**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 20, 2010 |
| **TO:** | Jenny Wu, Economic Analyst, Division of Economic Regulation |
| **FROM:** | Clarence Prestwood, Chief of Auditing, Office of Auditing and Performance Analysis |
| **RE:** | Docket No.: 100007-EI<br>Company Name: Tampa Electric Company<br>Company Code: EI806<br>Audit Purpose: Environmental Cost Recovery Clause<br>Audit Control No: 09-363-2-2 |



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 a response to the Office of Commission Clerk. There were no confidential work papers associated with this audit.

CP/ip
Attachment: Audit Report

cc: (With Attachment)
Office of Auditing and Performance Analysis (Mailhot, File Folder)
Office of Commission Clerk
Office of the General Counsel

(Without Attachment)
Office of Auditing and Performance Analysis (Harvey, Tampa District Office, Miami District Office, Tallahassee District Office)


**FLORIDA PUBLIC SERVICE COMMISSION**

**OFFICE OF AUDITING AND PERFORMANCE ANALYSIS**
**BUREAU OF AUDITING**

**TAMPA DISTRICT OFFICE**

# TAMPA ELECTRIC COMPANY

# ENVIRONMENTAL COST RECOVERY CLAUSE AUDIT

**HISTORICAL YEAR ENDED DECEMBER 31, 2009**

**DOCKET NO. 100007-EI**

**AUDIT CONTROL NO. 09-363-2-2**

Tomer Kopelovich, Audit Manager

Clarence Prestwood, Chief of Auditing

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**OFFICE OF AUDITING AND PERFORMANCE ANALYSIS**
**AUDITOR'S REPORT**

**April 8, 2010**

**TO: FLORIDA PUBLIC SERVICE COMMISSION**

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 (TECO) in support of its filing for Environmental Cost Recovery in Docket 100007-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 and the report is intended only for internal Commission use.

**OBJECTIVES AND PROCEDURES:**

Objective: Verify all negative depreciation expense amounts reported by TECO 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 of the company filing. Review TECO's justification for each negative depreciation amount including applicable company 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 2009. Also, we reviewed the filing and we did not find any negative depreciation.

Objective: Audit the capital investment project from Big Bend Unit 3 SCR and 3 other projects, determined by sampling procedures, among lines 1a through 1z on Form 42-7A: (i) verify that the investment is recorded in the correct plant accounts. (ii) reconcile the corresponding Plant-in-Service/Depreciation Base (line 2, Form 42-8A); (iii) verify the calculations of the CWIP-Non Interest Bearing (line 4); (iv) verify that the most recent Commission approved depreciation rate(s) and amortization period(s) are used in calculating the depreciation/amortization expense (line 8A, 8B).Verify that dismantlement expense (line 8C) is not included in depreciation/amortization expense (line 8a and line 8b).

Procedures: We reconciled Plant In Service (PIS), per filing, to the General Ledger. Staff examined a summary of ECRC capital expenditures for 2009. We judgmentally selected various projects 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 account numbers, and resources applicable to ECRC. Several items were selected for testing based upon the dollar amount. The testing included tracing the amounts to vendor vouchers to determine if items purchased were properly includible as ECRC investment.

Using beginning and end of year 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 and no differences were noted. 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 for all units of property replacing retired plant. We determined that there was no replacement of existing plant for any of the ECRC projects in 2009.

Objective: Verify the ECRC project-related plant additions, retirements, and adjustments for the period January 1, 2009 – December 31, 2009.

Procedures: We tested a sample of ECRC project related plant additions for proper amount, account and period. There were no retirements or adjustments.

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 that was projected to be placed in service as of December 31, 2009 was removed in rate base consideration in TECO Docket No. 080317-EI. No adjustment is necessary.

Objective: Reconcile the O & M project expenses to the general ledger for a statistical sample or a judgmental sample of the projects listed in Form 42-5A.

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

Procedures: Using judgmental 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, sub-accounts and resource codes. Nothing unusual was noted.

Objective: Audit the capital project SO2 Emissions Allowance. Verify the investments, the inventory (tonnages and dollars), the expensed amounts (tonnages and dollars), and the amount included in working capital (line 2, Form 42-8A).

