AUSLEY & MCMULLEN

ATTORNEYS AND COUNSELORS AT LAW

123 SOUTH CALHOUN STREET
P.O. BOX 391 (ZIP 32302)
TALLAHASSEE, FLORIDA 32301
(850) 224-9115 FAX (850) 222-7560

August 27, 2010

HAND DELIVERED

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10 AUG 27 PM 3:51
COMMISSION CLERK

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

Re: Environmental Cost Recovery Clause
FPSC Docket No. 100007-EI

Dear Ms. Cole:

Enclosed for filing in the above docket, on behalf of Tampa Electric Company, are the original and fifteen (15) copies of each of the following:

1. Petition of Tampa Electric Company.

2. Prepared Direct Testimony and Exhibit (HTB-3) of Howard T. Bryant.

3. Prepared Direct Testimony of Paul Carpinone.

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

Thank you for your assistance in connection with this matter.

Sincerely,

James D. Beasley

COM 5
APA 1
ECR 12
GCL 1 JDB/pp
RAD 1 Enclosures
SSC
ADM cc: All Parties of Record (w/encls.)
OPC Jenny Wu (w/CD-Schedules in Excel)
CLK 1 + RPR

DOCUMENT NUMBER-DATE
07174 AUG 27 ≘
FPSC-COMMISSION CLERK

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true and correct copy of the foregoing Petition and Testimonies filed on behalf of Tampa Electric Company, have been furnished by U. S. Mail or hand delivery (*) on this 27th day of August 2010 to the following:

Ms. Martha Carter Brown*
Office of General Counsel
Florida Public Service Commission
2540 Shumard Oak Boulevard
Room 370N – Gunter Building
Tallahassee, FL 32399-0850

Ms. Patricia Christensen
Office of Public Counsel
111 West Madison Street – Room 812
Tallahassee, FL 32399-1400

Mr. John W. McWhirter, Jr.
McWhirter, Reeves & Davidson, P.A.
400 North Tampa Street, Suite 2450
Tampa, FL 33601-5126

Ms. Vicki Gordon Kaufman
Mr. Jon C. Moyle
Keefe Anchor Gordon & Moyle, P.A.
118 N. Gadsden Street
Tallahassee, FL 32301

Mr. John T. Butler
Senior Attorney
Florida Power & Light Company
700 Universe Boulevard
Juno Beach, FL 33408-0420

Mr. R. Wade Litchfield
Florida Power & Light Company
215 South Monroe Street, Suite 810
Tallahassee, FL 32301-1859

Mr. Gary V. Perko
Hopping Green & Sams, P.A.
Post Office Box 6526
Tallahassee, FL 32314

Mr. John T. Burnett
Associate General Counsel - Florida
Mr. R. Alexander Glenn
Deputy General Counsel - Florida
Progress Energy Service Co., LLC
Post Office Box 14042
St. Petersburg, FL 33733

Mr. Paul Lewis, Jr.
Progress Energy Florida, Inc.
106 East College Avenue, Suite 800
Tallahassee, FL 32301-7740

Ms. Susan D. Ritenour
Secretary and Treasurer
Gulf Power Company
One Energy Place
Pensacola, FL 32520

Mr. Jeffrey A. Stone
Mr. Russell A. Badders
Mr. Steven R. Griffin
Beggs and Lane
Post Office Box 12950
Pensacola, FL 32591-2950

ATTORNEY

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Environmental Cost	)	
Recovery Clause.	)	DOCKET NO. 100007-EI
______________________	)	FILED: August 27, 2010

PETITION OF TAMPA ELECTRIC COMPANY

Tampa Electric Company ("Tampa Electric" or "the company"), hereby petitions the Commission for approval of the company's environmental cost recovery true-up and the cost recovery factor proposed for use during the period January 2011 through December 2011, and in support thereof, says:

Environmental Cost Recovery

1. Tampa Electric had a final true-up amount for the January 2009 through December 2009 period of an over-recovery amount of $831,312. [See Exhibit No. ____ (HTB-1), Document No. 1 (Schedule 42-1A).]

2. Tampa Electric projects an estimated/actual true-up amount for the January 2010 through December 2010 period, which is based on actual data for the period January 1, 2010 through June 30, 2010 and revised estimates for the period July 1, 2010 through December 31, 2010, to be an over-recovery of $3,155,800. [See Exhibit No. ____ (HTB-2), Document No. 1 (Schedule 42-1E), from the filing dated August 2, 2010.]

3. The company's projected environmental cost recovery for the period January 1, 2011 through December 31, 2011 total is $76,075,090 when adjusted for taxes and, when spread over projected kilowatt hour sales for the period January 1, 2011 through December 31, 2011, produces an average environmental cost recovery factor for the new period of 0.403 cents per KWH after application of the factors which adjust for variations in line losses. [See Exhibit No. ____ (HTB-3), Document No. 7 (Schedule 42-7P).

4. The accompanying Prepared Direct Testimony and Exhibits of Paul L. Carpinone and Howard T. Bryant present:

(a) A description of each of Tampa Electric's environmental compliance actions for which cost recovery is sought; and

(b) The costs associated with each environmental compliance action.

5. For reasons more fully detailed in the Prepared Direct Testimony of witness Howard T. Bryant, the environmental compliance costs sought to be approved for cost recovery proposed in this petition are consistent with the provisions of Section 366.8255, Florida Statutes, and with prior rulings by the Commission with respect to environmental compliance cost recovery for Tampa Electric and other investor-owned utilities.

WHEREFORE, Tampa Electric Company requests this Commission's approval of the company's prior period environmental cost recovery true-up calculations and projected environmental cost recovery charges to be collected during the period January 1, 2011 through December 31, 2011.

DATED this 27th day of August 2010.

Respectfully submitted,

JAMES D. BEASLEY
J. JEFFRY WAHLEN
Ausley & McMullen
Post Office Box 391
Tallahassee, FL 32302
(850) 224-9115

ATTORNEYS FOR TAMPA ELECTRIC COMPANY

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true and correct copy of the foregoing Petition, filed on behalf of Tampa Electric Company, has been furnished by U. S. Mail or hand delivery (*) on this 27th day of August 2010 to the following:

Ms. Martha Carter Brown*
Office of General Counsel
Florida Public Service Commission
2540 Shumard Oak Boulevard
Room 370N – Gerald L. Gunter Building
Tallahassee, FL 32399-0850

Ms. Patricia Christensen
Associate Public Counsel
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Mr. John W. McWhirter, Jr.
Post Office Box 3350
Tampa, FL 33601-3350

Ms. Vicki Kaufman
Mr. Jon C Moyle
Keefe Anchors Gordon & Moyle, PA
118 N. Gadsden Street
Tallahassee, FL 32301

Mr. John T. Butler
Managing Attorney - Regulatory
Florida Power & Light Company
700 Universe Boulevard
Juno Beach, FL 33408-0420

Mr. Wade Litchfield
Florida Power & Light Company
215 South Monroe Street, Suite 810
Tallahassee, FL 32301-1859

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Beggs and Lane
Post Office Box 12950
Pensacola, FL 32591-2950

ATTORNEY

TECO
TAMPA ELECTRIC

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 100007-EI

IN RE:

ENVIRONMENTAL COST RECOVERY FACTORS

PROJECTIONS

JANUARY 2011 THROUGH DECEMBER 2011

TESTIMONY AND EXHIBITS

OF

HOWARD T. BRYANT

BEFORE THE PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

HOWARD T. BRYANT

Q. Please state your name, address, occupation and employer.

A. My name is Howard T. Bryant. My business address is 702 North Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") as Manager, Rates in the Regulatory Affairs Department.

Q. Please provide a brief outline of your educational background and business experience.

A. I graduated from the University of Florida in June 1973 with a Bachelor of Science degree in Business Administration. I have been employed at Tampa Electric since 1981. My work has included various positions in Customer Service, Energy Conservation Services, Demand Side Management ("DSM") Planning, Energy Management and Forecasting, and Regulatory Affairs. In my current position I am responsible for the company's Energy Conservation Cost Recovery ("ECCR") clause, the

Environmental Cost Recovery Clause ("ECRC"), and retail rate design.

Q. Have you previously testified before the Florida Public Service Commission ("Commission")?

A. Yes. I have testified before this Commission on conservation and load management activities, DSM goals setting and DSM plan approval dockets, and other ECCR dockets since 1993, and ECRC activities since 2001.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to present, for Commission review and approval, the calculation of the revenue requirements and the projected ECRC factors for the period of January 2011 through December 2011. In support of the projected ECRC factors, my testimony identifies the capital and operating and maintenance ("O&M") costs associated with environmental compliance activities for the year 2011.

Q. Have you prepared an exhibit that shows the determination of recoverable environmental costs for the period of January 2011 through December 2011?

A. Yes. Exhibit No. ___ (HTB-3), containing eight documents, was prepared under my direction and supervision. Document Nos. 1 through 8 contain Forms 42-1P through 42-8P, which show the calculation and summary of O&M and capital expenditures that support the development of the environmental cost recovery factors for 2011.

Q. Are you requesting Commission approval of the projected environmental cost recovery factors for the company's various rate schedules?

A. Yes. The ECRC factors, prepared under my direction and supervision, are provided in Exhibit No. ____ (HTB-3), Document No. 7, on Form 42-7P. These annualized factors will apply for the period January through December 2011.

Q. What has Tampa Electric calculated as the net true-up to be applied in the period January 2011 through December 2011?

A. The net true-up applicable for this period is an over-recovery of $3,987,112. This consists of the final true-up over-recovery of $831,312 for the period of January 2009 through December 2009 and an estimated true-up over-recovery of $3,155,800 for the current period of January 2010 through December 2010. The detailed calculation supporting the estimated net true-up was provided on Forms 42-1E through 42-9E of Exhibit No. ___ (HTB-2) filed with the Commission on August 2, 2010.

Q. What was the major contributing factor that created the net over-recovery to be applied to the company's ECRC rates for the period January 2011 through December 2011?

A. The major contributing factor that created the net over-recovery was due to the combination of O&M and capital project expenditures being less than anticipated.

Q. Will Tampa Electric include any new environmental compliance projects for ECRC cost recovery for the period from January 2011 through December 2011?

A. Yes. Tampa Electric is including modest costs associated with its Greenhouse Gas ("GHG") Reduction Program approved by the Commission in Docket No. 090508-EI, Order No. PSC-10-0157-PPA-EI, issued March 22, 2010.

Q. What are the existing capital projects included in the calculation of the ECRC factors for 2011?

A. Tampa Electric proposes to include for ECRC recovery the 26 previously approved capital projects and their projected costs in the calculation of the ECRC factors for 2011. These projects are:

1) Big Bend Unit 3 Flue Gas Desulfurization ("FGD") Integration
2) Big Bend Units 1 and 2 Flue Gas Conditioning
3) Big Bend Unit 4 Continuous Emissions Monitors
4) Big Bend Fuel Oil Tank 1 Upgrade
5) Big Bend Fuel Oil Tank 2 Upgrade
6) Phillips Tank No. 1 Upgrade
7) Phillips Tank No. 4 Upgrade
8) Big Bend Unit 1 Classifier Replacement
9) Big Bend Unit 2 Classifier Replacement
10) Big Bend Section 114 Mercury Testing Platform
11) Big Bend Units 1 and 2 FGD
12) Big Bend FGD Optimization and Utilization
13) Big Bend NO_x Emissions Reduction
14) Big Bend Particulate Matter ("PM") Minimization and Monitoring
15) Polk NO_x Emissions Reduction
16) Big Bend Unit 4 SOFA
17) Big Bend Unit 1 Pre-SCR
18) Big Bend Unit 2 Pre-SCR

19) Big Bend Unit 3 Pre-SCR
20) Big Bend Unit 1 SCR
21) Big Bend Unit 2 SCR
22) Big Bend Unit 3 SCR
23) Big Bend Unit 4 SCR
24) Big Bend FGD Reliability
25) Clean Air Mercury Rule
26) SO_2 Emission Allowances

Some of these projects are described in more detail in the direct testimony of Tampa Electric Witness, Paul Carpinone.

Q. Have you prepared schedules showing the calculation of the recoverable capital project costs for 2011?

A. Yes. Form 42-3P contained in Exhibit No. ___ (HTB-3) summarizes the cost estimates projected for these projects. Form 42-4P, pages 1 through 26, provides the calculations of the costs, which result in recoverable jurisdictional capital costs of $60,102,337.

Q. What are the existing O&M projects included in the calculation of the ECRC factors for 2011?

A. Tampa Electric proposes to include for ECRC recovery the 22 previously approved O&M projects and their projected costs in the calculation of the ECRC factors for 2011. These projects are:

1) Big Bend Unit 3 FGD Integration
2) Big Bend Units 1 and 2 Flue Gas Conditioning
3) SO_2 Emissions Allowances
4) Big Bend Units 1 and 2 FGD
5) Big Bend PM Minimization and Monitoring
6) Big Bend NO_x Emissions Reduction
7) NPDES Annual Surveillance Fees
8) Gannon Thermal Discharge Study
9) Polk NO_x Emissions Reduction
10) Bayside SCR and Ammonia
11) Big Bend Unit 4 SOFA
12) Big Bend Unit 1 Pre-SCR
13) Big Bend Unit 2 Pre-SCR
14) Big Bend Unit 3 Pre-SCR
15) Clean Water Act Section 316(b) Phase II Study
16) Arsenic Groundwater Standard Program
17) Big Bend Unit 4 SCR
18) Big Bend Unit 3 SCR
19) Big Bend Unit 2 SCR
20) Big Bend Unit 1 SCR

21) Clean Air Mercury Rule
22) Greenhouse Gas Reduction Program

Some of these projects are described in more detail in the direct testimony of Tampa Electric Witness, Paul Carpinone.

Q. Have you prepared schedules showing the calculation of the recoverable O&M project costs for 2011?

A. Yes. Form 42-2P contained in Exhibit No. ___ (HTB-3) summarizes the recoverable jurisdictional O&M costs for these projects which total $19,905,131 for 2011.

Q. Do you have a schedule providing the description and progress reports for all environmental compliance activities and projects?

A. Yes. Project descriptions and progress reports, as well as the projected recoverable cost estimates, are provided in Form 42-5P, pages 1 through 32.

Q. What are the total projected jurisdictional costs for environmental compliance in the year 2011?

A. The total jurisdictional O&M and capital expenditures to be recovered through the ECRC are calculated on Form 42-1P. These expenditures total $80,007,468.

Q. How were environmental cost recovery factors calculated?

A. The environmental cost recovery factors were calculated as shown on Schedules 42-6P and 42-7P. The demand allocation factors were calculated by determining the percentage each rate class contributes to the monthly system peaks and then adjusted for losses for each rate class. The energy allocation factors were determined by calculating the percentage that each rate class contributes to total MWH sales and then adjusted for losses for each rate class. This information was based on applying historical rate class load research to the 2011 projected forecast of system demand and energy. Form 42-7P presents the calculation of the proposed ECRC factors by rate class.

Q. What are the ECRC billing factors by rate class for the period of January through December 2011 which Tampa Electric is seeking approval?

A. The computation of the billing factors by metering voltage level is shown in Exhibit No. ___ (HTB-3) Document No. 7, Form 42-7P. In summary, the January through December 2011 proposed ECRC billing factors are as follows:

Rate Class		**Factor by Voltage Level (¢/kWh)**
RS Secondary		0.404
GS, TS Secondary		0.403
GSD, SBF		
	Secondary	0.402
	Primary	0.398
	Transmission	0.394
IS		
	Secondary	0.396
	Primary	0.392
	Transmission	0.388
LS1		0.402
Average Factor		0.403

Q. When does Tampa Electric propose to begin applying these environmental cost recovery factors?

A. The environmental cost recovery factors will be effective concurrent with the first billing cycle for January 2011.

Q. What capital structure, components and cost rates did Tampa Electric rely on to calculate the revenue requirement rate of return for January 2011 through December 2011?

A. Tampa Electric relied upon the new capital structure approved by the Commission in Docket No. 080317-EI, to calculate the revenue requirement rate of return found on Form 42-8P.

Q. Are the costs Tampa Electric is requesting for recovery through the ECRC for the period January 2011 through December 2011 consistent with criteria established for ECRC recovery in Order No. PSC-94-0044-FOF-EI?

A. Yes. The costs for which ECRC treatment is requested meet the following criteria:

1. Such costs were prudently incurred after April 13, 1993;
2. The activities are legally required to comply with a governmentally imposed environmental regulation enacted, became effective or whose effect was triggered after the company's last test year upon which rates are based; and,

3. Such costs are not recovered through some other cost recovery mechanism or through base rates.

Q. Please summarize your testimony.

A. My testimony supports the approval of a final average environmental billing factor credit of 0.403 cents per kWh. This includes the projected capital and O&M revenue requirements of $80,007,468 associated with a total of 32 environmental projects and a true-up over-recovery provision of $3,987,112 that is primarily driven by the O&M and capital expenditures being less than anticipated. My testimony also explains that the projected environmental expenditures for 2011 are appropriate for recovery through the ECRC.

Q. Does this conclude your testimony?

A. Yes, it does.

INDEX

ENVIRONMENTAL COST RECOVERY COMMISSION FORMS

JANUARY 2011 THROUGH DECEMBER 2011

Form 42 - 1P

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Total Jurisdictional Amount to Be Recovered

For the Projected Period
January 2011 to December 2011

Line	Energy ($)	Demand ($)	Total ($)
1. Total Jurisdictional Revenue Requirements for the projected period			
a. Projected O&M Activities (Form 42-2P, Lines 7, 8 & 9)	$19,620,208	$284,923	$19,905,131
b. Projected Capital Projects (Form 42-3P, Lines 7, 8 & 9)	59,956,786	145,551	60,102,337
c. Total Jurisdictional Revenue Requirements for the projected period (Lines 1a + 1b)	79,576,994	430,474	80,007,468
2. True-up for Estimated Over/(Under) Recovery for the current period January 2010 to December 2010 (Form 42-2E, Line 5 + 6 + 10)	3,142,943	12,857	3,155,800
3. Final True-up for the period January 2009 to December 2009 (Form 42-1A, Line 3)	823,978	7,334	831,312
4. Total Jurisdictional Amount to Be Recovered/(Refunded) in the projection period January 2011 to December 2011 (Line 1 - Line 2- Line 3)	75,610,073	410,283	76,020,356
5. Total Projected Jurisdictional Amount Adjusted for Taxes (Line 4 x Revenue Tax Multiplier)	$75,664,512	$410,578	$76,075,090

Notes: Allocation to energy and demand in each period is in proportion to the respective period split of costs indicated on Lines 7 and 8 of Forms 42-5 and 42-7 of the actuals and estimates.

