ORIGINAL

TAMPA ELECTRIC

TAMPA ELECTRIC COMPANY

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 992014-EI

TESTIMONY
AND EXHIBIT OF

GREGORY M. NELSON

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

GREGORY M. NELSON

Q. Please state your name and business address.

A. My name is Gregory M. Nelson. My business address is 702 North Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") in the position of Manager, Environmental Planning in the Environmental and Fuels Department.

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

A. I received a Bachelor Degree in Mechanical Engineering from the Georgia Institute of Technology in 1982 and a Masters of Business Administration from the University of South Florida in 1987. I am a registered Professional Engineer in the State of Florida. I began my engineering career in 1982 in Tampa Electric's Engineering Development Program. In 1983, I worked in the Production Department where I was responsible for power plant performance projects. Since 1986, I have held various environmental permitting and compliance positions. In 1997, I was promoted to Administrator, Air Programs in the Environmental Planning Department. In this position, I was responsible for all air permitting and compliance programs. In 1998, I was promoted to Manager, Environmental Planning. My present responsibilities include the management of all of Tampa Electric's environmental programs.

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

A. Yes, I have provided testimony regarding environmental projects and their associated environmental requirements in Environmental Cost Recovery Clause ("ECRC") proceedings before this Commission.

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

A. The purpose of my testimony is to describe the reasonableness and prudence of Tampa Electric's Clean Air Act Compliance Plan ("Compliance Plan") which is presented for the Commission's review and approval in this proceeding. My testimony describes recent interactions among Tampa Electric, the U. S.

Environmental Protection Agency ("EPA"), and the Florida Department of Environmental Protection ("DEP") concerning federal and state environmental laws and regulations; how these interactions were settled with the DEP and made obligations in the form of a Consent Final Judgement ("CFJ"); the commitments contained in the CFJ, including environmental projects at Gannon and Big Bend Stations; and how these commitments are embodied in the company's Compliance Plan. My testimony also describes the repowering of Gannon Station ("Gannon Repowering Project"), which is a major component of the company's Compliance Plan, as well as other activities required by the CFJ including environmental projects at Gannon and Big Bend Stations.

Q. Have you prepared an exhibit in support of your testimony?

A. Yes I have. My Exhibit No. ___ (GMN-1), consisting of one document, was prepared under my direction and supervision.

Tampa Electric's Comprehensive Clean Air Act Compliance Plan

Q. Please describe Tampa Electric's Compliance Plan.

A. Under Section 366.825, Florida Statutes (1999), Tampa Electric documented its Compliance Plan to meet requirements of the Clean Air Act ("CAA"). Tampa Electric has followed the requirements of the CAA and has previously provided the Commission with its strategy to meet the Phase I and II sulfur dioxide ("SO_2") and nitrogen oxide ("NO_X") emissions reduction requirements. The Commission has approved Tampa Electric's requests to recover environmental compliance costs associated with several of these projects. As described in more detail below, Tampa Electric and DEP entered into a CFJ that requires more stringent emission limitations associated with NO_X, SO_2 and particulate matter ("PM").

Q. Please provide an overview of the Compliance Plan.

A. Tampa Electric has divided its Compliance Plan into several sections by pollutant; SO_2, NO_X, PM, and air toxics. It also identifies other potential future compliance issues, details of the CFJ, fuel source issues, and regulatory compliance dates and estimated costs. The Compliance Plan also provides the "Gannon Resource Utilization Study" which describes the detailed analysis of the alternatives to repowering Gannon Station that were considered. The "Gannon Resource Utilization

Study" is described in more detail in the direct testimony of Tampa Electric witness Mark D. Ward.

<u>Interactions with DEP and EPA</u>

Q. Please provide an overview of the interactions Tampa Electric has had with DEP and EPA.

A. In 1997, EPA began an investigation into alleged violations, by Tampa Electric and numerous other coal-fired electric utilities, of EPA's New Source Review ("NSR") rules and New Source Performance Standards currently codified in Title I of the Clean Air Act Amendments ("CAAA"). EPA asserted that these electric utilities, including Tampa Electric, should have applied for pre-construction permits for certain unit maintenance projects, and that the permitting review of such projects would have included NSR. According to EPA, this NSR permitting would have resulted in requirements that the units meet Best Available Control Technology ("BACT") standards for NO_X, SO_2 and PM. The electric utility industry, including Tampa Electric, disagrees with EPA's current interpretation of its NSR rules and believes that the activities performed were routine maintenance and therefore exempt from these requirements.

On November 3, 1999, despite Tampa Electric's longstanding efforts to reach a mutually agreeable settlement with the EPA, the Department of Justice, on behalf of EPA, sued Tampa Electric and seven other electric utilities for alleged violations of the CAAA associated with this NSR issue. This federal action triggered a 30-day period during which the DEP could resolve these issues as described by Section 113 of the CAA. Within this 30-day window, DEP filed a complaint which supported EPA's contention that Tampa Electric had not applied for appropriate air permits for certain unit maintenance projects at Gannon and Big Bend Stations and, therefore, had operated the coal-fired units without BACT for NO_X, SO_2 and PM. Following discussions on these issues, DEP and Tampa Electric negotiated a settlement. Effective December 16, 1999, the Circuit Court entered the CFJ that DEP and Tampa Electric had agreed to which addressed the DEP claims that Tampa Electric modified and then operated its generating units at Big Bend and Gannon without first going through an applicability determination under the NSR and then obtaining permits authorizing the modifications and without installing BACT to control NO_X, SO_2 and PM. The requirements of the CFJ include repowering Gannon Station and undertaking projects to reduce NO_X, SO_2 and PM emissions at Big Bend Station.

Q. To what extent has the company's Compliance Plan been influenced by interactions with DEP and EPA?

A. Tampa Electric's Compliance Plan has been significantly influenced by discussions held with both agencies. The Compliance Plan now includes the requirements of the CFJ. The CFJ enables Tampa Electric to continue to comply with environmental laws and regulations while enabling the company to meet its customers' growing demand for electric service. A copy of Tampa Electric's Compliance Plan, which includes the CFJ, is set forth as Document No. 1 of my Exhibit.

Q. Is the CFJ a fair and reasonable solution from the standpoint of Tampa Electric's ratepayers?

A. Yes. The CFJ avoids the uncertainties of protracted litigation and the potential of having to incur even greater costs for some unpredictable result of that litigation. It calls for appropriate actions at less cost than any other alternative the company could have pursued. Finally, although the company disagrees with DEP and EPA regarding their respective NSR interpretations on the applicable legal requirements and whether Tampa Electric was in compliance with them, the CFJ satisfies DEP's compliance requirements in a fair and reasonable manner. This certainly provides significant value to Tampa Electric and its customers.

Q. What is the status of Tampa Electric's interactions with EPA regarding CAA compliance?

A. Tampa Electric is continuing to have discussions with EPA regarding its agreement with DEP and any additional requirements EPA is considering. Tampa Electric believes that the requirements of the CFJ are consistent with the direction EPA has contended Tampa Electric should pursue and that if agreement to the terms of a consent decree is reached, the EPA compliance requirements will be compatible with those of the CFJ.

Consent Final Judgment Requirements

Q. Please describe in more detail the proposed repowering of Tampa Electric's Gannon Station as required by the CFJ and reflected in the company's Compliance Plan.

A. The Gannon Repowering Project will entail the repowering of Gannon Units 3, 4, and 5 with combined cycle technology utilizing natural gas to replace the current coal-fired technology. Coal-fired Units 1, 2, and 6 will be placed on reserve status by year-end 2004. The repowered units will be equipped with NO_x controls under the Compliance Plan. After the repowering is complete, the plant will be capable of generating 1,475 MW of electricity, as compared to the current output of 1,200 MW. Although Tampa Electric has no current plans to utilize units 1, 2 and 6 beyond 2004, they may, at some future date be repowered or converted to gas. Any future use of coal in any of these units is not permitted beyond December 31, 2004 under the terms of the CFJ.

Q. Is the Gannon Repowering Project compatible with other environmental compliance activities already implemented by Tampa Electric?

A. Yes it is. Tampa Electric was still required to meet the Phase II SO_2 and NO_x limitations by January 1, 2000. By far, the major compliance activities undertaken to date to meet the Phase II SO_2 limitations have been the integration of the Big Bend Unit 3 with the Big Bend Unit 4 flue gas desulfurization ("FGD" or "scrubber") system and the construction of a second FGD system to serve Big Bend Units 1 and 2.

Another significant compliance activity for the company has been its NO_x combustion optimization projects. These projects have achieved significant reductions for Phase II compliance and will make future NO_x reduction projects more cost effective.

The Gannon Repowering Project is entirely consistent and compatible with the company's SO_2 and NO_x environmental compliance projects to date. As stated above, SO_2 and NO_x emissions have been and are expected to continue to be significantly reduced.

Q. Please describe the other compliance requirements of the CFJ.

A. The CFJ requires the company to:

- Maximize the efficiency of its Big Bend Units 1 and 2 FGD system to target 95 percent sulfur removal efficiency and maximize scrubber utilization on all four boilers at Big Bend.

- Achieve major NO_x emission reductions through repowering or installing NO_x controls on Big Bend Unit 4 by 2007 and the remaining Big Bend units by 2010.

- Undertake a study of improved particulate removal and monitoring at Big Bend Station and make improvements as required by the results by May 2003. Additional requirements pertaining to PM requires the installation of a continuous emissions monitor, if determined to be feasible, on one of the Big Bend Station stacks.

- Invest up to $8 million over the cost of a selective catalytic reduction system ("SCR") for a combined cycle unit to demonstrate innovative technologies for further reductions of NO_x emissions.

- Contribute and participate with DEP in its Bay Regional Air Chemistry Experiment ("BRACE") program that studies nitrogen deposition in Tampa Bay and its associated impacts. This includes contributing up to $2 million over the next two years.

