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BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 110007-EI

IN RE:

ENVIRONMENTAL COST RECOVERY FACTORS

PROJECTIONS

JANUARY 2012 THROUGH DECEMBER 2012

DIRECT TESTIMONY

OF

PAUL L. CARPINONE

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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 2012 through December 2012 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.

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 2012 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. The first PM CEM was installed in February 2002. The installation and certification of the second PM CEM was completed in August 2009. Over time, however, the first PM CEM did not perform satisfactorily and replacement was required. Installation and certification of the replacement was completed in December 2010.

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 2012 through December 2012.

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 2012, capital expenditures are anticipated to be $1,500,000 for BOP and BACT equipment while O&M expenses associated with existing and recently installed BOP and BACT equipment and continued implementation of the BOP procedures are expected to be $390,400.

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 2012 through December 2012.

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. No capital expenditures are anticipated in 2012; however, Tampa Electric will perform maintenance on the previously approved and installed NO_x Reduction equipment. This activity is expected to result in approximately $395,000 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. Thus, Big Bend Units 3, 2 and/or 1 must operate 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 was 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 2012 through December 2012.

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 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 SCRs for Big Bend Units 1 through 4 were placed in-service April 2010, September 2009, July 2008 and May 2007, respectively.

For the period of January 2012 through December 2012, no capital or O&M expenditures are anticipated for the Big Bend Units 1 through 3 Pre-SCR projects. For 2012, there are no anticipated capital expenditures for Big Bend Units 1, 3 and 4 SCRs; however, the anticipated capital expenditure for Big Bend Unit 2 SCR is $2,000,000 for catalyst replacement. The 2012 SCR O&M expenses are projected to be $2,466,500 for Big Bend Unit 1 SCR, $2,536,400 for Big Bend Unit 2 SCR, $1,513,000 for Big Bend Unit 3 SCR and $998,300 for Big Bend Unit 4 SCR. O&M expenses are driven by ammonia purchases.

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) Clean Water Act Section 316(b) Phase II Study
6) Big Bend FGD System Reliability
7) Arsenic Groundwater Standard
8) Clean Air Mercury Rule ("CAMR")
9) 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 2012 through December 2012.

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 2012 through December 2012 capital expenditures for the Big Bend Unit 3 FGD Integration project are $2,394,700 for controls upgrades as well as duct replacements. O&M expenses are anticipated to be $4,490,200 for consumables and ongoing maintenance. The projected January 2012 through December 2012 capital expenditures for the Big Bend FGD Units 1 and 2 project are $1,820,600 for improvements to waste water treatment reliability and the oxidation air header, both scheduled to occur during the spring outage. O&M expenses are anticipated to be $8,835,100 for consumables and ongoing maintenance.

Q. Please describe the Gannon Thermal Discharge Study program activities and provide the estimated capital and O&M expenditures for the period of January 2012 through December 2012.

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 2012 through December 2012, there will be no capital expenditures for this program. Tampa Electric anticipates

O&M expenses will be approximately $20,000 for continuation of the ongoing study.

Q. Please describe the Bayside SCR Consumables program activities and provide the estimated capital and O&M expenditures for the period of January 2012 through December 2012.

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 2012 through December 2012, 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 $106,400 for the period.

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 2012 through December 2012.

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. On March 20, 2007 the EPA announced that the rule adopted pursuant to Section 316(b) be considered suspended. The suspension of the final rule was made on July 9, 2007. In March 2011, the Clean Water Act 316(b) Existing Facilities Proposed Rule was issued. The comment period for the proposed rule was extended until August 18, 2011 and the final rule is expected in July 2012. Tampa Electric believes that the current 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 2012 planned study activities will be approximately $30,000. No capital expenditures are anticipated.

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 2012 through December 2012.

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 2012 through December 2012, the anticipated capital expenditures will be $3,076,900 for the fines filter installation; 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 2012 through December 2012.

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 2012 through December 2012, there will be no capital expenditures for this program; however, Tampa Electric anticipates O&M expenses associated with the sampling activities will be approximately $667,000.

Q. Please describe the CAMR program activities and provide the estimated capital and O&M expenditures for the period of January 2012 through December 2012.

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. On May 3, 2011, the EPA published a new proposed rule for mercury and other hazardous air pollutants according to the National Emissions Standards for Hazardous Air Pollutants section of the Clean Air Act. The proposed rule calls for continued mercury monitoring requirements comparable to CAMR and additional monitoring and testing of other pollutants by 2014. Tampa Electric must conduct extensive emissions testing and engineering studies at Big Bend Station and Polk Power Station to determine what actions are required to meet the proposed standards.

Capital spending for this program is anticipated to continue in 2012 with ongoing monitoring and thereafter using company resources and consultants as needed. For the period of January 2012 through December 2012, the capital expenditures are anticipated to be $40,000 and the O&M expenditures projected to be $24,000.

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. In July 2010, the EPA proposed a new rule, the Clean Air Transport Rule to replace CAIR. In July 2011, the EPA issued the final CAIR replacement rule, now called the Cross State Air Pollution Rule ("CSAPR"). CSAPR is focused on reducing SO_2 and NO_x in 27 eastern states that contribute to ozone and/or fine particle pollution in other states. In the final rule, Florida is subject to the ozone season control program (May through September). The remand of CAIR and the subsequent finalization of

CSAPR 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 the EPA and Tampa Electric; therefore, the company anticipates continuing its efforts to complete and maintain the projects. The completed ECRC projects support compliance with CSAPR.

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. Subsequent to the vacatur, the company has continued utilizing the resources already secured to establish a baseline of mercury emissions.

On May 3, 2011 the EPA proposed rules under National Emission Standards for Hazardous Air Pollutants pursuant to a court order referred to as the Utility Maximum Achievable Control Technology ("U MACT"). The proposed rules are to replace CAMR and are expected to reduce not only mercury but acid gas, organics and certain non-mercury metals emissions and require MACT. The final U MACT rules are expected in late 2011 with implementation in 2014 or 2015. During this time of review of the proposed rules, the company will continue utilizing the resources already secured to establish a baseline of mercury and other emissions subject to the proposed rule.

Q. Please describe the GHG Reduction Program activities and provide the estimated capital and O&M expenditures for the period of January 2012 through December 2012.

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. Tampa Electric is required to report greenhouse gas emissions to the EPA for the first time in 2011. Reporting for the EPA's Greenhouse Gas Mandatory Reporting Rule will continue in 2012. For 2012, this activity is not anticipated to require capital expenditures; however, it is expected to result in approximately $40,000 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 2012. Additionally, my testimony identified other projects that are required for Tampa Electric to meet the environmental requirements and I provided the associated 2012 activities and projected expenditures.

Q. Does this conclude your testimony?

A. Yes it does.