State of Florida

Public Service Commission

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

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

DATE: April 22, 2008

TO: Jenny X. Wu, Economic Analyst, Division of Economic Regulation

FROM: Denise N. Vandiver, Chief of Auditing, Division of Regulatory Compliance & Consumer Assistance

RE: Docket No: 080007-EI; Company Name: Tampa Electric Company;
Audit Purpose: Environmental Cost Recovery Clause;
Audit Control No: 08-029-2-2; Company Code; EI806:

Attached is the final audit report for the utility stated above. I am sending the utility a copy of this memo and the audit report. If the utility desires to file a response to the audit report, it should send the response to the Division of Commission Clerk. There are no confidential work papers associated with this audit.

DNV:sbj
Attachments

Copy: Division of Regulatory Compliance and Consumer Assistance (Hoppe, District Offices, File Folder)
Division of Commission Clerk (2)
Division of Competitive Markets and Enforcement (Harvey)
General Counsel
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FLORIDA PUBLIC SERVICE COMMISSION

DIVISION OF REGULATORY COMPLIANCE AND CONSUMER ASSISTANCE
BUREAU OF AUDITING

TAMPA DISTRICT OFFICE

TAMPA ELECTRIC COMPANY

ENVIRONMENTAL COST RECOVERY CLAUSE AUDIT

HISTORICAL YEAR ENDED DECEMBER 31, 2007

DOCKET NO. 080007-EI

AUDIT CONTROL NO. 08-029-2-2

Daniel Acheampong, Audit Manager

Joseph W. Rohrbacher, Tampa District Supervisor

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DIVISION OF REGULATORY COMPLIANCE AND CONSUMER ASSISTANCE
AUDITOR'S REPORT

April 16, 2008

TO: FLORIDA PUBLIC SERVICE COMMISSION AND OTHER INTERESTED PARTIES

We have performed the procedures enumerated later in this report to meet the agreed upon objectives set forth by the Division of Economic Regulation in its audit service request. We have applied these procedures to the attached schedules prepared by Tampa Electric Company (TEC) in support of its filing for Environmental Cost Recovery in Docket 080007-EI.

This audit was performed following general standards and field work standards found in the AICPA Statements on Standards for Attestation Engagements. This report is based on agreed upon procedures which are only for internal Commission use.

OBJECTIVES AND PROCEDURES:

Objective: Verify all negative depreciation expense amounts reported by TEC for any of its Environmental Cost Recovery Clause (ECRC) projects regardless of whether the negative depreciation expense amount is shown or noted on Form 42-8A. Review TEC's justification for each negative depreciation amount including applicable workpapers.

Procedures: We requested that the company provide instances of negative depreciation recorded during the audit period. The Company responded that there was no negative depreciation for any of the ECRC projects in 2007. This was verified in the next objective.

Objective: Using sampling procedures, reconcile Plant in Service (line 2) and Depreciation Expense (line 8a) for the capital projects listed in Form 42-8A. Verify that the investment is recorded in the correct plant account(s). Verify that the most recent Commission approved depreciation rate(s) or amortization period(s) is used in calculating the depreciation/amortization expense (line 8a, 8b). Verify that dismantlement expense (line 8c) is not included in the depreciation expense (line 8b and line 3).

Procedures: To reconcile Plant In Service (PIS), per filing, to the General Ledger, staff examined a summary of ECRC capital expenditures for 2007. We judgmentally selected four months (January, February, March and December) for further analysis. This analysis included the examination of selected company expenditures. The expenditures were extracted from the general ledger using queries. The queries listed all capital expenditures for designated FERC accounts, subpoints and resources applicable to ECRC. Based upon dollar amount, several items were selected for testing. The testing included tracing amounts to vendor vouchers and/or contracts to determine if items purchased were properly includible as ECRC investment. All transactions tested were properly charged to ECRC.

Using beginning of period and end of period PIS balances by project and by account, we calculated average PIS for the year and applied PSC authorized depreciation rates (Order No. PSC-08-0014-PAA-EI). We compared the resulting computation to the depreciation expense recorded by the company. The company calculated depreciation expense based upon the monthly average of PIS. We determined that no dismantlement expense is included in depreciation expense.

Objective: Verify that where an ECRC project involves the replacement of existing plant assets, the company is retiring the installed costs of replaced units of property according to Rule 25-6.0142(4)(b), F.A.C. [Book cost of retirement shall be credited to plant and debited to accumulated depreciation; cost of removal shall be debited to accumulated depreciation]

Procedures: We requested that the company provide a schedule and supporting documentation of all units of property replacing retired plant.