Q. Please describe in more detail the requirement to maximize the efficiency of Big Bend's FGD systems.

A. The contract specifications for the Big Bend Units 1 and 2 FGD system provide the guaranteed removal efficiency of 95 percent. Since the CFJ has been entered, the FGD has achieved commercial operation with a sulfur removal efficiency of 95 percent. As such, Tampa Electric will comply with the requirements of this condition through the evaluation of the operational processes during 2000, the first year of its operations, and will ensure that guaranteed removal efficiencies are achieved. The DEP has not established more stringent SO_2 limits at this time.

In order to maximize the scrubber utilization for Big Bend Units 3 and 4, Tampa Electric will evaluate the operational processes of the scrubber system. Based on the results of this evaluation, Tampa Electric may be required to make capital and/or O&M improvements on this scrubber system. The evaluation may consist of a formal engineering report and require the utilization of outside consultants and testing. Based on this evaluation, Tampa Electric will probably develop a detailed operation and maintenance ("O&M") plan aimed at increasing the availability of the scrubber capability on Big Bend Unit 3 after accounting for outages and emergencies. The company believes that some capital costs will be required which are preliminarily projected to be approximately $3 million. Most of these costs are associated with stocking spare parts to reduce down time and upgrading internal support systems of the scrubber. These costs are extremely preliminary and do not include associated O&M costs.

Q. Please describe in more detail the requirement to achieve major NO_x emission reductions through repowering or installing NO_x controls on Big Bend units.

A. Because this requirement is many years away and many of the factors that will affect the cost-effectiveness of that decision are likely to change, Tampa Electric plans to evaluate the most appropriate manner to comply with this requirement over the next five to six years. Based on the requirements of the CFJ, the company must lower emissions to a level of 0.10 pounds per million Btu ("lb/mmBtu") at Big Bend 4 by 2007, and to a level no greater than 0.15 lb/mmBtu at Big Bend Units 1 through 3 by 2010. If the company were forced to comply with this requirement utilizing today's technology and options, it could cost up to $230 million in capital expenditures alone. Annual O&M costs would be approximately $7 million per year.

Q. Please describe in more detail the requirement to undertake a study of improved PM removal and monitoring at Big Bend Station.

A. Tampa Electric recently completed an electrostatic precipitator ("ESP") optimization study for Gannon Station as required by the DEP. The study required by the CFJ and BACT analysis may require efforts beyond those utilized in the Gannon study to satisfy the requirements of the BACT analysis. This study and BACT analysis may require testing of the ESP removal efficiency, replacement or redesign of components of the PM control systems, and the utilization of expertise from outside of Tampa Electric all based on a standard of reasonableness. Tampa Electric plans to continue to evaluate the most cost-effective means of compliance with this requirement.

Preliminarily, the company projects to spend approximately $11 million in capital costs to comply. Again, these costs are rough estimates and include costs of a preliminary evaluation and capital costs to implement. It does not include associated O&M.

Q. Please describe in more detail the requirement to evaluate innovative NO_x emission reduction technology.

A. The EPA's interpretation of BACT for combined cycle combustion turbines such as the units planned for the

Gannon Repowering Project requires post-combustion NO_x controls in addition to dry low NO_x burners. The CFJ recognizes this interpretation and among other control technologies requires Tampa Electric to consider a "zero-ammonia" NO_x reduction technology for one of the repowered units or another unit in Tampa Electric's system. Ammonia emissions associated with SCRs are commonly regulated due to the potential negative effects this pollutant can have on the environment and due to the safety issues associated with the handling of this substance. Accordingly the DEP has made an effort to promote the maximum environmental benefit utilizing cost-effective means through the requirement to consider "zero-ammonia" NO_x reduction technologies and others. Tampa Electric will, in coordination with the DEP, evaluate the cost-effectiveness and commercial feasibility of certain NO_x reduction technologies by May 2000. The company has already begun defining technical details and outlining possible methods of evaluation.

Q. Is Tampa Electric required to install NO_x control technologies on its repowered units?

A. Yes, the company is required to meet a NO_x emission level of 3.5 parts per million. Accordingly, the company will install six SCRs on the repowered units at Gannon Station. They are expected to cost approximately $8 million in capital costs.

Q. What benefits will the requirements of the CFJ bring by way of reduced emissions?

A. Repowering with natural gas at Gannon Station along with high-efficiency, state-of-the-art controls at Big Bend Station, will enable Tampa Electric to reduce SO_2 emissions by almost 80 percent, reduce NO_x by more than 85 percent and carbon dioxide (CO_2) emissions by more than 20 percent. These emissions reductions are based upon 1997 emissions compared to those expected in 2010.

Q. Does the repowering of an existing power plant such as Gannon Station provide environmental benefits over the development of a new greenfield site?

A. Yes, it provides significant environmental benefits. Gannon Station is located in an area that is zoned for heavy industry, and is already highly developed. The environmental impacts of an existing facility being repowered will be less than those of a similar facility at a new greenfield site. For instance air emissions, water intake and discharge impacts, transportation and other impacts will be significantly lowered in the Port Sutton area by the Gannon Repowering Project. This cannot be said for the construction of a similar facility at a greenfield site.

At a greenfield site, all of the impacts associated with the development of the power plant would be new, incremental impacts. For instance, the plant would be a new source of both air and water emissions in the area where the unit is located. Cooling water intake and discharge issues would need to be addressed, and the addition of intake structures or new consumption of water can have significant adverse environmental impacts. The development of a new site also has the potential to impact threatened or endangered species and their critical habitat, such as scrub areas or wetlands. Infrastructure needs such as road, rail, transmission and traffic issues are also a concern at new sites. All of these issues would need to be addressed through a comprehensive environmental assessment process such as the Florida Electrical Power Plant Siting Act, or the Federal Environmental Impact Statement process if the issuance of a federal permit were required. Transmission impacts are addressed in detail in the direct testimony of Gregory J. Ramon.

Q. Does Tampa Electric plan to seek cost recovery of the projects required under the CFJ through the ECRC?

A. As described in the direct testimony of Thomas L. Hernandez, the company is not seeking any rate relief in this proceeding. Any request for cost recovery associated with the activities called for in the Compliance Plan will be made by way of separate petitions in future proceedings if necessary.

Tampa Electric believes that all of the environmental control projects required by the CFJ, except for the repowered generating facility, are the types of projects that are eligible for recovery through the ECRC. As the company begins to evaluate each project individually, it will seek approval of these projects by way of separate petitions as the company has done with all of its environmental projects in the past.

Q. Why does Tampa Electric believe that these projects are the types of projects that are eligible for recovery through the ECRC?

A. The identified projects are legally required by the Circuit Court's entry of the CFJ which resolves issues raised by Florida under its SIP which construe and implement the CAA, the CAAA and associated regulations. Accordingly, the company will be required to demonstrate in future proceedings that these projects are the most cost-effective and prudent means to comply with the environmental requirements. As described in more detail in the direct testimony of Mr. Hernandez, these projects meet all requirements established in Section 366.8255, Florida Statutes.

Q. Does that conclude your testimony?

A. Yes it does.

TAMPA ELECTRIC COMPANY
DOCKET NO. 992014-EI
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EXHIBIT NO.____ (GMN-1)

TAMPA ELECTRIC COMPANY

EXHIBIT OF GREGORY M. NELSON

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TAMPA ELECTRIC

TAMPA ELECTRIC COMPANY
DOCKET NO.

COMPREHENSIVE CLEAN AIR ACT COMPLIANCE PLAN

January 2000

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Tampa Electric Company
COMPREHENSIVE CLEAN AIR ACT COMPLIANCE PLAN

Executive Summary

Tampa Electric Company (Tampa Electric or the company) is an investor-owned electric company that serves over 543,000 retail customers in Hillsborough and portions of Pasco, Pinellas, and Polk counties, in West Central Florida. Tampa Electric's system has a net electric generating capacity of approximately 3,600 MW comprised of 23 generating units. The company's 11 coal-fired units produced about 90 percent of its system energy requirements in 1998. Total 1998 energy sales, including wholesale sales, ere 18,513 GWh.

This Comprehensive Clean Air Act Compliance Plan (Compliance Plan) describes the many programs by which Tampa Electric is fulfilling required environmental responsibilities, as well as several emerging issues with the potential to impact Tampa Electric and the utility industry as a whole.

Title IV of the Clean Air Act Amendments of 1990 (CAAA) requires significant reductions in sulfur dioxide (SO_2) and nitrogen oxides (NO_X) from electric utility generating facilities. During Phase I, from January 1, 1995 through December 31, 1999, Tampa Electric began scrubbing SO_2 at its Big Bend Unit 3, switched to lower sulfur fuels through fuel blending, and utilized purchased SO_2 emission allowances. For Phase II, which begins January 1, 2000, the company installed a new Flue Gas Desulfurization (FGD) system at Big Bend Units 1 and 2, and plans to continue fuel blending and using SO_2 allowances. In order to comply with the Phase II NO_X emission limits, Tampa Electric has implemented combustion optimization projects at Big Bend and Gannon Stations, and plans to use system-wide averaging.

Beyond Phase II, Tampa Electric is required to make additional reductions in emissions of NO_X, SO_2 and particulate matter (PM). These requirements are contained in a Consent Final Judgment (CFJ), effective December 16, 1999, entered into with the Florida Department of Environmental Protection (DEP). These requirements will achieve additional reductions in SO_2, NO_X and PM.

Further emission reductions may be required as a result of the U.S. Environmental Protection Agency's (EPA) New Source Review (NSR) enforcement initiative, EPA's NSR regulatory reform and other potential EPA emission-limiting regulations for ozone, fine particulate matter ($PM_{2.5}$), mercury, carbon dioxide (CO_2) and/or acid rain.

