2	86.9	8/09
Bayside	1	CC	NG	809	701	792	3,403,937	53.2	93.9	4/03
Bayside	2	CC	NG	1205	929	1047	4,599,661	54.2	89.6	1/04
Bayside	3	GT	NG	70	56	61	52,274	10.3	92.8	7/09
Bayside	4	GT	NG	70	56	61	49,870	9.8	92.3	7/09
Bayside	5	GT	NG	70	56	61	40,129	7.9	92.5	4/09
Bayside	6	GT	NG	70	56	61	37,357	7.4	93.8	4/09
Polk	1	IGCC	BIT/LO	326	220	220	1,664,556	86.4	90.0	9/96
Polk	2	GT	NG/LO	176	151	183	26,100	2.2	64.8	7/00
Polk	3	GT	NG/LO	176	151	183	21,374	1.6	97.3	5/02
Polk	4	GT	NG	176	151	183	58,924	4.2	95.7	3/07
Polk	5	GT	NG	176	151	183	50,131	3.5	96.6	4/07
COT	1	IC	NG	3	3	3	0	0.0	49.6	4/01
COT	2	IC	NG	3	3	3	-59	0.0	100.0	4/01

Plant	Unit #	Fuel Type	Heat Rate	Total Fuel Burned	Total Fuel Cost	Unit Fuel Cost	
			(BTU/kWh)	(MMBTU)	($000)	($/MMBTU)	(¢/kWh)
Big Bend	1	BIT	10,231	20,239,754	59,796	2.95	3.02
Big Bend	2	BIT	10,178	22,361,688	65,230	2.92	2.97
Big Bend	3	BIT	10,577	25,746,754	78,389	3.04	3.22
Big Bend	4	BIT	10,321	24,530,703	74,297	3.03	3.13
Big Bend	CT4	NG/LO	10,999	512,121	3,744	7.31	8.04
Bayside	1	NG	7,260	24,713,917	167,077	6.76	4.91
Bayside	2	NG	7,376	33,925,039	227,544	6.71	4.95
Bayside	3	NG	11,502	601,251	4,103	6.82	7.85
Bayside	4	NG	11,406	568,810	3,852	6.77	7.72
Bayside	5	NG	11,712	470,000	3,152	6.71	7.85
Bayside	6	NG	11,437	427,257	2,902	6.79	7.77
Polk	1	BIT/LO	10,049	16,726,900	56,392	3.37	3.39
Polk	2	NG/LO	11,813	308,307	2,550	8.27	9.77
Polk	3	NG/LO	14,000	299,238	2,438	8.15	11.41
Polk	4	NG	12,246	721,576	4,768	6.61	8.09
Polk	5	NG	12,113	607,257	4,142	6.82	8.26
COT	1	NG	0	643	7.6	11.87	0.00
COT	2	NG	0	783	9.9	12.63	0.00

25. For each unit on the Company's system, provide the following data based upon historic data from 2010 and forecasted capacity factor values for the period 2011 through 2020. Please complete the tables below and provide an electronic copy in Excel (.xls file format) and hard copy.

Projected Unit Information – Capacity Factor (%)

Plant	Unit #	Unit Type	Fuel Type	Actual	Projected									
				2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020

A. Provided below is the table of projected capacity factor by unit for 2010 through 2020. The table is also in Excel on the enclosed CD.

Projected Unit Information – Capacity Factor (%)

Plant	Unit #	Unit Type	Fuel Type	Actual	Projected									
				2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
B Bend	1	ST	BIT	58.2	76.5	76.6	76.5	59.7	76.4	76.4	76.2	65.3	76.9	76.9
B Bend	2	ST	BIT	64.6	60.9	77.7	77.6	77.7	66.3	77.6	77.5	77.6	66.5	77.9
B Bend	3	ST	BIT	76.1	73.3	62.4	74.4	74.6	75.5	64.9	75.3	75.4	76.4	66.5
B Bend	4	ST	BIT	64.2	76.3	76.4	66.1	77.7	77.7	77.3	67.5	77.9	78.5	78.8
B Bend	CT4	GT	NG/LO	9.2	11.7	9.3	6.9	8.3	10.3	13.2	10.6	10.8	6.0	1.0
Bayside	1	CC	NG	53.2	38.9	43.3	42.5	43.9	37.9	48.7	47.3	48.6	20.5	19.8
Bayside	2	CC	NG	54.2	48.2	45.4	49.1	51.9	54.8	46.5	52.6	53.9	39.5	26.1
Bayside	3	GT	NG	10.3	6.9	5.7	8.8	9.0	12.3	15.3	13.4	13.9	7.3	2.6
Bayside	4	GT	NG	9.8	4.3	3.1	7.2	7.8	11.0	13.0	11.6	12.5	6.4	2.0
Bayside	5	GT	NG	7.9	13.0	11.3	13.3	12.7	16.7	19.2	17.2	18.1	11.1	5.0
Bayside	6	GT	NG	7.4	9.2	8.2	10.9	10.3	14.0	16.7	15.1	15.6	8.6	3.1
Polk	1	IGCC	BIT/LO	86.4	78.8	76.6	78.8	78.7	75.3	78.0	77.9	75.3	78.7	79.3
Polk	2	GT	NG/LO	2.2	0.3	0.4	0.8	0.6	1.0	0.9	1.0	0.7	0.5	0.0
Polk	3	GT	NG/LO	1.6	0.1	0.0	0.3	0.2	0.4	0.4	0.3	0.2	0.2	0.0
Polk	4	GT	NG	4.2	4.2	3.9	3.8	3.3	4.0	4.3	3.2	3.4	1.7	0.0
Polk	5	GT	NG	3.5	2.0	1.7	2.3	1.7	2.1	2.3	1.7	1.7	1.0	0.0
COT	1	IC	NG	0.0	0.0	0.0	0.1	0.0	0.0	0.1	0.1	0.1	0.3	0.4
COT	2	IC	NG	0.0	0.0	0.0	0.1	0.0	0.0	0.1	0.1	0.1	0.3	0.4

