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July 22, 2011

HAND DELIVERED

110000-OT

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

Re: Review of 2011 Ten-Year Site Plans
Supplemental Data Requests

Dear Ms. Cole:

Pursuant to Staff's letter dated July 1, 2011, we enclose the original and five copies and one CD of Tampa Electric Company's responses to Staff's Third Supplemental Data Requests for supplemental information on the company's generation expansion plans which will be used to supplement Tampa Electric's Company's 2011 Ten-Year Site Plan filed with the Commission on April 1, 2011.

Sincerely,

James D. Beasley

JDB/pp
Enclosures

cc: Larry D. Harris (w/hard copy)

COM ____
APA ____
ECR 3 1 CD containing Data requests also fwd.
GCL 1
RAD 1
SSC ____
ADM ____
OPC ____
CLK ____

1. Please provide a status update of all planned Renewable Energy facilities in terms of scheduled construction dates, upcoming and achieved milestones, and any other notable progress/alterations towards their completions.

A. For the period 2011-2020, Tampa Electric anticipates the installation of an additional 20 kW of PV in its service area each year through funding provided by the company's voluntary renewable energy program. The specific locations and exact timing of the installation of these systems as well as their capacities have not yet been determined and are dependent upon the ongoing success of the company's renewable energy 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-service March 2010), and an additional 16.8 kW of PV at the Manatee Viewing Center (in-service October 2010). All projects include an interactive educational display showcasing renewable technologies.

As part of Tampa Electric's current DSM Plan and in conjunction with the FSEC's SunSmart Schools program, the company plans to annually install a 10 kW PV system at a selected school in its service area over the next five years. The first school chosen to receive a 10 kW system is Centennial Middle School in Pasco County. Construction is scheduled for completion by December 2011.

2. Please list all planned Renewable Energy Contracts and/or facilities that have been cancelled, withdrawn, or delayed since the filing of the 2010 Ten-Year Site Plan. As part of this response, explain or describe the reason(s) for the change in the status of each.

A. In March 2009, Tampa Electric filed with the FPSC for cost recovery approval of a solar energy purchased power agreement with Energy 5.0. The Energy 5.0 contract was the most cost-effective solar option submitted in Tampa Electric's 2007 Renewable RFP.

On Dec. 15, 2009, the Commission determined that solar energy provided numerous benefits to Tampa Electric's customers and promoted the state's goal of developing and supporting Florida's renewable energy sources, particularly solar. As such, the Commission voted to approve full cost recovery of the contract. In January, the Commissioner who dissented on the original approval vote and requested that the decision be further discussed by the Commission. On Feb. 9, 2010, after hearing comments from the affected parties and discussing the merits of their prior decision, the Commission voted to vacate or withdraw its original Order and set the matter for an evidentiary hearing, which was scheduled for Jun. 30, 2010. On May 7, 2010, due to continued concerns regarding the Commission's legal authority to approve the contract and the economic impact to customers, Tampa Electric and Energy 5.0 entered into an agreement for the voluntary dismissal of the petition seeking approval of the contract with the Commission. On June 1, 2010 the Commission accepted Tampa Electric's request for voluntary dismissal.

3. Please complete the table below describing the status of the company's generating units during each month's peak demand, for each year from 2007 through 2010. Please also provide data for 2011 as available. As part of this response, include the actual values at monthly peak for planned capacity, scheduled maintenance, forced outages, available capacity, and the system peak demand. Please provide these responses in hardcopy and in electronic (Excel) format.

Year: (2007, 2008, 2009, 2010, 2011)					
Month	Capacity / Demand at Time of Peak (MW)				
	Planned Capacity	Scheduled Maintenance	Forced Outages	Available Capacity	Peak Demand
Jan					
Feb					
Mar					
Apr					
May					
Jun					
Jul					
Aug					
Sep					
Oct					
Nov					
Dec					

A. The requested data is provided in the attached forms and in Excel on the enclosed CD. Planned capacity values are taken from the respective year's Ten Year Site Plan. Planned capacity includes all firm purchase power agreements that are part of the planned reserve margins in the TYSP filing and also available for operating reserves at system peak. Forced outage capacities take into account both full forced and partial de-rated outages. The peak demand reflects total retail demand plus partial requirement (PR) sales to arrive at a system peak demand.