DOCKET NO. 100007-EI
ECRC 2011 PROJECTION FILING
EXHIBIT NO. HTB-3
DOCUMENT NO. 1

Form 42 - 2P

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2011 to December 2011

O&M Activities
(in Dollars)

Line		Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total	Method of Classification Demand	Method of Classification Energy
1.	Description of O&M Activities															
a.	Big Bend Unit 3 Flue Gas Desulfurization Integration	$430,200	$403,900	$482,600	$421,600	$427,300	$426,400	$425,800	$425,000	$390,300	$375,200	$460,500	$485,600	$5,154,400		$5,154,400
b.	Big Bend Units 1 & 2 Flue Gas Conditioning	0	0	0	0	0	0	0	0	0	0	0	0	0		0
c.	SO_2 Emissions Allowances	56,843	50,885	56,872	54,853	56,841	55,845	56,841	44,841	41,868	42,878	40,880	41,866	601,313		601,313
d.	Big Bend Units 1 & 2 FGD	596,800	676,500	612,600	589,700	591,700	592,400	588,600	587,400	733,400	900,100	701,300	620,800	7,791,300		7,791,300
e.	Big Bend PM Minimization and Monitoring	30,600	46,600	30,600	30,600	30,600	30,600	30,600	30,600	30,600	70,600	70,600	46,600	479,200		479,200
f.	Big Bend NO_x Emissions Reduction	58,000	58,000	8,000	40,500	115,500	28,000	8,000	8,000	8,000	8,000	28,000	28,000	396,000		396,000
g.	NPDES Annual Surveillance Fees	34,500	0	0	0	0	0	0	0	0	0	0	0	34,500	34,500	
h.	Gannon Thermal Discharge Study	0	0	10,000	0	0	0	10,000	0	0	10,000	0	0	30,000	30,000	
i.	Polk NO_x Reduction	3,500	3,500	7,000	4,000	3,500	4,000	4,000	4,000	3,500	6,000	3,500	3,500	50,000		50,000
j.	Bayside SCR and Ammonia	9,600	9,600	9,600	9,600	9,600	9,600	9,600	9,600	9,600	9,600	9,600	9,600	115,200		115,200
k.	Big Bend Unit 4 SOFA	0	0	0	0	0	0	0	0	0	0	0	0	0		0
l.	Big Bend Unit 1 Pre-SCR	0	0	0	0	0	0	0	0	0	0	0	0	0		0
m.	Big Bend Unit 2 Pre-SCR	0	0	0	0	0	0	0	0	0	0	0	0	0		0
n.	Big Bend Unit 3 Pre-SCR	0	0	0	0	0	0	0	0	0	0	0	0	0		0
o.	Clean Water Act Section 316(b) Phase II Study	0	0	20,000	0	0	0	20,000	0	0	20,000	0	0	60,000	60,000	
p.	Arsenic Groundwater Standard Program	10,000	5,000	35,000	10,000	5,000	10,000	5,000	10,000	35,000	5,000	5,000	35,000	170,000	170,000	
q.	Big Bend 1 SCR	8,600	22,000	8,600	104,900	104,100	104,900	104,900	104,100	104,900	110,600	80,300	101,000	958,900		958,900
r.	Big Bend 2 SCR	180,200	154,200	140,200	139,900	138,800	139,900	139,900	138,800	139,900	175,800	106,300	134,500	1,728,400		1,728,400
s.	Big Bend 3 SCR	180,200	140,800	153,600	139,900	138,800	139,900	139,900	138,800	139,900	142,800	106,300	134,500	1,695,400		1,695,400
t.	Big Bend 4 SCR	77,300	61,500	74,700	61,400	60,900	61,300	61,400	60,900	61,300	57,200	61,200	59,100	758,200		758,200
u.	Clean Air Mercury Rule	0	0	2,000	0	0	2,000	0	0	2,000	0	0	2,000	8,000		8,000
v.	Greenhouse Gas Reduction Program	0	0	0	0	0	0	56,100	0	0	0	0	0	56,100		56,100
2.	Total of O&M Activities	1,676,343	1,632,485	1,651,372	1,606,953	1,682,641	1,604,845	1,660,641	1,562,041	1,700,268	1,933,778	1,673,480	1,702,066	20,086,913	294,500	19,792,413
3.	Recoverable Costs Allocated to Energy	1,631,843	1,627,485	1,586,372	1,596,953	1,677,641	1,594,845	1,625,641	1,552,041	1,665,268	1,898,778	1,668,480	1,667,066	19,792,413		
4.	Recoverable Costs Allocated to Demand	44,500	5,000	65,000	10,000	5,000	10,000	35,000	10,000	35,000	35,000	5,000	35,000	294,500		
5.	Retail Energy Jurisdictional Factor	0.9933091	0.9780148	0.9917797	0.9906489	0.9908908	0.9927556	0.9928640	0.9922011	0.9938509	0.9951954	0.9910567	0.9923774			
6.	Retail Demand Jurisdictional Factor	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819			
7.	Jurisdictional Energy Recoverable Costs (A)	1,620,925	1,591,704	1,573,332	1,582,020	1,662,359	1,583,291	1,614,040	1,539,937	1,655,028	1,889,655	1,653,558	1,654,359	19,620,208		
8.	Jurisdictional Demand Recoverable Costs (B)	43,053	4,837	62,886	9,675	4,837	9,675	33,862	9,675	33,862	33,862	4,837	33,862	284,923		
9.	Total Jurisdictional Recoverable Costs for O&M Activities (Lines 7 + 8)	$1,663,978	$1,596,541	$1,636,218	$1,591,695	$1,667,196	$1,592,966	$1,647,902	$1,549,612	$1,688,890	$1,923,517	$1,658,395	$1,688,221	$19,905,131		

Notes:
(A) Line 3 x Line 5
(B) Line 4 x Line 6

DOCKET NO. 100007-EI
ECRC 2011 PROJECTION FILING
EXHIBIT NO. HTB-3
DOCUMENT NO. 2

Form 42-3P

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2011 to December 2011

Capital Investment Projects-Recoverable Costs

(in Dollars)

Line		Description (A)	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total	Method of Classification Demand	Method of Classification Energy
1.	a.	Big Bend Unit 3 Flue Gas Desulfurization Integration	$62,698	$62,545	$62,392	$62,238	$62,085	$61,931	$61,779	$61,625	$61,471	$61,318	$61,165	$61,012	$742,259		$742,259
	b.	Big Bend Units 1 and 2 Flue Gas Conditioning	34,331	34,201	34,070	33,940	33,810	33,680	33,550	33,419	33,290	33,159	33,029	32,898	403,377		403,377
	c.	Big Bend Unit 4 Continuous Emissions Monitors	6,447	6,431	6,416	6,402	6,387	6,372	6,358	6,343	6,328	6,314	6,299	6,284	76,381		76,381
	d.	Big Bend Fuel Oil Tank # 1 Upgrade	4,355	4,345	4,335	4,324	4,313	4,303	4,292	4,282	4,272	4,261	4,250	4,240	51,572	51,572	
	e.	Big Bend Fuel Oil Tank # 2 Upgrade	7,164	7,146	7,129	7,112	7,094	7,077	7,060	7,042	7,026	7,009	6,991	6,974	84,824	84,824	
	f.	Phillips Upgrade Tank # 1 for FDEP	463	461	460	458	457	456	454	453	452	450	449	448	5,461	5,461	
	g.	Phillips Upgrade Tank # 4 for FDEP	727	726	723	721	719	716	714	712	710	707	706	703	8,584	8,584	
	h.	Big Bend Unit 1 Classifier Replacement	10,922	10,886	10,851	10,816	10,780	10,745	10,710	10,675	10,640	10,605	10,570	10,534	128,734		128,734
	i.	Big Bend Unit 2 Classifier Replacement	7,921	7,896	7,872	7,847	7,822	7,797	7,773	7,748	7,724	7,698	7,674	7,649	93,421		93,421
	j.	Big Bend Section 114 Mercury Testing Platform	1,096	1,094	1,092	1,090	1,088	1,086	1,084	1,082	1,080	1,079	1,076	1,075	13,022		13,022
	k.	Big Bend Units 1 & 2 FGD	719,427	727,841	737,667	748,520	748,017	746,836	744,926	743,017	741,106	743,372	746,390	748,998	8,896,117		8,896,117
	l.	Big Bend FGD Optimization and Utilization	203,665	203,262	202,857	202,453	202,048	201,644	201,240	200,835	200,431	200,027	199,623	199,218	2,417,303		2,417,303
	m.	Big Bend NO_x Emissions Reduction	66,446	66,359	66,273	66,186	66,099	66,012	65,926	65,840	65,753	65,666	65,579	65,492	791,631		791,631
	n.	Big Bend PM Minimization and Monitoring	91,272	91,063	90,854	90,644	90,434	90,225	90,015	89,806	89,597	89,387	89,177	88,967	1,081,441		1,081,441
	o.	Polk NO_x Emissions Reduction	16,022	15,978	15,935	15,892	15,850	15,807	15,764	15,721	15,677	15,635	15,592	15,549	189,422		189,422
	p.	Big Bend Unit 4 SOFA	26,174	26,124	26,075	26,025	25,976	25,925	25,876	25,826	25,777	25,727	25,677	25,627	310,809		310,809
	q.	Big Bend Unit 1 Pre-SCR	22,004	21,960	21,915	21,872	21,828	21,784	21,740	21,696	21,652	21,608	21,564	21,520	261,143		261,143
	r.	Big Bend Unit 2 Pre-SCR	17,541	17,501	17,462	17,422	17,382	17,343	17,303	17,263	17,224	17,184	17,144	17,104	207,873		207,873
	s.	Big Bend Unit 3 Pre-SCR	30,212	30,154	30,098	30,042	29,986	29,930	29,872	29,816	29,760	29,704	29,648	29,592	358,814		358,814
	t.	Big Bend Unit 1 SCR	994,830	993,115	991,483	989,893	988,079	986,266	984,453	982,640	980,827	979,014	977,200	975,388	11,823,188		11,823,188
	u.	Big Bend Unit 2 SCR	1,053,639	1,051,835	1,050,112	1,048,425	1,046,522	1,044,619	1,042,715	1,040,812	1,038,909	1,037,006	1,035,103	1,033,199	12,522,896		12,522,896
	v.	Big Bend Unit 3 SCR	862,642	861,241	861,784	862,325	860,926	859,526	858,126	856,726	855,327	853,926	860,294	870,973	10,323,816		10,323,816
	w.	Big Bend Unit 4 SCR	649,135	648,113	647,091	646,070	645,047	644,025	643,003	641,982	640,960	639,937	638,915	637,894	7,722,172		7,722,172
	x.	Big Bend FGD System Reliability	126,523	127,766	129,892	131,781	132,772	140,559	154,901	162,931	173,389	195,012	222,412	261,656	1,959,594		1,959,594
	y.	Clean Air Mercury Rule	13,701	13,673	13,645	13,615	13,587	13,559	13,895	14,355	14,326	14,296	14,266	14,236	167,154		167,154
	z.	SO_2 Emissions Allowances (B)	(385)	(384)	(382)	(381)	(380)	(378)	(377)	(375)	(374)	(373)	(371)	(370)	(4,530)		(4,530)
2.		Total Investment Projects - Recoverable Costs	5,028,972	5,031,332	5,038,101	5,045,732	5,038,728	5,037,845	5,043,152	5,042,272	5,043,334	5,059,728	5,090,422	5,136,860	60,636,478	150,441	60,486,037
3.		Recoverable Costs Allocated to Energy	5,016,263	5,018,654	5,025,454	5,033,117	5,026,145	5,025,293	5,030,632	5,029,783	5,030,874	5,047,301	5,078,026	5,124,495	60,486,037		
4.		Recoverable Costs Allocated to Demand	12,709	12,678	12,647	12,615	12,583	12,552	12,520	12,489	12,460	12,427	12,396	12,365	150,441		
5.		Retail Energy Jurisdictional Factor	0.9933091	0.9780148	0.9917797	0.9906489	0.9908908	0.9927556	0.9928640	0.9922011	0.9938509	0.9951954	0.9910567	0.9923774			
6.		Retail Demand Jurisdictional Factor	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819			
7.		Jurisdictional Energy Recoverable Costs (C)	4,982,700	4,908,318	4,984,143	4,986,052	4,980,361	4,988,888	4,994,733	4,990,556	4,999,939	5,023,051	5,032,612	5,085,433	59,956,786		
8.		Jurisdictional Demand Recoverable Costs (D)	12,296	12,266	12,236	12,205	12,174	12,144	12,113	12,083	12,055	12,023	11,993	11,963	145,551		
9.		Total Jurisdictional Recoverable Costs for Investment Projects (Lines 7 + 8)	$4,994,996	$4,920,584	$4,996,379	$4,998,257	$4,992,535	$5,001,032	$5,006,846	$5,002,639	$5,011,994	$5,035,074	$5,044,605	$5,097,396	$60,102,337		

Notes:
(A) Each project's Total System Recoverable Expenses on Form 42-8P, Line 9
(B) Project's Total Return Component on Form 42-8P, Line 6
(C) Line 3 x Line 5
(D) Line 4 x Line 6

DOCKET NO. 100007-EI
ECRC 2011 PROJECTION FILING
EXHIBIT NO. HTB-3
DOCUMENT NO. 3

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2011 to December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 3 Flue Gas Desulfurization Integration
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$8,239,658	$8,239,658	$8,239,658	$8,239,658	$8,239,658	$8,239,658	$8,239,658	$8,239,658	$8,239,658	$8,239,658	$8,239,658	$8,239,658	$8,239,658	
3.	Less: Accumulated Depreciation	(3,400,809)	(3,416,602)	(3,432,395)	(3,448,188)	(3,463,981)	(3,479,774)	(3,495,567)	(3,511,360)	(3,527,153)	(3,542,946)	(3,558,739)	(3,574,532)	(3,590,325)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$4,838,849	4,823,056	4,807,263	4,791,470	4,775,677	4,759,884	4,744,091	4,728,298	4,712,505	4,696,712	4,680,919	4,665,126	4,649,333	
6.	Average Net Investment		4,830,953	4,815,160	4,799,367	4,783,574	4,767,781	4,751,988	4,736,195	4,720,402	4,704,609	4,688,816	4,673,023	4,657,230	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		35,100	34,985	34,871	34,756	34,641	34,526	34,412	34,297	34,182	34,067	33,953	33,838	$413,628
	b. Debt Component Grossed Up For Taxes (C)		11,805	11,767	11,728	11,689	11,651	11,612	11,574	11,535	11,496	11,458	11,419	11,381	139,115
8.	Investment Expenses														
	a. Depreciation (D)		15,793	15,793	15,793	15,793	15,793	15,793	15,793	15,793	15,793	15,793	15,793	15,793	189,516
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		62,698	62,545	62,392	62,238	62,085	61,931	61,779	61,625	61,471	61,318	61,165	61,012	742,259
	a. Recoverable Costs Allocated to Energy		62,698	62,545	62,392	62,238	62,085	61,931	61,779	61,625	61,471	61,318	61,165	61,012	742,259
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9933091	0.9780148	0.9917797	0.9906489	0.9908908	0.9927556	0.9928640	0.9922011	0.9938509	0.9951954	0.9910567	0.9923774	
11.	Demand Jurisdictional Factor		0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	
12.	Retail Energy-Related Recoverable Costs (E)		62,278	61,170	61,879	61,656	61,519	61,482	61,338	61,144	61,093	61,023	60,618	60,547	735,747
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$62,278	$61,170	$61,879	$61,656	$61,519	$61,482	$61,338	$61,144	$61,093	$61,023	$60,618	$60,547	$735,747

Notes:
(A) Applicable depreciable base for Big Bend; account 312.45
(B) Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.63490).
(C) Line 6 x 2.9324% x 1/12.
(D) Applicable depreciation rate is 2.3%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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DOCKET NO. 100007-EI
ECRC 2011 PROJECTION FILING
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DOCUMENT NO. 4

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2011 to December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Units 1 and 2 Flue Gas Conditioning
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$5,017,734	$5,017,734	$5,017,734	$5,017,734	$5,017,734	$5,017,734	$5,017,734	$5,017,734	$5,017,734	$5,017,734	$5,017,734	$5,017,734	$5,017,734	
3.	Less: Accumulated Depreciation	(2,856,218)	(2,869,627)	(2,883,036)	(2,896,445)	(2,909,854)	(2,923,263)	(2,936,672)	(2,950,081)	(2,963,490)	(2,976,899)	(2,990,308)	(3,003,717)	(3,017,126)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$2,161,516	2,148,107	2,134,698	2,121,289	2,107,880	2,094,471	2,081,062	2,067,653	2,054,244	2,040,835	2,027,426	2,014,017	2,000,608	
6.	Average Net Investment		2,154,812	2,141,403	2,127,994	2,114,585	2,101,176	2,087,767	2,074,358	2,060,949	2,047,540	2,034,131	2,020,722	2,007,313	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		15,656	15,559	15,461	15,364	15,266	15,169	15,072	14,974	14,877	14,779	14,682	14,584	$181,443
	b. Debt Component (C)		5,266	5,233	5,200	5,167	5,135	5,102	5,069	5,036	5,004	4,971	4,938	4,905	61,026
8.	Investment Expenses														
	a. Depreciation (D)		13,409	13,409	13,409	13,409	13,409	13,409	13,409	13,409	13,409	13,409	13,409	13,409	160,908
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		34,331	34,201	34,070	33,940	33,810	33,680	33,550	33,419	33,290	33,159	33,029	32,898	403,377
	a. Recoverable Costs Allocated to Energy		34,331	34,201	34,070	33,940	33,810	33,680	33,550	33,419	33,290	33,159	33,029	32,898	403,377
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9933091	0.9780148	0.9917797	0.9906489	0.9908908	0.9927556	0.9928640	0.9922011	0.9938509	0.9951954	0.9910567	0.9923774	
11.	Demand Jurisdictional Factor		0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	
12.	Retail Energy-Related Recoverable Costs (E)		34,101	33,449	33,790	33,623	33,502	33,436	33,311	33,158	33,085	33,000	32,734	32,647	399,836
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$34,101	$33,449	$33,790	$33,623	$33,502	$33,436	$33,311	$33,158	$33,085	$33,000	$32,734	$32,647	$399,836

Notes:
(A) Applicable depreciable base for Big Bend; accounts 312.41 ($2,676,217) and 312.42 ($2,341,517)
(B) Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.63490).
(C) Line 6 x 2.9324% x 1/12
(D) Applicable depreciation rates are 3.3% and 3.1%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2011 to December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 4 Continuous Emissions Monitors
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$866,211	$866,211	$866,211	$866,211	$866,211	$866,211	$866,211	$866,211	$866,211	$866,211	$866,211	$866,211	$866,211	
3.	Less: Accumulated Depreciation	(357,653)	(359,169)	(360,685)	(362,201)	(363,717)	(365,233)	(366,749)	(368,265)	(369,781)	(371,297)	(372,813)	(374,329)	(375,845)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$508,558	507,042	505,526	504,010	502,494	500,978	499,462	497,946	496,430	494,914	493,398	491,882	490,366	
6.	Average Net Investment		507,800	506,284	504,768	503,252	501,736	500,220	498,704	497,188	495,672	494,156	492,640	491,124	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		3,690	3,678	3,667	3,656	3,645	3,634	3,623	3,612	3,601	3,590	3,579	3,568	$43,543
	b. Debt Component (C)		1,241	1,237	1,233	1,230	1,226	1,222	1,219	1,215	1,211	1,208	1,204	1,200	14,646
8.	Investment Expenses														
	a. Depreciation (D)		1,516	1,516	1,516	1,516	1,516	1,516	1,516	1,516	1,516	1,516	1,516	1,516	18,192
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		6,447	6,431	6,416	6,402	6,387	6,372	6,358	6,343	6,328	6,314	6,299	6,284	76,381
	a. Recoverable Costs Allocated to Energy		6,447	6,431	6,416	6,402	6,387	6,372	6,358	6,343	6,328	6,314	6,299	6,284	76,381
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9933091	0.9780148	0.9917797	0.9906489	0.9908908	0.9927556	0.9928640	0.9922011	0.9938509	0.9951954	0.9910567	0.9923774	
11.	Demand Jurisdictional Factor		0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	
12.	Retail Energy-Related Recoverable Costs (E)		6,404	6,290	6,363	6,342	6,329	6,326	6,313	6,294	6,289	6,284	6,243	6,236	75,713
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$6,404	$6,290	$6,363	$6,342	$6,329	$6,326	$6,313	$6,294	$6,289	$6,284	$6,243	$6,236	$75,713

Notes:
(A) Applicable depreciable base for Big Bend; account 315.44
(B) Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.63490).
(C) Line 6 x 2.9324% x 1/12
(D) Applicable depreciation rate is 2.1%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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DOCKET NO. 100007-EI
ECRC 2011 PROJECTION FILING
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DOCUMENT NO. 4