26. Please complete the table below, providing a list of all of the Company's steam units or combustion turbines that are candidates for repowering. As part of this response, please provide the unit's fuel and unit type, summer capacity rating, in-service date, and what potential conversion/repowering would be most applicable. Also include a description of any major obstacles that could affect repowering efforts at any of these sites, such as unit age, land availability, or other requirements.

Plant Name	Fuel & Unit Type	Summer Capacity (MW)	In-Service Date	Potential Conversion Type

A. Steam and combustion turbines that are candidates for repowering are discussed below:

The existing four peaking combustion turbines (CT) at Polk Power Station (Polk Units 2-5) would be capable of repowering to combined cycle operation by adding a heat recovery steam generator (HRSG) to each CT along with a steam turbine (one steam turbine for two HRSG's or a single steam turbine for all four HRSG's) and associated steam side equipment & piping. The major obstacles to repowering would be regulatory approval, air and water permitting, construction permitting, well and water usage issues and cooling pond capacity issues.

The existing coal-fired steam units at Big Bend could theoretically be repowered although engineering costs would be high, physical space would be an issue and plant efficiency could be impacted due to a non-optimum steam cycle.

Plant Name	Fuel & Unit Type	Summer Capacity (MW)	In-Service Date	Potential Conversion Type
Polk 2	NG / GT	151	7/00	CC
Polk 3	NG / GT	151	5/02	CC
Polk 4	NG / GT	151	3/07	CC
Polk 5	NG / GT	151	4/07	CC

27. Please complete the table below, in electronic (Excel) and hard copy, regarding the Company's generation fleet and the typical use of each unit. Please identify capacity type as either Baseload, Intermediate, or Peaking, and group units by their capacity type. Please use the abbreviations for fuel and generation facilities from the FRCC Load and Resource Plan for the table below. (For example, a combustion turbine that is not part of a combined cycle unit is identified with generator code "GT.") Please complete the tables below and provide an electronic copy in Excel (.xls file format) and hard copy.

Existing Facilities as of January 1, 2011

Plant	Unit #	Unit Type	Fuel Type	Typical Capacity Factor	Capacity Type	Summer Capacity
				(%)		(MW)
				Sub-Total	Baseload	
				Sub-Total	Intermediate	
				Sub-Total	Peaking	
					Total	

Planned Facilities during 2011 to 2020

Plant	Unit #	Unit Type	Fuel Type	Typical Capacity Factor	Capacity Type	Summer Capacity
				(%)		(MW)
				Sub-Total	Baseload	
				Sub-Total	Intermediate	
				Sub-Total	Peaking	
					Total	

A. The tables provided below contain information on the Company's existing and planned generating units including the capacity type of each. The tables are also in Excel on the enclosed CD.

Existing Facilities as of January 1, 2011

Plant	Unit #	Unit Type	Fuel Type	Typical Capacity Factor	Capacity Type	Summer Capacity
				(%)		(MW)
Big Bend	1	ST	BIT	58.2	Baseload	385
Big Bend	2	ST	BIT	64.6	Baseload	385
Big Bend	3	ST	BIT	76.1	Baseload	365
Big Bend	4	ST	BIT	64.2	Baseload	417
Polk	1	IGCC	BIT	86.4	Baseload	220
				Sub-Total	**Baseload**	1772
Bayside	1	CC	NG	53.2	Intermediate	701
Bayside	2	CC	NG	54.2	Intermediate	929
				Sub-Total	**Intermediate**	1630
Big Bend	CT4	GT	NG	9.2	Peaking	56
Bayside	3	GT	NG	10.3	Peaking	56
Bayside	4	GT	NG	9.8	Peaking	56
Bayside	5	GT	NG	7.9	Peaking	56
Bayside	6	GT	NG	7.4	Peaking	56
Polk	2	GT	NG	2.2	Peaking	151
Polk	3	GT	NG	1.6	Peaking	151
Polk	4	GT	NG	4.2	Peaking	151
Polk	5	GT	NG	3.5	Peaking	151
COT	1	IC	NG	0	Peaking	3
COT	2	IC	NG	0	Peaking	3
				Sub-Total	**Peaking**	890
					Total	4292