Intro and Purpose

Tampa Electric Company
COMPREHENSIVE CLEAN AIR ACT COMPLIANCE PLAN

Introduction and Purpose

Tampa Electric is an investor-owned electric utility. Tampa Electric is engaged in the generation, purchase, transmission, distribution, and sale of electric energy. Tampa Electric serves over 543,000 retail customers in its service area of approximately 2,000 square miles in West Central Florida, including Hillsborough County, and parts of Pasco, Pinellas, and Polk counties, with a population of over one million people. Tampa Electric's coal-fired units produced about 90 percent of its system energy requirements in 1998. Total 1998 energy sales, including wholesale sales, were 18,513 GWh.

The company has six electric generating plants, five of which are in operation, with a total net winter generating capability of 3,615 MW, consisting of fossil steam units, combustion turbine peaking units, diesel units and an integrated gasification combined cycle (IGCC) unit. The six plants are: Big Bend (1,742 MW capability from four coal-fired steam units), Gannon (1,180 MW capability from six coal-fired steam units), Hookers Point (215 MW capability from five generators served by six No. 6 oil-fired boilers), and four No. 2 oil-fired combustion turbine units located at Big Bend and Gannon (194 MW), all in the Tampa Bay area; Polk Power Station (250 MW capability from one IGCC unit fueled with synthesis gas derived from coal and petcoke; alternate fuel is No. 2 oil) in southwestern Polk County; and Phillips (34 MW capability from two No. 6 oil-fired slow-speed diesel units) and Dinner Lake in Highlands County. Dinner Lake (11 MW from one natural gas-fired steam electric unit) was placed on long-term reserve standby status in March 1994

Units at Hookers Point began commercial service from 1948 to 1955, at Gannon from 1957 to 1969, and at Big Bend from 1970 to 1985. The Polk IGCC unit began commercial service in September 1996. Dinner Lake began commercial service in 1966 and Phillips in 1983. Tampa Electric purchased Phillips and Dinner Lake Stations from the Sebring Utilities Commission in 1991.

Tampa Electric is committed to compliance with applicable environmental laws and regulations. The purpose of this Compliance Plan is to describe Tampa Electric's current strategies for meeting the requirements of federal, state and local environmental laws and regulations, and changes in the application and enforcement thereof, that impact existing and planned electric generating and delivery facilities. It is intended to be a reference document to assist in evaluating impacts of agency compliance activities and to assist in developing future operational and compliance strategies. These strategies must allow flexibility for future operations.

Section 1

Tampa Electric Company
COMPREHENSIVE CLEAN AIR ACT COMPLIANCE PLAN

1. Summary

The federal Clean Air Act (CAA), 42 United States Code, beginning at Section 7401 (42 U.S.C. 7401, et seq.), enacted in 1970, empowers the EPA to regulate air quality and emissions from a wide variety of sources. EPA rules implementing the statute are found in Parts 50-99 of "Title 40-Protection of Environment," in the Code of Federal Regulations (40 CFR 50-99).

DEP regulates air quality and emissions under its authority in Chapter 403 of the Florida Statues (Ch. 403, FS) and through its rules in Chapter 62 of the Florida Administrative Code (Ch. 62, FAC). DEP's authority includes the rules which Florida has the responsibility to administer and enforce under the federally-approved Florida State Implementation Plan (SIP) and the separate EPA delegation of Prevention of Significant Deterioration (PSD) authority.

In November 1990, Congress passed the CAAA, which brought about many new air pollution control programs. The main titles of the CAAA are:

Title I - Attainment and Maintenance of National Ambient Air Quality Standards (AAQS)

Title II - Mobile Sources

Title III - Hazardous Air Pollutants

Title IV - Acid Deposition Control

Title V - Permits

Title VI - Stratospheric Ozone Protection

Titles VII through XI - Various Provisions

Some of the EPA rules that implement the CAAA titles relevant to electric power generation are:

Title I - 40 CFR 50, 52, 60, 61, 81

Title II - 40 CFR 85

Title III - 40 CFR 63, 68

Title IV - 40 CFR 72, 73, 75, 76

Title V - 40 CFR 70

Title VI - 40 CFR 82

The titles of the implementing EPA rules, in the order listed above are:

40 CFR 50 - National Primary and Secondary Ambient Air Quality Standards (AAQS)

40 CFR 52 - Approval and Promulgation of Implementation Plans

40 CFR 60 - Standards of Performance for New Stationary Sources

40 CFR 61 - National Emission Standards for Hazardous Air Pollutants (NESHAPS)

40 CFR 81 - Designation of Areas for Air Quality Planning Purposes

40 CFR 85 - Control of Air Pollution from Mobile Sources

40 CFR 63 - NESHAPS for Source Categories

40 CFR 68 - Chemical Accident Prevention Provisions

40 CFR 72 - Permits Regulation

40 CFR 73 - Sulfur Dioxide Allowance System

40 CFR 75 - Continuous Emission Monitoring

40 CFR 76 - Acid Rain Nitrogen Oxides Reduction Program

40 CFR 70 - State Operating Permit Programs

40 CFR 82 - Protection of Stratospheric Ozone

Title I of the CAAA empowers EPA to manage air quality through ambient air quality standards, to conduct pre-construction reviews of new stationary emission sources, and to permit construction of stationary emission sources. Under Title II, EPA regulates air emissions from mobile sources such as cars, trucks, buses and planes. Title III requires EPA to identify the hazardous air pollutant chemicals that must be controlled and the categories of major emission sources of the chemicals. EPA is responsible for setting maximum achievable control technology standards for each category. Title IV contains provisions for the SO_2 allowance and emission reduction programs; the NO_X emission reduction program; acid deposition permits and compliance plans; monitoring, reporting and recordkeeping; and clean coal technology incentives. Title V establishes the program for facility-wide operating permits regulating air emissions. Title VI provides for phasing out the production and import of ozone-depleting substances, and governs the use and recycling of the substances.

Although all sections of the CAAA affect Tampa Electric, Title IV has had the most significant impact on the company. The EPA Acid Rain Program under Title IV of the CAAA set as its primary goals the reduction of annual SO_2 emissions by 10 million tons and annual NO_X emissions by 2 million tons below 1980 levels. To achieve these reductions, the law requires a two-phase program that reduces the allowable SO_2 and NO_X emissions from fossil fuel-fired power plants.

Phase I of the CAAA Title IV began on January 1, 1995 (January 1, 1996 for NO_X due to a litigation delay) and continues through December 31, 1999. Under the EPA Acid Rain Program, Big Bend Units 1, 2 and 3 were designated Phase I units. Tampa Electric also designated Big Bend Unit 4 as a Phase I substitution unit. Thus, Big Bend Unit 4 became Tampa Electric's only Phase I NO_X unit since it has a Group 1 boiler type under the NO_X rules.

Phase II of the CAAA Title IV begins January 1, 2000. Phase II further reduces the annual SO_2 and NO_X emissions of Phase I units, and sets restrictions on smaller plants (greater than 25 MW) fired by coal, oil and gas as well as all new utility units. Phase II SO_2 compliance affects Big Bend, Gannon and Polk coal units as well as Hookers Point and future fossil-fueled generating units. Phillips and Dinner Lake Stations and existing combustion turbines are not affected. Phase II NO_X compliance affects only Big Bend Units 1, 2, 3 and 4 and Gannon Units 3, 4, 5, and 6, and limits their emission rates based on the type of boiler.

Tampa Electric initially concluded that fuel blending for reduced coal sulfur content, along with the use of purchased SO_2 allowances, was the most viable strategy for CAAA Title IV SO_2 compliance. The use of low sulfur coal required the addition of flue gas conditioning systems on Big Bend Units 1 through 3 to maintain performance of the electrostatic precipitators (ESP) used for controlling PM emissions. The company subsequently determined that it was feasible to integrate Big Bend Unit 3 with the existing Big Bend Unit 4 Flue Gas Desulfurization (FGD) system to allow burning high sulfur coal in Unit 3 in addition to Unit 4, fuel blending at Big Bend Units 1 and 2, and purchasing SO_2 emission allowances when economical. The Big Bend Unit 3 FGD integration project was completed and the system was placed in service June 1995, which reduced the amount of SO_2 allowance purchases and also reduced Tampa Electric's purchases of higher cost, lower sulfur coal. Big Bend Unit 4, Tampa Electric's only unit affected by EPA's Phase I NO_X program, must meet a NO_X emissions limit of 0.45 pounds per million Btu's of heat input on an annual average basis, effective January 1, 1996. This is accomplished by controlling NO_X emissions through combustion tuning inherent to this boiler's original design and did not require any modifications.

For Phase II of CAAA Title IV, Tampa Electric developed several compliance alternatives. A screening process was conducted on selected alternatives, and detailed engineering and economic analyses were completed to determine the most practical and cost effective Phase II compliance plan. Construction of a FGD system retrofit for Big Bend Units 1 and 2 was determined to be the most cost effective SO_2 compliance alternative for Tampa Electric's system. The Big Bend Units 1 and 2 FGD system will reduce SO_2 emissions by about 70,000 tons per year, thus allowing greater fuel flexibility at Gannon Station. Although Tampa Electric, through the Big Bend pollution controls, has more allowances to utilize at Gannon, current regulations limit emissions of SO_2 under the CAAA Title I AAQS. For Gannon, Tampa Electric will comply with the Title IV Phase II SO_2 requirements through the use of lower sulfur fuels and/or through the acquisition of more allowances, if necessary. The degree of fuel sulfur reductions required to comply with AAQS will be established through the Title V operating permit process.