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2011 to December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Fuel Oil Tank # 1 Upgrade
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$497,578	$497,578	$497,578	$497,578	$497,578	$497,578	$497,578	$497,578	$497,578	$497,578	$497,578	$497,578	$497,578	
3.	Less: Accumulated Depreciation	(159,496)	(160,574)	(161,652)	(162,730)	(163,808)	(164,886)	(165,964)	(167,042)	(168,120)	(169,198)	(170,276)	(171,354)	(172,432)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$338,082	337,004	335,926	334,848	333,770	332,692	331,614	330,536	329,458	328,380	327,302	326,224	325,146	
6.	Average Net Investment		337,543	336,465	335,387	334,309	333,231	332,153	331,075	329,997	328,919	327,841	326,763	325,685	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		2,452	2,445	2,437	2,429	2,421	2,413	2,405	2,398	2,390	2,382	2,374	2,366	$28,912
	b. Debt Component (C)		825	822	820	817	814	812	809	806	804	801	798	796	9,724
8.	Investment Expenses														
	a. Depreciation (D)		1,078	1,078	1,078	1,078	1,078	1,078	1,078	1,078	1,078	1,078	1,078	1,078	12,936
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		4,355	4,345	4,335	4,324	4,313	4,303	4,292	4,282	4,272	4,261	4,250	4,240	51,572
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		4,355	4,345	4,335	4,324	4,313	4,303	4,292	4,282	4,272	4,261	4,250	4,240	51,572
10.	Energy Jurisdictional Factor		0.9933091	0.9780148	0.9917797	0.9906489	0.9908908	0.9927556	0.9928640	0.9922011	0.9938509	0.9951954	0.9910567	0.9923774	
11.	Demand Jurisdictional Factor		0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	
12.	Retail Energy-Related Recoverable Costs (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
13.	Retail Demand-Related Recoverable Costs (F)		4,213	4,204	4,194	4,183	4,173	4,163	4,152	4,143	4,133	4,122	4,112	4,102	49,894
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$4,213	$4,204	$4,194	$4,183	$4,173	$4,163	$4,152	$4,143	$4,133	$4,122	$4,112	$4,102	$49,894

Notes:
(A) Applicable depreciable base for Big Bend; account 312.40
(B) Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.63490).
(C) Line 6 x 2.9324% x 1/12
(D) Applicable depreciation rate is 2.6%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2011 to December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Fuel Oil Tank # 2 Upgrade
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$818,401	$818,401	$818,401	$818,401	$818,401	$818,401	$818,401	$818,401	$818,401	$818,401	$818,401	$818,401	$818,401	
3.	Less: Accumulated Depreciation	(262,348)	(264,121)	(265,894)	(267,667)	(269,440)	(271,213)	(272,986)	(274,759)	(276,532)	(278,305)	(280,078)	(281,851)	(283,624)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$556,053	554,280	552,507	550,734	548,961	547,188	545,415	543,642	541,869	540,096	538,323	536,550	534,777	
6.	Average Net Investment		555,167	553,394	551,621	549,848	548,075	546,302	544,529	542,756	540,983	539,210	537,437	535,664	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		4,034	4,021	4,008	3,995	3,982	3,969	3,956	3,943	3,931	3,918	3,905	3,892	$47,554
	b. Debt Component (C)		1,357	1,352	1,348	1,344	1,339	1,335	1,331	1,326	1,322	1,318	1,313	1,309	15,994
8.	Investment Expenses														
	a. Depreciation (D)		1,773	1,773	1,773	1,773	1,773	1,773	1,773	1,773	1,773	1,773	1,773	1,773	21,276
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		7,164	7,146	7,129	7,112	7,094	7,077	7,060	7,042	7,026	7,009	6,991	6,974	84,824
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		7,164	7,146	7,129	7,112	7,094	7,077	7,060	7,042	7,026	7,009	6,991	6,974	84,824
10.	Energy Jurisdictional Factor		0.9933091	0.9780148	0.9917797	0.9906489	0.9908908	0.9927556	0.9928640	0.9922011	0.9938509	0.9951954	0.9910567	0.9923774	
11.	Demand Jurisdictional Factor		0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	
12.	Retail Energy-Related Recoverable Costs (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
13.	Retail Demand-Related Recoverable Costs (F)		6,931	6,914	6,897	6,881	6,863	6,847	6,830	6,813	6,798	6,781	6,764	6,747	82,066
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$6,931	$6,914	$6,897	$6,881	$6,863	$6,847	$6,830	$6,813	$6,798	$6,781	$6,764	$6,747	$82,066

Notes:
(A) Applicable depreciable base for Big Bend; account 312.40
(B) Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.63490).
(C) Line 6 x 2.9324% x 1/12
(D) Applicable depreciation rate is 2.6%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2011 to December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: Phillips Upgrade Tank # 1 for FDEP
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$57,277	$57,277	$57,277	$57,277	$57,277	$57,277	$57,277	$57,277	$57,277	$57,277	$57,277	$57,277	$57,277	
3.	Less: Accumulated Depreciation	(24,252)	(24,395)	(24,538)	(24,681)	(24,824)	(24,967)	(25,110)	(25,253)	(25,396)	(25,539)	(25,682)	(25,825)	(25,968)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$33,025	32,882	32,739	32,596	32,453	32,310	32,167	32,024	31,881	31,738	31,595	31,452	31,309	
6.	Average Net Investment		32,954	32,811	32,668	32,525	32,382	32,239	32,096	31,953	31,810	31,667	31,524	31,381	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		239	238	237	236	235	234	233	232	231	230	229	228	$2,802
	b. Debt Component (C)		81	80	80	79	79	79	78	78	78	77	77	77	943
8.	Investment Expenses														
	a. Depreciation (D)		143	143	143	143	143	143	143	143	143	143	143	143	1,716
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		463	461	460	458	457	456	454	453	452	450	449	448	5,461
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		463	461	460	458	457	456	454	453	452	450	449	448	5,461
10.	Energy Jurisdictional Factor		0.9933091	0.9780148	0.9917797	0.9906489	0.9908908	0.9927556	0.9928640	0.9922011	0.9938509	0.9951954	0.9910567	0.9923774	
11.	Demand Jurisdictional Factor		0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	
12.	Retail Energy-Related Recoverable Costs (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
13.	Retail Demand-Related Recoverable Costs (F)		448	446	445	443	442	441	439	438	437	435	434	433	5,281
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$448	$446	$445	$443	$442	$441	$439	$438	$437	$435	$434	$433	$5,281

Notes:
(A) Applicable depreciable base for Phillips; account 342.28
(B) Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.63490).
(C) Line 6 x 2.9324% x 1/12
(D) Applicable depreciation rate is 3.0%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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DOCUMENT NO. 4

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2011 to December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: Phillips Upgrade Tank # 4 for FDEP
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$90,472	$90,472	$90,472	$90,472	$90,472	$90,472	$90,472	$90,472	$90,472	$90,472	$90,472	$90,472	$90,472	
3.	Less: Accumulated Depreciation	(38,723)	(38,949)	(39,175)	(39,401)	(39,627)	(39,853)	(40,079)	(40,305)	(40,531)	(40,757)	(40,983)	(41,209)	(41,435)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$51,749	51,523	51,297	51,071	50,845	50,619	50,393	50,167	49,941	49,715	49,489	49,263	49,037	
6.	Average Net Investment		51,636	51,410	51,184	50,958	50,732	50,506	50,280	50,054	49,828	49,602	49,376	49,150	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		375	374	372	370	369	367	365	364	362	360	359	357	$4,394
	b. Debt Component (C)		126	126	125	125	124	123	123	122	122	121	121	120	1,478
8.	Investment Expenses														
	a. Depreciation (D)		226	226	226	226	226	226	226	226	226	226	226	226	2,712
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		727	726	723	721	719	716	714	712	710	707	706	703	8,584
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		727	726	723	721	719	716	714	712	710	707	706	703	8,584
10.	Energy Jurisdictional Factor		0.9933091	0.9780148	0.9917797	0.9906489	0.9908908	0.9927556	0.9928640	0.9922011	0.9938509	0.9951954	0.9910567	0.9923774	
11.	Demand Jurisdictional Factor		0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	
12.	Retail Energy-Related Recoverable Costs (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
13.	Retail Demand-Related Recoverable Costs (F)		703	702	699	698	696	693	691	689	687	684	683	680	8,305
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$703	$702	$699	$698	$696	$693	$691	$689	$687	$684	$683	$680	$8,305

Notes:
(A) Applicable depreciable base for Phillips; account 342.28
(B) Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.63490).
(C) Line 6 x 2.9324% x 1/12
(D) Applicable depreciation rate is 3.0%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2011 to December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 1 Classifier Replacement
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$1,316,257	$1,316,257	$1,316,257	$1,316,257	$1,316,257	$1,316,257	$1,316,257	$1,316,257	$1,316,257	$1,316,257	$1,316,257	$1,316,257	$1,316,257	
3.	Less: Accumulated Depreciation	(562,472)	(566,092)	(569,712)	(573,332)	(576,952)	(580,572)	(584,192)	(587,812)	(591,432)	(595,052)	(598,672)	(602,292)	(605,912)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$753,785	750,165	746,545	742,925	739,305	735,685	732,065	728,445	724,825	721,205	717,585	713,965	710,345	
6.	Average Net Investment		751,975	748,355	744,735	741,115	737,495	733,875	730,255	726,635	723,015	719,395	715,775	712,155	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		5,464	5,437	5,411	5,385	5,358	5,332	5,306	5,279	5,253	5,227	5,201	5,174	$63,827
	b. Debt Component (C)		1,838	1,829	1,820	1,811	1,802	1,793	1,784	1,776	1,767	1,758	1,749	1,740	21,467
8.	Investment Expenses														
	a. Depreciation (D)		3,620	3,620	3,620	3,620	3,620	3,620	3,620	3,620	3,620	3,620	3,620	3,620	43,440
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		10,922	10,886	10,851	10,816	10,780	10,745	10,710	10,675	10,640	10,605	10,570	10,534	128,734
	a. Recoverable Costs Allocated to Energy		10,922	10,886	10,851	10,816	10,780	10,745	10,710	10,675	10,640	10,605	10,570	10,534	128,734
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9933091	0.9780148	0.9917797	0.9906489	0.9908908	0.9927556	0.9928640	0.9922011	0.9938509	0.9951954	0.9910567	0.9923774	
11.	Demand Jurisdictional Factor		0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	
12.	Retail Energy-Related Recoverable Costs (E)		10,849	10,647	10,762	10,715	10,682	10,667	10,634	10,592	10,575	10,554	10,475	10,454	127,606
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$10,849	$10,647	$10,762	$10,715	$10,682	$10,667	$10,634	$10,592	$10,575	$10,554	$10,475	$10,454	$127,606

Notes:
(A) Applicable depreciable base for Big Bend; account 312.41
(B) Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.63490).
(C) Line 6 x 2.9324% x 1/12
(D) Applicable depreciation rate is 3.3%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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ECRC 2011 PROJECTION FILING
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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2011 to December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 2 Classifier Replacement
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$984,794	$984,794	$984,794	$984,794	$984,794	$984,794	$984,794	$984,794	$984,794	$984,794	$984,794	$984,794	$984,794	
3.	Less: Accumulated Depreciation	(429,750)	(432,294)	(434,838)	(437,382)	(439,926)	(442,470)	(445,014)	(447,558)	(450,102)	(452,646)	(455,190)	(457,734)	(460,278)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$555,044	552,500	549,956	547,412	544,868	542,324	539,780	537,236	534,692	532,148	529,604	527,060	524,516	
6.	Average Net Investment		553,772	551,228	548,684	546,140	543,596	541,052	538,508	535,964	533,420	530,876	528,332	525,788	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		4,024	4,005	3,987	3,968	3,950	3,931	3,913	3,894	3,876	3,857	3,839	3,820	$47,064
	b. Debt Component (C)		1,353	1,347	1,341	1,335	1,328	1,322	1,316	1,310	1,304	1,297	1,291	1,285	15,829
8.	Investment Expenses														
	a. Depreciation (D)		2,544	2,544	2,544	2,544	2,544	2,544	2,544	2,544	2,544	2,544	2,544	2,544	30,528
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		7,921	7,896	7,872	7,847	7,822	7,797	7,773	7,748	7,724	7,698	7,674	7,649	93,421
	a. Recoverable Costs Allocated to Energy		7,921	7,896	7,872	7,847	7,822	7,797	7,773	7,748	7,724	7,698	7,674	7,649	93,421
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9933091	0.9780148	0.9917797	0.9906489	0.9908908	0.9927556	0.9928640	0.9922011	0.9938509	0.9951954	0.9910567	0.9923774	
11.	Demand Jurisdictional Factor		0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	
12.	Retail Energy-Related Recoverable Costs (E)		7,868	7,722	7,807	7,774	7,751	7,741	7,718	7,688	7,677	7,661	7,605	7,591	92,603
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$7,868	$7,722	$7,807	$7,774	$7,751	$7,741	$7,718	$7,688	$7,677	$7,661	$7,605	$7,591	$92,603

Notes:
(A) Applicable depreciable base for Big Bend; account 312.42
(B) Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.63490).
(C) Line 6 x 2.9324% x 1/12
(D) Applicable depreciation rate is 3.1%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2011 to December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Section 114 Mercury Testing Platform
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$120,737	$120,737	$120,737	$120,737	$120,737	$120,737	$120,737	$120,737	$120,737	$120,737	$120,737	$120,737	$120,737	
3.	Less: Accumulated Depreciation	(28,471)	(28,672)	(28,873)	(29,074)	(29,275)	(29,476)	(29,677)	(29,878)	(30,079)	(30,280)	(30,481)	(30,682)	(30,883)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$92,266	92,065	91,864	91,663	91,462	91,261	91,060	90,859	90,658	90,457	90,256	90,055	89,854	
6.	Average Net Investment		92,166	91,965	91,764	91,563	91,362	91,161	90,960	90,759	90,558	90,357	90,156	89,955	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		670	668	667	665	664	662	661	659	658	657	655	654	$7,940
	b. Debt Component (C)		225	225	224	224	223	223	222	222	221	221	220	220	2,670
8.	Investment Expenses														
	a. Depreciation (D)		201	201	201	201	201	201	201	201	201	201	201	201	2,412
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		1,096	1,094	1,092	1,090	1,088	1,086	1,084	1,082	1,080	1,079	1,076	1,075	13,022
	a. Recoverable Costs Allocated to Energy		1,096	1,094	1,092	1,090	1,088	1,086	1,084	1,082	1,080	1,079	1,076	1,075	13,022
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9933091	0.9780148	0.9917797	0.9906489	0.9908908	0.9927556	0.9928640	0.9922011	0.9938509	0.9951954	0.9910567	0.9923774	
11.	Demand Jurisdictional Factor		0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	
12.	Retail Energy-Related Recoverable Costs (E)		1,089	1,070	1,083	1,080	1,078	1,078	1,076	1,074	1,073	1,074	1,066	1,067	12,908
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$1,089	$1,070	$1,083	$1,080	$1,078	$1,078	$1,076	$1,074	$1,073	$1,074	$1,066	$1,067	$12,908

Notes:
(A) Applicable depreciable base for Big Bend; account 311.40
(B) Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.63490).
(C) Line 6 x 2.9324% x 1/12
(D) Applicable depreciation rate is 2.0%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2011 to December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Units 1 and 2 FGD (Less Gypsum Revenue)
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$674,000	$1,477,500	$965,000	$160,000	$170,000	$20,000	$20,000	$20,000	$20,000	$880,000	$175,000	$55,000	$4,636,500
	b. Clearings to Plant		0	0	3,086,500	0	0	0	0	0	0	0	1,495,000	55,000	4,636,500
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$86,578,686	$86,578,686	$86,578,686	$89,665,186	$89,665,186	$89,665,186	$89,665,186	$89,665,186	$89,665,186	$89,665,186	$89,665,186	$91,160,186	$91,215,186	
3.	Less: Accumulated Depreciation	(34,264,197)	(34,473,429)	(34,682,661)	(34,891,893)	(35,108,584)	(35,325,275)	(35,541,966)	(35,758,657)	(35,975,348)	(36,192,039)	(36,408,730)	(36,625,421)	(36,845,725)	
4.	CWIP - Non-Interest Bearing	0	674,000	2,151,500	30,000	190,000	360,000	380,000	400,000	420,000	440,000	1,320,000	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$52,314,489	52,779,257	54,047,525	54,803,293	54,746,602	54,699,911	54,503,220	54,306,529	54,109,838	53,913,147	54,576,456	54,534,765	54,369,461	
6.	Average Net Investment		52,546,873	53,413,391	54,425,409	54,774,947	54,723,256	54,601,565	54,404,874	54,208,183	54,011,492	54,244,801	54,555,610	54,452,113	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		381,788	388,084	395,437	397,977	397,601	396,717	395,288	393,859	392,429	394,125	396,383	395,631	$4,725,319
	b. Debt Component (C)		128,407	130,525	132,998	133,852	133,725	133,428	132,947	132,467	131,986	132,556	133,316	133,063	1,589,270
8.	Investment Expenses														
	a. Depreciation (D)		209,232	209,232	209,232	216,691	216,691	216,691	216,691	216,691	216,691	216,691	216,691	220,304	2,581,528
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		719,427	727,841	737,667	748,520	748,017	746,836	744,926	743,017	741,106	743,372	746,390	748,998	8,896,117
	a. Recoverable Costs Allocated to Energy		719,427	727,841	737,667	748,520	748,017	746,836	744,926	743,017	741,106	743,372	746,390	748,998	8,896,117
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9933091	0.9780148	0.9917797	0.9906489	0.9908908	0.9927556	0.9928640	0.9922011	0.9938509	0.9951954	0.9910567	0.9923774	
11.	Demand Jurisdictional Factor		0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	
12.	Retail Energy-Related Recoverable Costs (E)		714,613	711,839	731,603	741,521	741,203	741,426	739,610	737,222	736,549	739,800	739,715	743,289	8,818,390
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$714,613	$711,839	$731,603	$741,521	$741,203	$741,426	$739,610	$737,222	$736,549	$739,800	$739,715	$743,289	$8,818,390

Notes:
(A) Applicable depreciable base for Big Bend; account 312.46
(B) Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.63490).
(C) Line 6 x 2.9324% x 1/12
(D) Applicable depreciation rates are 2.9%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2011 to December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend FGD Optimization and Utilization
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$21,739,737	$21,739,737	$21,739,737	$21,739,737	$21,739,737	$21,739,737	$21,739,737	$21,739,737	$21,739,737	$21,739,737	$21,739,737	$21,739,737	$21,739,737	
3.	Less: Accumulated Depreciation	(5,031,493)	(5,073,135)	(5,114,777)	(5,156,419)	(5,198,061)	(5,239,703)	(5,281,345)	(5,322,987)	(5,364,629)	(5,406,271)	(5,447,913)	(5,489,555)	(5,531,197)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$16,708,244	16,666,602	16,624,960	16,583,318	16,541,676	16,500,034	16,458,392	16,416,750	16,375,108	16,333,466	16,291,824	16,250,182	16,208,540	
6.	Average Net Investment		16,687,423	16,645,781	16,604,139	16,562,497	16,520,855	16,479,213	16,437,571	16,395,929	16,354,287	16,312,645	16,271,003	16,229,361	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		121,245	120,943	120,640	120,338	120,035	119,732	119,430	119,127	118,825	118,522	118,220	117,917	$1,434,974
	b. Debt Component (C)		40,778	40,677	40,575	40,473	40,371	40,270	40,168	40,066	39,964	39,863	39,761	39,659	482,625
8.	Investment Expenses														
	a. Depreciation (D)		41,642	41,642	41,642	41,642	41,642	41,642	41,642	41,642	41,642	41,642	41,642	41,642	499,704
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		203,665	203,262	202,857	202,453	202,048	201,644	201,240	200,835	200,431	200,027	199,623	199,218	2,417,303
	a. Recoverable Costs Allocated to Energy		203,665	203,262	202,857	202,453	202,048	201,644	201,240	200,835	200,431	200,027	199,623	199,218	2,417,303
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9933091	0.9780148	0.9917797	0.9906489	0.9908908	0.9927556	0.9928640	0.9922011	0.9938509	0.9951954	0.9910567	0.9923774	
11.	Demand Jurisdictional Factor		0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	
12.	Retail Energy-Related Recoverable Costs (E)		202,302	198,793	201,189	200,560	200,208	200,183	199,804	199,269	199,199	199,066	197,838	197,699	2,396,110
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$202,302	$198,793	$201,189	$200,560	$200,208	$200,183	$199,804	$199,269	$199,199	$199,066	$197,838	$197,699	$2,396,110