Planned Facilities during 2011 to 2020

Plant	Unit #	Unit Type	Fuel Type	Typical Capacity Factor	Capacity Type	Summer Capacity
				(%)		(MW)
N/A						
				Sub-Total	**Baseload**	
Polk 2-5 CC	1	CC	NG	66.3	Intermediate	970
				Sub-Total	**Intermediate**	970
Future CT	1	GT	NG	6.7	Peaking	56
Future CT	2	GT	NG	6.7	Peaking	56
Future CT	3	GT	NG	6.7	Peaking	56
Future CT	4	GT	NG	3.8	Peaking	56
Future CT	5	GT	NG	3.5	Peaking	56
Future CT	6	GT	NG	4.0	Peaking	56
Future CT	7	GT	NG	4.2	Peaking	56
Future CT	8	GT	NG	3.9	Peaking	56
				Sub-Total	**Peaking**	448
					Total	1418

28. Please complete the table below regarding the system's installed capacity, categorized by capacity type, for the period 2001 through 2020. Please complete the table below and provide an electronic copy in Excel (.xls file format) and hard copy.

Year		Baseload Capacity	Intermediate Capacity	Peaking Capacity	Total Installed Capacity
Actual	2001				
	2002				
	2003				
	2004				
	2005				
	2006				
	2007				
	2008				
	2009				
	2010				
Projected	2011				
	2012				
	2013				
	2014				
	2015				
	2016				
	2017				
	2018				
	2019				
	2020				

A. Listed below is the Company's actual and projected capacity categorized by capacity type. The table below is also in Excel on the enclosed CD.

Year		Baseload Capacity	Intermediate Capacity	Peaking Capacity	Total Installed Capacity
Actual	2001	3,077	0	434	3,511
	2002	3,063	0	504	3,567
	2003	2,634	690	439	3,763
	2004	1,967	1,620	439	4,026
	2005	1,947	1,632	511	4,090
	2006	1,928	1,632	511	4,071
	2007	1,847	1,632	802	4,281
	2008	1,815	1,628	759	4,202
	2009	1,785	1,630	757	4,172
	2010	1,787	1,630	890	4,307
Projected	2011	1,772	1,630	890	4,292
	2012	1,772	1,630	890	4,292
	2013	1,772	1,630	1,058	4,460
	2014	1,772	1,630	1,114	4,516
	2015	1,772	1,630	1,170	4,572
	2016	1,772	1,630	1,226	4,628
	2017	1,772	1,630	1,282	4,684
	2018	1,772	1,630	1,338	4,740
	2019	1,772	2,600	734	5,106
	2020	1,772	2,600	734	5,106

29. Please provide the system average heat rate for the generation fleet for each year for the period 2001 through 2020. Please complete the table below and provide an electronic copy in Excel (.xls file format) and hard copy.

	Year	System Average Heat Rate (BTU/kWh)
Actual	2001	
	2002	
	2003	
	2004	
	2005	
	2006	
	2007	
	2008	
	2009	
	2010	
Projected	2011	
	2012	
	2013	
	2014	
	2015	
	2016	
	2017	
	2018	
	2019	
	2020	

A. Listed below is the Company's actual and projected system average heat rate from 2001 through 2020. The table below is also in Excel on the enclosed CD.

Year		System Average Heat Rate (BTU/kWh)
Actual	2001	10,800
	2002	11,107
	2003	10,399
	2004	9,446
	2005	9,344
	2006	9,494
	2007	9,358
	2008	9,354
	2009	9,107
	2010	9,075
Projected	2011	9,365
	2012	9,487
	2013	9,353
	2014	9,313
	2015	9,349
	2016	9,364
	2017	9,312
	2018	9,295
	2019	9,150
	2020	9,078

30. Please provide the average cost of a residential customer bill, based upon a monthly usage of 1200 kilowatt-hours, in nominal and real dollars for the period 2001 through 2020. Please use the Consumer Price Index to calculate real residential bill values. Please complete the table below and provide an electronic copy in Excel (.xls file format) and hard copy.

Year		Residential Bill ($/1200-kWh)		CPI
		Real	Nominal	
Actual	2001			
	2002			
	2003			
	2004			
	2005			
	2006			
	2007			
	2008			
	2009			
	2010			
Projected	2011			
	2012			
	2013			
	2014			
	2015			
	2016			
	2017			
	2018			
	2019			
	2020			

A. Listed below are average historical residential bills for 1200 kWh for the period 2001 through 2010. Tampa Electric does not forecast average bills. The deflator used to calculate the price is the Consumer Price Index, all urban consumers, not seasonally adjusted (CPI-U Index 1982-1984 =100). The following table is in Excel format on the enclosed CD.

Year		Residential Bill ($/1200-kWh)		CPI
		Real	Nominal	
Actual	2001	58.49	103.57	177.07
	2002	61.70	110.98	179.88
	2003	60.46	111.22	183.96
	2004	61.97	117.06	188.88
	2005	59.37	115.94	195.29
	2006	64.38	129.78	201.59
	2007	65.36	135.51	207.34
	2008	64.82	139.55	215.30
	2009	65.05	139.55	214.54
	2010	62.84	137.22	218.36
Projected	2011	58.50	130.37	222.87
	2012	N/A	N/A	N/A
	2013	N/A	N/A	N/A
	2014	N/A	N/A	N/A
	2015	N/A	N/A	N/A
	2016	N/A	N/A	N/A
	2017	N/A	N/A	N/A
	2018	N/A	N/A	N/A
	2019	N/A	N/A	N/A
	2020	N/A	N/A	N/A

POWER PURCHASES / SALES

31. Please identify each of the Company's existing and planned power purchase contracts, including firm capacity imports reflected in Schedule 7 of the Company's Ten-Year Site Plan. Provide the seller, capacity, associated energy, and term of each purchase, and provide unit information if a unit power purchase. Please complete the table below and provide an electronic copy in Excel (.xls file format) and hard copy.