Year: 2007					
Month	Capacity / Demand at Time of Peak (MW)				
	Planned Capacity	Scheduled Maintenance	Forced Outages	Available Capacity	Peak Demand
Jan	5,042	0	528	4,514	3,424
Feb	5,042	452	437	4,153	3,560
Mar	5,222	488	457	4,277	3,130
Apr	4,832	447	485	3,900	3,407
May	4,957	0	1,200	3,757	3,646
Jun	4,957	0	388	4,569	3,968
Jul	4,957	0	816	4,141	4,157
Aug	4,957	0	542	4,415	4,295
Sep	4,957	0	503	4,454	4,000
Oct	4,957	235	1,219	3,503	3,933
Nov	4,957	957	329	3,671	3,111
Dec	5,312	1,060	463	3,789	3,028

Year: 2008					
Month	Capacity / Demand at Time of Peak (MW)				
	Planned Capacity	Scheduled Maintenance	Forced Outages	Available Capacity	Peak Demand
Jan	5,562	397	102	5,062	3,862
Feb	5,562	1,460	111	3,991	3,136
Mar	5,562	1,443	753	3,366	2,971
Apr	4,975	387	1,425	3,163	3,325
May	4,950	0	719	4,231	3,823
Jun	4,950	0	901	4,049	4,101
Jul	4,950	0	54	4,895	4,052
Aug	4,950	0	483	4,466	4,063
Sep	5,050	0	260	4,789	3,946
Oct	4,962	217	207	4,537	3,565
Nov	4,962	541	652	3,769	3,119
Dec	5,419	780	898	3,740	3,313

Year: 2009					
Month	Capacity / Demand at Time of Peak (MW)				
	Planned Capacity	Scheduled Maintenance	Forced Outages	Available Capacity	Peak Demand
Jan	5,498	383	636	4,479	4,147
Feb	5,498	623	359	4,516	4,110
Mar	5,498	623	403	4,472	3,191
Apr	5,030	959	342	3,730	3,265
May	5,142	0	1,117	4,025	3,678
Jun	5,142	0	1,199	3,943	4,151
Jul	5,254	0	818	4,436	3,926
Aug	5,254	0	1,336	3,918	3,873
Sep	5,275	0	356	4,919	3,736
Oct	5,175	0	575	4,600	3,876
Nov	5,175	0	826	4,349	2,945
Dec	5,667	653	333	4,681	2,904

Year: 2010					
Month	Capacity / Demand at Time of Peak (MW)				
	Planned Capacity	Scheduled Maintenance	Forced Outages	Available Capacity	Peak Demand
Jan	5,674	395	673	4,606	4,631
Feb	5,674	840	722	4,113	3,562
Mar	5,651	1,442	435	3,774	3,420
Apr	5,179	432	1,213	3,534	3,021
May	5,179	432	109	4,638	3,764
Jun	5,179	3	770	4,406	4,034
Jul	5,179	0	84	5,095	4,028
Aug	5,179	0	263	4,916	4,024
Sep	5,179	0	316	4,863	3,818
Oct	5,179	375	556	4,248	3,480
Nov	5,179	701	427	4,051	2,982
Dec	5,651	0	363	5,288	4,155

Year: 2011					
Month	Capacity / Demand at Time of Peak (MW)				
	Planned Capacity	Scheduled Maintenance	Forced Outages	Available Capacity	Peak Demand
Jan	5,616	0	401	5,215	3,912
Feb	5,616	0	1,000	4,616	3,021
Mar	5,616	911	1,155	3,550	2,723
Apr	5,139	701	673	3,765	3,448
May	5,086	701	236	4,149	3,599
Jun					
Jul					
Aug					
Sep					
Oct					
Nov					
Dec					

4. Please complete the following table describing the company's historic actual peak demand and available capacity, and the company's projected (from the previous year's forecast) peak demand and planning capacity. As part of this response, also provide the variance between the actual and projected values. Please provide these responses in hardcopy and in electronic (Excel) format.