We determined that there was no replacement of existing plant for any of the ECRC projects in 2007.

Objective: Verify calculations of the monthly depreciation expense offsets required by Order No. PSC-99-2513-FOF-EI to adjust ECRC costs for retirements and replacements recovered through base rates.

Procedures: We determined that all ECRC Plant was placed in service subsequent to TEC's latest rate case. As a result, there is no ECRC PIS being recovered through base rates and no adjustment is necessary for the company to be in compliance with Commission Order PSC-99-2513-FOF-EI.

Objective: Verify the accuracy of recoverable Operation and Maintenance (O&M) expenses recorded in the ECRC filing.

Reconcile actual O&M project costs for a statistical sample or judgment sample of the O&M projects listed in Form 42-5A.

Procedures: Using judgmental and block sampling, we traced selected O&M costs for the projects listed in Form-42-5A. The sample items were taken from general ledger queries for ECRC accounts, subpoints and resource codes.

Immaterial differences occurred. No exceptions made.

Objectives: Report the monthly SO2 allowance expenses for 2007 including revenues, inventory amounts (tonnages and dollars), expensed amounts (tonnages and dollars), and the amount included in working capital.

Procedures: We obtained inventory schedules for SO2 allowances for each month in the test period and selected four months (August, September, October and December) for testing. We traced SO2 allowance expense to SO2 emissions from market based sales, co-generation purchases and consumption by Big Bend and Polk.

Objectives: To verify that that True-Up and Interest were properly calculated.

Procedures: We recomputed the 2007 ECRC True-Up and Interest using the approved recoverable True-Up amount per Commission Order PSC-07-0922-FOF-EI and 30-day commercial interest rates.

Objectives: Verify the accuracy of recoverable revenues recorded in the ECRC filing.

Procedures: Using KWH's for recoverable sales and Commission approved ECRC rates, we recalculated 2007 ECRC revenues billed. We compared this balance to the ECRC filing. Minor differences occurred as a result of rounding.

We adjusted 2007 ECRC revenues, per the filing, using the Regulatory Assessment Fee. This balance was compared to the 2007 ECRC revenues recorded in the General Ledger (G/L). Minor differences were noted as a result of manual adjustments to customer billing posted in the G/L.

No exception was made for the above immaterial differences.

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount for the Period
January 2007 to December 2007

Form 42 - 2A

Current Period True-Up Amount
(in Dollars)

Line		January	February	March	April	May	June	July	August	September	October	November	December	End of Period Total
1.	ECRC Revenues (net of Revenue Taxes)	($5,265,935)	($4,789,886)	($4,781,167)	($4,928,971)	($5,337,681)	($5,850,945)	($6,496,394)	($6,565,988)	($7,081,686)	($6,089,819)	($5,198,503)	($4,937,115)	($67,324,090)
2.	True-Up Provision	2,894,853	2,894,853	2,894,853	2,894,853	2,894,853	2,894,853	2,894,853	2,894,853	2,894,853	2,894,853	2,894,853	2,894,852	34,738,235
3.	ECRC Revenues Applicable to Period (Lines 1 + 2)	(2,371,082)	(1,895,033)	(1,886,314)	(2,034,118)	(2,442,828)	(2,956,092)	(3,601,541)	(3,671,135)	(4,186,833)	(3,194,966)	(2,303,650)	(2,042,263)	(32,585,856)
4.	Jurisdictional ECRC Costs													
	a. O & M Activities (Form 42-5A, Line 9)	823,958	1,399,886	1,248,559	(188,756)	(11,254,749)	(3,092,906)	(5,563,023)	(20,943,114)	(8,269,493)	(11,010,637)	(5,903,794)	(13,601,439)	(76,355,508)
	b. Capital Investment Projects (Form 42-7A, Line 9)	1,385,233	1,371,847	1,400,704	1,390,507	1,566,905	2,097,636	2,094,801	2,087,565	2,108,984	2,075,179	2,111,380	2,125,816	21,814,557
	c. Total Jurisdictional ECRC Costs	2,209,191	2,771,733	2,649,263	1,201,751	(9,687,844)	(995,270)	(3,468,222)	(18,855,549)	(6,162,509)	(8,935,458)	(3,792,414)	(11,475,623)	(54,540,951)
5.	Over/Under Recovery (Line 3 - Line 4c)	(4,580,273)	(4,666,766)	(4,535,577)	(3,235,869)	7,245,016	(1,960,822)	(133,319)	15,184,414	1,975,676	5,740,492	1,488,764	9,433,360	21,955,096
6.	Interest Provision (Form 42-3A, Line 10)	83,871	51,117	18,508	(11,110)	(15,058)	(16,268)	(33,568)	(13,892)	11,590	14,568	17,039	27,933	134,730
7.	Beginning Balance True-Up & Interest Provision	34,738,235	27,346,980	19,836,478	12,424,556	6,282,724	10,617,829	5,745,886	2,684,146	14,959,815	14,052,228	16,912,435	15,523,385	34,738,235
	a. Deferred True-Up from January to December 2006 (Order No. PSC-07-0922-FOF-EI)	(11,895,683)	(11,895,683)	(11,895,683)	(11,895,683)	(11,895,683)	(11,895,683)	(11,895,683)	(11,895,683)	(11,895,683)	(11,895,683)	(11,895,683)	(11,895,683)	(11,895,683)
8.	True-Up Collected/(Refunded) (see Line 2)	(2,894,853)	(2,894,853)	(2,894,853)	(2,894,853)	(2,894,853)	(2,894,853)	(2,894,853)	(2,894,853)	(2,894,853)	(2,894,853)	(2,894,853)	(2,894,852)	(34,738,235)
9.	End of Period Total True-Up (Lines 5+6+7+7a+8)	15,451,297	7,940,795	528,873	(5,612,959)	(1,277,854)	(6,149,797)	(9,211,537)	3,064,132	2,156,545	5,016,752	3,627,702	10,194,143	10,194,143
10.	Adjustment to Period True-Up Including Interest	0	0	0	0	0	0	0	0	0	0	0	0	0
11.	End of Period Total True-Up (Lines 9 + 10)	$15,451,297	$7,940,795	$528,873	($5,612,959)	($1,277,854)	($6,149,797)	($9,211,537)	$3,064,132	$2,156,545	$5,016,752	$3,627,702	$10,194,143	$10,194,143