Existing Purchased Power Agreements as of January 1, 2011

Seller	Contract Term		Contract Capacity (MW)		Annual Generation	Capacity Factor	Primary Fuel (if any)	Description
	Begins	Ends	Summer	Winter	(MWh)	(%)		

Planned Purchased Power Agreements for 2011 through 2020

Seller	Contract Term		Contract Capacity (MW)		Annual Generation	Capacity Factor	Primary Fuel (if any)	Description
	Begins	Ends	Summer	Winter	(MWh)	(%)		

A. The requested data is provided in the tables below and in Excel on the enclosed CD.

Existing Purchased Power Agreements as of January 1, 2011

Seller	Contract Term		Contract Capacity (MW)		Annual Generation	Capacity Factor	Primary Fuel	Description
	Begins	Ends	Summer	Winter	(MWh)	(%)	(if any)	
Calpine Energy Services	May 2006	April 2011	170	170	Varies	Varies	Nat Gas	Peaking Product
RRI Energy (formally Reliant Energy)	Jan 2008	May 2012	158	158	Varies	Varies	Nat Gas	Peaking Product
Pasco Cogen	Jan 2009	Dec 2018	121	121	Varies	Varies	Nat Gas	Intermediate Product
Invenergy	Jan 1993	Dec 2012	356	441	Varies	Varies	Nat Gas	Intermediate/ Peaking Product

Planned Purchased Power Agreements for 2011 through 2020

Seller	Contract Term		Contract Capacity (MW)		Annual Generation	Capacity Factor	Primary Fuel	Description
	Begins	Ends	Summer	Winter	(MWh)	(%)	(if any)	
N/A								
N/A								
N/A								

32. Please identify each of the Company's existing and planned power sales, including firm capacity exports reflected in Schedule 7 of the Company's Ten-Year Site Plan. Provide the purchaser, capacity, associated energy, and term of each purchase, and provide unit information if a unit power sale. Please complete the table below and provide an electronic copy in Excel (.xls file format) and hard copy.

Existing Power Sales as of January 1, 2011

Purchaser	Contract Term		Contract Capacity (MW)		Annual Generation	Capacity Factor	Primary Fuel	Description
	Begins	Ends	Summer	Winter	(MWh)	(%)	(if any)	

Planned Power Sales for 2011 through 2020

Purchaser	Contract Term		Contract Capacity (MW)		Annual Generation	Capacity Factor	Primary Fuel	Description
	Begins	Ends	Summer	Winter	(MWh)	(%)	(if any)	

A. Other than the existing power sales listed below, Tampa Electric has no additional firm power sales projected within its ten-year planning horizon. The company, however, will prudently evaluate entering into future firm sales agreements as valid, economically viable opportunities present themselves. The tables below are also in Excel on the enclosed CD.

Existing Power Sales as of January 1, 2011

Purchaser	Contract Term		Contract Capacity (MW)		Annual Generation	Capacity Factor	Primary Fuel (if any)	Description
	Begins	Ends	Summer	Winter	(MWh)	(%)		
FPC - Sebring	Mar 1993	Feb 2011	71.1	71.1	Varies	Varies	System Average	Block PR Sale
Wauchula	Apr 1993	Sep 2011	12.4	12.4	Varies	Varies	System Average	Full Load Service
St. Cloud	Oct 1993	Dec 2012	15.2	15.2	Varies	Varies	System Average	Block PR Sale

Planned Power Sales for 2011 through 2020

Purchaser	Contract Term		Contract Capacity (MW)		Annual Generation	Capacity Factor	Primary Fuel (if any)	Description
	Begins	Ends	Summer	Winter	(MWh)	(%)		
None								
None								
None								

33. Please discuss and identify the impacts on the Company's capacity needs of all known firm power purchases and sales over the planning horizon. As part of this discussion, please include whether options to extend purchases or sales exist, and the potential effects of expiration of these purchase or sales.

A. All of Tampa Electric's existing purchase power contracts are scheduled to expire over the ten-year planning horizon.

- Calpine Peaking contract expires April 2011
- RRI Energy (formerly Reliant Energy Services) Peaking contract expires May 2012
- Invenergy Intermediate/Peaking contract from Hardee Power Station expires December 2012
- Pasco Cogen Intermediate contract expires in December 2018

(Refer to the table in Tampa Electric's response to Supplemental Data Request No. 31 for exact dates and capacities)

There are no terms within these contracts that give Tampa Electric the right to extend them. As shown in the ten-year site plan, as these contracts expire, Tampa Electric forecasts to meet any reserve margin shortfall through self-build options; however, the company will continue to evaluate viable purchase power opportunities as an option for economically and reliability meeting the needs of its customers.