Procedures: We obtained inventory schedules for SO2 allowances for each month in the test period and selected six months (April, May, July, August, October, and November) for testing. We traced SO2 allowance expense to SO2 emissions from market based sales, co-generation purchases and consumption. We prepared an inventory amount schedule to include tonnage and dollars. Our calculation agrees with the company calculation.

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

Procedures: We recomputed the 2009 ECRC True-Up and Interest using the approved recoverable True-Up amount per Commission Order PSC-09-0709-FOF-EI and 30-day commercial paper interest rates. No differences were noted.

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

Procedures: Using KWHs for recoverable sales and Commission approved ECRC rates, we recalculated 2009 ECRC revenues billed. We compared this balance to the ECRC filing. Staff's calculation agrees with the company calculation.

Form 42 - 2A

**Tampa Electric Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount for the Period
**January 2009 to December 2009**

**Current Period True-Up Amount**
(in Dollars)

| Line | | Actual January | Actual February | Actual March | Actual April | Actual May | Actual June | Actual July | Actual August | Actual September | Actual October | Actual November | Actual December | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1. | ECRC Revenues (net of Revenue Taxes) | $3,325,406 | $3,271,914 | $2,993,030 | $3,046,026 | $3,434,524 | $3,783,674 | $4,070,650 | $3,976,794 | $3,980,974 | $3,822,610 | $3,332,462 | $3,004,594 | $42,042,658 |
| 2. | True-Up Provision | 392,598 | 392,598 | 392,598 | 392,598 | 392,598 | 392,598 | 392,598 | 392,598 | 392,598 | 392,598 | 392,598 | 392,593 | 4,711,171 |
| 3. | ECRC Revenues Applicable to Period (Lines 1 + 2) [1] | 3,718,004 | 3,664,512 | 3,385,628 | 3,438,624 | 3,827,122 | 4,176,272 | 4,463,248 | 4,369,392 | 4,373,572 | 4,215,208 | 3,725,060 | 3,397,187 | 46,753,829 |
| 4. | Jurisdictional ECRC Costs | | | | | | | | | | | | | |
| | a. O & M Activities (Form 42-5A, Line 9) | 1,120,310 | 1,094,397 | 1,139,054 | 1,405,267 | 897,593 | 1,101,448 | 1,074,727 | 1,189,881 | 1,265,565 | 1,403,444 | 1,125,992 | 1,295,184 | 14,112,862 |
| | b. Capital Investment Projects (Form 42-7A, Line 9) | 3,103,129 | 3,099,629 | 3,106,967 | 3,093,907 | 3,079,351 | 3,073,427 | 3,080,041 | 3,072,334 | 3,837,279 | 4,160,593 | 4,182,813 | 4,169,923 | 41,059,393 |
| | c. Total Jurisdictional ECRC Costs | 4,223,439 | 4,194,026 | 4,246,021 | 4,499,174 | 3,976,944 | 4,174,875 | 4,154,768 | 4,262,215 | 5,102,844 | 5,564,037 | 5,308,805 | 5,465,107 | 55,172,255 |
| 5. | Over/Under Recovery (Line 3 - Line 4c) [1] | (505,435) | (529,514) | (860,393) | (1,060,550) | (149,822) | 1,397 | 308,480 | 107,177 | (729,272) | (1,348,829) | (1,583,745) | (2,067,920) | (8,418,426) |
| 6. | Interest Provision (Form 42-3A, Line 10) | (2,118) | (3,048) | (3,161) | (2,884) | (2,381) | (2,344) | (2,408) | (2,095) | (1,963) | (2,024) | (2,359) | (2,606) | (29,391) |
| 7. | Beginning Balance True-Up & Interest Provision [1] | 4,711,171 | 3,811,020 | 2,885,860 | 1,629,708 | 173,676 | (371,125) | (764,670) | (851,196) | (1,138,712) | (2,262,545) | (4,005,996) | (5,984,698) | 4,711,171 |
| | a. Deferred True-Up from January to December 2008 (Order No. PSC-09-0759-FOF-EI) | (8,112,993) | (8,112,993) | (8,112,993) | (8,112,993) | (8,112,993) | (8,112,993) | (8,112,993) | (8,112,993) | (8,112,993) | (8,112,993) | (8,112,993) | (8,112,993) | (8,112,993) |
| 8. | True-Up Collected/(Refunded) (see Line 2) | (392,598) | (392,598) | (392,598) | (392,598) | (392,598) | (392,598) | (392,598) | (392,598) | (392,598) | (392,598) | (392,598) | (392,593) | (4,711,171) |
| 9. | End of Period Total True-Up (Lines 5+6+7+7a+8) [1] | (4,301,973) | (5,227,133) | (6,483,285) | (7,939,317) | (8,484,118) | (8,877,663) | (8,964,189) | (9,251,705) | (10,375,538) | (12,118,989) | (14,097,691) | (16,560,810) | (16,560,810) |
| 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) [1] | ($4,301,973) | ($5,227,133) | ($6,483,285) | ($7,939,317) | ($8,484,118) | ($8,877,663) | ($8,964,189) | ($9,251,705) | ($10,375,538) | ($12,118,989) | ($14,097,691) | ($16,560,810) | ($16,560,810) |