Year	Peak Demand	Projected (Year Before) Peak Demand	Variance	Available Capacity During Peak	Projected Capacity During Peak	Variance
	(MW)	(MW)	(%)	(MW)	(MW)	(%)
2007						
2008						
2009						
2010						

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

Year	Peak Demand	Projected (Year Before) Peak Demand	Variance	Available Capacity During Peak	Projected Capacity During Peak	Variance
	(MW)	(MW)	(%)	(MW)	(MW)	(%)
2007	4,295	4,291	0.1%	4,415	4,937	-10.6%
2008	4,101	4,262	-3.8%	4,049	4,975	-18.6%
2009	4,151	4,215	-1.5%	3,943	5,142	-23.3%
2010	4,631	4,310	7.4%	4,606	5,244	-12.2%

5. Please complete the following table below describing the company's usage of interruptible or curtailable load. As part of the response, please describe, for each type of load management, the total number of customers available to be interrupted or curtailed, the number of customers interrupted each year, total load interrupted and available to be interrupted, and the average duration of interruptions. Please complete this table for each of the following groups: interruptible load, curtailable load, residential load management, and commercial load management. Please provide these responses in hardcopy and in electronic (Excel) format.

(Interruptible Load, Curtailable Load, Residential LM, Commercial LM)						
Year	Total Customers Available for Interruption	Total Customer(s) Interrupted	Interruptions per Customer per Year	Total Interrupted Load	Total Interruptible Load Available	Average Duration of Interruption
	(-)	(-)	(int/yr)	(MW)	(MW)	(mins)
1995						
1996						
1997						
1998						
1999						
2000						
2001						
2002						
2003						
2004						
2005						
2006						
2007						
2008						
2009						
2010						

A. Tampa Electric's usage of interruptible load management is provided in the attached tables and in Excel on the enclosed CD. In a year with multiple interruptions, the event that occurred coincident with a system peak or the non-coincident event with the largest MW reduction was reported.

Interruptible Load						
Year	Total Customers Available for Interruption	Total Customer(s) Interrupted	Interruptions per Customer per Year	Total Interrupted Load	Total Interruptible Load Available	Average Duration of Interruption
	(-)	(-)	(int/yr)	(MW)	(MW)	(mins)
1995	No data available	No data available	No data available	No data available	240	No data available
1996	34	34	3	No data available	152	19
1997	34	34	2	No data available	228	15
1998	34	34	4	200	204	166
1999	33	33	16	120	152	207
2000	32	31	5	178	182	105
2001	30	1	1	0.2	181	5
2002	29	29	1	141	206	53
2003	29	29	2	200	221	169
2004	29	0	0	0.0	254	0
2005	28	28	3	174	198	91
2006	23	23	1	169	187	223
2007	24	0	0	0	159	0
2008	24	24	3	53	120	45
2009	24	1	1	36	120	37
2010	22	22	1	113	117	100

Residential Load Management						
Year	Total Customers Available for Interruption	Total Customer(s) Interrupted	Interruptions per Customer per Year	Total Interrupted Load	Total Interruptible Load Available	Average Duration of Interruption
	(-)	(-)	(int/yr)	(MW)	(MW)	(mins)
1995	73,093	59,205	27	156	245	150
1996	73,947	59,897	20	243	260	83
1997	78,030	63,204	52	90	95	178
1998	78,160	63,310	47	148	160	158
1999	77,695	74,587	59	96	98	162
2000	76,989	73,909	53	178	209	162
2001	75,551	72,529	23	182	196	100
2002	75,219	67,095	32	69	99	132
2003	74,026	68,992	28	74	77	137
2004	72,124	68,590	17	79	95	78
2005	68,040	64,706	32	85	90	65
2006	60,452	57,490	26	73	77	61
2007	54,533	44,172	8	25	69	49
2008	51,492	41,709	14	54	69	50
2009	49,370	39,990	9	34	56	51
2010	46,024	37,279	2	18	33	53