ENVIRONMENTAL ISSUES

34. Please discuss the impact of environmental restrictions, relating to air or water quality or emissions, on the Company's system during the 2010 period, such as unit curtailments. As part of your discussion, please include the potential for environmental restrictions to impact unit dispatch or retirement during the 2011 through 2020 period.

A. Tampa Electric Company (TEC) operates the Company's power plants in compliance with all issued permits and all other environmental regulations. In order to remain in compliance with specific permit conditions, it is sometimes necessary to reduce unit output (or even shut down units) if/when pollution control equipment malfunctions. Occurrences of equipment malfunction are unplanned. There are no planned environmental restrictions that will impact unit dispatch or retirement during the 2011 through 2020 period. TEC continues to monitor and evaluate evolving regulatory and legislative developments to determine the potential impacts to unit dispatch or retirement and our customers.

35. Please provide the rate of emissions, on an annual and per megawatt-hour basis, of regulated materials and carbon dioxide for the generation fleet each year for the period 2001 through 2020. Please complete the table below and provide an electronic copy in Excel (.xls file format) and hard copy.

Year		SOX		NOX		Mercury		Particulates		CO2e	
		lb/MWh	Tons	lb/MWh	Tons	lb/MWh	Tons	lb/MWh	Tons	lb/MWh	Tons
Actual	2001										
	2002										
	2003										
	2004										
	2005										
	2006										
	2007										
	2008										
	2009										
	2010										
Projected	2011										
	2012										
	2013										
	2014										
	2015										
	2016										
	2017										
	2018										
	2019										
	2020										

A. The requested data is provided in the table below and in Excel on the enclosed CD.

Year		SOX		NOX		Mercury		Particulates		CO2e	
		lb/MWh	Tons	lb/MWh	Tons	lb/MWh	Tons	lb/MWh	Tons	lb/MWh	Tons
Actual	2001	8.75	70,611	6.93	55,973	0.00004	0.326	0.61	4,957	2268.6	18,313,855
	2002	8.55	66,789	6.98	54,568	0.00004	0.320	0.40	3,139	2339.2	18,276,652
	2003	5.51	44,340	5.53	44,465	0.00003	0.232	0.30	2,415	2173.2	17,482,576
	2004	1.58	13,855	3.39	29,697	0.00002	0.139	0.10	906	1782.9	15,601,704
	2005	1.51	13,095	2.86	24,829	0.00001	0.099	0.14	1,178	1708.8	14,834,551
	2006	1.64	14,901	3.44	31,274	0.00001	0.113	0.14	1,241	1827.1	16,605,165
	2007	1.29	11,744	2.70	24,537	0.00001	0.127	0.14	1,282	1735.4	15,754,821
	2008	1.23	10,966	2.08	18,473	0.00001	0.115	0.15	1,334	1706.4	15,169,810
	2009	1.09	9,959	1.17	10,690	0.00001	0.071	0.10	948	1658.2	15,202,841
	2010	1.14	10,817	0.62	5,893	0.00001	0.066	0.07	705	1720.8	16,379,212
Projected	2011	1.74	16,444	0.75	7,083	0.00001	0.112	0.16	1,562	1792.4	16,975,905
	2012	1.71	16,452	0.74	7,144	0.00001	0.111	0.17	1,585	1775.8	17,039,644
	2013	1.72	16,814	0.74	7,265	0.00001	0.107	0.16	1,609	1775.5	17,398,525
	2014	1.69	16,705	0.72	7,136	0.00001	0.107	0.16	1,573	1754.4	17,391,876
	2015	1.64	16,439	0.71	7,147	0.00001	0.105	0.16	1,600	1742.3	17,416,536
	2016	1.62	16,471	0.71	7,217	0.00001	0.107	0.16	1,625	1741.3	17,653,843
	2017	1.63	16,755	0.71	7,270	0.00001	0.107	0.16	1,611	1730.7	17,801,221
	2018	1.60	16,688	0.69	7,132	0.00001	0.105	0.15	1,593	1719.9	17,892,792
	2019	1.56	16,607	0.73	7,752	0.00001	0.108	0.15	1,642	1713.2	18,185,633
	2020	1.57	16,908	0.73	7,847	0.00001	0.109	0.15	1,625	1714.9	18,416,077

Note: Data in the CO2e column represents only the tons of CO2 produced.

FUEL

36. Please provide, on a system-wide basis, the historic average fuel price (in nominal $/MMBTU) for each fuel type for the period 2001 through 2010. Also, provide the forecasted annual average fuel price (in nominal $/MMBTU) for each fuel type for the period 2011 through 2020. Please complete the table below and provide an electronic copy in Excel (.xls file format) and hard copy.