Phase II NO_X reduction requirements dictate annual average emission rate limits affecting Big Bend Units 1, 2, 3 and 4, and Gannon Units 3, 4, 5 and 6. Tampa Electric's NO_X compliance strategy includes combustion optimization/tuning with the replacement of coal classifiers at Big Bend Units 1 and 2 and Gannon Units 5 and 6. It also includes the use of high-moisture, low-Btu coals at Gannon Units 3, 4, 5, and 6 which requires the addition of two fine-mesh coal crushers in the Gannon coal field. In addition to these emission reduction projects, Tampa Electric will exercise the option to achieve compliance with the Title IV Phase II NO_X requirements by using a system-wide annual average NO_X emission rate applicable to all affected units.

The projects associated with implementing Tampa Electric's CAAA Title IV Phase I and II compliance plans for SO_2 and NO_X have been reviewed by the Florida Public Service Commission (FPSC). The FPSC has approved Tampa Electric's requests to recover certain environmental compliance costs associated with these projects.

In 1997, EPA began an investigation into alleged violations by Tampa Electric and several other coal-fired electric utilities of EPA's New Source Review (NSR) policy, a segment of Title I of the CAAA. EPA asserted that certain electric utilities, including Tampa Electric, should have applied for pre-construction permits for certain unit maintenance projects, and that the permitting review of such projects would have included NSR, resulting in requirements that the units meet best available control technology (BACT) standards for NO_X, SO_2 and PM. The electric utility industry, including Tampa Electric, disagrees with EPA's current interpretation of its NSR rules. On November 3, 1999, despite Tampa Electric's longstanding efforts to reach a mutually-agreeable settlement with the EPA, the Department of Justice (DOJ) sued Tampa Electric and seven other electric utilities on behalf of EPA for alleged violations of the CAA associated with this NSR issue. At issue are the coal-fired Gannon Units 3, 4, and 6, and Big Bend Units 1 and 2.

Following this federal action, DEP also contended that Tampa Electric had not applied for appropriate air permits for certain unit maintenance projects at Gannon and Big Bend Stations and, therefore, had operated the coal-fired units without BACT for NO_X, SO_2 and PM. Following negotiations within the CAA 30-day notice period, DEP and Tampa Electric reached a settlement. Effective December 16, 1999, DEP and Tampa Electric entered into a CFJ which addresses the DEP claims that Tampa Electric modified and then operated its generating units at Big Bend and Gannon without first obtaining permits authorizing the modifications and without installing BACT to control NO_X, SO_2 and PM. The requirements of the CFJ include repowering Gannon Station and further reducing NO_X, SO_2 and PM emissions at Gannon and Big Bend Stations. The CFJ was entered on December 16, 1999 in the Circuit Court of the Thirteenth Judicial Circuit in and for Hillsborough County. The CFJ is included as Appendix A.

Tampa Electric monitors and evaluates the development of future federal, state, and local regulations and policies relating to environmental compliance requirements. The company evaluates potential future outcomes and impacts on its operations. The company also evaluates various possible degrees of emissions reductions and corresponding options in terms of control technologies that might be needed to meet potential future requirements.

Section 2

2. SO_2 Compliance Plan

2.1 Overview of Compliance Requirements

The Acid Rain Program, created under Title IV of the CAAA, sets as its primary goal a nationwide reduction of annual SO_2 emissions by 10 million tons below 1980 levels to be achieved in two phases. SO_2 emissions from electric utilities, encompassing over 2,000 units, will be capped at 8.95 million tons per year. The primary goal of the program is to achieve this nationwide reduction in SO_2 emissions, which involves allocating a fixed number of annual SO_2 emission allowances to electric utilities. In order to emit SO_2, one allowance is required for each ton of SO_2 emitted.

Phase I of the Acid Rain Program began January 1, 1995 and required 110 power plants to reduce their emissions to a level equivalent to the product of an SO_2 emissions rate of 2.5 pounds per mmBtu times the average of their 1985 through 1987 heat input based on fuel usage. Unused allowances may be bought, sold, traded, or banked by facilities for future use. Big Bend Units 1, 2 and 3 were designated by EPA as Phase I units, and Tampa Electric later chose to designate Big Bend Unit 4 as a Phase I substitution unit. Under the Acid Rain Program, utilities may trade allowances among the units within their systems and/or buy or sell allowances from other sources.

Table 2.1 shows for Phase I, the 86,485 annual SO_2 allowances EPA granted to Tampa Electric for the 1,742 MW capacity of Big Bend Units 1 through 4:

Table 2.1

TOTAL PHASE I SO_2 ALLOWANCES

YEARS 1995 - 1999

BIG BEND UNIT	ANNUAL SO_2 ALLOWANCES
Big Bend 1	27,662
Big Bend 2	26,387
Big Bend 3	26,036
Big Bend 4	6,400
TOTAL	**86,485**

With the exception of all combustion turbine generating units existing at the time of enactment, Phase II of the CAAA Title IV SO_2 reduction requirements affects all existing fossil-fueled electric power generating units over 25 MW and all new fossil-fueled units. This includes over 2,000 existing generating units. Phase II requires these units to reduce emissions to a level equivalent to the product of a SO_2 emission rate of 1.2 pounds per mmBtu times the average of their 1985 through 1987 heat input based on fuel usage. SO_2 emissions from these utilities will be capped at 8.95 million tons per year, about 10 million tons less than 1980 levels.

Phase II compliance must be implemented by January 1, 2000, and affects all of Tampa Electric's existing and future electric generating units, with the exception of the Phillips and Dinner Lake Stations and existing combustion turbines. For Phase II, EPA allocated annual SO_2 allowances to Tampa Electric for years 2000 through 2009, based on 1985 through 1987 emissions from Big Bend, Gannon, and Hookers Point, as shown in Table 2.2. The total 84,609 SO_2 allowances includes 83,882 original base allowances plus 727 allowances that EPA reallocated due to corrections required in 1998 (See Federal Register, September 28, 1998).

Table 2.2

TOTAL PHASE II SO_2 ALLOWANCES

YEARS 2000 — 2009

BIG BEND UNIT	ANNUAL SO_2 ALLOWANCES
Big Bend 1	12,132
Big Bend 2	12,196
Big Bend 3	11,444
Big Bend 4	8,780
TOTAL	**44,552**

GANNON UNIT	ANNUAL SO_2 ALLOWANCES
Gannon 1	3,842
Gannon 2	4,425
Gannon 3	5,664
Gannon 4	6,223
Gannon 5	6,537
Gannon 6	10,081
TOTAL	**36,772**

HOOKERS POINT	ANNUAL SO_2 ALLOWANCES
Hookers Point Boiler 1	177
Hookers Point Boiler 2	207
Hookers Point Boiler 3	469
Hookers Point Boiler 4	701
Hookers Point Boiler 5	1,253
Hookers Point Boiler6	478
TOTAL	**3,285**

POLK UNIT	ANNUAL SO_2 ALLOWANCES
Polk Unit 1 IGCC	0
Polk Unit 2 CT	0
Polk Unit 3 CT	0
Polk Unit 4 CT	0
Polk Unit 5 CT	0
Polk Unit 6 CT	0
Polk Unit 7 CT	0
All other future Polk units	0
TOTAL	**0**
TOTAL TAMPA ELECTRIC	**84,609**

The company must account for its total actual tons of SO_2 emissions from all applicable generating units, and offset emissions in excess of the allocation with the acquisition of additional SO_2 allowances. The applicable Tampa Electric units are Big Bend Units 1 through 4, Gannon Units 1 through 6, Hookers Point boilers 1 through 6 (which serve turbine-generator Units 1 through 5), Polk Unit 1 (IGCC/HRSG stack), the future Polk combustion turbine units, and all future fossil-fueled units.

Thus, Phase II provides 84,609 annual allowances in years 2000 through 2009 for 3,372 MW of generating capacity (in 2000) compared to 86,485 allowances for 1,742 MW in Phase I.

For years 2010 through 2020, the number of SO_2 annual allowances reduces to 83,944 as shown in Table 2.3:

Table 2.3

TOTAL PHASE II SO_2 ALLOWANCES

YEARS 2010 — 2020

STATION	TOTAL EPA ANNUAL SO_2 ALLOWANCES
Big Bend	44,644
Gannon	36,018
Hookers Point	3,282
Polk	0
TOTALTAMPA ELECTRIC	**83,944**

The original Phase I SO_2 units, Big Bend Units 1, 2, and 3 were required to have Continuous Emission Monitor Systems (CEMS) installed and operational in November 1993, in accordance with 40 CFR 75. The Phase II units and Big Bend Unit 4 were required to install CEMS by November 1994. The systems measure, record, and electronically report volumetric flue gas flow, SO_2, NO_X, and CO_2 to provide the basis of measurement for compliance with the Phase I and Phase II SO_2 and NO_X limits.

Big Bend Unit 4, which had CEMS installed when built in 1985, met the New Source Performance Standards (NSPS) in 40 CFR 60, Subpart Da. In November 1994, the CEMS were retrofitted similar to the other Big Bend units to become compliant with the Phase I and II requirements,. Gannon Units 1 through 6 and the three stacks serving Hookers Point Boilers 1 through 6 were equipped with CEMS by November 1994. The original equipment associated with Polk Unit 1, placed in service in September 1996, included CEMS that measure emissions from the IGCC/HRSG stack. The company expects that all future units of applicable size will have similar CEMS.

2.2 CAAA Title IV Phase I Compliance

Tampa Electric began its CAAA compliance plan in 1990. In January 1994, the "Tampa Electric Company Clean Air Act Amendments of 1990 Compliance Plan Evaluation - Phase I" was completed and was provided to the FPSC. This plan reviewed several options to comply with the first phase of the CAAA Title IV Acid Rain provisions. This initial Phase I plan included fuel blending with low sulfur coal and purchasing SO_2 allowances. To accommodate burning lower sulfur coals in Big Bend Units 1 through 3, flue gas conditioning systems were required to provide necessary ESP performance for control of PM emissions. As part of an ongoing effort to reduce compliance costs and meet compliance requirements in the most cost-effective manner, this plan was followed by an FGD integration study. This study indicated that integrating Big Bend Unit 3 with the existing Big Bend Unit 4 FGD system, in conjunction with fuel blending for reduced SO_2 emissions, and SO_2 allowance purchases, was the best option for compliance with the Phase I SO_2 reduction requirements.