Notes:
(A) Applicable depreciable base for Big Bend; accounts 311.45 ($39,818) and 312.45 ($21,699,919)
(B) Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.63490).
(C) Line 6 x 2.9324% x 1/12
(D) Applicable depreciation rates are 1.5% and 2.3%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2011 to December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend NO_x Emissions Reduction
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$3,460,592	$3,460,592	$3,460,592	$3,460,592	$3,460,592	$3,460,592	$3,460,592	$3,460,592	$3,460,592	$3,460,592	$3,460,592	$3,460,592	$3,460,592	
3.	Less: Accumulated Depreciation	2,468,249	2,459,325	2,450,401	2,441,477	2,432,553	2,423,629	2,414,705	2,405,781	2,396,857	2,387,933	2,379,009	2,370,085	2,361,161	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$5,928,841	5,919,917	5,910,993	5,902,069	5,893,145	5,884,221	5,875,297	5,866,373	5,857,449	5,848,525	5,839,601	5,830,677	5,821,753	
6.	Average Net Investment		5,924,379	5,915,455	5,906,531	5,897,607	5,888,683	5,879,759	5,870,835	5,861,911	5,852,987	5,844,063	5,835,139	5,826,215	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		43,045	42,980	42,915	42,850	42,785	42,720	42,656	42,591	42,526	42,461	42,396	42,331	$512,256
	b. Debt Component (C)		14,477	14,455	14,434	14,412	14,390	14,368	14,346	14,325	14,303	14,281	14,259	14,237	172,287
8.	Investment Expenses														
	a. Depreciation (D)		8,924	8,924	8,924	8,924	8,924	8,924	8,924	8,924	8,924	8,924	8,924	8,924	107,088
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		66,446	66,359	66,273	66,186	66,099	66,012	65,926	65,840	65,753	65,666	65,579	65,492	791,631
	a. Recoverable Costs Allocated to Energy		66,446	66,359	66,273	66,186	66,099	66,012	65,926	65,840	65,753	65,666	65,579	65,492	791,631
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9933091	0.9780148	0.9917797	0.9906489	0.9908908	0.9927556	0.9928640	0.9922011	0.9938509	0.9951954	0.9910567	0.9923774	
11.	Demand Jurisdictional Factor		0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	
12.	Retail Energy-Related Recoverable Costs (E)		66,001	64,900	65,728	65,567	65,497	65,534	65,456	65,327	65,349	65,351	64,993	64,993	784,696
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$66,001	$64,900	$65,728	$65,567	$65,497	$65,534	$65,456	$65,327	$65,349	$65,351	$64,993	$64,993	$784,696

Notes:
(A) Applicable depreciable base for Big Bend; accounts 312.41 ($1,675,171), 312.42 ($1,075,718), and 312.43 ($709,703)
(B) Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.63490).
(C) Line 6 x 2.9324% x 1/12
(D) Applicable depreciation rates are 3.3%, 3.1%, and 2.6%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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ECRC 2011 PROJECTION FILING
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Form 42-4P
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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2011 to December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: PM Minimization and Monitoring
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$8,655,951	$8,655,951	$8,655,951	$8,655,951	$8,655,951	$8,655,951	$8,655,951	$8,655,951	$8,655,951	$8,655,951	$8,655,951	$8,655,951	$8,655,951	
3.	Less: Accumulated Depreciation	(1,467,265)	(1,488,845)	(1,510,425)	(1,532,005)	(1,553,585)	(1,575,165)	(1,596,745)	(1,618,325)	(1,639,905)	(1,661,485)	(1,683,065)	(1,704,645)	(1,726,225)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$7,188,686	7,167,106	7,145,526	7,123,946	7,102,366	7,080,786	7,059,206	7,037,626	7,016,046	6,994,466	6,972,886	6,951,306	6,929,726	
6.	Average Net Investment		7,177,896	7,156,316	7,134,736	7,113,156	7,091,576	7,069,996	7,048,416	7,026,836	7,005,256	6,983,676	6,962,096	6,940,516	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		52,152	51,995	51,839	51,682	51,525	51,368	51,211	51,055	50,898	50,741	50,584	50,427	$615,477
	b. Debt Component (C)		17,540	17,488	17,435	17,382	17,329	17,277	17,224	17,171	17,119	17,066	17,013	16,960	207,004
8.	Investment Expenses														
	a. Depreciation (D)		21,580	21,580	21,580	21,580	21,580	21,580	21,580	21,580	21,580	21,580	21,580	21,580	258,960
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		91,272	91,063	90,854	90,644	90,434	90,225	90,015	89,806	89,597	89,387	89,177	88,967	1,081,441
	a. Recoverable Costs Allocated to Energy		91,272	91,063	90,854	90,644	90,434	90,225	90,015	89,806	89,597	89,387	89,177	88,967	1,081,441
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9933091	0.9780148	0.9917797	0.9906489	0.9908908	0.9927556	0.9928640	0.9922011	0.9938509	0.9951954	0.9910567	0.9923774	
11.	Demand Jurisdictional Factor		0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	
12.	Retail Energy-Related Recoverable Costs (E)		90,661	89,061	90,107	89,796	89,610	89,571	89,373	89,106	89,046	88,958	88,379	88,289	1,071,957
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$90,661	$89,061	$90,107	$89,796	$89,610	$89,571	$89,373	$89,106	$89,046	$88,958	$88,379	$88,289	$1,071,957

Notes:
(A) Applicable depreciable base for Big Bend; accounts 312.41 ($1,513,263), 312.42 ($5,153,072), 312.43 ($955,619), 315.41 ($17,504), 315.44 ($351,594), and 315.43 ($664,899)
(B) Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.63490).
(C) Line 6 x 2.9324% x 1/12
(D) Applicable depreciation rates are 3.3%, 3.1%, 2.6%, 2.5%, 2.1%, and 2.5%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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DOCKET NO. 100007-EI
ECRC 2011 PROJECTION FILING
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DOCUMENT NO. 4

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2011 to December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: Polk NO_x Emissions Reduction
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$1,561,473	$1,561,473	$1,561,473	$1,561,473	$1,561,473	$1,561,473	$1,561,473	$1,561,473	$1,561,473	$1,561,473	$1,561,473	$1,561,473	$1,561,473	
3.	Less: Accumulated Depreciation	(364,794)	(369,218)	(373,642)	(378,066)	(382,490)	(386,914)	(391,338)	(395,762)	(400,186)	(404,610)	(409,034)	(413,458)	(417,882)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$1,196,679	1,192,255	1,187,831	1,183,407	1,178,983	1,174,559	1,170,135	1,165,711	1,161,287	1,156,863	1,152,439	1,148,015	1,143,591	
6.	Average Net Investment		1,194,467	1,190,043	1,185,619	1,181,195	1,176,771	1,172,347	1,167,923	1,163,499	1,159,075	1,154,651	1,150,227	1,145,803	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		8,679	8,646	8,614	8,582	8,550	8,518	8,486	8,454	8,421	8,389	8,357	8,325	$102,021
	b. Debt Component (C)		2,919	2,908	2,897	2,886	2,876	2,865	2,854	2,843	2,832	2,822	2,811	2,800	34,313
8.	Investment Expenses														
	a. Depreciation (D)		4,424	4,424	4,424	4,424	4,424	4,424	4,424	4,424	4,424	4,424	4,424	4,424	53,088
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		16,022	15,978	15,935	15,892	15,850	15,807	15,764	15,721	15,677	15,635	15,592	15,549	189,422
	a. Recoverable Costs Allocated to Energy		16,022	15,978	15,935	15,892	15,850	15,807	15,764	15,721	15,677	15,635	15,592	15,549	189,422
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9933091	0.9780148	0.9917797	0.9906489	0.9908908	0.9927556	0.9928640	0.9922011	0.9938509	0.9951954	0.9910567	0.9923774	
11.	Demand Jurisdictional Factor		0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	
12.	Retail Energy-Related Recoverable Costs (E)		15,915	15,627	15,804	15,743	15,706	15,692	15,652	15,598	15,581	15,560	15,453	15,430	187,761
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$15,915	$15,627	$15,804	$15,743	$15,706	$15,692	$15,652	$15,598	$15,581	$15,560	$15,453	$15,430	$187,761

Notes:
(A) Applicable depreciable base for Polk; account 342.81
(B) Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.63490).
(C) Line 6 x 2.9324% x 1/12
(D) Applicable depreciation rate is 3.4%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2011 to December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 4 SOFA
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$2,558,730	$2,558,730	$2,558,730	$2,558,730	$2,558,730	$2,558,730	$2,558,730	$2,558,730	$2,558,730	$2,558,730	$2,558,730	$2,558,730	$2,558,730	
3.	Less: Accumulated Depreciation	(387,446)	(392,563)	(397,680)	(402,797)	(407,914)	(413,031)	(418,148)	(423,265)	(428,382)	(433,499)	(438,616)	(443,733)	(448,850)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$2,171,284	2,166,167	2,161,050	2,155,933	2,150,816	2,145,699	2,140,582	2,135,465	2,130,348	2,125,231	2,120,114	2,114,997	2,109,880	
6.	Average Net Investment		2,168,726	2,163,609	2,158,492	2,153,375	2,148,258	2,143,141	2,138,024	2,132,907	2,127,790	2,122,673	2,117,556	2,112,439	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		15,757	15,720	15,683	15,646	15,609	15,571	15,534	15,497	15,460	15,423	15,385	15,348	$186,633
	b. Debt Component (C)		5,300	5,287	5,275	5,262	5,250	5,237	5,225	5,212	5,200	5,187	5,175	5,162	62,772
8.	Investment Expenses														
	a. Depreciation (D)		5,117	5,117	5,117	5,117	5,117	5,117	5,117	5,117	5,117	5,117	5,117	5,117	61,404
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		26,174	26,124	26,075	26,025	25,976	25,925	25,876	25,826	25,777	25,727	25,677	25,627	310,809
	a. Recoverable Costs Allocated to Energy		26,174	26,124	26,075	26,025	25,976	25,925	25,876	25,826	25,777	25,727	25,677	25,627	310,809
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9933091	0.9780148	0.9917797	0.9906489	0.9908908	0.9927556	0.9928640	0.9922011	0.9938509	0.9951954	0.9910567	0.9923774	
11.	Demand Jurisdictional Factor		0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	
12.	Retail Energy-Related Recoverable Costs (E)		25,999	25,550	25,861	25,782	25,739	25,737	25,691	25,625	25,618	25,603	25,447	25,432	308,084
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$25,999	$25,550	$25,861	$25,782	$25,739	$25,737	$25,691	$25,625	$25,618	$25,603	$25,447	$25,432	$308,084

Notes:
(A) Applicable depreciable base for Big Bend; account 312.44
(B) Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.63490).
(C) Line 6 x 2.9324% x 1/12
(D) Applicable depreciation rate is 2.4%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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ECRC 2011 PROJECTION FILING
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DOCUMENT NO. 4

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2011 to December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 1 Pre-SCR
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$1,649,121	$1,649,121	$1,649,121	$1,649,121	$1,649,121	$1,649,121	$1,649,121	$1,649,121	$1,649,121	$1,649,121	$1,649,121	$1,649,121	$1,649,121	
3.	Less: Accumulated Depreciation	(215,425)	(219,960)	(224,495)	(229,030)	(233,565)	(238,100)	(242,635)	(247,170)	(251,705)	(256,240)	(260,775)	(265,310)	(269,845)	
4.	CWIP - Non-Interest Bearing	367,767	367,767	367,767	367,767	367,767	367,767	367,767	367,767	367,767	367,767	367,767	367,767	367,767	
5.	Net Investment (Lines 2 + 3 + 4)	$1,801,463	1,796,928	1,792,393	1,787,858	1,783,323	1,778,788	1,774,253	1,769,718	1,765,183	1,760,648	1,756,113	1,751,578	1,747,043	
6.	Average Net Investment		1,799,196	1,794,661	1,790,126	1,785,591	1,781,056	1,776,521	1,771,986	1,767,451	1,762,916	1,758,381	1,753,846	1,749,311	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		13,072	13,039	13,006	12,974	12,941	12,908	12,875	12,842	12,809	12,776	12,743	12,710	$154,695
	b. Debt Component (C)		4,397	4,386	4,374	4,363	4,352	4,341	4,330	4,319	4,308	4,297	4,286	4,275	52,028
8.	Investment Expenses														
	a. Depreciation (D)		4,535	4,535	4,535	4,535	4,535	4,535	4,535	4,535	4,535	4,535	4,535	4,535	54,420
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		22,004	21,960	21,915	21,872	21,828	21,784	21,740	21,696	21,652	21,608	21,564	21,520	261,143
	a. Recoverable Costs Allocated to Energy		22,004	21,960	21,915	21,872	21,828	21,784	21,740	21,696	21,652	21,608	21,564	21,520	261,143
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9933091	0.9780148	0.9917797	0.9906489	0.9908908	0.9927556	0.9928640	0.9922011	0.9938509	0.9951954	0.9910567	0.9923774	
11.	Demand Jurisdictional Factor		0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	
12.	Retail Energy-Related Recoverable Costs (E)		21,857	21,477	21,735	21,667	21,629	21,626	21,585	21,527	21,519	21,504	21,371	21,356	258,853
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$21,857	$21,477	$21,735	$21,667	$21,629	$21,626	$21,585	$21,527	$21,519	$21,504	$21,371	$21,356	$258,853

Notes:
(A) Applicable depreciable base for Big Bend; account 312.41
(B) Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.63490).
(C) Line 6 x 2.9324% x 1/12
(D) Applicable depreciation rate is 3.3%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2011 to December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 2 Pre-SCR
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$1,581,887	$1,581,887	$1,581,887	$1,581,887	$1,581,887	$1,581,887	$1,581,887	$1,581,887	$1,581,887	$1,581,887	$1,581,887	$1,581,887	$1,581,887	
3.	Less: Accumulated Depreciation	(194,132)	(198,219)	(202,306)	(206,393)	(210,480)	(214,567)	(218,654)	(222,741)	(226,828)	(230,915)	(235,002)	(239,089)	(243,176)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$1,387,755	1,383,668	1,379,581	1,375,494	1,371,407	1,367,320	1,363,233	1,359,146	1,355,059	1,350,972	1,346,885	1,342,798	1,338,711	
6.	Average Net Investment		1,385,712	1,381,625	1,377,538	1,373,451	1,369,364	1,365,277	1,361,190	1,357,103	1,353,016	1,348,929	1,344,842	1,340,755	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		10,068	10,038	10,009	9,979	9,949	9,920	9,890	9,860	9,831	9,801	9,771	9,741	$118,857
	b. Debt Component (C)		3,386	3,376	3,366	3,356	3,346	3,336	3,326	3,316	3,306	3,296	3,286	3,276	39,972
8.	Investment Expenses														
	a. Depreciation (D)		4,087	4,087	4,087	4,087	4,087	4,087	4,087	4,087	4,087	4,087	4,087	4,087	49,044
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		17,541	17,501	17,462	17,422	17,382	17,343	17,303	17,263	17,224	17,184	17,144	17,104	207,873
	a. Recoverable Costs Allocated to Energy		17,541	17,501	17,462	17,422	17,382	17,343	17,303	17,263	17,224	17,184	17,144	17,104	207,873
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9933091	0.9780148	0.9917797	0.9906489	0.9908908	0.9927556	0.9928640	0.9922011	0.9938509	0.9951954	0.9910567	0.9923774	
11.	Demand Jurisdictional Factor		0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	
12.	Retail Energy-Related Recoverable Costs (E)		17,424	17,116	17,318	17,259	17,224	17,217	17,180	17,128	17,118	17,101	16,991	16,974	206,050
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$17,424	$17,116	$17,318	$17,259	$17,224	$17,217	$17,180	$17,128	$17,118	$17,101	$16,991	$16,974	$206,050

Notes:
(A) Applicable depreciable base for Big Bend; account 312.42
(B) Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.63490).
(C) Line 6 x 2.9324% x 1/12
(D) Applicable depreciation rate is 3.1%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2011 to December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 3 Pre-SCR
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$2,706,507	$2,706,507	$2,706,507	$2,706,507	$2,706,507	$2,706,507	$2,706,507	$2,706,507	$2,706,507	$2,706,507	$2,706,507	$2,706,507	$2,706,507	
3.	Less: Accumulated Depreciation	(189,926)	(195,731)	(201,536)	(207,341)	(213,146)	(218,951)	(224,756)	(230,561)	(236,366)	(242,171)	(247,976)	(253,781)	(259,586)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$2,516,581	2,510,776	2,504,971	2,499,166	2,493,361	2,487,556	2,481,751	2,475,946	2,470,141	2,464,336	2,458,531	2,452,726	2,446,921	
6.	Average Net Investment		2,513,679	2,507,874	2,502,069	2,496,264	2,490,459	2,484,654	2,478,849	2,473,044	2,467,239	2,461,434	2,455,629	2,449,824	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		18,264	18,221	18,179	18,137	18,095	18,053	18,010	17,968	17,926	17,884	17,842	17,800	$216,379
	b. Debt Component (C)		6,143	6,128	6,114	6,100	6,086	6,072	6,057	6,043	6,029	6,015	6,001	5,987	72,775
8.	Investment Expenses														
	a. Depreciation (D)		5,805	5,805	5,805	5,805	5,805	5,805	5,805	5,805	5,805	5,805	5,805	5,805	69,660
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		30,212	30,154	30,098	30,042	29,986	29,930	29,872	29,816	29,760	29,704	29,648	29,592	358,814
	a. Recoverable Costs Allocated to Energy		30,212	30,154	30,098	30,042	29,986	29,930	29,872	29,816	29,760	29,704	29,648	29,592	358,814
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9933091	0.9780148	0.9917797	0.9906489	0.9908908	0.9927556	0.9928640	0.9922011	0.9938509	0.9951954	0.9910567	0.9923774	
11.	Demand Jurisdictional Factor		0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	
12.	Retail Energy-Related Recoverable Costs (E)		30,010	29,491	29,851	29,761	29,713	29,713	29,659	29,583	29,577	29,561	29,383	29,366	355,668
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$30,010	$29,491	$29,851	$29,761	$29,713	$29,713	$29,659	$29,583	$29,577	$29,561	$29,383	$29,366	$355,668

Notes:
(A) Applicable depreciable base for Big Bend; account 312.43 ($1,995,677) and 315.43 ($710,830)
(B) Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.63490).
(C) Line 6 x 2.9324% x 1/12
(D) Applicable depreciation rate is 2.6% and 2.5%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2011 to December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 1 SCR
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$5,000	$15,000	$22,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$42,000
	b. Clearings to Plant		0	0	42,000	0	0	0	0	0	0	0	0	0	42,000
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$84,809,021	$84,809,021	$84,809,021	$84,851,021	$84,851,021	$84,851,021	$84,851,021	$84,851,021	$84,851,021	$84,851,021	$84,851,021	$84,851,021	84,851,021	
3.	Less: Accumulated Depreciation	(1,477,570)	(1,664,189)	(1,850,808)	(2,037,427)	(2,224,161)	(2,410,895)	(2,597,629)	(2,784,363)	(2,971,097)	(3,157,831)	(3,344,565)	(3,531,299)	(3,718,033)	
4.	CWIP - Non-Interest Bearing	0	5,000	20,000	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$83,331,451	83,149,832	82,978,213	82,813,594	82,626,860	82,440,126	82,253,392	82,066,658	81,879,924	81,693,190	81,506,456	81,319,722	81,132,988	
6.	Average Net Investment		83,240,641	83,064,022	82,895,903	82,720,227	82,533,493	82,346,759	82,160,025	81,973,291	81,786,557	81,599,823	81,413,089	81,226,355	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		604,799	603,515	602,294	601,018	599,661	598,304	596,947	595,591	594,234	592,877	591,520	590,164	$7,170,924
	b. Debt Component (C)		203,412	202,981	202,570	202,141	201,684	201,228	200,772	200,315	199,859	199,403	198,946	198,490	2,411,801
8.	Investment Expenses														
	a. Depreciation (D)		186,619	186,619	186,619	186,734	186,734	186,734	186,734	186,734	186,734	186,734	186,734	186,734	2,240,463
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		994,830	993,115	991,483	989,893	988,079	986,266	984,453	982,640	980,827	979,014	977,200	975,388	11,823,188
	a. Recoverable Costs Allocated to Energy		994,830	993,115	991,483	989,893	988,079	986,266	984,453	982,640	980,827	979,014	977,200	975,388	11,823,188
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9933091	0.9780148	0.9917797	0.9906489	0.9908908	0.9927556	0.9928640	0.9922011	0.9938509	0.9951954	0.9910567	0.9923774	
11.	Demand Jurisdictional Factor		0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	
12.	Retail Energy-Related Recoverable Costs (E)		988,174	971,281	983,333	980,636	979,078	979,121	977,428	974,976	974,796	974,310	968,461	967,953	11,719,547
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$988,174	$971,281	$983,333	$980,636	$979,078	$979,121	$977,428	$974,976	$974,796	$974,310	$968,461	$967,953	$11,719,547