Nominal Fuel Price ($/MMBTU)		Uranium	Coal	Natural Gas	Residual Oil	Distillate Oil
Actual	2001					
	2002					
	2003					
	2004					
	2005					
	2006					
	2007					
	2008					
	2009					
	2010					
Projected	2011					
	2012					
	2013					
	2014					
	2015					
	2016					
	2017					
	2018					
	2019					
	2020					

A. The requested data is provided in the table below and in Excel on the enclosed CD.

Nominal Fuel Price ($/MMBTU)		Uranium	Coal	Natural Gas	Residual Oil	Distillate Oil
Actual	2001	N/A	1.99	4.84	4.48	6.16
	2002	N/A	1.88	5.84	5.08	5.31
	2003	N/A	1.97	6.44	5.66	6.82
	2004	N/A	2.10	7.13	5.55	7.64
	2005	N/A	2.23	9.37	8.01	11.99
	2006	N/A	2.47	9.60	9.94	14.90
	2007	N/A	2.54	9.50	10.43	16.08
	2008	N/A	2.88	10.60	15.24	22.21
	2009	N/A	3.02	7.99	12.12	17.61
	2010	N/A	3.09	6.73	N/A	16.04
Projected	2011	N/A	3.44	6.72	N/A	18.05
	2012	N/A	3.54	7.03	N/A	18.87
	2013	N/A	3.68	7.26	N/A	19.68
	2014	N/A	3.91	7.46	N/A	20.49
	2015	N/A	3.99	7.78	N/A	23.85
	2016	N/A	4.02	8.09	N/A	25.19
	2017	N/A	4.04	8.37	N/A	26.59
	2018	N/A	4.21	8.50	N/A	32.30
	2019	N/A	4.37	8.67	N/A	33.86
	2020	N/A	4.54	8.51	N/A	35.37

37. Please provide, on a system-wide basis, the historic annual fuel usage (in GWh) for each fuel type for the period 2001 through 2010. Also, provide the forecasted annual fuel usage (in GWh) for each fuel type for the period 2011 through 2020. Please complete the table below and provide an electronic copy in Excel (.xls file format) and hard copy.

Fuel Usage (GWh)		Uranium	Coal	Natural Gas	Residual Oil	Distillate Oil
Actual	2001					
	2002					
	2003					
	2004					
	2005					
	2006					
	2007					
	2008					
	2009					
	2010					
Projected	2011					
	2012					
	2013					
	2014					
	2015					
	2016					
	2017					
	2018					
	2019					
	2020					

A. The requested data is provided in the table below and in Excel on the enclosed CD.

Fuel Usage (GWh)		Uranium	Coal	Natural Gas	Residual Oil	Distillate Oil
Actual	2001	N/A	15534	312	90	211
	2002	N/A	14875	473	87	191
	2003	N/A	12322	3561	103	103
	2004	N/A	10709	6652	65	75
	2005	N/A	9660	7567	71	64
	2006	N/A	10969	7136	29	45
	2007	N/A	10191	7899	32	36
	2008	N/A	10193	7535	18	33
	2009	N/A	9619	8660	24	33
	2010	N/A	10613	8375	0	49
Projected	2011	N/A	11425	7465	0	52
	2012	N/A	11655	7486	0	50
	2013	N/A	11658	7890	0	50
	2014	N/A	11516	8260	0	51
	2015	N/A	11666	8276	0	50
	2016	N/A	11786	8437	0	53
	2017	N/A	11707	8812	0	52
	2018	N/A	11680	9077	0	50
	2019	N/A	11811	9369	0	49
	2020	N/A	11946	9485	0	46

38. Please discuss how the Company compares its fuel price forecasts to recognized, authoritative independent forecasts.

A. Fuel commodity price forecasting for the base case is derived through analysis of historical and current prices combined with price forecasts obtained from various consultants and agencies. These sources include the New York Mercantile Exchange, Energy Information Administration, Wood Mackenzie, Hill & Associates (now part of Wood Mackenzie Energy Group), PIRA Energy Group, Coal Daily, Inside FERC and Platt's Oilgram. The company carefully examines its final fuel forecasts for trending relationships among fuels and anomalies (e.g., an unexplainable spike in natural gas prices) in an attempt to eliminate elements that could impact the validity of long-term energy pricing and planning.

The company also produces 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 by about 35%.

39. For each fuel type (coal, natural gas, nuclear fuel, etc.), please discuss in detail the expected industry trends and factors for the period 2011 through 2020. As part of this discussion, please include how these factors and trends will affect the Company.

A. The following discussion provides details of the expected industry trends and factors for each fuel type and their effect on Tampa Electric:

Coal
The coal industry is expected to be in a state of much uncertainty during the period 2011 through 2020. Beyond the ramifications of a global recession, volatile crude oil and natural gas prices, labor resource constraints, and land access and use limitations, political uncertainty is the biggest unknown. The Clean Air Interstate Rule, federal and state renewal portfolio standards, and Carbon Dioxide Emission restrictions all dramatically impact coal utilization and coal pricing. This uncertainty not only impacts Tampa Electric's choice of future power plants, but potentially impacts existing coal-fired power plants.

Natural Gas
The natural gas industry will be influenced primarily by the evolving unconventional gas production in North America and the international market for LNG. Both global demand and North American demand for natural gas have been softened by the economic downturn. However, significant restrictions on carbon dioxide emissions could increase the demand for natural gas as coal plants are limited or shut down. Tampa Electric is affected by the evolving gas market since production is coming from the mid-continent instead of the Gulf of Mexico. Tampa Electric's pipeline contracts must access this changing supply location.