2.3 CAAA Title IV Phase II Compliance

Tampa Electric continued its efforts with a study of compliance options for the CAAA Title IV Phase II SO_2 emissions reduction requirements. The results were published in the May 1998 document "Tampa Electric Company CAAA Phase II Compliance" and was provided to the FPSC. By incorporating the results of previous studies and the successful operation of the Big Bend Unit 3 and 4 FGD system integration, Tampa Electric developed viable options to meet the more stringent Phase II regulations. The study concluded that a stand-alone retrofitted FGD system for Big Bend Units 1 and 2, along with fuel blending and purchasing SO_2 allowances, was the most cost-effective option for the Tampa Electric system. The FGD system installed on Units 1 and 2 will reduce SO_2 emissions by approximately 70,000 tons per year. For Gannon, Tampa Electric will utilize fuel blending and, as necessary, purchase SO_2 allowances as part of its system-wide SO_2 compliance strategy. Emissions resulting from Tampa Electric's other Phase II generating units do not exceed the amount of SO_2 allowances allocated for the Tampa Electric system.

2.4 CAAA Title IV and V Permitting

Tampa Electric was issued Phase I Title IV Acid Rain Permits. Tampa Electric has also applied for the Phase II Acid Rain Permits, which will be issued as part of the facilities' Title V Operating Permits.

Tampa Electric applied for the required CAAA Title V Operating Permits for Big Bend, Gannon, Hookers Point, Polk, Phillips and Dinner Lake Stations. Thus far, the permits for Hookers Point, Polk, Phillips and Dinner Lake have been issued. DEP is expected to issue the Big Bend and Gannon Title V permits in 2000. The Title V Operating Permits are extremely detailed and provide comprehensive air-related information regarding required operating conditions, monitoring and testing, emission limits, and reporting requirements, including all of the CAAA Title IV requirements. Tampa Electric's Title V permit applications, including emissions inventories, contain detailed descriptions of all air-related systems, site activities, regulatory requirements, potential emissions and pre-existing emission limits.

As part of the Gannon Station Title V permitting process, DEP modeled SO_2 ambient air concentrations and found modeled exceedances of the three-hour SO_2 ambient air quality standard. To address this, Tampa Electric investigated two alternatives for reducing SO_2 emissions from Gannon Station. The first alternative involved raising the Gannon Unit 5 and 6 stacks by 14 meters to a height of 110 meters to prevent plume downwash and, therefore, prevent SO_2 from reaching the ground prematurely. The second alternative involved the use of lower sulfur coal to comply with the standard. Tampa Electric is continuing to evaluate these two alternatives.

Section 3

3. NO_X Compliance Plan

3.1 Overview of Compliance Requirements

The Acid Rain Program under Title IV of the CAAA requires a 2 million-ton reduction in NO_X emissions from 1980 levels. The EPA NO_X Emission Reduction Program is implemented in two phases for two groups of coal-fired electric utility boilers. The NO_X program differs from the SO_2 program in that it neither caps the NO_X emissions nor uses an allowance trading system.

The Phase I NO_X program for Group 1 boilers became effective on January 1, 1996, and affected all dry-bottom and tangentially-fired boilers that are required to meet NO_X performance standards (40 CFR 76). Big Bend Unit 4, a tangentially-fired dry-bottom boiler with an existing state NO_X permit limit of 0.60 pounds per mmBtu (30-day rolling average) was Tampa Electric's only unit affected by Phase I of EPA's NO_X program. This was due to Tampa Electric designating it as a Phase I SO_2 substitution unit. As such, effective January 1, 1996, Big Bend Unit 4 NO_X emissions were limited to 0.45 pounds per million Btu of heat input on an annual average basis under the Acid Rain Program in addition to its existing NO_X limit. This is being accomplished through the unit's original design, which controls NO_X emissions through combustion tuning. This approach did not require any physical or design modifications.

The EPA Phase II NO_X emission limitations, as outlined in 40 CFR 76 and adopted by EPA in December 1996, apply to Big Bend Units 1, 2, 3, and 4, and Gannon Units 3, 4, 5 and 6, effective January 1, 2000. Big Bend Unit 4, a Phase I Group 1 boiler, will continue to be required to meet the Phase I limit of 0.45 pounds per mmBtu. Gannon Units 1 and 2 are not affected since the Phase II NO_X requirements do not apply to cyclone boilers of this size. Polk Unit 1, an IGCC unit, is not affected since it is not a defined boiler type for which EPA has set NO_X emission limitations in its Acid Rain rules.

The Phase II NO_X limits reflect maximum annual average limits based on the type of boiler, and are applicable to each unit individually. Big Bend Units 1, 2 and 3, and Gannon Units 5 and 6, all with wet bottom boilers, are limited to 0.84 pounds per mmBtu, annual average, effective January 1, 2000. Gannon Units 3 and 4, both with cyclone boilers, are limited to 0.86 pounds per mmBtu, annual average, effective January 1, 2000. As an alternative to unit-specific emission limits, EPA Rule 40 CFR 76.11 allows the company to submit a petition to EPA for system-wide emission averaging plan, which allows more operational flexibility and can be a more cost-effective compliance method.

3.2 NO_X Compliance Alternatives

During EPA's rule development process for the Title IV Phase II NO_X program, Tampa Electric continued to demonstrate to EPA that higher emission limits for the uniquely designed Riley Stoker Turbo-Furnace wet bottom boilers were necessary. Big Bend Units 1, 2 and 3 and Gannon Units 5 and 6 have these turbo-fired furnace boilers.

Tampa Electric has achieved better than expected NO_X reductions from its Phase II affected units through the use of combustion optimization. Tampa Electric has committed to attain the NO_X reduction levels required by the Title IV NO_X Reduction Rule with system-wide averaging in the initial years of Phase II.

In developing methods and approaches to comply with the CAAA Title IV Phase II NO_X requirements, the following NO_X control technologies were evaluated for cost-effectiveness for the Riley Stoker Turbo-Furnace boilers on Big Bend Units 1 and 2 and Gannon Units 5 and 6:

1. Selective Non-Catalytic Reduction (SNCR)
2. Selective Catalytic Reduction (SCR)
3. Natural Gas Reburning
4. Coal Reburning
5. Overfire Air
6. Low NO_X Burners
7. Combustion Optimization

For the degree of NO_X reduction required, combustion optimization was found to be the most cost-effective approach in meeting the Phase II NO_X requirements. The emission rates achieved for Big Bend Units 1, 2 and 3 and Gannon Units 5 and 6 will allow Tampa Electric to meet system-wide average compliance when the emission rates of these units are averaged with the emission rates of Big Bend Unit 4 and Gannon Units 3 and 4. Except for low NO_X burners, which cannot be applied to the cyclone boilers of Gannon Units 3 and 4, the same control technologies were evaluated for the cyclone units.

3.3 CAAA Title IV Phase II Compliance

Based on the costs and the operational criteria used to judge the potential NO_X control options for Big Bend Units 1, 2 and 3 and Gannon Units 3, 4, 5, and 6, Tampa Electric's approach to meet the CAAA Title IV Phase II NO_X limits has been through combustion optimization. This control option, which provides NO_X reductions from least-cost control measures first, was found to be the optimal first choice in a "top down approach." This approach may also reduce the costs for additional NO_X controls if higher levels of reductions are required in the future.

Replacement of the existing coal classifiers has been an integral part of combustion optimization for the Riley Stoker Turbo-Furnace boilers on Big Bend Units 1 and 2 and Gannon Units 5 and 6. The new classifiers provide the coal fineness and fuel distribution that is needed for low NO_X combustion in these boilers that cannot be provided by the existing classifiers. The classifier installations were completed in July 1999 and are necessary to continue to burn coal at these facilities.

Based on the costs and operational criteria used to judge the potential NO_X control options for the Gannon Units 3 and 4 cyclone boilers, the optimal first "top down" choice of NO_X control is combustion optimization. For these cyclone boilers, combustion optimization consists of burning optimal percentages of high moisture, low BTU coal, increasing the fineness of the coal through the addition of two coalfield crushers, and performing combustion tuning through boiler air flow and fuel balancing.

In addition, Tampa Electric submitted a system-wide averaging plan to EPA as part of its Phase II NO_X compliance strategy to incorporate additional compliance flexibility. The system-wide annual average will be applicable to Big Bend Units 1, 2, 3, and 4, and Gannon Units 3, 4, 5, and 6 and is projected to be 0.76 pounds per mmBtu. The submittal was filed with EPA.

If the system-wide averaging plan and the combustion optimizations cannot achieve the required NO_X reductions, Tampa Electric may, as feasible, implement neural networks for the Riley Stoker Turbo-Furnaces and water injection and/or overfire air for the cyclone units. In the event these measures are not feasible or do not meet the required limit, the installation of other NO_X controls will be considered for one or more of the affected units.

Section 4

4. Particulate Matter Compliance Plan

Requirements to limit PM emissions are addressed under Title I of the CAAA. Accordingly, Tampa Electric has complied with and will continue to comply with all applicable PM ambient air quality standards as defined by EPA. To date, Tampa Electric operates ESPs on all of its coal-fired units at Big Bend and Gannon Stations to control PM emissions. In 1999, Tampa Electric performed an optimization study, as required by the Gannon Station Fuel Yard Permit issued by DEP, to evaluate the ESP operations at Gannon. The results of the study will identify the optimum parameter ranges required to operate the ESP at the required efficiency. These operating ranges will then be incorporated into the permit by a date mutually agreed-upon by DEP and Tampa Electric.