Notes:
(A) Applicable depreciable base for Big Bend; account 311.41 ($22,573,533), 312.41 ($47,375,714), 315.41 ($14,043,372), and 316.41 ($858,402).
(B) Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.63490).
(C) Line 6 x 2.9324% x 1/12
(D) Applicable depreciation rate is 1.4%, 3.3%, 2.5% and 1.2%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2011 to December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 2 SCR
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$5,000	$15,000	$22,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$42,000
	b. Clearings to Plant		0	0	42,000	0	0	0	0	0	0	0	0	0	42,000
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$91,494,865	$91,494,865	$91,494,865	$91,536,865	$91,536,865	$91,536,865	$91,536,865	$91,536,865	$91,536,865	$91,536,865	$91,536,865	$91,536,865	$91,536,865	
3.	Less: Accumulated Depreciation	(3,058,383)	(3,254,290)	(3,450,197)	(3,646,104)	(3,842,120)	(4,038,136)	(4,234,152)	(4,430,168)	(4,626,184)	(4,822,200)	(5,018,216)	(5,214,232)	(5,410,248)	
4.	CWIP - Non-Interest Bearing	0	5,000	20,000	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$88,436,482	88,245,575	88,064,668	87,890,761	87,694,745	87,498,729	87,302,713	87,106,697	86,910,681	86,714,665	86,518,649	86,322,633	86,126,617	
6.	Average Net Investment		88,341,028	88,155,121	87,977,714	87,792,753	87,596,737	87,400,721	87,204,705	87,008,689	86,812,673	86,616,657	86,420,641	86,224,625	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		641,856	640,506	639,217	637,873	636,449	635,025	633,600	632,176	630,752	629,328	627,904	626,479	$7,611,165
	b. Debt Component (C)		215,876	215,422	214,988	214,536	214,057	213,578	213,099	212,620	212,141	211,662	211,183	210,704	2,559,866
8.	Investment Expenses														
	a. Depreciation (D)		195,907	195,907	195,907	196,016	196,016	196,016	196,016	196,016	196,016	196,016	196,016	196,016	2,351,865
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		1,053,639	1,051,835	1,050,112	1,048,425	1,046,522	1,044,619	1,042,715	1,040,812	1,038,909	1,037,006	1,035,103	1,033,199	12,522,896
	a. Recoverable Costs Allocated to Energy		1,053,639	1,051,835	1,050,112	1,048,425	1,046,522	1,044,619	1,042,715	1,040,812	1,038,909	1,037,006	1,035,103	1,033,199	12,522,896
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9933091	0.9780148	0.9917797	0.9906489	0.9908908	0.9927556	0.9928640	0.9922011	0.9938509	0.9951954	0.9910567	0.9923774	
11.	Demand Jurisdictional Factor		0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	
12.	Retail Energy-Related Recoverable Costs (E)		1,046,589	1,028,710	1,041,480	1,038,621	1,036,989	1,037,051	1,035,274	1,032,695	1,032,521	1,032,024	1,025,846	1,025,323	12,413,123
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$1,046,589	$1,028,710	$1,041,480	$1,038,621	$1,036,989	$1,037,051	$1,035,274	$1,032,695	$1,032,521	$1,032,024	$1,025,846	$1,025,323	$12,413,123

Notes:

(A) Applicable depreciable base for Big Bend; account 311.42 ($25,276,351), 312.42 ($49,342,307), 315.42 ($15,957,028), and 316.42 ($961,179).
(B) Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.63490).
(C) Line 6 x 2.9324% x 1/12
(D) Applicable depreciation rates are 1.6%, 3.1%, 2.5% and 2.0%.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2011 to December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 3 SCR
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$400,000	$0	$0	$0	$0	$0	$0	$0	$1,600,000	$0	$2,000,000
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	2,000,000	0	2,000,000
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$78,714,883	$78,714,883	$78,714,883	$78,714,883	$78,714,883	$78,714,883	$78,714,883	$78,714,883	$78,714,883	$78,714,883	$78,714,883	$80,714,883	$80,714,883	
3.	Less: Accumulated Depreciation	(4,645,109)	(4,789,282)	(4,933,455)	(5,077,628)	(5,221,801)	(5,365,974)	(5,510,147)	(5,654,320)	(5,798,493)	(5,942,666)	(6,086,839)	(6,231,012)	(6,379,518)	
4.	CWIP - Non-Interest Bearing	0	0	0	400,000	400,000	400,000	400,000	400,000	400,000	400,000	400,000	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$74,069,774	73,925,601	73,781,428	74,037,255	73,893,082	73,748,909	73,604,736	73,460,563	73,316,390	73,172,217	73,028,044	74,483,871	74,335,365	
6.	Average Net Investment		73,997,688	73,853,515	73,909,342	73,965,169	73,820,996	73,676,823	73,532,650	73,388,477	73,244,304	73,100,131	73,755,958	74,409,618	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		537,643	536,595	537,001	537,406	536,359	535,311	534,264	533,216	532,169	531,121	535,886	540,635	$6,427,606
	b. Debt Component (C)		180,826	180,473	180,610	180,746	180,394	180,042	179,689	179,337	178,985	178,632	180,235	181,832	2,161,801
8.	Investment Expenses														
	a. Depreciation (D)		144,173	144,173	144,173	144,173	144,173	144,173	144,173	144,173	144,173	144,173	144,173	148,506	1,734,409
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		862,642	861,241	861,784	862,325	860,926	859,526	858,126	856,726	855,327	853,926	860,294	870,973	10,323,816
	a. Recoverable Costs Allocated to Energy		862,642	861,241	861,784	862,325	860,926	859,526	858,126	856,726	855,327	853,926	860,294	870,973	10,323,816
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9933091	0.9780148	0.9917797	0.9906489	0.9908908	0.9927556	0.9928640	0.9922011	0.9938509	0.9951954	0.9910567	0.9923774	
11.	Demand Jurisdictional Factor		0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	
12.	Retail Energy-Related Recoverable Costs (E)		856,870	842,306	854,700	854,261	853,084	853,299	852,002	850,044	850,068	849,823	852,600	864,334	10,233,391
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$856,870	$842,306	$854,700	$854,261	$853,084	$853,299	$852,002	$850,044	$850,068	$849,823	$852,600	$864,334	$10,233,391

Notes:
(A) Applicable depreciable base for Big Bend; account 311.43 ($21,689,422), 312.43 ($44,509,823), 315.43 ($13,690,954), and 316.43 ($824,684).
(B) Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.63490).
(C) Line 6 x 2.9324% x 1/12
(D) Applicable depreciation rates are 1.2%, 2.6%, 2.5%, and 2.7%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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DOCKET NO. 100007-EI
ECRC 2011 PROJECTION FILING
EXHIBIT NO. HTB-3, PAGE 1-26
DOCUMENT NO. 4

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2011 to December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 4 SCR
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$61,183,337	$61,183,337	$61,183,337	$61,183,337	$61,183,337	$61,183,337	$61,183,337	$61,183,337	$61,183,337	$61,183,337	$61,183,337	$61,183,337	$61,183,337	
3.	Less: Accumulated Depreciation	(5,114,785)	(5,220,043)	(5,325,301)	(5,430,559)	(5,535,817)	(5,641,075)	(5,746,333)	(5,851,591)	(5,956,849)	(6,062,107)	(6,167,365)	(6,272,623)	(6,377,881)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$56,068,552	55,963,294	55,858,036	55,752,778	55,647,520	55,542,262	55,437,004	55,331,746	55,226,488	55,121,230	55,015,972	54,910,714	54,805,456	
6.	Average Net Investment		56,015,923	55,910,665	55,805,407	55,700,149	55,594,891	55,489,633	55,384,375	55,279,117	55,173,859	55,068,601	54,963,343	54,858,085	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		406,993	406,228	405,463	404,699	403,934	403,169	402,404	401,640	400,875	400,110	399,345	398,581	$4,833,441
	b. Debt Component (C)		136,884	136,627	136,370	136,113	135,855	135,598	135,341	135,084	134,827	134,569	134,312	134,055	1,625,635
8.	Investment Expenses														
	a. Depreciation (D)		105,258	105,258	105,258	105,258	105,258	105,258	105,258	105,258	105,258	105,258	105,258	105,258	1,263,096
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		649,135	648,113	647,091	646,070	645,047	644,025	643,003	641,982	640,960	639,937	638,915	637,894	7,722,172
	a. Recoverable Costs Allocated to Energy		649,135	648,113	647,091	646,070	645,047	644,025	643,003	641,982	640,960	639,937	638,915	637,894	7,722,172
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	-
10.	Energy Jurisdictional Factor		0.9933091	0.9780148	0.9917797	0.9906489	0.9908908	0.9927556	0.9928640	0.9922011	0.9938509	0.9951954	0.9910567	0.9923774	
11.	Demand Jurisdictional Factor		0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	
12.	Retail Energy-Related Recoverable Costs (E)		644,792	633,864	641,772	640,029	639,171	639,359	638,415	636,975	637,019	636,862	633,201	633,032	7,654,491
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$644,792	$633,864	$641,772	$640,029	$639,171	$639,359	$638,415	$636,975	$637,019	$636,862	$633,201	$633,032	$7,654,491

Notes:
(A) Applicable depreciable base for Big Bend; account 311.44 ($16,857,250), 312.44 ($32,996,126), 315.44 ($10,642,027), and 316.44 ($687,934).
(B) Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.63490).
(C) Line 6 x 2.9324% x 1/12
(D) Applicable depreciation rate is 1.4%, 2.4%, 2.1%, and 1.7%.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2011 to December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend FGD System Reliability
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$18,000	$282,500	$200,000	$100,000	$150,000	$1,500,000	$1,500,000	$200,000	$2,000,000	$2,500,000	$3,190,000	$500,000	$12,140,500
	b. Clearings to Plant		0	0	340,500	0	0	0	0	0	0	0	11,300,000	500,000	12,140,500
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$11,566,029	$11,566,029	$11,566,029	$11,906,529	$11,906,529	$11,906,529	$11,906,529	$11,906,529	$11,906,529	$11,906,529	$11,906,529	$23,206,529	$23,706,529	
3.	Less: Accumulated Depreciation	(828,433)	(850,722)	(873,011)	(895,300)	(918,242)	(941,184)	(964,126)	(987,068)	(1,010,010)	(1,032,952)	(1,055,894)	(1,078,836)	(1,123,436)	
4.	CWIP - Non-Interest Bearing	0	18,000	300,500	160,000	260,000	410,000	1,910,000	3,410,000	3,610,000	5,610,000	8,110,000	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$10,737,596	10,733,307	10,993,518	11,171,229	11,248,287	11,375,345	12,852,403	14,329,461	14,506,519	16,483,577	18,960,635	22,127,693	22,583,093	
6.	Average Net Investment		10,735,451	10,863,412	11,082,373	11,209,758	11,311,816	12,113,874	13,590,932	14,417,990	15,495,048	17,722,106	20,544,164	22,355,393	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		78,000	78,930	80,521	81,446	82,188	88,015	98,747	104,756	112,582	128,763	149,267	162,427	$1,245,642
	b. Debt Component (C)		26,234	26,547	27,082	27,393	27,642	29,602	33,212	35,233	37,865	43,307	50,203	54,629	418,949
8.	Investment Expenses														
	a. Depreciation (D)		22,289	22,289	22,289	22,942	22,942	22,942	22,942	22,942	22,942	22,942	22,942	44,600	295,003
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		126,523	127,766	129,892	131,781	132,772	140,559	154,901	162,931	173,389	195,012	222,412	261,656	1,959,594
	a. Recoverable Costs Allocated to Energy		126,523	127,766	129,892	131,781	132,772	140,559	154,901	162,931	173,389	195,012	222,412	261,656	1,959,594
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9933091	0.9780148	0.9917797	0.9906489	0.9908908	0.9927556	0.9928640	0.9922011	0.9938509	0.9951954	0.9910567	0.9923774	
11.	Demand Jurisdictional Factor		0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	
12.	Retail Energy-Related Recoverable Costs (E)		125,676	124,957	128,824	130,549	131,563	139,541	153,796	161,660	172,323	194,075	220,423	259,662	1,943,049
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$125,676	$124,957	$128,824	$130,549	$131,563	$139,541	$153,796	$161,660	$172,323	$194,075	$220,423	$259,662	$1,943,049

Notes:
(A) Applicable depreciable base for Big Bend; account 312.44 ($1,456,209) and 312.45 ($22,250,320)
(B) Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.63490).
(C) Line 6 x 2.9324% x 1/12
(D) Applicable depreciation rate is 2.4% and 2.3%.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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DOCKET NO. 100007-EI
ECRC 2011 PROJECTION FILING
EXHIBIT NO. HTB-3, PAGE 1-26
DOCUMENT NO. 4

Form 42-4P
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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2011 to December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: Clean Air Mercury Rule
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$75,000	$0	$0	$0	$0	$0	$75,000
	b. Clearings to Plant		0	0	0	0	0	0	50,000	0	0	0	0	0	50,000
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$1,168,957	$1,168,957	$1,168,957	$1,168,957	$1,168,957	$1,168,957	$1,168,957	$1,218,957	$1,218,957	$1,218,957	$1,218,957	$1,218,957	$1,218,957	
3.	Less: Accumulated Depreciation	(57,339)	(60,261)	(63,183)	(66,105)	(69,027)	(71,949)	(74,871)	(77,793)	(80,840)	(83,887)	(86,934)	(89,981)	(93,028)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	25,000	25,000	25,000	25,000	25,000	25,000	
5.	Net Investment (Lines 2 + 3 + 4)	$1,111,618	1,108,696	1,105,774	1,102,852	1,099,930	1,097,008	1,094,086	1,166,164	1,163,117	1,160,070	1,157,023	1,153,976	1,150,929	
6.	Average Net Investment		1,110,157	1,107,235	1,104,313	1,101,391	1,098,469	1,095,547	1,130,125	1,164,641	1,161,594	1,158,547	1,155,500	1,152,453	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		8,066	8,045	8,024	8,002	7,981	7,960	8,211	8,462	8,440	8,418	8,395	8,373	$98,377
	b. Debt Component (C)		2,713	2,706	2,699	2,691	2,684	2,677	2,762	2,846	2,839	2,831	2,824	2,816	33,088
8.	Investment Expenses														
	a. Depreciation (D)		2,922	2,922	2,922	2,922	2,922	2,922	2,922	3,047	3,047	3,047	3,047	3,047	35,689
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		13,701	13,673	13,645	13,615	13,587	13,559	13,895	14,355	14,326	14,296	14,266	14,236	167,154
	a. Recoverable Costs Allocated to Energy		13,701	13,673	13,645	13,615	13,587	13,559	13,895	14,355	14,326	14,296	14,266	14,236	167,154
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9933091	0.9780148	0.9917797	0.9906489	0.9908908	0.9927556	0.9928640	0.9922011	0.9938509	0.9951954	0.9910567	0.9923774	
11.	Demand Jurisdictional Factor		0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	
12.	Retail Energy-Related Recoverable Costs (E)		13,609	13,372	13,533	13,488	13,463	13,461	13,796	14,243	14,238	14,227	14,138	14,127	165,695
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$13,609	$13,372	$13,533	$13,488	$13,463	$13,461	$13,796	$14,243	$14,238	$14,227	$14,138	$14,127	$165,695

Notes:
(A) Applicable depreciable base for Big Bend and Polk; accounts 312.41, 312.43, 312.44, 315.40 ($1,218,957), and 345.81
(B) Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.63490).
(C) Line 6 x 2.9324% x 1/12
(D) Applicable depreciation rate is 3.3%, 2.6%, 2.4%, 3.0%, and 3.1%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2011 to December 2011

For Project: SO_2 Emissions Allowances
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Purchases/Transfers		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Sales/Transfers		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Auction Proceeds/Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Working Capital Balance														
	a. FERC 158.1 Allowance Inventory	$0	0	0	0	0	0	0	0	0	0	0	0	0	
	b. FERC 158.2 Allowances Withheld	0	0	0	0	0	0	0	0	0	0	0	0	0	
	c. FERC 182.3 Other Regl. Assets - Losses	0	0	0	0	0	0	0	0	0	0	0	0	0	
	d. FERC 254.01 Regulatory Liabilities - Gains	(39,725)	(39,568)	(39,454)	(39,325)	(39,178)	(39,018)	(38,863)	(38,704)	(38,544)	(38,412)	(38,290)	(38,170)	(38,036)	
3.	Total Working Capital Balance	($39,725)	($39,568)	($39,454)	($39,325)	($39,178)	($39,018)	($38,863)	($38,704)	($38,544)	($38,412)	($38,290)	($38,170)	($38,036)	
4.	Average Net Working Capital Balance		($39,647)	($39,511)	($39,389)	($39,252)	($39,098)	($38,941)	($38,783)	($38,624)	($38,478)	($38,351)	($38,230)	($38,103)	
5.	Return on Average Net Working Capital Balance														
	a. Equity Component Grossed Up For Taxes (A)		(288)	(287)	(286)	(285)	(284)	(283)	(282)	(281)	(280)	(279)	(278)	(277)	($3,390)
	b. Debt Component Grossed Up For Taxes (B)		(97)	(97)	(96)	(96)	(96)	(95)	(95)	(94)	(94)	(94)	(93)	(93)	($1,140)
6.	Total Return Component		(385)	(384)	(382)	(381)	(380)	(378)	(377)	(375)	(374)	(373)	(371)	(370)	($4,530)
7.	Expenses:														
	a. Gains		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Losses		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. SO_2 Allowance Expense		56,843	50,885	56,872	54,853	56,841	55,845	56,841	44,841	41,868	42,878	40,880	41,866	601,313
8.	Net Expenses (C)		56,843	50,885	56,872	54,853	56,841	55,845	56,841	44,841	41,868	42,878	40,880	41,866	601,313
9.	Total System Recoverable Expenses (Lines 6 + 7)		$56,458	$50,501	$56,490	$54,472	$56,461	$55,467	$56,464	$44,466	$41,494	$42,505	$40,509	$41,496	$596,783
	a. Recoverable Costs Allocated to Energy		56,458	50,501	56,490	54,472	56,461	55,467	56,464	44,466	41,494	42,505	40,509	41,496	596,783
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9933091	0.9780148	0.9917797	0.9906489	0.9908908	0.9927556	0.9928640	0.9922011	0.9938509	0.9951954	0.9910567	0.9923774	
11.	Demand Jurisdictional Factor		0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	
12.	Retail Energy-Related Recoverable Costs (D)		56,080	49,391	56,026	53,963	55,947	55,065	56,061	44,119	41,239	42,301	40,147	41,180	591,519
13.	Retail Demand-Related Recoverable Costs (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Juris. Recoverable Costs (Lines 12 + 13)		$56,080	$49,391	$56,026	$53,963	$55,947	$55,065	$56,061	$44,119	$41,239	$42,301	$40,147	$41,180	$591,519

Notes:
(A) Line 4 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.63490).
(B) Line 4 x 2.9324% x 1/12.
(C) Line 8 is reported on Schedule 2P
(D) Line 9a x Line 10
(E) Line 9b x Line 11

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Project Title: Big Bend Unit 3 Flue Gas Desulfurization Integration

Project Description:

This project involved the integration of Big Bend Unit 3 flue gases into the Big Bend Unit 4 Flue Gas Desulfurization ("FGD") system. The integration was accomplished by installing interconnecting ductwork between Unit 3 precipitator outlet ducts and the Unit 4 FGD inlet duct. The Unit 4 FGD outlet duct was interconnected with the Unit 3 chimney via new ductwork and a new stack breaching. New ductwork, linings, isolation dampers, support steel, and stack annulus pressurization fans were procured and installed. Modifications to the materials handling systems and controls were also necessary.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2010 through December 2010, is $764,341 compared to the original projection of $761,341 representing no variance.

The actual/estimated O&M expense for the period January 2010 through December 2010 is $4,115,482 compared to the original projection of $4,241,800 resulting in an insignificant variance

Progress Summary: The project is complete and in-service.