Exhibit 1

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
*Calculation of the Final True-Up Amount for the Period*
**January 2009 to December 2009**

Form 42 - 5A

**O&M Activities**
(in Dollars)

| Line | | Actual January | Actual February | Actual March | Actual April | Actual May | Actual June | Actual July | Actual August | Actual September | Actual October | Actual November | Actual 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 | $251,805 | $212,491 | $232,543 | $302,316 | $265,328 | $212,406 | $226,268 | $275,390 | $255,405 | $333,901 | $204,373 | $244,696 | $3,036,922 | | $3,036,922 |
| | 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 | 6,914 | 2,254 | 1,909 | 2,015 | (91,654) | 926 | 2,120 | 2,120 | 2,027 | 1,755 | 2,431 | 1,722 | (65,461) | | (65,461) |
| | d. Big Bend Units 1 & 2 FGD | 641,230 | 556,730 | 621,191 | 798,241 | 514,842 | 674,204 | 684,305 | 782,664 | 719,128 | 670,954 | 665,003 | 733,731 | 8,062,222 | | 8,062,222 |
| | e. Big Bend PM Minimization and Monitoring | 40,867 | 71,601 | 21,126 | 28,445 | 18,636 | 48,831 | 17,330 | 27,201 | 38,040 | 34,288 | 23,533 | 31,388 | 401,286 | | 401,286 |
| | f. Big Bend $NO_x$ Emissions Reduction | 28,343 | 89,687 | 50,001 | 7,874 | 9,568 | 15,700 | 319 | 0 | 1,681 | 22,495 | 0 | 0 | 225,667 | | 225,667 |
| | 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 | 19,115 | 62,481 | 0 | 12,469 | (135) | 0 | 33,954 | 48,810 | 554 | 8 | 177,255 | 177,255 | |
| | i. Polk $NO_x$ Reduction | 2,334 | 740 | 1,054 | 17,310 | 1,995 | 4,603 | 3,723 | 2,609 | 2,364 | 6,819 | (3,555) | 11,029 | 51,026 | | 51,026 |
| | *j. Bayside SCR and Ammonia* | *0* | *22,768* | *23,634* | *0* | *7,398* | *8,057* | *7,359* | *8,371* | *8,298* | *8,427* | *8,609* | *7,844* | 110,963 | | 110,963 |
| | k. Big Bend Unit 4 SOFA | 0 | 0 | 0 | (24,282) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | (24,282) | | (24,282) |
| | 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 | 16,541 | 48,806 | 950 | 0 | 0 | 1,425 | 0 | 1,744 | 0 | 2,535 | 0 | 0 | 72,001 | | 72,001 |
| | 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 | 1,874 | 0 | 0 | 6,872 | 2,494 | 0 | 0 | 3,995 | 9,151 | 0 | 0 | 0 | 24,386 | 24,386 | |