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount for the Period
January 2007 to December 2007

Form 42 - 5A

O&M Activities
(in Dollars)

Line		January	February	March	April	May	June	July	August	September	October	November	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	$299,597	$812,230	$367,415	$440,618	$271,213	$376,445	$386,471	$365,484	$273,624	$329,863	$229,196	$294,284	$4,446,440		$4,446,440
	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	(25,909)	13,178	15,874	(1,028,135)	(12,471,000)	(4,077,470)	(6,696,385)	(22,941,710)	(9,369,596)	(12,403,958)	(6,981,217)	(14,996,919)	(90,963,247)		(90,963,247)
	d. Big Bend Units 1 & 2 FGD	615,331	290,459	312,229	459,151	372,698	358,403	412,162	445,740	395,247	493,366	376,953	420,248	4,951,987		4,951,987
	e. Big Bend PM Minimization and Monitoring	12,234	48,962	46,732	17,941	33,164	26,893	23,480	23,562	31,944	15,131	24,804	39,130	343,977		343,977
	f. Big Bend NO_x Emissions Reduction	15,319	128,663	324,729	(128,422)	14,248	11,196	7,158	37,686	(117)	5,146	6,693	17,861	440,160		440,160
	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	4,902	6,031	4,850	1,725	977	7,632	6,332	0	1,108	1,425	1,254	8,414	44,650	44,650	
	i. Polk NO_x Emissions Reduction	2,588	2,142	6,840	3,394	12,833	10,325	5,711	3,340	8,608	3,223	7,950	5,464	72,418		72,418
	j. Bayside SCR Consumables	8,158	0	8,069	0	8,877	0	17,737	8,413	(406)	17,143	6,559	0	74,550		74,550
	k. Big Bend Unit 4 SOFA	0	9,844	159,897	(9,689)	2,977	0	0	0	11,189	25,108	63,260	0	262,586		262,586
	l. Big Bend Unit 1 Pre-SCR	543	0	0	0	0	(543)	0	0	0	4,586	0	0	4,586		4,586
	m. Big Bend Unit 2 Pre-SCR	1,100	0	2,710	0	5,713	(14,188)	33	0	10,267	0	0	1,000	6,635		6,635
	n. Big Bend Unit 3 Pre-SCR	0	0	0	0	0	0	0	0	0	0	4,947	19,048	23,995		23,995
	o. Clean Water Act Section 316(b) Phase II Study	(124,116)	146,545	38,124	45,528	34,912	19,489	0	11,320	38,666	0	69,667	61,279	341,414	341,414	
	p. Arsenic Groundwater Standard Program	0	0	0	0	0	0	0	10,230	0	0	0	0	10,230	10,230	
	q. Big Bend 4 SCR	0	0	0	0	7,596	80,867	60,481	198,086	62,847	(12,674)	101,433	95,732	594,368		594,368
2.	Total of O&M Activities	844,247	1,458,054	1,287,469	(197,889)	(11,705,792)	(3,200,951)	(5,776,820)	(21,837,849)	(8,536,619)	(11,521,641)	(6,088,501)	(14,034,459)	(79,310,751)	$430,794	($79,741,545)
3.	Recoverable Costs Allocated to Energy	928,961	1,305,478	1,244,495	(245,142)	(11,741,681)	(3,228,072)	(5,783,152)	(21,859,399)	(8,576,393)	(11,523,066)	(6,159,422)	(14,104,152)	(79,741,545)		
4.	Recoverable Costs Allocated to Demand	(84,714)	152,576	42,974	47,253	35,889	27,121	6,332	21,550	39,774	1,425	70,921	69,693	430,794		
5.	Retail Energy Jurisdictional Factor	0.9751201	0.9593379	0.9698850	0.9563200	0.9614843	0.9662495	0.9629945	0.9590358	0.9686989	0.9556497	0.9696286	0.9691337			
6.	Retail Demand Jurisdictional Factor	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743			
7.	Jurisdictional Energy Recoverable Costs (A)	905,849	1,252,395	1,207,017	(234,434)	(11,289,442)	(3,119,123)	(5,569,144)	(20,963,946)	(8,307,942)	(11,012,015)	(5,972,352)	(13,668,809)	(76,771,946)		
8.	Jurisdictional Demand Recoverable Costs (B)	(81,891)	147,491	41,542	45,678	34,693	26,217	6,121	20,832	38,449	1,378	68,558	67,370	416,438		
9.	Total Jurisdictional Recoverable Costs for O&M Activities (Lines 7 + 8)	$823,958	$1,399,886	$1,248,559	($188,756)	($11,254,749)	($3,092,906)	($5,563,023)	($20,943,114)	($8,269,493)	($11,010,637)	($5,903,794)	($13,601,439)	($76,355,508)		