Projections: Estimated depreciation plus return for the period January 2011 through December 2011, is expected to be $742,259.

Estimated O&M costs for the period January 2011 through December 2011 are projected to be $5,154,400.

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Project Title: Big Bend Units 1 & 2 Flue Gas Conditioning

Project Description:

The existing electrostatic precipitators were not designed for the range of fuels needed for compliance with the Clean Air Act Amendments ("CAAA"). Flue gas conditioning was required to assure operation of the generating units in accordance with applicable permits and regulations. This equipment is still required to ensure compliance with the CAAA in the event the FGD system on Units 1 & 2 is not operating.

The project involved the addition of molten sulfur unloading, storage and conveying to sulfur burners and catalytic converters where SO_2 is converted to SO_3. The control and injection system then injects this into the ductwork ahead of the electrostatic precipitators.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2010 through December 2010 is $422,124 compared to the original projection of $422,124 representing no variance.

The actual/estimated O&M expense for this project for the period January 2010 through December 2010 is $0 and did not vary from the original projection.

Progress Summary: The project is complete and in-service.

Projections: Estimated depreciation plus return for the period January 2011 through December 2011 is projected to be $403,377.

There are no estimated O&M costs for the period January 2011 through December 2011.

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Project Title: Big Bend Unit 4 Continuous Emissions Monitors

Project Description:

Continuous emissions monitors (CEMs) were installed on the flue gas inlet and outlet of Big Bend Unit 4 to monitor compliance with the CAAA requirements. The monitors are capable of measuring, recording and electronically reporting SO_2, NO_x and volumetric gas flow out of the stack. The project consisted of monitors, a CEM building, the CEMs control and power cables to supply a complete system.

40 CFR Part 75 includes the general requirements for the installation, certification, operation and maintenance of CEMs and specific requirements for the monitoring of pollutants, opacity and volumetric flow. These regulations are very comprehensive and specific as to the requirements for CEMs, and in essence, they define the components needed and their configuration.

Project Accomplishment:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2010 through December 2010 is $78,510 compared to the original projection of $78,510 representing no variance.

Progress Summary: The project is complete and in-service.

Projections: Estimated depreciation plus return for the period January 2011 through December 2011 is projected to be $76,381.

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Project Title: Big Bend Unit 1 Classifier Replacement

Project Description:

The boiler modifications at Big Bend Unit 1 are part of Tampa Electric's NO_X compliance strategy for Phase II of the CAAA. The classifier replacements will optimize coal fineness by providing a uniform particle size. This finer classification, combined with the equalized distribution of coal to outlet pipes and furnaces, will enable a uniform, staged combustion. As a result, firing systems will operate at lower NO_X levels.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2010 through December 2010 is $133,795 compared to the original projection of $133,795 representing no variance.

Progress Summary: The project was placed in-service December 1998.

Projections: Estimated depreciation plus return for the period January 2011 through December 2011 is projected to be $128,734.

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Project Title: Big Bend Unit 2 Classifier Replacement

Project Description:

The boiler modifications at Big Bend Unit 2 are part of Tampa Electric's NO_X compliance strategy for Phase II of the CAAA. The classifier replacements will optimize coal fineness by providing a more uniform particle size. This finer classification, combined with the equalized distribution of coal to outlet pipes and furnaces, will enable a uniform, staged combustion. As a result, firing systems will operate at lower NO_X levels.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2010 through December 2010 is $96,974 compared to the original projection of $96,974 representing no variance.

Progress Summary: The project was placed in-service May 1998.

Projections: Estimated depreciation plus return for the period January 2011 through December 2011 is projected to be $93,241.

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Project Title: Big Bend Units 1 & 2 FGD

Project Description:

The Big Bend Units 1 & 2 FGD system consists of equipment capable of removing SO_2 from the flue gas generated by the combustion of coal. The FGD was installed in order to comply with Phase II of the CAAA. Compliance with Phase II is required by January 1, 2000. The CAAA impose SO_2 emission limits on existing steam electric units with an output capacity of greater than 25 megawatts and all new utility units. Tampa Electric conducted an exhaustive analysis of options to comply with Phase II of the CAAA that culminated in the selection of the FGD project to serve Big Bend Units 1 & 2.

In Docket No. 980693-EI, Order No. PSC-99-0075-FOF-EI, issued January 11, 1999, the Commission found that the FGD project was the most cost-effective alternative for compliance with the SO_2 requirements of Phase II of the CAAA.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2010 through December 2010 is $8,724,524 compared to the original projection of $8,823,552, representing an insignificant variance.

The actual/estimated O&M expense for the period January 2010 through December 2010 is $7,648,553 as compared to the original estimate of $7,443,300 representing an insignificant variance.

Progress Summary: The project was placed in-service in December 1999.

Projections: Estimated depreciation plus return for the period January 2011 through December 2011 is expected to be $8,896,117.

Estimated O&M costs for the period January 2011 through December 2011 are projected to be $7,791,300.

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Project Title: Big Bend Section 114 Mercury Testing Platform

Project Description:

The Mercury Emissions Information Collection Effort is mandated by the EPA. The EPA asserts that Section 114 of the CAAA grants to the EPA the authority to request the collection of information necessary for it to study whether it is appropriate and necessary to develop performance or emission standards for electric utility steam generating units.

In a letter dated November 25, 1998, Tampa Electric was notified by the EPA that, pursuant to Section 114 of the CAAA, the company was required to periodically sample and analyze coal shipments for mercury and chlorine content during the period January 1, 1999 through December 31, 1999.

In addition to coal sampling, stack testing and analyses are also required. Tampa Electric received a second letter from EPA, dated March 11, 1999, requiring Tampa Electric to perform specialized mercury testing of the inlet and outlet of the last emission control device installed for Big Bend Units 1, 2 or 3, and Polk Unit 1 as part of the mercury data collection. Part of the cost incurred to perform the stack testing is due to the need to construct special test facilities at the Big Bend stack testing location to meet EPA's testing requirements.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2010 through December 2010, is $13,303 compared to the original projection of $13,303 representing no variance.

Progress Summary: The project was placed in-service in December 1999 and was completed in May 2000.

Projections: Estimated depreciation plus return for the period January 2011 through December 2011 is expected to be $13,022.

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Project Title: Big Bend FGD Optimization and Utilization

Project Description:

In order to meet the requirements of the FDEP Consent Final Judgment and the EPA Consent Decree, Tampa Electric was required to optimize the SO_2 removal efficiency and operations of the Big Bend Units 1, 2 and 3 FGD systems. Tampa Electric performed activities in three key areas to improve the performance and reliability of the Big Bend Units 1, 2 and 3 FGD systems. The majority of the improvements required on the Unit 3 tower module included the tower piping, nozzle and internal improvements, ductwork improvements, electrical system reliability improvements, tower control improvements, dibasic acid system improvements, booster fan reliability, absorber system improvements, quencher system improvements, and tower demister improvements. Big Bend Units 1 and 2 FGD system improvements included additional preventative maintenance, oxidation air control improvements, and tower water, air reagent and start-up piping upgrades. In order to ensure reliability of the FGD systems, improvements to the common limestone supply, gypsum de-watering stack reliability and wastewater treatment plant were also being performed.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2010 through December 2010 is $2,475,526 compared to the original projection of $2,475,526 representing no variance.

Progress Summary: The project was placed in-service in January 2002.

Projections: Estimated depreciation plus return for the period January 2011 through December 2011 is expected to be $2,417,303.

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Project Title: Big Bend PM Minimization and Monitoring

Project Description:

In order to meet the requirements of the FDEP Consent Final Judgment and the EPA Consent Decree, Tampa Electric is required to develop a Best Operational Practices ("BOP") study to minimize emissions from each electrostatic precipitator ("ESP") at Big Bend, as well as perform a best available control technology ("BACT") analysis for the upgrade of each existing ESP. The company is also required to install and operate particulate matter continuous emission monitors on Big Bend Units 1, 2 and 3 FGD systems. Tampa Electric has identified improvements that are necessary to optimize ESP performance such as modifications to the turning vanes and precipitator distribution plates, and upgrades to the controls and software system of the precipitators. Tampa Electric has incurred costs associated with the recommendations of the BOP study and the BACT analysis in 2001 and will continue to experience O&M and capital expenditures during 2002 and beyond.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2010 through December 2010 is $1,082,908 as compared to the original projection of $1,064,831 resulting in an insignificant variance.

The actual/estimated O&M expense the period January 2010 through December 2010 is $436,889 as compared to the original projection of $470,000, resulting in an insignificant variance.

Progress Summary: This project was placed in-service July 2005.

Projections: Estimated depreciation plus return for the period January 2011 through December 2011 is expected to be $1,081,441.

Estimated O&M costs for the period January 2011 through December 2011 are projected to be $479,200.

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Project Title: Big Bend NO_x Emissions Reduction

Project Description:

In order to meet the requirements of the FDEP Consent Final Judgment and the EPA Consent Decree, Tampa Electric is required to spend up to $3 million with the goal to reduce NO_x emissions at Big Bend Station. The Consent Decree requires that by December 31, 2002, the company must achieve at least a 30 percent reduction beyond 1998 levels for Big Bend Units 1 and 2 and at least a 15 percent reduction in NO_x emissions from Big Bend Unit 3. Tampa Electric has identified projects that are the first steps to decrease NO_x emissions in these units such as burner and windbox modifications and the installation of a neural network system on each of the Big Bend units.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2010 through December 2010 is $796,466 as compared to the original projection of $804,002 representing an insignificant variance.

The actual/estimated O&M expense the period January 2010 through December 2010 is $469,137 as compared to the original projection of $396,000, resulting in a variance of 18.5 percent. The variance is driven by the increase in maintenance related to the installation of catalyst on Big Bend Units 3 SCR.

Progress Summary: The project was placed in-service January 2006.

Projections: Estimated depreciation plus return for the period January 2011 through December 2011 is expected to be $791,631.

Estimated O&M costs for the period January 2011 through December 2011 are projected to be $396,000.

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Project Title: Big Bend Fuel Oil Tank No. 1 Upgrade

Project Description:

The Big Bend Fuel Oil Tank No. 1 Upgrade is a 500,000 gallon field-erected fuel storage tank that is required to meet the requirements of FDEP Rule 62-762 as an existing field-erected above ground storage tank containing a regulated pollutant (diesel fuel). The rule required various modifications and a complete internal inspection by the end of 1999.

The scope of work for this project included cleaning and inspecting the tank in accordance with API 653 specifications, coating the internal floor plus 30 inches up the tank wall, installing an AEI Segundo bottom to the tank as well as installing a leak detection system, installing a spill containment for piping fittings and valves surrounding the tank, installing a new truck unloading facility and spill containment for the truck unloading facility, installing level instrumentation for overfill protection, installing secondary containment for below ground piping or reroute to above ground, and conducting a tank closure assessment.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2010 through December 2010 is $53,079 compared to the original projection of $53,079 representing no variance.

Progress Summary: The project was placed in-service October 1998.

Projections: Estimated depreciation plus return for the period January 2011 through December 2011 is projected to be $51,572.

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Project Title: Big Bend Fuel Oil Tank No. 2 Upgrade

Project Description:

The Big Bend Fuel Oil Tank No. 2 Upgrade is a 4,200,000 gallon field-erected fuel storage tank that is required to meet the requirements of FDEP Rule 62-762 as an existing field-erected above ground storage tank containing a regulated pollutant (diesel fuel). The rule required various modifications and a complete internal inspection by the end of 1999.

The scope of work for this project included cleaning and inspecting the tank in accordance with API 653 specifications, coating the internal floor plus 30 inches up the tank wall, installing an AEI Segundo bottom to the tank as well as installing a leak detection system, installing a spill containment for piping fittings and valves surrounding the tank, installing a new truck unloading facility and spill containment for the truck unloading facility, installing level instrumentation for overfill protection, installing secondary containment for below ground piping or reroute to above ground, and conducting a tank closure assessment.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2010 through December 2010 is $87,302 compared to the original projection of $87,302 representing no variance.

Progress Summary: The project was placed in-service December 1998.

Projections: Estimated depreciation plus return for the period January 2011 through December 2011 is projected to be $84,824.

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Project Title: Phillips Oil Tank No. 1 Upgrade

Project Description:

The Phillips Oil Tank No. 1 Upgrade is a 1,300,000 gallon field-erected fuel storage tank that is required to meet the requirements of FDEP Rule 62-762 as an existing field-erected above ground storage tank containing a regulated pollutant (diesel fuel). The rule required various modifications and a complete internal inspection by the end of 1999.

The scope of work for this project included cleaning and inspecting the tank in accordance with API 653 specifications, coating the internal floor plus 30 inches up the tank wall, installing a spill containment for piping fittings and valves surrounding the tank, installing level instrumentation for overfill protection, installing secondary containment for below ground piping or reroute to above ground, and conducting a tank closure assessment.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2010 through December 2010, is $5,667 compared to the original projection of $5,667 representing no variance.

Progress Summary: The project is complete and was placed in-service October 1998.

Projections: Estimated depreciation plus return for the period January 2011 through December 2011 is projected to be $5,461.

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Project Title: Phillips Oil Tank No. 4 Upgrade

Project Description:

The Phillips Oil Tank No. 4 Upgrade is a 57,000 gallon field-erected fuel storage tank that is required to meet the requirements of FDEP Rule 62-762 as an existing field-erected above ground storage tank containing a regulated pollutant (diesel fuel). The rule required various modifications and a complete internal inspection by the end of 1999.

The scope of work for this project included cleaning and inspecting the tank in accordance with API 653 specifications, coating the internal floor plus 30 inches up the tank wall, installing a spill containment for piping fittings and valves surrounding the tank, installing level instrumentation for overfill protection, installing secondary containment for below ground piping or reroute to above ground, and conducting a tank closure assessment.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2010 through December 2010 is $8,899 compared to the original projection of $8,899 representing no variance.

Progress Summary: The project is complete and was placed in-service October 1998.

Projections: Estimated depreciation plus return for the period January 2011 through December 2011 is projected to be $8,584.

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Project Title: SO_2 Emission Allowances

Project Description:

The acid rain control title of the CAAA sets forth a comprehensive regulatory mechanism designed to control acid rain by limiting sulfur dioxide emissions by electric utilities. The CAAA requires reductions in SO_2 emissions in two phases. Phase I began on January 1, 1995 and applies to 110 mostly coal-fired utility plants containing about 260 generating units. These plants are owned by some 40 jurisdictional utility systems that are expected to reduce annual SO_2 emissions by as much as 4.5 million tons. Phase II began on January 1, 2000, and applies to virtually all existing steam-electric generating utility units with capacity exceeding 25 megawatts and to new generating utility units of any size. The EPA issues to the owners of generating units allowances (defined as an authorization to emit, during or after a specified calendar year, one ton of SO_2) equal to the number of tons of SO_2 emissions authorized by the CAAA. EPA does not assess a charge for the allowances it awards.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated return on average net working capital for the period January 2010 through December 2010 is ($4,759) compared to the original projection of ($4,516) representing an insignificant variance.

The actual/estimated O&M for the period January 2010 through December 2010 is $137,684 compared to the original projection of $563,564 representing a variance of 75.6 percent. The variance is driven by fewer allowances consumed at a lower unit price than originally projected.

Progress Summary: SO_2 emission allowances are being used by Tampa Electric to meet compliance standards for Phase I of the CAAA.

Project Projections: Estimated return on average net working capital for the period January 2011 through December 2011 is projected to be ($4,530).

Estimated O&M costs for the period January 2011 through December 2011 are projected to be $601,313.

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Project Title: National Pollutant Discharge Elimination System ("NPDES") Annual Surveillance Fees

Project Description:

Chapter 62-4.052, Florida Administrative Code ("F. A. C."), implements the annual regulatory program and surveillance fees for wastewater permits. These fees are in addition to the application fees described in Rule 62-4.050, F. A. C. Tampa Electric's Big Bend, Hookers Point, Polk Power and Gannon Stations are affected by this rule.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated O&M expense for the period January 2010 through December 2010 is $34,500 compared to the original projection of $34,500 representing no variance.

Progress Summary: NPDES Surveillance fees are paid annually for the prior year.

Projections: Estimated O&M costs for the period January 2011 through December 2011 are projected to be $34,500.

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Project Title: Gannon Thermal Discharge Study

Project Description:

This project is a direct requirement from the FDEP in conjunction with the renewal of Tampa Electric's Industrial Wastewater Facility Permit under the provisions of Chapter 403, Florida Statutes, and applicable rules of the Florida Administrative Code, which constitute authorization for the company's Gannon Station facility to discharge to waters of the State under the NPDES. The FDEP permit is Permit No. FL0000809. Specifically, Tampa Electric is required to perform a 316(a) determination for Gannon Station to ensure the protection and propagation of a balanced, indigenous population of shellfish, fish and wildlife with in the primary area of study. The project will have two facets: 1) develop the plan of study and identify the thermal plume, and 2) implement the plan of study through appropriate sampling to make the determination if any adverse impacts are occurring.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated O&M expense for the period January 2010 through December 2010 is $20,000 compared to the original projection of $30,000, which represents a variance of 33.3 percent. The variance is due to the timing of requests for additional information from the FDEP.

Progress Summary: This project was approved by the Commission in Docket No. 010593-EI on September 4, 2001. The project is expected to continue through at least 2011.

Projections: Estimated O&M costs for the period January 2011 through December 2011 are projected to be $30,000.

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Project Title: Polk NO_x Emissions Reduction

Project Description:

This project is designed to meet a lower NO_x emissions limit established by the FDEP for Polk Unit 1 by July 1, 2005. The lower limit of 15 parts per million by volume dry basis at 15 percent O_2 is specified in FDEP Permit No. PSD-FL-194F issued February 5, 2002. The project will consist of two phases: 1) the humidification of syngas through the installation of a syngas saturator; and 2) the modification of controls and the installation of additional guide vanes to the diluent nitrogen compressor.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2010 through December 2010 is $195,609 as compared to the original projection of $195,609 representing no variance.

The actual/estimated O&M for the period January 2010 through December 2010 is $(139,797) compared to the original projection of $50,000, which represents a variance of 379.6 percent. The variance is due to the sale of NO_x emissions which offset the cost of maintenance activities.

Progress Summary: The project was placed in-service January 2005.

Project Projections: Estimated depreciation plus return for the period January 2011 through December 2011 is projected to be $189,422.

Estimated O&M costs for the period January 2011 through December 2011 are projected to be $50,000.

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Project Title: Bayside SCR Consumables

Project Description:

This project is necessary to achieve the NO_x emissions limit of 3.5 parts per million established by the FDEP Consent Final Judgment and the EPA Consent Decree for the natural gas-fired Bayside Power Station. To achieve this NO_x limit, the installation of selective catalytic reduction (SCR) systems is required. An SCR system requires consumable goods – primarily anhydrous ammonia – to be injected into the catalyst bed in order to achieve the required NO_x emissions limit. Principally, the project is designed to capture the cost of consumable goods necessary to operate the SCR systems.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated O&M expense for the period January 2010 through December 2010 is $114,898 compared to the original projection of $114,000 resulting in an insignificant variance.

Progress Summary: This project was approved by the Commission in Docket No. 021255-EI, Order No. PSC-03-0469-PAA-EI, issued April 4, 2003. As an O&M project, expenses are ongoing annually.

Projections: Estimated O&M costs for the period January 2011 through December 2011 are projected to be $115,200.

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Project Title: Big Bend Unit 4 Separated Overfire Air ("SOFA")

Project Description:

This project is necessary to assist in achieving the NO_x emissions limit established by the FDEP Consent Final Judgment and the EPA Consent Decree for Big Bend Unit 4. A SOFA system stages secondary combustion air to prevent NO_x formation that would otherwise require removal by post-combustion technology. In-furnace combustion control through a SOFA system is the most cost-effective means to reduce NO_x emissions prior to the application of these technologies. Costs associated with the SOFA system will entail capital expenditures for equipment installation and subsequent annual maintenance.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2010 through December 2010 is $317,962 compared to the original projection of $317,962 representing no variance.

The actual/estimated O&M for the period January 2010 through December 2010 is $61,525 compared to the original projection of $62,000, resulting in an insignificant variance.

Progress Summary: The project was placed in-service November 2004.