Section 5

5. Air Toxics Compliance Plan

5.1. Overview of Compliance Requirements

The CAAA required the EPA to perform a study of the hazards to public health reasonably anticipated to occur as a result of emissions by electric utility steam generating units of hazardous air pollutants (HAPs), to prepare a report to Congress containing the results of the study, and to regulate electric utility steam generating units if EPA finds that such regulation is appropriate and necessary. The Final Utility Study Report was issued on February 24, 1998. The report stated that mercury is the HAP emission of greatest potential concern from coal-fired utilities, and that additional research and monitoring are merited. However, the EPA deferred making any determination as to whether regulation of electric utility steam generating units is appropriate and necessary. Instead, under the authority provided in Section 114 of the CAA (42 U.S.C. 7414) the EPA required that all coal-fired electric utility steam generating units provide certain information to allow EPA to calculate the annual mercury emissions from each such unit. Under authority of Section 114, EPA is authorized to administer and request information and data collection related to compliance with the CAAA. EPA will use the requested information to evaluate, if it is appropriate and necessary, to regulate emissions of HAPs from electric utility steam generating units. Future mercury regulations could range from no change to requiring the installation of wet FGD systems or activated carbon injection.

In addition, CAA Section 112 (r) and 40 CFR Part 68 require certain companies to plan and implement prevention plans and procedures to decrease the likelihood of releases of 77 toxic and 63 flammable chemicals, particularly to the extent that there would be off-site consequences. Nationally, more than 66,000 businesses are covered by these Risk Management Program requirements. These requirements range from a less stringent Program 1 to a most stringent Program 3, depending on the chemicals present, off-site consequence potential, and the accident history of the facilities. The Risk Management Plans (RMPs) for applicable facilities were required to be submitted to EPA by June 21, 1999. Tampa Electric's RMP is discussed in Section 5.3.

5.2. Mercury Information Collection Request (ICR)

EPA issued the Mercury Information Collection Request (ICR) to gather data on mercury emissions from electric utility power station during 1999. Part I of the ICR required all electric utilities to identify their unit types, fuel types and pollution control devices. Part II requires all coal-fired electric utility units to submit quarterly reports on the mercury and chlorine content in coal. Part III requires selected utilities to conduct a one-time speciated mercury stack emissions test. Tampa Electric was required to participate in this information-gathering project. Tampa Electric is conducting fuel sampling and analysis for all coals at Big Bend, Gannon and Polk Stations during 1999 and is submitting quarterly reports of these analyses to EPA. In addition, Tampa Electric was required to perform mercury stack emissions testing at Big Bend and Polk Stations. The emissions stack testing was performed on Polk Unit 1 and Big Bend Unit 3 in November 1999. At Big Bend, a testing platform was constructed on the Unit 3 stack to facilitate completion of the required testing method. The results of these stack tests will be provided to EPA within 90 days after the test completion date.

5.3. Risk Management Program

Tampa Electric submitted a RMP to the EPA for the hydrogen in the syngas system at Polk Power Station. Because there are no off-site consequences and there have been no accidental releases of hydrogen in the past five years that resulted in any of the consequences covered by 40 CFR Part 68, Polk is only subject to the Program 1 RMP requirements.

EPA's RMP rule also applies to facilities storing more than 10,000 pounds of propane. Tampa Electric's Eastern Operations Center and Central Operations Center in Tampa, and its Plant City Operations Center have propane vehicle fuel stored in quantities above the 10,000 pound threshold. Currently, RMPs are not required for these three facilities due to a U.S Court of Appeals judicial stay of the rule for liquefied propane gas, as well as an EPA administrative stay of the effective date of the rule for facilities storing no more than 67,000 pounds of RMP flammable hydrocarbon fuels including propane.

If EPA is allowed to regulate propane in the future, EPA rule revisions could possibly allow Tampa Electric to manage the three operating centers with quantities of propane below the threshold to require the submittal of RMPs. If ammonia systems for SCRs or other developing technologies are installed at Gannon or Big Bend in the future and those systems contain greater than 10,000 pounds of ammonia, then it will be necessary to develop and submit RMPs to EPA for these facilities.

Section 6

6. Other Potential Future Compliance Issues

There are several evolving environmental issues that may impact future operations. Some of the issues have the potential to result in requirements for additional emission reductions from current levels. Tampa Electric has considered these potential requirements in its development of options selected in this Compliance Plan.

6.1 Ozone Non-Attainment Status of the Tampa Bay Airshed

Description:

The Tampa Bay airshed is likely to be designated as non-attainment for ozone concentrations in the ambient air. If this designation is made, the state will have to formulate a method to reduce emissions of NO_X and volatile organic compounds to resolve the non-attainment status. Part of the state plan may include requirements for reduction in NO_X emissions from utility sources.

Time Frame:

Although rulemaking concerning the new ozone standards is currently in dispute, the Tampa Bay airshed ozone measurements are near the trigger level for the one-hour standard.

6.2 $PM_{2.5}$ Non-Attainment Status of the Tampa Bay Airshed

Description:

The Tampa Bay airshed may possibly be designated as non-attainment for $PM_{2.5}$ concentrations in the ambient air. If this designation is made, the state will have to formulate a method to reduce emissions of NO_X, SO_2 and PM to resolve the non-attainment status. Part of the state plan may include requirements for the reduction of NO_X, SO_2 and PM emissions from utility sources. PM reductions can be accomplished through several means, such as ESP upgrades and baghouses for coal units. SO_2 reductions can be accomplished through lower sulfur fuel on coal units, additional FGD systems for coal units, natural gas reburn for coal units, purchase of emission allowances and repowering of coal units. NO_X reductions can be accomplished through the options described above under the ozone non-attainment issue.

Time Frame:

If the Tampa Bay airshed is designated non-attainment, Tampa Electric's system may be impacted between 2004 and 2008.

6.3 Potential Mercury Regulations for Utility Sources

Description:

The EPA is currently evaluating the necessity of proposing mercury regulations. These regulations would likely be source-specific emission limitations. The options to reduce mercury emissions include carbon injection or repowering the Big Bend units. The degree to which one or more of the technologies would be used and the generating units to which the technology would be applied depends upon the amount of emission reductions required.

Time Frame:

The time frame is uncertain but is not likely to occur prior to 2005.

6.4 Potential CO_2 Regulations for Utility Sources

Description:

The EPA is currently evaluating the necessity of proposing CO_2 regulations. These regulations would likely be imposed as part of a system-wide limit and/or trading program similar to the Title IV Acid Rain Program. The options which may be potential remedies include implementing carbon sequestration projects, purchasing CO_2 emission allowances and repowering coal units.

Time Frame:

The time frame is uncertain but is likely to occur after 2008.

6.5 Potential NSR Regulations Reform

Description:

The EPA is in the process of drafting changes to the NSR regulations and is near promulgation of stricter language. In connection with the EPA's actions into the investigation of possible NSR violations, a dialogue between UARG and other industries occurred with the EPA in an attempt to resolve the EPA's concerns through an agreement on NSR regulation reform. One possible action that could result would be to set a future date for implementation of NSPS for utility boilers at some date certain (after 2010 and before 2030) and in exchange, utilities would be afforded more operational and maintenance flexibility in the interim.

Time Frame:

The time frame for potential reform is uncertain but will likely occur between 2010 and 2030.

6.6 New Acid Rain Regulations

Description:

EPA is considering requiring further reductions of SO_2 and NO_X emissions from utility sources.

Time Frame:

The time frame is uncertain but will likely occur after 2005.

6.7 Impact of Tampa Electric's Current Compliance Activities on Potential Future Compliance Issues

Tampa Electric is monitoring and evaluating potential future environmental issues as they develop to determine possible strategies. Tampa Electric's overall strategy is to approach each air emission parameter on a system-wide basis considering the applicable generating units.

Tampa Electric's future actions with regard to the CFJ will address and mitigate potential requirements for the majority of these issues since the repowering of Gannon and the use of NO_X control technologies at Gannon and Big Bend will significantly lower overall NO_X emissions.

Significant reductions in all pollutant emissions will be realized with the implementation of the CFJ. In addition, the NO_X controls on the Gannon and Big Bend units and optimization of the FGD systems will greatly reduce Tampa Electric's contribution to the NO_X budget in the Tampa Bay airshed, thereby helping to mitigate ozone non-attainment issues, PM, NSR reform, and potential new Acid Rain regulations. The reduction in emissions of these pollutants should allow Tampa Electric to meet the requirements of or at least mitigate the impact of potential future compliance issues described in Sections 6.1 through 6.6 above.

Section 7

7. Consent Final Judgment

7.1 Objectives and Overview

In 1997, EPA began an investigation into alleged violations by Tampa Electric and several other coal-fired electric utilities of EPA's NSR policy, a segment of Title I of the CAAA. EPA asserted that certain electric utilities, including Tampa Electric, should have applied for pre-construction permits for certain unit maintenance projects, and that the permitting review of such projects would have included NSR, resulting in requirements that the units meet BACT standards for NO_X, SO_2 and PM. The electric utility industry, including Tampa Electric, disagrees with EPA's current interpretation of its NSR rules. On November 3, 1999, despite Tampa Electric's longstanding efforts to reach a mutually agreeable settlement with the EPA, the DOJ sued Tampa Electric and seven other electric utilities on behalf of EPA for alleged violations of the CAA associated with this NSR issue. At issue are the coal-fired Gannon Units 3, 4, and 6, and Big Bend Units 1 and 2.