Nuclear Fuel
Tampa Electric does not have nuclear fueled generation facilities.

Oil
Crude oil, heavy oil and distillate fuel oil have all shown levels of pricing volatility over the past three years and are expected to continue in the foreseeable future. Global tensions, global economics, weather related supply disruptions, and aging refining capacity have caused the price of crude and its related products to change dramatically. All of these risk factors will continue in the future, so continued price volatility is likely. Fortunately, Tampa Electric does not depend on oil-fired generation for much of its energy, so this volatility should have limited impact on the company.

40. What steps has the Company taken to ensure gas supply availability and transport over the 2011 through 2020 planning period?

A. Tampa Electric has taken three primary steps to ensure gas supply availability for the time period 2011 – 2020. The company has 1) contracted for and utilizes underground storage, 2) participated in the Southeast Supply Header project, and 3) developed natural gas supplier relationships with vendors who own natural gas production in supply growth regions such as the Barnett Shale and Fayetteville expansions.

To ensure natural gas transportation over the period of 2011 – 2020, Tampa Electric has accessed the Gulfstream pipeline via the Bayside lateral. This provides access to two separate pipelines at our largest gas-fired power plant. Tampa Electric has also contracted for additional firm capacity on Florida Gas Transmission's phase VIII expansion. This capacity is needed to cover Tampa Electric's growing dependency on natural gas fired generation.

Tampa Electric expects to further enhance its gas supply and transport portfolio over the near future. Tampa Electric is considering additional paths to access mid-continent and Rockies gas and liquefied natural gas. Tampa Electric also expects to continue growing its underground storage position as the company's natural gas needs grow.

41. Regarding existing and planned natural gas pipeline expansion projects, including new pipelines, affecting the Company for the period 2011 through 2020, please identify each project and discuss it in detail.

A. Numerous natural gas pipeline projects have been completed, are in the works, or are proposed to move natural gas from the Rockies and the mid-continent (unconventional gas) to eastern markets. These are the primary projects that directly impact the Florida market and Tampa Electric Company.

- Transco South 4A Expansion – a 550,000 MMBtu/day expansion from compressor station 85 to Mobile Bay with a projected in-service of May, 2011
- Florida Gas Transmission Phase VIII – a 400,000 MMBtu/day expansion in the market area with a projected in-service date of April, 2011
- Gulfstream Bartow Extension – an expansion of Gulfstream to Progress Energy's re-powered Bartow power plant
- Southeast Supply Header Phase 2 – an expansion to bring additional volumes of mid-continent gas supplies to the Gulf Coast

42. Please discuss in detail any existing or planned natural gas pipeline expansion project, including new pipelines and off-shore projects, outside the State of Florida that will affect the Company over the period 2011 through 2020.

A. In addition to the pipeline expansion projects listed in Tampa Electric's response to Data Request No. 41, several liquefied natural gas (LNG) regasification facilities and their associated pipelines have been proposed to bring LNG into Florida and the Gulf Coast region. Some of the key projects that are likely to influence the state of Florida are: the Gulf Crossing Pipeline, the Pascagoula LNG, and potential Ocean Express and Calypso LNG from the Bahamas.

43. Regarding unconventional natural gas production (shale gas, tight sands, etc.), please discuss in detail the expected industry factors and trends for the period 2011 through 2020. As part of this discussion, please include how these factors and trends will affect the Company.

A. Unconventional natural gas production has been surprisingly strong and became a significant factor in the U.S. supply portfolio beginning around 2006. In particular, the Barnett and Fayetteville shale production regions increased output significantly in 2008 and again in 2009. In 2010, the Marcellus shale production region began providing significant natural gas supplies to the mid-Atlantic region. Production from these regions is expected to continue to grow for the next several years and will then begin tapering off around 2013. This growth in on-shore production has helped offset the declines in production in the Gulf of Mexico.

Tampa Electric continuously strives to diversify its natural gas receipt points to improve reliability and purchasing flexibility. In addition to diversifying its receipt points along the Gulf Coast, Tampa Electric has consciously moved more of its gas supply to on-shore sources. This movement reflects the evolution in the gas supply market and increased supply reliability during tropical activity in the Gulf. To facilitate access to this secure gas supply, Tampa Electric has participated in the Southeast Supply Header project. Tampa Electric expects to participate in other opportunities to access this shale gas during 2011 through 2020.

44. Regarding liquefied natural gas (LNG) imports to the United States, please discuss in detail the expected industry factors and trends for the period 2011 through 2020. As part of this discussion, please include how these factors and trends will affect the Company.

A. Liquefied natural gas (LNG) production is projected to increase significantly in the next several years as three major liquefaction projects in Qatar begin producing LNG. This surge of LNG production is coming at a time when global energy demand is down due to the economic downturn and the production from non-conventional gas in the United States has been surprisingly high. While this increased LNG production may primarily serve Asian and European markets, some experts believe much of this increased production will come to the U.S., particularly in the summer months. Thus, forecasted natural gas prices are lower than they were forecast to be a couple years ago due to the strong supply expectations combined with the lower demand expectations.

45. Please discuss in detail the Company's plans for the use of firm natural gas storage for the period 2011 through 2020.