| | p. Arsenic Groundwater Standard Program | 0 | 0 | 3,823 | 48,905 | 3,716 | 19,902 | 10 | 0 | 63 | 35,644 | 39 | 0 | 112,101 | 112,101 | |
| | q. Big Bend 2 SCR | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 76,894 | 82,836 | 94,651 | 34,282 | 288,662 | | 288,662 |
| | r. Big Bend 3 SCR | 74,326 | 70,010 | 111,526 | 102,378 | 103,782 | 74,818 | 100,169 | 74,217 | 90,747 | 127,985 | 87,287 | 140,649 | 1,157,896 | | 1,157,896 |
| | s. Big Bend 4 SCR | 34,936 | 31,206 | 60,962 | 70,283 | 53,751 | 43,897 | 43,567 | 24,158 | 36,515 | 45,711 | 49,545 | 98,992 | 593,523 | | 593,523 |
| | t. *Clean Air Mercury Rule* | *0* | *0* | *0* | *0* | *550* | *705* | *342* | *0* | *0* | *1,129* | *0* | *0* | *2,726* | | *2,726* |
| 2. | Total of O&M Activities | 1,133,671 | 1,106,292 | 1,148,036 | 1,422,840 | 910,406 | 1,117,942 | 1,085,376 | 1,202,471 | 1,274,266 | 1,423,288 | 1,132,468 | 1,304,340 | 14,261,395 | $348,243 | $13,913,153 |
| 3. | Recoverable Costs Allocated to Energy | 1,097,297 | 1,106,292 | 1,125,098 | 1,304,582 | 904,196 | 1,085,570 | 1,085,501 | 1,198,476 | 1,231,099 | 1,338,835 | 1,131,876 | 1,304,332 | 13,913,152 | | |
| 4. | Recoverable Costs Allocated to Demand | 36,374 | 0 | 22,938 | 118,258 | 6,210 | 32,372 | (125) | 3,995 | 43,167 | 84,453 | 592 | 8 | 348,243 | | |
| 5. | Retail Energy Jurisdictional Factor | 0.9891913 | 0.9892481 | 0.9928581 | 0.9902713 | 0.9861120 | 0.9860367 | 0.9901851 | 0.9896329 | 0.9943798 | 0.9877819 | 0.9943001 | 0.9929605 | | | |
| 6. | Retail Demand Jurisdictional Factor | 0.9587232 | 0.9587232 | 0.9587232 | 0.9587232 | 0.9587232 | 0.9587232 | 0.9587232 | 0.9587232 | 0.9587232 | 0.9587232 | 0.9587232 | 0.9587232 | | | |
| 7. | Jurisdictional Energy Recoverable Costs (A) | 1,085,437 | 1,094,397 | 1,117,063 | 1,291,890 | 891,639 | 1,070,412 | 1,074,847 | 1,186,051 | 1,224,180 | 1,322,477 | 1,125,424 | 1,295,176 | 13,778,993 | | |
| 8. | Jurisdictional Demand Recoverable Costs (B) | 34,873 | 0 | 21,991 | 113,377 | 5,954 | 31,036 | (120) | 3,830 | 41,385 | 80,967 | 568 | 8 | 333,869 | | |
| 9. | Total Jurisdictional Recoverable Costs for O&M Activities (Lines 7 + 8) | $1,120,310 | $1,094,397 | $1,139,054 | $1,405,267 | $897,593 | $1,101,448 | $1,074,727 | $1,189,881 | $1,265,565 | $1,403,444 | $1,125,992 | $1,295,184 | $14,112,862 | | |