Commercial/Industrial Load Management						
Year	Total Customers Available for Interruption	Total Customer(s) Interrupted	Interruptions per Customer per Year	Total Interrupted Load	Total Interruptible Load Available	Average Duration of Interruption
	(-)	(-)	(int/yr)	(MW)	(MW)	(mins)
1995	44	44	27	2.7	2.7	150
1996	39	39	20	2.7	2.7	83
1997	29	29	52	2.7	2.7	178
1998	26	26	47	2.7	2.7	158
1999	19	19	59	0.4	0.4	162
2000	15	15	53	0.3	0.3	162
2001	13	13	23	0.2	0.2	100
2002	11	11	32	0.3	0.3	132
2003	8	8	28	0.3	0.3	137
2004	19	19	17	0.3	0.3	78
2005	15	15	32	0.8	0.8	65
2006	6	6	26	0.4	0.4	61
2007	6	6	8	0.2	0.2	49
2008	6	6	14	0.2	0.2	50
2009	7	7	9	0.2	0.2	51
2010	7	7	2	0.2	0.2	53

Commercial/Industrial Standby Generator Program						
Year	Total Customers Available for Interruption	Total Customer(s) Interrupted	Interruptions per Customer per Year	Total Interrupted Load	Total Interruptible Load Available	Average Duration of Interruption
	(-)	(-)	(int/yr)	(MW)	(MW)	(mins)
1995	41	41	3	8	8	236
1996	48	0	0	0	8	0
1997	48	48	4	18	19	275
1998	42	42	16	19	20	279
1999	39	39	29	17	19	268
2000	42	42	26	19	21	246
2001	42	42	4	19	21	154
2002	44	44	9	21	21	246
2003	43	43	11	21	21	242
2004	40	40	2	20	20	240
2005	34	34	5	18	19	280
2006	32	32	1	18	18	276
2007	41	0	0	0	18	0
2008	79	0	0	0	18	0
2009	82	82	2	23	51	171
2010	91	0	0	0	40	0

Commercial Demand Response						
Year	Total Customers Available for Interruption	Total Customer(s) Interrupted	Interruptions per Customer per Year	Total Interrupted Load	Total Interruptible Load Available	Average Duration of Interruption
	(-)	(-)	(int/yr)	(MW)	(MW)	(mins)
2008	77	76	1	29	35	120
2009	83	72	3	31	35	110
2010	103	102	1	36	36	120

6. Please indicate the number of customers since 1995 participating in interruptible, curtailable, and load management programs that have requested to discontinue their participation. Please provide annual figures for each of the following programs individually: interruptible load, curtailable load, residential load management, and commercial load management.

A. The table below shows the number of customers that have been removed from the interruptible and load management programs. Prior to 2005 Tampa Electric did not independently track the number of customers requesting to be removed from the residential load management program. Additionally, the company has not tracked customers asking to be removed from commercial and industrial load management.

Year	Interruptible	Residential Load Management	Com. / Ind. Load Management
1995	0	N/A	N/A
1996	0	N/A	N/A
1997	0	N/A	N/A
1998	0	N/A	N/A
1999	0	N/A	N/A
2000	1	N/A	N/A
2001	0	N/A	N/A
2002	0	N/A	N/A
2003	0	N/A	N/A
2004	1	N/A	N/A
2005	3	8,623	N/A
2006	1	5,481	N/A
2007	0	3,474	N/A
2008	0	2,872	N/A
2009	2	2,603	N/A
2010	0	2,651	N/A

7. Please explain or describe the reason(s) given, if any, by those customers that chose to discontinue participation in interruptible, curtailable, or load management programs.

A. Customers chose to discontinue participation in the interruptible program for three primary reasons; (1) the facility was closing, (2) operations changed or shut down and (3) the program was not conducive to their business operations any longer.

Customers chose to discontinue participation in the residential load management program for two primary reasons; (1) the length, frequency and/or the duration of the control event was not compatible with their lifestyle and (2) it was too uncomfortable during the control events and not worth the credit they received on their bill.

Customers chose to discontinue participation in the commercial and industrial load management programs for four primary reasons; (1) the account was closing, (2) the facility was being demolished, (3) it was too uncomfortable during the control events and not worth the credit they received on their bill and (4) the tariff agreement requirements no longer met their needs.

8. In both the 2009 (p. 21) and 2010 (p. 41) reviews of the utilities Ten-Year Site Plans, the Commission has stated that, "...in an era of rising rates, utilities should study all options available to mitigate price increases, including possible modification of current planning criteria." Please provide and discuss any such studies that have been performed, including those that demonstrate the benefit of maintaining the company's current level of planning reserve. If no such studies have been conducted, please describe and explain the reason(s).