Following this federal action, DEP also contended that Tampa Electric had not applied for appropriate air permits for certain unit maintenance projects at Gannon and Big Bend Stations and, therefore, had operated the coal-fired units without BACT for NO_X, SO_2 and PM. Following negotiations within the CAA 30-day notice period, DEP and Tampa Electric reached a settlement. Effective December 16, 1999, DEP and Tampa Electric entered into a CFJ which addresses the DEP claims that Tampa Electric modified and then operated its generating units at Big Bend and Gannon without first obtaining permits authorizing the modifications and without installing BACT to control NO_X, SO_2 and PM.

The requirements of the CFJ include repowering Gannon Station and further reducing NO_X, SO_2 and PM emissions at Gannon and Big Bend Stations. The CFJ was entered on December 16, 1999 in the Circuit Court of the Thirteenth Judicial Circuit in and for Hillsborough County.

As a key element of the CFJ, Tampa Electric is required to repower Gannon station (Gannon Repowering Project) from coal to natural gas using combustion turbines in a combined cycle mode. This will be accomplished by using existing Units 3, 4, and 5. All coal-related assets including coal-handling equipment will be retired. The steam turbines/generators and associated non-coal related equipment from Units 1 and 2 will be shut down and placed on reserve standby coincident with the repowering of Unit 5. Unit 6 will be shut down and placed on reserve standby by the end of 2004. These units will be available to Tampa Electric as future supply-side resource options via repowering to meet the growing demand and energy needs of its customers. The company does not currently have plans to utilize the units, but it may, at some time in the future, repower or convert the units to natural gas if those options prove to be cost-effective.

The repowering schedule anticipates starting engineering on the project in January 2000 with commercial operation of the repowered Unit 5 on May 1, 2003. The repowering of Units 3 and 4 will be completed on May 1, 2004. When these three units are repowered, the total station capacity will increase from about 1,200 MW to 1,475 MW.

The CFJ also requires Tampa Electric to reduce SO2, NOX and PM emissions at Big Bend and Gannon conduct studies of NOX removal technologies and PM monitors, work with DEP on its study of nitrogen deposition in Tampa Bay, and work with DEP to develop and implement state tax policy aimed at emission reductions and other environmental programs.

7.2 Gannon Repowering Project Analysis

Tampa Electric's analysis demonstrating that the Gannon Repowering Project is the most cost-effective alternative is provided in Appendix B. This analysis demonstrates the feasibility of repowering and also includes NO_X control technologies at Big Bend beginning in 2007 and completed by 2010. The repowering option was compared with several other options including continuing Tampa Electric's current Phase II compliance plan, installing environmental equipment on each Gannon unit, closing Gannon and purchasing power, and building new replacement generation. Under the CFJ, Tampa Electric was required to reduce emissions, so it was not feasible to continue with the current Phase II plan. The repowering option was the most cost-effective option given the more stringent environmental requirements of the CFJ.

The types of additional environmental controls to be installed at Big Bend will be dependent on the outcome of the various studies. Tampa Electric has not yet begun these required evaluations but will provide the results and complete analyses of the most cost-effective compliance options to both the DEP and FPSC.

Over time, Tampa Electric has operated its electrical generating facilities in the most cost-effective and prudent manner to ensure safe, reliable supply of electricity while complying with applicable environmental requirements. To date, Tampa Electric has put into place economical and effective measures to comply with the CAAA Title IV Phase I and Phase II requirements, as detailed above. Tampa Electric has continued to operate its existing generating facilities, as well as plan and build new generation capacity, in accordance with environmental regulations. The decision to go forward with the Gannon Repowering Project is consistent with Tampa Electric's environmental and operational policies.

Ongoing operation and maintenance activities, which are essential to ensure reliability of the Tampa Electric system, are in danger of curtailment due to the determination by EPA and DEP that certain maintenance activities at existing coal-fired generation triggered more stringent requirements to install new and costly emissions control technology. While there is no doubt that Gannon, despite being 40 years old, has many years of service remaining, the installation of emissions control technology such as FGD systems or SCRs on each unit would not be cost-effective nor would the discontinuation of ongoing maintenance be practical or prudent due to safety and reliability concerns. The recent proposals to bring additional gas supply into Florida made the option of natural gas repowering at Gannon a viable option. Therefore, the repowering of Gannon Units 3, 4 and 5 was able to meet the more stringent environmental requirements while maintaining reliability with the added benefit of increasing Tampa Electric's fuel diversity.

7.3 Impact of CFJ on SO_2 Compliance

Tampa Electric is required by the CFJ to repower or shutdown the units at the Gannon Station, maximize the FGD utilization for the Big Bend units and optimize the FGD efficiency for the Big Bend Units 1 and 2 with a minimum of 95 percent removal. The Gannon Repowering Project will dramatically reduce total emissions of SO_2 from this facility by replacing the coal-fired generation with natural gas-fired combined cycle units. At the conclusion of the conversion project, no coal-fired generation will remain in service at this facility.

The requirement to maximize the FGD system's utilization at Big Bend Station will require detailed engineering, testing and evaluation, and potential operational changes of the existing and the recently-constructed wet limestone FGD system. This compliance activity is a prudent and cost-effective measure to reduce SO_2 emissions. This requirement allows continued fuel flexibility to maintain stable and competitive fuel expenses, while ensuring the maximum utilization of existing capital investments in SO_2control equipment.

These projects will significantly reduce total emissions of SO_2 from the Tampa Electric system. In the interim, Tampa Electric's Phase II SO_2 compliance plan continues to be the most cost effective means to meet Phase II SO_2 requirements. Overall, Tampa Electric's SO_2 emissions from 1997 to 2010 are expected to be reduced by approximately 80 percent as shown in Figure 7.1 below.

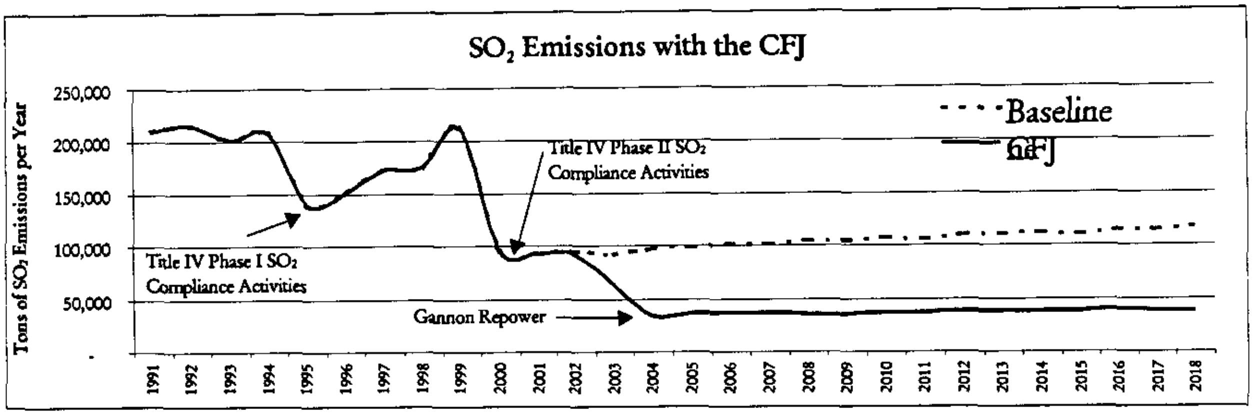


Figure 7.1: Estimated SO_2 Emissions with the Implementation of the CFJ

7.4 Impact of CFJ on NO_X Compliance

Tampa Electric is required by the CFJ to repower or shutdown the units at Gannon Station; shutdown, repower or install NO_X controls on Big Bend Unit 4 in 2007; and shutdown, repower or install NO_X controls on Big Bend Units 1, 2 and 3 by 2010. The intent of the CFJ is that by 2010 all of the units at the Big Bend and Gannon Stations will meet BACT standards for NO_X. The methodology of NO_X emission controls for these units has not been established at this time.

The Gannon Repowering Project will have the result of reducing NO_X emissions through the replacement of coal-fired generation with natural gas combined cycle generation. The combined cycle units will be required to meet a NO_X emission limit of 3.5 pounds per mmBtu.

As required by the CFJ, Tampa Electric may install a "zero ammonia" NO_X control technology on one of the units during the repowering project if this technology is found to be commercially viable by the DEP. If there are no "zero ammonia" technologies found to be commercially viable or the incremental cost of the technology is more than $8 million greater than the cost of an SCR, then Tampa Electric will review other NO_X reduction technologies for natural gas-fired or coal-fired generating facilities. The reduction of NO_X emissions resulting from the application of the reviewed technologies, in addition to the combustion optimization and tuning already performed, may eliminate or reduce the need for SCRs at Big Bend.

These projects will significantly reduce total emissions of NO_X from the Tampa Electric system. In the interim, Tampa Electric's Phase II NO_X compliance plan continues to be the most cost-effective means to meet Phase II NO_X requirements. Overall, Tampa Electric's NO_X emissions from 1997 to 2010 are expected to be reduced by approximately 85 percent as shown in Figure 7.2 below.