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

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount for the Period
January 2007 to December 2007

Form 42-7A

Capital Investment Projects-Recoverable Costs

(in Dollars)

Line		Description (A)	January	February	March	April	May	June	July	August	September	October	November	December	End of Period Total	Method of Classification Demand	Method of Classification Energy
1.	a.	Big Bend Unit 3 Flue Gas Desulfurization Integration	$70,024	$69,871	$69,718	$69,565	$69,411	$69,258	$69,105	$68,951	$68,798	$68,645	$68,492	$68,339	$830,177		$830,177
	b.	Big Bend Units 1 and 2 Flue Gas Conditioning	40,562	40,433	40,302	40,173	40,042	39,912	39,782	39,652	39,522	39,392	39,261	39,132	478,165		478,165
	c.	Big Bend Unit 4 Continuous Emissions Monitors	7,149	7,135	7,120	7,106	7,090	7,076	7,061	7,046	7,032	7,017	7,003	6,987	84,822		84,822
	d.	Big Bend Fuel Oil Tank # 1 Upgrade	4,855	4,845	4,835	4,824	4,814	4,803	4,793	4,782	4,772	4,761	4,750	4,740	57,574	$ 57,574	
	e.	Big Bend Fuel Oil Tank # 2 Upgrade	7,986	7,968	7,951	7,934	7,917	7,900	7,883	7,865	7,848	7,831	7,814	7,797	94,694	94,694	
	f.	Phillips Upgrade Tank # 1 for FDEP	530	528	527	526	524	523	521	519	518	517	515	514	6,262	6,262	
	g.	Phillips Upgrade Tank # 4 for FDEP	832	830	828	825	824	821	819	817	815	812	811	808	9,842	9,842	
	h.	Big Bend Unit 1 Classifier Replacement	12,602	12,567	12,532	12,497	12,462	12,427	12,391	12,357	12,321	12,287	12,251	12,216	148,910		148,910
	i.	Big Bend Unit 2 Classifier Replacement	9,102	9,077	9,052	9,028	9,003	8,978	8,954	8,929	8,905	8,881	8,856	8,831	107,596		107,596
	j.	Big Bend Section 114 Mercury Testing Platform	1,189	1,187	1,185	1,183	1,181	1,179	1,177	1,175	1,173	1,171	1,170	1,167	14,137		14,137
	k.	Big Bend Units 1 & 2 FGD	773,612	771,887	769,929	767,971	766,012	764,054	762,096	760,138	758,179	756,222	754,264	752,306	9,156,670		9,156,670
	l.	Big Bend FGD Optimization and Utilization	222,958	222,554	222,150	221,745	221,341	220,937	220,534	220,130	219,725	219,321	218,917	218,513	2,648,825		2,648,825
	m.	Big Bend NO_x Emissions Reduction	73,064	72,909	72,754	72,600	72,445	72,291	72,136	69,327	66,554	66,474	66,393	66,311	843,258		843,258
	n.	Big Bend PM Minimization and Monitoring	92,943	92,747	92,551	92,355	92,159	91,963	91,767	91,571	91,375	91,180	90,983	90,788	1,102,382		1,102,382
	o.	Polk NO_x Emissions Reduction	18,075	18,032	17,989	17,946	17,902	17,860	17,817	17,774	17,731	17,688	17,645	17,603	214,062		214,062