A. Tampa Electric has not performed any studies that modify the current planning criteria. In general, since the adoptions of the 20 percent reserve margin criterion in December 1999 (Docket No. 981890-EU), Tampa Electric has significantly improved the overall system availability of its generating fleet with the repowering of the coal units at Gannon Station to natural gas combined cycle (Bayside 1&2), the additions of simple cycle combustion turbines at the Polk Power Station and in 2009 the addition of 5 aero derivative, quick start, black start units at Bayside and Big Bend Power Stations.

Tampa Electric may consider a modification to the current reserve planning criteria.

9. For the next planned generating unit identified in the company's 2011 Ten-Year Site Plan, please provide the estimated annual value of deferral for each year for five years. As part of this response, identify which unit is capable of being deferred, and what potential impacts this deferral would have on any pre-existing contracts or purchases.

A. The 2013 combustion turbines would be the next unit(s) capable of being deferred. The value of deferral in 2011 dollars for each year is found in the table below. The deferral of the 2013 combustion turbines would not have any direct impact to any pre-existing contracts or purchases.

Deferral Year	CPWRR ($ 2011)
1 Year Deferral (2013 to 2014)	$3,465,000
2 Year Deferral (2013 to 2015)	$6,734,000
3 Year Deferral (2013 to 2016)	$9,916,000
4 Year Deferral (2013 to 2017)	$13,132,000
5 Year Deferral (2013 to 2018)	$16,188,000

10. Please explain or describe the impact(s) of having an operating capacity that was reduced from current levels by 5% during the two previous peak seasons (Jan/Feb 2011, and July/Aug 2010).

A. If the planned capacity, not operating reserves, of 5,179 MW in the summer of 2010 (July/Aug) were reduced by 5 percent, the reduced planned capacity would be 4,920 MW. Using the same amount of scheduled maintenance and forced outages from the table data from question 3, the reduced available capacity would be 4,836 MW for July 2010 and 4,658 for August 2010.

If the planned capacity of 5,616 MW in the winter of 2011 (Jan/Feb) were reduced by 5 percent, the reduced planned capacity would be 5,335 MW. Using the same amount of scheduled maintenance and forced outages from the table data from question 3, the reduced available capacity would be 4,934 MW for January 2011 and 4,335 for February 2011.

Although it appears that reducing the planned capacity by 5 percent does not have a negative system impact on Tampa Electric's system, it is important to realize that the recent economic recession significantly lowered Tampa Electric Company's forecasted and actual peak loads. This resulted in a reserve margin greater than twenty percent at the time of the actual peak demands during the summer of 2010 and the winter of 2011. The 20 percent reserve margin criterion was adopted by three of the Florida IOUs in 1999 (Docket No. 981890-EU) and was achieved by the summer of 2004.

11. Why does TECO believe it is appropriate to continue use of a 7 percent minimum generation-only requirement? Please provide any analyses supporting your answer.

A. Tampa Electric believes it is still appropriate to use a 7 percent minimum generation only planning requirement. Although, Tampa Electric has significantly improved the overall system availability of its generating fleet with the repowering of the coal units at Gannon Station to natural gas combined cycle (Bayside 1&2), the additions of simple cycle combustion turbines at the Polk Power Station and in 2009 the addition of 5 aero derivative, quick start, black start units at Bayside and Big Bend Power Stations, if the reserve margin was made up entirely from load management and interruptible customers, Tampa Electric would likely curtail non-firm load more often and in longer durations.

12. Please discuss the current status of TECO's three 2013 in-service date Combustion Turbines, including the status of any permitting that has been done, whether any purchases have been made, and any other information relating to the construction of the three units. As part of this response, please discuss what ramifications a delay of one to three years would have on the project and existing contracts.

A. Tampa Electric has submitted in a transmission interconnect study for the 2013 combustion turbines. No further construction-related activities have commenced at this time.

A delay to the construction schedule of one to three years will cause Tampa Electric's reserve margin to fall below 20 percent starting in the summer of 2013. At this point, Tampa Electric would need to enter into a purchase power agreement(s) on a firm basis to ensure continued system reliability.