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



Exhibit 2

Form 42-7A

**Tampa Electric Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount for the Period
**January 2009 to December 2009**

**Capital Investment Projects-Recoverable Costs**

(in Dollars)

| Line | | Description (A) | Actual January | Actual February | Actual March | Actual April | Actual May | Actual June | Actual July | Actual August | Actual September | Actual October | Actual November | Actual December | End of Period Total | Method of Classification Demand | Method of Classification Energy |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1. | a. | Big Bend Unit 3 Flue Gas Desulfurization Integration | $66,346 | $66,193 | $66,040 | $65,887 | $65,759 | $65,612 | $65,459 | $65,305 | $65,152 | $64,998 | $64,846 | $64,692 | $786,289 | | $786,289 |
| | b. | Big Bend Units 1 and 2 Flue Gas Conditioning | 37,440 | 37,310 | 37,180 | 37,050 | 36,931 | 36,804 | 36,674 | 36,544 | 36,414 | 36,284 | 36,153 | 36,024 | 440,808 | | 440,808 |
| | c. | Big Bend Unit 4 Continuous Emissions Monitors | 6,796 | 6,781 | 6,767 | 6,752 | 6,740 | 6,726 | 6,712 | 6,697 | 6,682 | 6,667 | 6,653 | 6,638 | 80,611 | | 80,611 |
| | d. | Big Bend Fuel Oil Tank # 1 Upgrade | 4,604 | 4,593 | 4,583 | 4,572 | 4,564 | 4,554 | 4,543 | 4,534 | 4,523 | 4,512 | 4,502 | 4,491 | 54,575 | $ 54,575 | |
| | e. | Big Bend Fuel Oil Tank # 2 Upgrade | 7,573 | 7,555 | 7,538 | 7,521 | 7,508 | 7,490 | 7,474 | 7,456 | 7,439 | 7,422 | 7,404 | 7,387 | 89,767 | 89,767 | |
| | f. | Phillips Upgrade Tank # 1 for FDEP | 497 | 495 | 493 | 491 | 491 | 489 | 488 | 486 | 485 | 484 | 482 | 481 | 5,862 | 5,862 | |
| | g. | Phillips Upgrade Tank # 4 for FDEP | 780 | 778 | 775 | 773 | 772 | 769 | 767 | 765 | 762 | 760 | 758 | 756 | 9,215 | 9,215 | |
| | h. | Big Bend Unit 1 Classifier Replacement | 11,759 | 11,725 | 11,689 | 11,654 | 11,623 | 11,589 | 11,554 | 11,519 | 11,483 | 11,448 | 11,413 | 11,379 | 138,835 | | 138,835 |
| | i. | Big Bend Unit 2 Classifier Replacement | 8,510 | 8,485 | 8,461 | 8,436 | 8,415 | 8,390 | 8,365 | 8,341 | 8,316 | 8,291 | 8,266 | 8,242 | 100,518 | | 100,518 |
| | j. | Big Bend Section 114 Mercury Testing Platform | 1,142 | 1,140 | 1,138 | 1,137 | 1,136 | 1,133 | 1,131 | 1,129 | 1,127 | 1,126 | 1,123 | 1,122 | 13,584 | | 13,584 |
| | k. | Big Bend Units 1 & 2 FGD | 750,756 | 749,929 | 748,929 | 747,696 | 746,208 | 744,372 | 742,706 | 740,849 | 738,957 | 737,041 | 735,095 | 733,135 | 8,915,673 | | 8,915,673 |
| | l. | Big Bend FGD Optimization and Utilization | 213,260 | 212,856 | 212,452 | 212,048 | 211,731 | 211,348 | 210,943 | 210,539 | 210,135 | 209,731 | 209,326 | 208,921 | 2,533,290 | | 2,533,290 |
| | m. | Big Bend $NO_x$ Emissions Reduction | 66,999 | 66,927 | 66,854 | 66,780 | 66,737 | 66,667 | 66,592 | 66,530 | 66,557 | 66,632 | 66,559 | 66,472 | 800,306 | | 800,306 |
| | n. | Big Bend PM Minimization and Monitoring | 89,766 | 90,356 | 90,910 | 90,901 | 90,897 | 90,769 | 90,707 | 90,633 | 90,445 | 90,244 | 90,046 | 89,846 | 1,085,520 | | 1,085,520 |
| | o. | Polk $NO_x$ Emissions Reduction | 17,045 | 17,001 | 16,959 | 16,915 | 16,879 | 16,837 | 16,794 | 16,752 | 16,709 | 16,666 | 16,623 | 16,579 | 201,759 | | 201,759 |