Projections: Estimated depreciation plus return for the period January 2011 through December 2011 is projected to be $310,809.

There are no estimated O&M costs for the period January 2011 through December 2011.

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Project Title: Big Bend Unit 1 Pre-SCR

Project Description:

In order to meet the requirements of the FDEP Consent Final Judgment and the EPA Consent Decree, Tampa Electric is required to make additional reductions of NO_x emissions at Big Bend Station on a per unit basis at prescribed times from 2011 through 2011. Based on a comprehensive study, Tampa Electric has declared the future fuel for Big Bend Station to be coal which will necessitate the installation of cost-effective SCR technology on the generating units to meet NO_x emissions requirements. Therefore, this project is a necessary precursor to an SCR system designed to reduce inlet NO_x concentrations to the SCR system thereby mitigating overall capital and O&M costs. The Big Bend Unit 1 Pre-SCR technologies include a neural network system, secondary air controls and windbox modifications.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2010 through December 2010 is $267,482 compared to the original projection of $267,482 representing no variance.

The actual/estimated O&M for the period January 2010 through December 2010 is $22,165 compared to the original projection of $75,000 representing a variance of 70.4 percent. The variance is due to prioritization of other maintenance items. No impact to the operation of the equipment occurred.

Progress Summary: This project was approved by the Commission in Docket No. 040750-EI, Order No. PSC-04-1080-CO-EI, issued November 4, 2004.

Projections: Estimated depreciation plus return for the period January 2011 through December 2011 is projected to be $261,143.

There are no estimated O&M costs for the period January 2011 through December 2011.

Tampa Electric Company
Environmental Cost Recovery Clause
January 2011 through December 2011
Description and Progress Report for
Environmental Compliance Activities and Projects

Project Title: Big Bend Unit 2 Pre-SCR

Project Description:

In order to meet the requirements of the FDEP Consent Final Judgment and the EPA Consent Decree, Tampa Electric is required to make additional reductions of NO_x emissions at Big Bend Station on a per unit basis at prescribed times from 2011 through 2011. Based on a comprehensive study, Tampa Electric has declared the future fuel for Big Bend Station to be coal which will necessitate the installation of cost-effective SCR technology on the generating units to meet NO_x emissions requirements. Therefore, this project is a necessary precursor to an SCR system designed to reduce inlet NO_x concentrations to the SCR system thereby mitigating overall capital and O&M costs. The Big Bend Unit 2 Pre-SCR technologies include secondary air controls and windbox modifications.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2010 through December 2010 is $213,590 compared to the original projection of $213,590 representing no variance.

The actual/estimated O&M for the period January 2010 through December 2010 is $0 compared to the original projection of $31,000, which represents a variance of 100.0 percent. The variance is due to the timing of activities. The project is anticipated to be on target by year end.

Progress Summary: This project was approved by the Commission in Docket No. 040750-EI, Order No. PSC-04-1080-CO-EI, issued November 4, 2004.

Projections: Estimated depreciation plus return for the period January 2011 through December 2011 is projected to be $207,873.

There are no estimated O&M costs for the period January 2011 through December 2011.

Tampa Electric Company
Environmental Cost Recovery Clause
January 2011 through December 2011
Description and Progress Report for
Environmental Compliance Activities and Projects

Project Title: Big Bend Unit 3 Pre-SCR

Project Description:

In order to meet the requirements of the FDEP Consent Final Judgment and the EPA Consent Decree, Tampa Electric is required to make additional reductions of NO_x emissions at Big Bend Station on a per unit basis at prescribed times from 2011 through 2011. Based on a comprehensive study, Tampa Electric has declared the future fuel for Big Bend Station to be coal, which will necessitate the installation of cost-effective SCR technology on the generating units to meet NO_x emissions requirements. Therefore, this project is a necessary precursor to an SCR system designed to reduce inlet NO_x concentrations to the SCR system thereby mitigating overall capital and O&M costs. The Big Bend Unit 3 Pre-SCR technologies include a neutral network system, secondary air controls, windbox modifications and primary coal/air flow controls.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2010 through December 2010 is $366,931 compared to the original projection of $366,931 resulting in no variance.

The actual/estimated O&M for the period January 2010 through December 2010 is $0 compared to the original projection of $31,000, which represents a variance of 100.0 percent. The variance is due to the timing of activities. The project is anticipated to be on target by year end.

Progress Summary: This project was approved by the Commission in Docket No. 040750-EI, Order No. PSC-04-1080-CO-EI, issued November 4, 2004.

Projections: Estimated depreciation plus return for the period January 2011 through December 2011 is projected to be $358,814.

There are no estimated O&M costs for the period January 2011 through December 2011.

Tampa Electric Company
Environmental Cost Recovery Clause
January 2011 through December 2011
Description and Progress Report for
Environmental Compliance Activities and Projects

Project Title: Clean Water Act Section 316(b) Phase II Study

Project Description:

This project is a direct requirement from the EPA to reduce impingement and entrainment of aquatic organisms related to the withdrawal of waters for cooling purposes through cooling water intake structures. The Phase II Rule requires that power plants meeting certain criteria to comply with national performance standards for impingement and entrainment. Accordingly, Tampa Electric must develop its compliance strategies for its H. L. Culbreath Bayside Power and the Big Bend Power Stations and then submit these strategies for approval through a Comprehensive Demonstration Study to the FDEP.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated O&M for the period January 2010 through December 2010 is $42,765 compared to the original projection of $60,000, which represents a variance of 28.7 percent. This variance is due to the costs being less than anticipated as well as the timing of requests for additional information from the FDEP.

Progress Summary: This project was approved by the Commission in Docket No. 041300-EI, Order No. PSC-05-0164-PAA-EI, issued February 10, 2005.

Projections: Estimated O&M costs for the period January 2011 through December 2011 are projected to be $60,000.

Tampa Electric Company
Environmental Cost Recovery Clause
January 2011 through December 2011
Description and Progress Report for
Environmental Compliance Activities and Projects

Project Title: Big Bend Unit 1 SCR

Project Description:

In order to meet the requirements of the FDEP Consent Final Judgment and the EPA Consent Decree, Tampa Electric is required to make additional reductions of NO_x emissions at Big Bend Station on a per unit basis at prescribed times from 2011 through 2011. Based on a comprehensive study, Tampa Electric has declared the future fuel for Big Bend Station to be coal, which will necessitate the installation of cost-effective SCR technology on the generating units to meet NO_x emissions requirements. This project is associated with the installation of an SCR system on Big Bend Unit 1 and is scheduled to go in-service May 2011.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2010 through December 2010 is $8,256,118 compared to the original projection of $9,152,077, which represents variance of 9.8 percent. This variance is due to the coordination of contractor labor and activities.

The actual/estimated O&M for the period January 2010 through December 2010 is $923,808 compared to the original projection of $1,001,600 resulting an insignificant variance.

Progress Summary: This project was approved by the Commission in Docket No. 041376-EI, Order No. PSC-05-0616-CO-EI, issued June 3, 2005.

Projections: Estimated depreciation plus return for the period January 2011 through December 2011 is projected to be $11,823,188.

Estimated O&M costs for the period January 2011 through December 2011 are projected to be $958,900.

Tampa Electric Company
Environmental Cost Recovery Clause
January 2011 through December 2011
Description and Progress Report for
Environmental Compliance Activities and Projects

Project Title: Big Bend Unit 2 SCR

Project Description:

In order to meet the requirements of the FDEP Consent Final Judgment and the EPA Consent Decree, Tampa Electric is required to make additional reductions of NO_x emissions at Big Bend Station on a per unit basis at prescribed times from 2011 through 2011. Based on a comprehensive study, Tampa Electric has declared the future fuel for Big Bend Station to be coal, which will necessitate the installation of cost-effective SCR technology on the generating units to meet NO_x emissions requirements. This project is associated with the installation of an SCR system on Big Bend Unit 2 and is scheduled to go in-service April 2011.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2010 through December 2010 is $12,790,727 compared to the original projection of $13,080,679, resulting an insignificant variance.

The actual/estimated O&M for the period January 2010 through December 2010 is $1,279,925 compared to the original projection of $1,668,100 representing a variance of 23.3 percent. The variance is due to the outage schedule resulting in lower ammonia consumption.

Progress Summary: This project was approved by the Commission in Docket No. 041376-EI, Order No. PSC-05-0616-CO-EI, issued June 3, 2005.

Projections: Estimated depreciation plus return for the period January 2011 through December 2011 is projected to be $12,522,896.

Estimated O&M costs for the period January 2011 through December 2011 are projected to be $1,728,400.

Tampa Electric Company
Environmental Cost Recovery Clause
January 2011 through December 2011
Description and Progress Report for
Environmental Compliance Activities and Projects

Project Title: Big Bend Unit 3 SCR

Project Description:

In order to meet the requirements of the FDEP Consent Final Judgment and the EPA Consent Decree, Tampa Electric is required to make additional reductions of NO_x emissions at Big Bend Station on a per unit basis at prescribed times from 2011 through 2011. Based on a comprehensive study, Tampa Electric has declared the future fuel for Big Bend Station to be coal which will necessitate the installation of cost-effective SCR technology on the generating units to meet NO_x emissions requirements. This project is associated with the installation of an SCR system on Big Bend Unit 3 and is scheduled to go in-service May 2011.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2010 through December 2010 is $10,460,882 compared to the original projection of $10,716,474 resulting in an insignificant variance.

The actual/estimated O&M for the period January 2010 through December 2010 is $1,359,000 compared to the original projection of $1,668,100 representing a variance of 18.5 percent. The variance is due to less ammonia used than originally anticipated.

Progress Summary: This project was approved by the Commission in Docket No. 041376-EI, Order No. PSC-05-0616-CO-EI, issued June 3, 2005.

Projections: Estimated depreciation plus return for the period January 2011 through December 2011 is projected to be $10,323,816.

Estimated O&M costs for the period January 2011 through December 2011 are projected to be $1,695,400.

Tampa Electric Company
Environmental Cost Recovery Clause
January 2011 through December 2011
Description and Progress Report for
Environmental Compliance Activities and Projects

Project Title: Big Bend Unit 4 SCR

Project Description:

In order to meet the requirements of the FDEP Consent Final Judgment and the EPA Consent Decree, Tampa Electric is required to make additional reductions of NO_x emissions at Big Bend Station on a per unit basis at prescribed times from 2011 through 2011. Based on a comprehensive study, Tampa Electric has declared the future fuel for Big Bend Station to be coal which will necessitate the installation of cost-effective SCR technology on the generating units to meet NO_x emissions requirements. This project is associated with the installation of an SCR system on Big Bend Unit 4 and is scheduled to go in-service June 2011.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2010 through December 2010 is $7,869,338 compared to the original projection of $8,062,688 resulting in an insignificant variance.

The actual/estimated O&M for the period January 2010 through December 2010 is $1,199,231 compared to the original projection of $778,700 representing a variance of 54.0 percent. The variance is due to the increased usage of ammonia as well as less outage days used than originally anticipated.

Progress Summary: This project went in to service in May 2007.

Projections: Estimated depreciation plus return for the period January 2011 through December 2011 is projected to be $7,722,172.

Estimated O&M costs for the period January 2011 through December 2011 are projected to be $758,200.

Tampa Electric Company
Environmental Cost Recovery Clause
January 2011 through December 2011
Description and Progress Report for
Environmental Compliance Activities and Projects

Project Title: Arsenic Groundwater Standard Program

Project Description:
The Arsenic Groundwater Standard Program that is required by the Environmental Protection Agency and the Department of Environmental Protection became effective January 1, 2005. It requires regulated entities of the State of Florida to monitor the drinking water and groundwater Maximum Contaminant Level ("MCL") for arsenic under the federal rule known as the Safe Drinking Water Act.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated O&M for the period January 2010 through December 2010 is $58,790 compared to the original projection of $50,000, resulting in a variance of 17.6 percent. The variance is due to requests for additional information from the FDEP resulting in increased compliance costs.

Progress Summary: In Docket No. 050683-EI, Order No. PSC-06-0138-PAA-EI, issued February 23, 2006, the Commission granted Tampa Electric cost recovery approval for prudent costs associated with this project.

Projections: Estimated O&M costs for the period January 2011 through December 2011 are projected to be $170,000.

Tampa Electric Company
Environmental Cost Recovery Clause
January 2011 through December 2011
Description and Progress Report for
Environmental Compliance Activities and Projects

Project Title: Big Bend Flue Gas Desulfurization ("FGD") System Reliability

Project Description:
The Big Bend FGD Reliability project is necessary to maintain the FGD system operations that are required by the Consent Decree. Tampa Electric is required to operate the FGD systems at Big Bend Station whenever coal is combusted in the units with few exceptions. The compliance dates for the strictest operational characteristics are January 1, 2011 for Big Bend Unit 3 and January 1, 2013 for Big Bend Units 1 and 2.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2010 through December 2010 is $1,534,108 compared to the original projection of $1,624,618, resulting in an insignificant variance.

Progress Summary: In Docket No. 050598-EI, Order No. PSC-06-0602-PAA-EI, issued July 10, 2006, the Commission granted cost recovery approval for prudent costs associated with this project.

Projections: Estimated depreciation plus return for the period January 2011 through December 2011 is projected to be $1,959,594.

Tampa Electric Company
Environmental Cost Recovery Clause
January 2011 through December 2011
Description and Progress Report for
Environmental Compliance Activities and Projects

Project Title: Clean Air Mercury Rule ("CAMR")

Project Description:
The EPA established standards of performance for mercury for new and existing coal-fired electric utility steam generating units as defined in the federal CAA Section 111, effective January 2010. CAMR will permanently cap and reduce mercury emissions nation-wide in two phases: Phase I cap is 38 tons per year with a compliance date of 2011 and Phase II cap is 15 tons per year with a compliance date of 2018. Tampa Electric's Big Bend and Polk Power Stations will be affected by the nation-wide mercury emissions reduction rule. According to Rule, the company must install emission-monitoring systems that sample mercury found in flue gas on Big Bend Units 1 through 4 and Polk Unit 1.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2010 through December 2010 is $166,207 compared to the original projection of $166,583, resulting in an insignificant variance.

The actual/estimated O&M for the period January 2010 through December 2010 is $103,159 compared to the original projection of $8,000, resulting in a variance of 1189.5 percent. The variance is due to the EPA Information Collection Request requiring extensive air emission testing at Polk Power Station and Big Bend Station. EPA is collecting data in support of Clean Air Act National Emission Standards for Hazardous Air Pollutant rulemaking that is under way.

Progress Summary: A petition was filed on August 30, 2006 seeking Commission approval of cost recovery through the ECRC for the new CAMR program.

Projections: Estimated depreciation plus return for the period January 2011 through December 2011 is projected to be $167,154.

Estimated O&M costs for the period January 2011 through December 2011 are projected to be $8,000.

Tampa Electric Company
Environmental Cost Recovery Clause
January 2011 through December 2011
Description and Progress Report for
Environmental Compliance Activities and Projects

Project Title: Greenhouse Gas Reduction Program

Project Description:
On September 22, 2009, the EPA enacted a new rule for reporting Greenhouse Gas ("GHG") emissions from large sources and suppliers effective January 1, 2010 in preparation for the first annual GHG report, due March 31, 2011. The new rule is intended to collect accurate and timely emissions data to inform future policy decisions as set forth in the final rule for GHG emission reporting pursuant to the Florida Climate Protection Act, Chapter 403.44 of the Florida Statutes and the docket EPA-HQ-OAR2008-0508-054. The nationwide GHG emissions reduction rule will impact Tampa Electric's generation fleet, components of its transmission and distribution system as well as company service vehicles. According to the rule, the company must begin collecting greenhouse gas emissions data effective January 1, 2010 to establish a baseline inventory to report to the EPA.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated O&M for the period January 2010 through December 2010 is $158,405. The project was not approved by the Commission in time to be added to the 2010 Projection.

Progress Summary: Cost recovery was approved in Docket No. 090508-EI, Order No. PSC-10-0157-PAA-EI, issued March 22, 2010.

Projections: Estimated O&M costs for the period January 2011 through December 2011 are projected to be $56,100.

Form 42 - 6P

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Energy & Demand Allocation % By Rate Class
January 2011 to December 2011

Rate Class	(1) Average 12 CP Load Factor at Meter (%)	(2) Projected Sales at Meter (MWh)	(3) Effective Sales at Secondary Level (MWh)	(4) Projected Avg 12 CP at Meter (MW)	(5) Demand Loss Expansion Factor	(6) Energy Loss Expansion Factor	(7) Projected Sales at Generation (MWh)	(8) Projected Avg 12 CP at Generation (MW)	(9) Percentage of MWh Sales at Generation (%)	(10) Percentage of 12 CP Demand at Generation (%)	(11) 12 CP & 25% Allocation Factor (%)
RS	54.79%	8,863,147	8,863,147	1,847	1.08070	1.05580	9,357,688	1,996	46.99%	56.74%	54.30%
GS, TS	65.43%	1,064,630	1,064,630	186	1.08070	1.05578	1,124,019	201	5.64%	5.71%	5.69%
GSD, SBF	75.00%	7,700,505	7,687,468	1,112	1.07588	1.05197	8,100,664	1,198	40.68%	34.05%	35.71%
IS	103.01%	1,066,368	1,048,065	118	1.03248	1.01870	1,086,314	122	5.46%	3.47%	3.97%
LS1	2445.31%	231,963	231,963	1	1.08070	1.05580	244,906	1	1.23%	0.03%	0.33%
TOTAL *		18,926,613	18,895,273	3,264			19,913,591	3,518	100.00%	100.00%	100.00%

Notes: (1) Average 12 CP load factor based on 2010 projected calendar data
(2) Projected MWh sales for the period January 2011 to December 2011
(3) Effective sales at secondary level for the period January 2011 to December 2011.
(4) Based on 12 months average CP at meter
(5) Based on 2010 demand losses
(6) Based on 2010 energy losses
(7) Column 2 x Column 6
(8) Column 4 x Column 5
(9) Based on 12 months average percentage of sales at generation.
(10) Column 8 / Total Column 8
(11) Column 9 x 0.25 + Column 10 x 0.75

* Totals on this schedule may not foot due to rounding

DOCKET NO. 100007-EI
ECRC 2011 PROJECTION FILING
EXHIBIT NO. HTB-3
DOCUMENT NO. 6

Form 42 - 7P

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Energy & Demand Allocation % By Rate Class
January 2011 to December 2011

Rate Class	(1) Percentage of MWh Sales at Generation (%)	(2) 12 CP & 25% Allocation Factor (%)	(3) Energy-Related Costs ($)	(4) Demand-Related Costs ($)	(5) Total Environmental Costs ($)	(6) Projected Sales at Meter (MWh)	(7) Effective Sales at Secondary Level (MWh)	**(8) Environmental Cost Recovery Factors (¢/kWh)**
RS	46.99%	54.30%	35,554,754	222,954	35,777,708	8,863,147	8,863,147	**0.404**
GS, TS	5.64%	5.69%	4,267,478	23,372	4,290,850	1,064,630	1,064,630	**0.403**
GSD, SBF	40.68%	35.71%	30,780,323	146,607	30,926,930	7,700,505	7,687,468	
Secondary								**0.402**
Primary								**0.398**
Transmission								**0.394**
IS	5.46%	3.97%	4,131,282	16,290	4,147,572	1,066,368	1,048,065	
Secondary								**0.396**
Primary								**0.392**
Transmission								**0.388**
LS1	1.23%	0.33%	930,673	1,355	932,028	231,963	231,963	**0.402**
TOTAL *	100.00%	100.00%	75,664,512	410,578	76,075,090	18,926,613	18,895,273	**0.403**

* Totals on this schedule may not foot due to rounding

Notes:
(1) From Form 42-6P, Column 9
(2) From Form 42-6P, Column 11
(3) *Column* 1 x Total Energy Jurisdictional Dollars from Form 42-1P, line 5
(4) Column 2 x Total Demand Jurisdictional Dollars from Form 42-1P, line 5
(5) Column 3 + Column 4
(6) From Form 42-6P, Column 2
(7) From Form 42-6P, Column 3
(8) Column 5 / Column 7 x 100

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DOCKET NO. 100007-EI
ECRC 2011 PROJECTION FILING
EXHIBIT NO. HTB-3
DOCUMENT NO. 7

DOCKET NO. 100007-EI
ECRC 2011 PROJECTION FILING
EXHIBIT NO. HTB-3
DOCUMENT NO. 8

Form 42 - 8P

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2011 to December 2011

Calculation of Revenue Requirement Rate of Return
(In Dollars)

	(1) Jurisdictional Rate Base 2009 Test Year ($000)	(2) Ratio %	(3) Cost Rate %	(4) Weighted Cost Rate %
Long Term Debt	$ 1,384,999	40.29%	6.80%	2.7397%
Short Term Debt	7,905	0.23%	2.75%	0.0063%
Preferred Stock	0	0.00%	0.00%	0.0000%
Customer Deposits	99,502	2.89%	6.07%	0.1754%
Common Equity	1,632,612	47.49%	11.25%	5.3426%
Deferred ITC - Weighted Cost	8,964	0.26%	9.19%	0.0239%
Accumulated Deferred Income Taxes & Zero Cost ITCs	303,629	8.83%	0.00%	0.0000%
Total	$ 3,437,611	100.00%		8.2879%

ITC split between Debt and Equity:

Long Term Debt	$ 1,384,999	Long Term Debt	45.78%
Short Term Debt	7,905	Short Term Debt	0.26%
Equity - Preferred	0	Equity - Preferred	0.00%
Equity - Common	1,632,612	Equity - Common	53.96%
Total	$ 3,025,516	**Total**	100.00%

Deferred ITC - Weighted Cost:

Debt = .0239% * 46.04%	0.0110%
Equity = .0239% * 53.96%	0.0129%
Weighted Cost	0.0239%

Total Equity Cost Rate:

Preferred Stock	0.0000%
Common Equity	5.3426%
Deferred ITC - Weighted Cost	0.0129%
	5.3555%
Times Tax Multiplier	1.628002
Total Equity Component	8.7188%

Total Debt Cost Rate:

Long Term Debt	2.7397%
Short Term Debt	0.0063%
Customer Deposits	0.1754%
Deferred ITC - Weighted Cost	0.0110%
Total Debt Component	2.9324%

Notes:

Column (1) - From Order No. PSC-09-0571-FOF-EI
Column (2) - Column (1) / Total Column (1)
Column (3) - From Order No. PSC-09-0571-FOF-EI
Column (4) - Column (2) x Column (3)

TECO.