Questions 13-17 relate to Tampa Electric Company's Carbon Capture & Sequestration demonstration project for the US Department of Energy, in partnership with Research Triangle Institute Inc. (RTI), being conducted at Polk Unit 1.

13. Please discuss the reliability impacts of the project, if any. This discussion should include any capacity gains or losses to the Polk IGCC unit as a result of project equipment and/or processes, whether additional maintenance has been or will be required, and other similar considerations. Of particular interest is whether or not the unit's ability to deliver capacity during peak periods will be impacted, and if so, what associated costs and/or benefits exist (such as reduced fuel consumption or a need to increase power purchases in order to meet customer demand).

A. The DOE sponsored project to demonstrate Warm Gas Clean-up and Carbon Capture and Sequestration (WGC/CCS) is currently in the Front End Engineering Design (FEED) stage. Detailed answers to question 13 are not yet available. Based on preliminary design information and project objectives the company can offer the following discussion:

1. The project is being designed to minimize any reliability impact to the operation of Polk 1. The demonstration equipment will use only a portion of the syngas produced in the process and it can be rapidly isolated from the existing generating unit if needed.

2. The net capacity of the Polk IGCC unit is expected to be reduced (on the order of 10MW) when the demonstration system is in service. Any increase in fuel costs or purchased power expense as a result of operating the demonstration system would be considered a project expense and would be reimbursed from the DOE to Tampa Electric customers through the fuel and purchased power clause.

3. Since the demonstration system can be isolated from the Polk IGCC unit, any maintenance required on the demonstration equipment should not impact the operation of generating unit.

During peak periods, the demonstration system can be isolated from the Polk IGCC unit if needed and therefore capacity during peak periods should not be affected.

14. Please discuss whether the technology being utilized in the Carbon Capture & Sequestration demonstration project is applicable to other units within Tampa Electric's generating fleet.

A. The carbon capture technology utilized by the demonstration project is directly applicable to IGCC units. Currently, Polk 1 is the only operating IGCC unit in Tampa Electric's system. The carbon capture technology could potentially be adapted to natural gas fired units with the addition of additional process equipment.

The sequestration technology being utilized by the demonstration equipment could be applied to any unit with a functioning carbon capture system (either pre-combustion, or post-combustion capture).

15. Please discuss whether TECO is receiving any compensation from RTI related to the project for the use of the Polk Unit 1 facility. Discuss how TECO's ratepayers could benefit from such compensation.

A. At the current stage of the project (FEED stage), Tampa Electric is being reimbursed for its direct cost of labor for the time that personnel spend participating in the FEED effort. This reimbursement comes from the DOE through RTI. Agreements covering the operating phase of the projects are currently being developed. These agreements will provide for the recovery of any direct cost to Tampa Electric or its customers (fuel, purchased power, O&M, etc.) that result from participation in the project.

16. Please describe and discuss any costs not covered by the $168 million in DOE grant funds that may result from the construction/installation and operation of this project, such as Polk Unit 1 being shut down for project construction/installation and replacement power or fuel from the resulting derate. If such costs do exist or are anticipated, please discuss whether TECO will seek recovery from its ratepayers, and if so through what recovery mechanism it will do so.

A. The project agreements are being structured such that incremental costs associated with the construction and operation of the project will be borne by the project, not Tampa Electric or its customers. Construction work that would require Polk Unit 1 to be shut down will be scheduled during planned outages (or unrelated forced outages) such that no incremental outage time is required for the demonstration unit construction or tie in.

17. Please discuss the benefits of the demonstration project to Tampa Electric's ratepayers, including any related equipment and the resulting carbon capture and sequestration.

A. Carbon capture and sequestration technology is one potential option to enable compliance with future regulation of CO_2 emissions. Participation in the WGC/CCS demonstration project can provide the following benefits to Tampa Electric's ratepayers:

1. The project will determine if the technology performs as expected (technical viability).

2. The project will provide an understanding of the costs involved with constructing and operating the technology (financial viability).

3. The project will give Tampa Electric experience with operating the technology (operational performance and viability).

4. If the demonstration equipment is proven to be viable (technically, financially and operationally) Tampa Electric will have the option to keep the equipment on site for use in compliance with future carbon regulation.

The above benefits are expected to accrue without costs to Tampa Electric or its ratepayers during the demonstration period.