| | p. | Big Bend Unit 4 SOFA | 27,352 | 27,302 | 27,253 | 27,203 | 27,165 | 27,118 | 27,068 | 27,018 | 26,969 | 26,919 | 26,870 | 26,820 | 325,057 | | 325,057 |
| | q. | Big Bend Unit 1 Pre-SCR | 23,049 | 23,005 | 22,961 | 22,917 | 22,883 | 22,840 | 22,796 | 22,753 | 22,709 | 22,665 | 22,621 | 22,577 | 273,776 | | 273,776 |
| | r. | Big Bend Unit 2 Pre-SCR | 18,485 | 18,445 | 18,406 | 18,365 | 18,332 | 18,295 | 18,256 | 18,216 | 18,176 | 18,137 | 18,097 | 18,057 | 219,267 | | 219,267 |
| | s. | Big Bend Unit 3 Pre-SCR | 32,111 | 32,053 | 31,997 | 31,939 | 31,895 | 31,613 | 31,226 | 31,170 | 31,113 | 31,056 | 31,000 | 30,944 | 378,117 | | 378,117 |
| | 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 | 760,573 | 1,119,568 | 1,120,549 | 1,119,411 | 4,120,101 | | 4,120,101 |
| | v. | Big Bend Unit 3 SCR | 919,651 | 918,474 | 917,164 | 915,710 | 914,741 | 913,439 | 911,683 | 910,083 | 908,477 | 906,876 | 905,255 | 903,635 | 10,945,188 | | 10,945,188 |
| | w. | Big Bend Unit 4 SCR | 692,320 | 691,133 | 689,945 | 688,758 | 687,860 | 686,742 | 685,554 | 684,365 | 683,177 | 681,989 | 680,801 | 679,613 | 8,232,257 | | 8,232,257 |
| | x. | Big Bend FGD System Reliability | 131,693 | 131,463 | 131,251 | 131,042 | 130,888 | 130,685 | 130,392 | 130,104 | 129,898 | 129,682 | 129,465 | 129,249 | 1,565,812 | | 1,565,812 |
| | y. | Clean Air Mercury Rule | 9,951 | 10,166 | 10,463 | 10,611 | 13,362 | 13,462 | 13,531 | 13,563 | 13,579 | 13,659 | 13,764 | 13,790 | 149,901 | | 149,901 |
| | z. | $SO_2$ Emissions Allowances (B) | (435) | (433) | (431) | (430) | (428) | (425) | (422) | (418) | (416) | (413) | (409) | (408) | (5,068) | | (5,068) |
| 2. | | Total Investment Projects - Recoverable Costs | 3,137,450 | 3,133,732 | 3,129,777 | 3,124,728 | 3,123,089 | 3,117,318 | 3,110,993 | 3,104,933 | 3,859,441 | 4,212,444 | 4,207,262 | 4,199,853 | 41,461,020 | $ 159,419 | $ 41,301,601 |
| 3. | | Recoverable Costs Allocated to Energy | 3,123,996 | 3,120,311 | 3,116,388 | 3,111,371 | 3,109,754 | 3,104,016 | 3,097,721 | 3,091,692 | 3,846,232 | 4,199,266 | 4,194,116 | 4,186,738 | 41,301,601 | | |
| 4. | | Recoverable Costs Allocated to Demand | 13,454 | 13,421 | 13,389 | 13,357 | 13,335 | 13,302 | 13,272 | 13,241 | 13,209 | 13,178 | 13,146 | 13,115 | 159,419 | | |
| 5. | | Retail Energy Jurisdictional Factor | 0.9891913 | 0.9892481 | 0.9928581 | 0.9902713 | 0.9861120 | 0.9860367 | 0.9901851 | 0.9896329 | 0.9943798 | 0.9877819 | 0.9943001 | 0.9929805 | | | |
| 6. | | Retail Demand Jurisdictional Factor | 0.9587232 | 0.9587232 | 0.9587232 | 0.9587232 | 0.9587232 | 0.9587232 | 0.9587232 | 0.9587232 | 0.9587232 | 0.9587232 | 0.9587232 | 0.9587232 | | | |
| 7. | | Jurisdictional Energy Recoverable Costs (C) | 3,090,230 | 3,086,762 | 3,094,131 | 3,081,101 | 3,066,566 | 3,060,674 | 3,067,317 | 3,059,640 | 3,824,615 | 4,147,959 | 4,170,210 | 4,157,349 | 40,906,554 | | |
| 8. | | Jurisdictional Demand Recoverable Costs (D) | 12,899 | 12,867 | 12,836 | 12,806 | 12,785 | 12,753 | 12,724 | 12,694 | 12,664 | 12,634 | 12,603 | 12,574 | 152,839 | | |
| 9. | | Total Jurisdictional Recoverable Costs for Investment Projects (Lines 7 + 8) | $3,103,129 | $3,099,629 | $3,106,967 | $3,093,907 | $3,079,351 | $3,073,427 | $3,080,041 | $3,072,334 | $3,837,279 | $4,160,593 | $4,182,813 | $4,169,923 | $41,059,393 | | |

**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



Exhibit 3