	p.	Big Bend Unit 4 SOFA	28,544	28,494	28,445	28,395	28,346	28,296	28,246	28,197	28,147	28,096	28,047	27,997	339,250		339,250
	q.	Big Bend Unit 1 Pre-SCR	21,814	24,031	23,966	23,928	23,887	23,846	23,806	23,765	23,726	23,686	23,654	23,620	283,729		283,729
	r.	Big Bend Unit 2 Pre-SCR	17,447	19,397	19,357	19,318	19,278	19,238	19,199	19,159	19,119	19,079	19,039	19,000	228,630		228,630
	s.	Big Bend Unit 3 Pre-SCR	7,225	7,552	7,865	8,214	8,249	8,246	9,484	10,732	10,757	10,809	15,576	20,500	125,209		125,209
	t.	Big Bend Unit 1 SCR	0	0	0	0	0	0	0	0	0	0	0	0	0		0
	u.	Big Bend Unit 2 SCR	0	0	0	0	0	0	0	0	0	0	0	0	0		0
	v.	Big Bend Unit 3 SCR	0	0	0	0	0	0	0	0	0	0	0	0	0		0
	w.	Big Bend Unit 4 SCR	0	0	0	0	169,240	704,920	709,200	711,383	712,140	709,259	707,615	707,807	5,131,544		5,131,544
	x.	Big Bend FGD System Reliability	18,024	25,414	42,726	55,199	64,410	72,680	74,416	76,434	77,949	79,256	84,667	97,882	769,057		769,057
	y.	Clean Air Mercury Rule	0	0	0	0	0	0	0	811	1,651	1,725	1,824	1,902	7,913		7,913
	z.	SO_2 Emissions Allowances (B)	(7,837)	(7,573)	(7,539)	(7,466)	(6,940)	(6,309)	(5,942)	(4,872)	(3,662)	(2,784)	(1,990)	(1,203)	(64,117)		(64,117)
2.		Total Investment Projects - Recoverable Costs	1,420,700	1,429,885	1,444,243	1,453,866	1,629,597	2,170,899	2,175,245	2,176,622	2,175,095	2,171,325	2,177,557	2,193,557	22,618,591	$ 168,372	$ 22,450,219
3.		Recoverable Costs Allocated to Energy	1,406,497	1,415,714	1,430,102	1,439,757	1,615,518	2,156,852	2,161,229	2,162,639	2,161,142	2,157,404	2,163,667	2,179,698	22,450,219		
4.		Recoverable Costs Allocated to Demand	14,203	14,171	14,141	14,109	14,079	14,047	14,016	13,983	13,953	13,921	13,890	13,859	168,372		
5.		Retail Energy Jurisdictional Factor	0.9751201	0.9593379	0.9698850	0.9563200	0.9614843	0.9662495	0.9629945	0.9590358	0.9686989	0.9556497	0.9696286	0.9691337			
6.		Retail Demand Jurisdictional Factor	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743			
7.		Jurisdictional Energy Recoverable Costs (C)	1,371,503	1,358,148	1,387,034	1,376,868	1,553,295	2,084,057	2,081,252	2,074,048	2,093,496	2,061,722	2,097,953	2,112,419	21,651,795		
8.		Jurisdictional Demand Recoverable Costs (D)	13,730	13,699	13,670	13,639	13,610	13,579	13,549	13,517	13,488	13,457	13,427	13,397	162,762		
9.		Total Jurisdictional Recoverable Costs for Investment Projects (Lines 7 + 8)	$1,385,233	$1,371,847	$1,400,704	$1,390,507	$1,566,905	$2,097,636	$2,094,801	$2,087,565	$2,106,984	$2,075,179	$2,111,380	$2,125,816	$21,814,557		

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