A. Tampa Electric currently has 1,250,000 MMBtu of underground natural gas storage capacity that is used for operational balancing purposes. For example, Tampa Electric will inject gas into storage during a weekend when loads are down. Then, Tampa Electric will pull the gas out during the weekdays when demand is up or a coal unit outage requires more natural gas fired generation. Tampa Electric expects to add additional storage capacity between 2011 and 2020 to help manage our growing dependency on natural gas fired generation and purchases, but those negotiations have not begun yet.

46. Please discuss the actions taken by the Company to promote competition within and among coal transportation modes.

A. Tampa Electric issued a solid fuel delivery request for proposal in 2007. This proposal was issued to a wide variety of transportation companies including all possible modes and participants, including terminals, barging companies, rail companies, trucking companies, and domestic and foreign ocean vessels. As a result of this request, Tampa Electric is using two vendors for river barging and a rail delivery provider to the new rail unloading facility at Big Bend. These dual delivery modes provide Tampa Electric with the opportunity to promote competition between rail transportation and waterborne transportation. This also allows Tampa Electric to access additional coal supplies from rail served mines.

47. Regarding coal transportation by rail, please discuss the expected industry trends and factors for the period 2011 through 2020. As part of this discussion, please include how these factors and trends will affect the Company. Also include a discussion of any expected changes to terminals and port facilities that could affect coal transportation for the Company.

A. Coal transportation by rail for the industry has improved during the last couple of years as mergers and technology changes have been addressed. Those improvements are expected to continue for the period 2011 through 2020. However, the surge in coal exportation driven by the demand for coal in Asia has altered the normal flow of coal via railroad. This has not caused a material disruption to the delivery of coal for electric generation, but it is a factor that must be monitored.

48. Regarding coal transportation by water, please discuss the expected industry trends and factors for the period 2011 through 2020. As part of this discussion, please include how these factors and trends will affect the Company. Also include a discussion of any expected changes to terminals and port facilities that could affect coal transportation for the Company.

A. Increased demand for coal in Asia coupled with production issues in Australia, Venezuela and Columbia have caused a surge in coal exports from the United States. While the production limitations should get corrected, the demand for coal is likely to keep coal exports higher than historic levels. This impact to coal supply and coal transportation logistics will be monitored.

49. Regarding planned changes and construction projects at coal generating units, please discuss the expected changes for coal handling, blending, unloading, and storage for the period 2011 through 2020.

A. Tampa Electric currently has no plans to change its coal handling, blending or storage facilities at the coal generating power plants.

50. For the period 2011 through 2020, please discuss in detail the Company's plans for the storage and disposal of spent nuclear fuel. As part of this discussion, please include the Company's expectation regarding Yucca Mountain, dry cask storage, and litigation involving spent nuclear fuel, and the future of the Nuclear Waste Disposal Act.

A. Tampa Electric does not have any nuclear fueled generation facilities.

51. Regarding uranium production, please discuss the expected industry trends and factors for the period 2011 through 2020. As part of this discussion, please include how these factors and trends will affect the Company.

A. Tampa Electric does not have any nuclear fueled generation facilities.

52. Regarding the transportation of heavy fuel oil and distillate fuel oil, please discuss the expected industry trends and factors for the period 2011 through 2020. As part of this discussion, please include how these factors and trends will affect the Company.

A. Tampa Electric does not use heavy oil in its generation mix. Distillate fuel oil is a small component of Tampa Electric's generation fuel mix. Distillate fuel oil is a backup fuel for Polk Units 1 through 3 as well as the Aero Combustion Turbine unit at Big Bend. Industry trends for these commodities will not have a large impact on the company's generation cost. The largest impact comes from the fuel cost associated with coal transportation via train or barge.

53. Please discuss the effect of changes in fossil fuel prices on the competitiveness of renewable technologies.

A. Decreases in fossil fuel prices would tend to make renewable technologies less cost competitive and vice versa.

54. Please discuss the effect of renewable resource development (for electric generation and non-generation technologies) on fossil fuel prices.

A. Conceptually, development of renewable resources should lower fossil fuel prices as renewable energy displaces fossil fuel fired electric generation. However, the issue is complex and has many interactions. The actual impact would be dependent on other associated legislation (e.g., carbon dioxide emission limits), quantity and timing of renewable resources and renewable standards, renewable resource mix for a particular geographic area, load growth and reserve margin, etc.

TRANSMISSION

55. Please provide a list of all proposed transmission lines in the planning period that require certification under the Transmission Line Siting Act. Please also include those that have been approved, but are not yet in-service.

Transmission Line	Line Length (Miles)	Nominal Voltage (kV)	Date Need Approved	Date TLSA Certified	In-Service Date

A. The table below lists all proposed transmission lines in the planning period that require certification under the Transmission Line Siting Act.

Transmission Line	Line Length (Miles)	Nominal Voltage (kV)	Date Need Approved	Date TLSA Certified	In-Service Date
Willow Oak-Wheeler-Davis	**30**	**230**	**02/21/2007**	**08/07/08 Modified on 09/10/2009**	**2018**
Lake Agnes to Gifford	**27.5**	**230**	**09/26/2007**	**02/5/2009**	**TBD**