TAMPA ELECTRIC

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 100007-EI

IN RE:

ENVIRONMENTAL COST RECOVERY FACTORS

PROJECTIONS

JANUARY 2011 THROUGH DECEMBER 2011

DIRECT TESTIMONY

OF

PAUL L. CARPINONE

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

PAUL CARPINONE

Q. Please state your name, address, occupation and employer.

A. My name is Paul Carpinone. My business address is 702 North Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") as Director, Environmental Health & Safety in the Environmental Health and Safety Department.

Q. Please provide a brief outline of your educational background and business experience.

A. I received a Bachelor of Science degree in Water Resources Engineering Technology from the Pennsylvania State University in 1978. I have been a Registered Professional Engineer in the State of Florida and Pennsylvania since 1984. Prior to joining Tampa Electric, I worked for Seminole Electric Cooperative as a Civil Engineer in various positions and in environmental consulting. In February 1988, I joined Tampa Electric as a Principal Engineer, and I have primarily worked in the area of Environmental Health and Safety. In 2006, I became Director, Environmental Health and Safety. My responsibilities include the development and administration of the company's environmental, health and safety policies and goals. I am also responsible for ensuring resources, procedures and programs meet or surpass compliance with applicable environmental, health and safety requirements, and that rules and policies are in place and functioning appropriately and consistently throughout the company.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to demonstrate that the activities for which Tampa Electric seeks cost recovery through the Environmental Cost Recovery Clause ("ECRC") for the January 2011 through December 2011 projection period are activities necessary for the company to comply with various environmental requirements. Specifically, I will describe the ongoing activities that are associated with the Consent Final Judgment ("CFJ") entered into with the Florida Department of Environmental Protection ("FDEP") and the Consent Decree ("CD") lodged with the U.S. Environmental Protection Agency ("EPA") and the Department of Justice. I will also discuss other programs previously approved by the Commission for recovery through the ECRC as well as the suspension of the Clean Water Act Section 316(b) Phase II Study, the vacatur of the Clean Air Mercury Rule, and EPA's mandatory reporting rule for greenhouse gases.

Q. Please provide an overview of the ongoing environmental compliance requirements that are the result of the CFJ and the CD ("the Orders").

A. The general ongoing requirements of the Orders provide for further reductions of sulfur dioxide ("SO_2"), particulate matter ("PM") and nitrogen oxides ("NO_x") emissions at Big Bend Station.

Q. What do the Orders require for SO_2 emission reductions?

A. The Orders require Tampa Electric to create a plan for optimizing the availability and removal efficiency of the flue gas desulfurization systems ("FGD" or "scrubbers"). The plans were submitted to the EPA in two phases, and were approved in July 2000, and February 2001, respectively.

Phase I required Tampa Electric to work scrubber outages around the clock and to utilize contract labor, when necessary, to speed the return of a malfunctioning scrubber to service. In addition, Phase I required Tampa Electric to review all critical scrubber spare parts and increase the number and availability of spare parts to ensure a speedy return to service of a malfunctioning scrubber.

Phase II outlined capital projects Tampa Electric was to perform to upgrade each scrubber at Big Bend Station. It also addressed the use of environmental dispatching in the event of a scrubber outage. All of the preliminary SO_2 emission reduction projects have been completed. However, additional work will occur in 2011 associated with the Big Bend Units 1 and 2 FGD and Big Bend FGD System Reliability programs to comply with the elimination of the allowed scrubber outage days for 2013.

Q. What do the Orders require for PM emission reductions?

A. The Orders require Tampa Electric to develop and implement a best operational practices ("BOP") study to minimize PM emissions from each electrostatic precipitator ("ESP") and complete and implement a best available control technology ("BACT") analysis of the

ESPs at Big Bend Station. The Orders also require the company to demonstrate the operation of a PM continuous emission monitoring system ("CEM") on Big Bend Units 3 and 4 and demonstrate the operation of a second PM CEM on another Big Bend unit. Pursuant to the Orders, the installation of the second PM CEM was required on or before May 1, 2007, if the first PM CEM had been shown to be feasible and remained in operation and if Tampa Electric advised the EPA that it had elected to continue to combust coal in Big Bend Units 1, 2 and 3. The first PM CEM was installed in February 2002. The installation and certification of the second PM CEM was completed in August 2009. The replacement to the PM CEM in operation will be installed in September of 2010 and certification activity will begin following installation as required by the Orders.

Q. Please describe the Big Bend PM Minimization and Monitoring program activities and provide the estimated capital and O&M expenditures for the period of January 2011 through December 2011.

A. The Big Bend PM Minimization and Monitoring program was approved by the Commission in Docket No. 001186-EI, Order No. PSC-00-2104-PAA-EI, issued November 6, 2000. In the

Order, the Commission found that the program met the requirements for recovery through the ECRC. Tampa Electric had previously identified various projects to improve precipitator performance and reduce PM emissions as required by the Orders. In 2011, there will be O&M expenses associated with existing and recently installed BOP and BACT equipment and continued implementation of the BOP procedures. These activities are expected to result in approximately $479,200 of O&M expenses.

Q. What do the Orders require for NO_x reductions?

A. The Orders require Tampa Electric to perform NO_x emission reductions projects on Big Bend Units 1, 2 and 3 and pursuant to an amendment, for Big Bend Unit 4 projects to be substituted for Big Bend Unit 3 projects. The NO_x emission reductions use the 1998 NO_x emissions as the baseline year for determining the level of reduction achieved. Tampa Electric was also required by the Orders to demonstrate innovative technologies or provide additional NO_x technologies beyond those required by the early NO_x emission reduction activities.

Q. Please describe the Big Bend NO_x Emission Reduction program activities and provide the estimated capital and

O&M expenses for the period of January 2011 through December 2011.

A. The Big Bend NO_x Emission Reduction program was approved by the Commission in Docket No. 001186-EI, Order No. PSC-00-2104-PAA-EI, issued November 6, 2000. In the Order, the Commission found that the program met the requirements for recovery through the ECRC. In 2011, Tampa Electric will perform maintenance on the previously approved and installed NO_x Reduction equipment. This activity is expected to result in approximately $396,000 of O&M expenses.

Q. Please describe long-term NO_x requirements associated with the Orders and Tampa Electric's efforts to comply with the requirements.

A. The Orders require Big Bend Unit 4 to begin operating with a Selective Catalytic Reduction ("SCR") system or other NO_x control technology, be repowered, or shut down and scheduled for dismantlement by June 1, 2007. Big Bend Units 3, 2 and/or 1 must either begin operating with an SCR system or other NO_x control technology, be repowered, or be shut down and scheduled for dismantlement one unit per year by May 1, 2008, May 1, 2009 and May 1, 2010, respectively.

In order to meet the NO_x emission rates and timing requirements of the Orders, Tampa Electric engaged an experienced consulting firm, Sargent and Lundy, to assist with the performance of a comprehensive study designed to identify the long-range plans for the generating units at Big Bend Station. The results of the study clearly indicated that the option to remain coal-fired at Big Bend Station and install the necessary NO_x reduction technologies is the most cost-effective alternative to satisfy the NO_x emission reductions required by the Orders. This decision was communicated to the EPA and FDEP in August 2004. Tampa Electric also apprised the Commission of this decision in its filing made in Docket No. 040750-EI in August 2004.

Q. Please describe the Big Bend Units 1 through 3 Pre-SCR and the Big Bend Units 1 through 4 SCR projects and provide estimated capital and O&M expenditures for the period of January 2011 through December 2011.

A. In Docket No. 040750-EI, Order No. PSC-04-0986-PAA-EI, issued October 11, 2004, the Commission approved cost recovery of the Big Bend Units 1 through 3 Pre-SCR and the

Big Bend Unit 4 SCR projects. The Big Bend Units 1 through 3 SCR projects were approved by the Commission in Docket No. 041376-EI, Order No. PSC-05-0502-PAA-EI, issued May 9, 2005. The purpose of the Pre-SCR technologies is to reduce inlet NO_x concentrations to the SCR systems, thereby mitigating overall SCR capital and O&M costs. These Pre-SCR technologies include neural networks, windbox modifications, secondary air controls and coal/air flow controls. The SCR projects at Big Bend Units 1 through 4 encompass the design, procurement, installation and annual O&M expenses associated with an SCR system for each unit.

The projected costs for the period of January 2011 through December 2011 for which Tampa Electric is seeking ECRC recovery are for the Big Bend Units 1 through 3 Pre-SCR and Big Bend Units 1, 2, 3 and 4 SCR capital and O&M expenditures associated with the engineering, procurement, construction, start-up, tuning, operation and ongoing maintenance for the projects. No capital or O&M expenditures are anticipated for Big Bend Units 1 through 3 Pre-SCR for 2011. Big Bend Unit 4 SCR was placed in-service May 2007. There are no anticipated capital expenditures for 2011; however, the O&M expenses for this project are anticipated to be $758,200. Big Bend Unit 3

SCR was placed in-service July 2008. Capital expenditures of $2,000,000 for 2011 are anticipated for the replacement of the SCR catalyst along with O&M expenditures of $1,695,400. Big Bend Unit 2 SCR was placed in-service June 2009 and will have anticipated capital expenditures of $42,000 with O&M costs of $1,728,400 for 2011. Big Bend Unit 1 SCR was placed in service April 2010 and will have anticipated capital expenditures of $42,000 with O&M costs of $958,900 for 2011.

Q. Please identify and describe the other Commission approved programs you will discuss.

A. The programs previously approved by the Commission that I will discuss include:

1) Big Bend Unit 3 FGD Integration
2) Big Bend Units 1 and 2 FGD
3) Gannon Thermal Discharge Study
4) Bayside SCR Consumables
5) Big Bend Unit 4 Separated Over-fired Air ("SOFA")
6) Clean Water Act Section 316(b) Phase II Study
7) Big Bend FGD System Reliability
8) Arsenic Groundwater Standard
9) Clean Air Mercury Rule ("CAMR")

10) Greenhouse Gas ("GHG") Reduction Program

Q. Please describe the Big Bend Unit 3 FGD Integration and the Big Bend Units 1 and 2 FGD activities and provide the estimated capital and O&M expenditures for the period of January 2011 through December 2011.

A. The Big Bend Unit 3 FGD Integration program was approved by the Commission in Docket No. 960688-EI, Order No. PSC-96-1048-FOF-EI, issued August 14, 1996. The Big Bend Units 1 and 2 FGD program was approved by the Commission in Docket No. 980693-EI, Order No. PSC-99-0075-FOF-EI, issued January 11, 1999. In those Orders, the Commission found that the programs met the requirements for recovery through the ECRC. The programs were implemented to meet the SO_2 emission requirements of the Phase I and II Clean Air Act Amendments ("CAAA") of 1990.

The projected January 2011 through December 2011, O&M expenses for the Big Bend Unit 3 FGD Integration project are $5,154,400. No capital expenditures are anticipated for this project. The projected capital and O&M expenditures for the Big Bend Units 1 and 2 FGD project for January 2011 through December 2011 are $4,636,500 and $7,791,300, respectively.

Q. Please describe the Gannon Thermal Discharge Study program activities and provide the estimated capital and O&M expenditures for the period of January 2011 through December 2011.

A. The Gannon Thermal Discharge Study program was approved by the Commission in Docket No. 010593-EI, Order No. PSC-01-1847-PAA-EI, issued September 14, 2001. In that Order, the Commission found that the program met the requirements for recovery through the ECRC. For the period of January 2011 through December 2011, there will be no capital expenditures for this program. Tampa Electric anticipates O&M expenses will be approximately $30,000 for the period.

Q. Please describe the Bayside SCR Consumables program activities and provide the estimated capital and O&M expenditures for the period of January 2011 through December 2011.

A. The Bayside SCR Consumables program was approved by the Commission in Docket No. 021255-EI, Order No. PSC-03-0469-PAA-EI, issued April 4, 2003. For the period of January 2011 through December 2011, there will be no capital expenditures for this program. Tampa Electric anticipates O&M expenses associated with the consumable goods (primarily anhydrous ammonia) will be approximately $115,200 for the period.

Q. Please describe the Big Bend Unit 4 SOFA program activities and provide the capital and O&M expenditures for the period of January 2011 through December 2011.

A. The Big Bend Unit 4 SOFA program was approved by Commission for ECRC recovery in Docket No. 030226-EI, Order No. PSC-03-0684-PAA-EI, issued June 6, 2003. In that Order, the Commission found that the program met the requirements for recovery through the ECRC contingent upon Big Bend Unit 4 remaining coal fired. On August 19, 2004, Tampa Electric submitted a letter to the EPA declaring the intent for Big Bend Units 1 through 4 to remain coal fired and, as such, complied with the applicable provisions of the CD associated with the decision. The SOFA project was completed in 2004. For the period of January 2011 through December 2011, Tampa Electric anticipates will be no capital or O&M expenditures for this program.

Q. Please describe the Clean Water Act Section 316(b) Phase II Study program activities and provide the estimated capital and O&M expenditures for the period of January

2011 through December 2011.

A. The Clean Water Act Section 316(b) Phase II Study program was approved by the Commission in Docket No. 041300-EI, Order No. PSC-05-0164-PAA-EI, issued February 10, 2005. For the period of January 2011 through December 2011, there will be no capital expenditures for this program. EPA announced on March 20, 2007, that the rule adopted pursuant to Section 316(b) be considered suspended. The suspension of the final rule was made on July 9, 2007. Tampa Electric believes that the work will continue to be useful for purposes related to the Phase II Rule and does not intend to suspend the work because it would not be cost-effective or appropriate to do so. Therefore, Tampa Electric anticipates O&M expenses associated with the sampling and study activities will be approximately $60,000 for the period.

Q. Please describe the Big Bend FGD System Reliability program activities and provide the estimated capital and O&M expenses for the period of January 2011 through December 2011.

A. Tampa Electric's Big Bend FGD System Reliability program was approved by the Commission in Docket No. 050598-EI, Order No. PSC-06-0602-PAA-EI, issued July 10, 2006. The Commission granted cost recovery approval for prudent costs associated with this project. The Big Bend FGD System Reliability project has been running concurrently with the installation of SCR systems on the generating units.

For the period of January 2011 through December 2011, the anticipated capital expenditures will be $12,140,500 however; no O&M expenditures are anticipated for this project.

Q. Please describe the Arsenic Groundwater Standard program activities and provide the estimated capital and O&M expenditures for the period of January 2011 through December 2011.

A. The Arsenic Groundwater Standard program was approved by the Commission in Docket No. 050683-EI, Order No. PSC-06-0138-PAA-EI, issued February 23, 2006. In that Order, the Commission found that the program met the requirements for recovery through the ECRC and granted Tampa Electric cost recovery approval for prudently incurred costs. The new groundwater standard applies to Tampa Electric's H.L. Culbreath Bayside, Big Bend and Polk Power Stations.

For the period of January 2011 through December 2011, there will be no capital expenditures for this program; however, Tampa Electric anticipates O&M expenses associated with the sampling activities will be approximately $170,000.

Q. Please describe the CAMR program activities and provide the estimated capital and O&M expenditures for the period of January 2011 through December 2011.

A. The CAMR program was approved by the Commission in Docket No. 060583-EI, Order No. PSC-06-0926-PAA-EI, issued November 6, 2006. In that Order, the Commission found that the program met the requirements for recovery through the ECRC and granted Tampa Electric cost recovery approval for prudently incurred costs.

On February 8, 2008, the Washington D.C. Circuit Court vacated EPA's rule removing power plants from the Clean Air Act list of regulated sources of hazardous air pollutants under section 112. At the same time, the Court vacated the Clean Air Mercury Rule. EPA is reviewing the Court's decisions and evaluating its impacts. Currently, the FDEP has begun mercury rulemaking this year that will likely have monitoring requirements comparable to CAMR.

Given the vacatur, capital spending for this program is anticipated to be complete in 2011 with monitoring to commence thereafter, using company resources. For the period of January 2011 through December 2011, the capital expenditures are anticipated to be $75,000 and the O&M expenditures to be $8,000.

Q. What is the impact of the recent remand of the CAIR and vacatur of the CAMR rules on Tampa Electric's ECRC projects?

A. The remand of CAIR should have minimal impact on Tampa Electric's ECRC projects associated with NO_x and SO_2 abatement. These projects were initiated as a result of the CD signed between EPA and Tampa Electric; therefore, the company anticipates continuing its efforts to complete and maintain the projects.

The vacatur of CAMR occurred after Tampa Electric had begun the procurement of equipment necessary to meet the intent of the original rule; however, the company was able to stop a significant portion of the total equipment purchase.

Tampa Electric anticipates a replacement to the CAMR rule to become effective in the near future therefore, during this time of review, the company plans to utilize the resources already secured to establish a baseline of mercury emissions.

Q. Please describe the GHG Reduction Program activities and provide the estimated capital and O&M expenditures for the period of January 2011 through December 2011.

A. Tampa Electric's GHG Reduction Program approved by the Commission in Docket No. 090508-EI, Order No. PSC-10-0157-PPA-EI, issued March 22, 2010 is a result of the EPA's Mandatory Reporting Rule requiring annual reporting of greenhouse gas emissions. In 2011 Tampa Electric will report greenhouse gas emissions to the EPA for the first time. This activity is expected to result in approximately $56,100 O&M expenses.

Q. Please summarize your testimony.

A. Tampa Electric's settlement agreements with FDEP and EPA require significant reductions in emissions from Tampa Electric's Big Bend and Gannon Stations. The Orders established definite requirements and time frames in which air quality improvements must be made and result in reasonable and fair outcomes for Tampa Electric, its community and customers, and the environmental agencies. My testimony identified projects that are legally required by these Orders. I described the progress Tampa Electric has made to achieve the more stringent environmental standards. I have identified estimated costs, by project, which the company expects to incur in 2011. Additionally, my testimony identified other projects that are required for Tampa Electric to meet the environmental requirements and I provided the associated 2011 activities and projected expenditures.

Q. Does this conclude your testimony?

A. Yes it does.