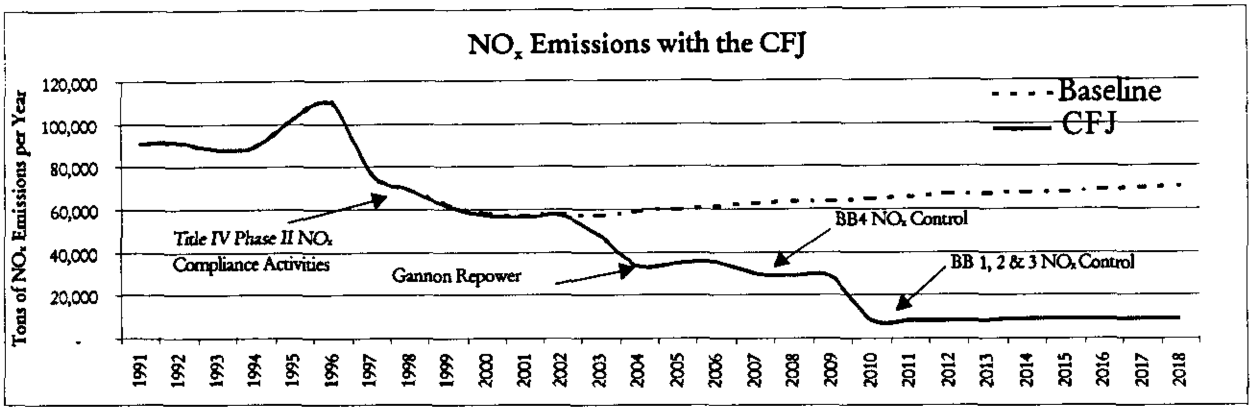


Figure 7.2: Estimated NO$_X$ Emissions with the Implementation of the CFJ

7.5 Impact of CFJ on PM Emissions

Since the repowered units at Gannon Station will be fired with natural gas, PM emissions will be reduced by approximately 45 percent in 2010 compared to 1997 emission levels. Figure 7.3 below shows the effect of the Gannon Repowering Project on system PM emissions.

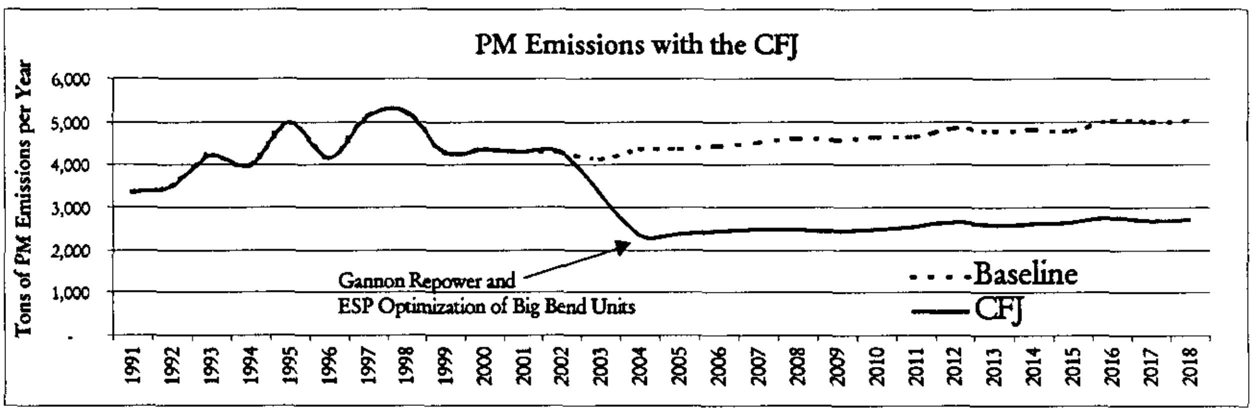


Figure 7.3: Estimated PM Emissions with the Implementation of the CFJ

In addition to repowering Gannon Station with natural gas, the CFJ stipulates that an ESP optimization study must be performed at Big Bend Station. The results of this study may identify measures that can be implemented to allow Tampa Electric to operate the ESPs at Big Bend Station in a manner that will further reduce PM emissions from each unit.

As required by the CFJ, Tampa Electric will also evaluate and report to the DEP the feasibility of installing a continuous in-stack PM monitor on one of the Big Bend stacks by March 1, 2002. DEP will then evaluate the feasibility and may require the installation of the monitor by May 1, 2003. Tampa Electric is currently evaluating the available monitoring technologies available to comply with the requirement.

Section 8

8. Fuel Sources

Fuel diversity is a key variable in Tampa Electric's CAAA Title IV Phase I and II SO_2 compliance plans. Tampa Electric's Phase I and II SO_2 compliance plans have combined the use of lower sulfur coals in certain units with the installation of FGD systems and the use of higher sulfur coals for other units to meet the overall CAAA Acid Rain Program requirements. Tampa Electric has tested alternative power plant fuels in an effort to augment traditional fuels with useful by-products and renewable sources. Petroleum coke (pet coke) and wood-derived fuel have been tested, and the company has received approval from DEP to burn these fuels on a regular basis. Although wood-derived fuel (essentially waste paper) has been used on a limited basis, pet coke produced an estimated 234 GWh of net energy in 1998.

These strategies have also reduced the number of SO_2 allowances used over time. Through ongoing monitoring of fuel and allowance market prices, Tampa Electric operates its units to meet environmental limits and minimize overall costs. Tampa Electric's present sources of fuel primarily include coal and oil. However, three natural gas pipelines with capacity of 1 billion cubic feet per day each are presently proposed for Florida with in-service dates of 2002 and 2003. The Florida Gas Transmission pipeline has announced major expansions of its system as well. This increased availability and the resulting reduced cost of natural gas transportation has made natural gas a viable fuel alternative for Tampa Electric.

Under the CFJ, future sources of fuel will include coal, natural gas and oil. Light oil will be used as secondary fuel for gas-fired generating units and for the existing simple-cycle combustion turbines. The future use of natural gas will greatly reduce NO_X, SO_2 and PM emissions.

Section 9

9. Regulatory Compliance Dates and Costs

The CAAA have established many new requirements, which affect Tampa Electric's environmental compliance plans. Table 9.1 lists several of the key CAAA Phase I, Phase II and CFJ requirements that specifically impact Tampa Electric's compliance strategy. Table 9.2 provides a summary of the project costs that have been undertaken to date by Tampa Electric. Table 9.2 does not provide a breakdown of the estimated projects costs associated with the CFJ requirements. The total cost of compliance with the CFJ is currently estimated to be approximately one billion dollars. Of this total, $673 million is the estimated cost of repowering Gannon Station. The remaining $327 million represents a high-level estimate of the expected costs for additional environmental projects and activities required by the CFJ. As the projects are evaluated in more detail, the cost estimates will be refined.

Table 9.1

REGULATORY COMPLIANCE DATES			
Regulatory Compliance Requirement	**Applicable Regulation**	**Affected Units**	**Compliance Date**
Phase I CEMS operational	Title IV – Phase I	Big Bend 1-4	November 1993
Phase II CEMS operational	Title IV - Phase I	Gannon 1-6 Hookers Point Boilers 1-6	November 1994
Phase I SO_2 allowance compliance begins using CEMS	Title IV – Phase I	Big Bend 1-4	January 1, 1995
Phase I NO_x annual average emission limits measurement with CEMS begins	Title IV – Phase I	Big Bend 4	January 1, 1996
Submit Polk Risk Management Plan	Section 112(r)	Polk Power Station	June 21, 1999
Phase II SO_2 allowance compliance begins using CEMS	Title IV – Phase II	Gannon 1-6 Hookers Point Boilers 1-6 Polk IGCC 1 Any future fossil fuel-fired units	January 1, 2000
Phase II NO_x annual average emission limits measurement with CEMS begins	Title IV – Phase II	Gannon 3-6 Big Bend 1-4	January 1, 2000
Complete Mercury testing including coal and stack testing	Section 114	Big Bend Station Gannon Station Polk Power Station	December 1999
Conduct feasibility study for PM monitor	CFJ	One Big Bend Unit	March 1, 2002
Optimize FGD utilization and efficiency	CFJ	Big Bend 1-4	May 1, 2002
Perform ESP optimization study, BACT analysis and implement upgrades	CFJ	Big Bend Station	May 1, 2003
Install PM monitor, if feasible	CFJ	One Big Bend Unit	May 1, 2003
Complete phase-in natural gas units	CFJ	Gannon Station	May 2004
Study NO_x control methodology and installation	CFJ	Big Bend 4 Big Bend 1-3	May 2007 May 2010

Table 9.2

INSTALLATION DATES AND COSTS			
Project	**Installation Date**	**Affected Units**	**Project Costs (Millions)**
Phase I CEMS installation	November 1993	Big Bend 1-3	$2.612
Flue Gas Conditioning System	December 1993	Big Bend 1 Big Bend 2 Big Bend 3	$2.676 $2.342 $2.595
Phase II CEMS installation	November 1994	Big Bend 4 Gannon 1-6 Hookers Point Boilers 1-6	$0.866 $3.939 $1.473
BB3 FGD Integration	June 21, 1995	Big Bend 3	$8.559
BB 1 & 2 FGD	December 31, 1999	Big Bend 4	$83.395
Mercury Testing	December 31, 1999	Big Bend Station Gannon Station Polk Power Station	$0.150
Electrostatic Precipitator Optimization Study	December 31, 1999	Gannon 1-6	$0.110
Classifier Replacement for Phase II NO_x compliance	December 1998 May 1998 December 1997 July 1999	Big Bend 1 Big Bend 2 Gannon 5 Gannon 6	$1.316 $0.985 $1.357 $1.412
Coalfield Crusher for Phase II NO_x compliance	June 1999	Gannon Station	$5.211

Appendix 1

Appendix A

CONSENT FINAL JUDGMENT

IN THE CIRCUIT COURT OF THE THIRTEENTH JUDICIAL C.RCUIT
IN AND FOR HILLSBOROUGH COUNTY, FLORIDA

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL PROTECTION,

Plaintiff,

vs. CASE NO.: 99-9737

TAMPA ELECTRIC COMPANY,

Defendant.
_______________________________/

CONSENT FINAL JUDGMENT

I. INTRODUCTION AND PURPOSE

A. This Consent Final Judgment is entered into between Plaintiff, State of Florida, Department of Environmental Protection (the "DEP"), and Defendant, Tampa Electric Company ("TAMPA ELECTRIC COMPANY"), to reach a settlement of certain matters at issue between them. The Consent Final Judgment provides for the implementation of certain actions, the investigation and implementation of certain pollution prevention technology, and the contribution of funds to assist the DEP in its Bay Regional Air Chemistry Experiment program relating to nitrogen deposition in Tampa Bay.

B. "Consent Final Judgment" means this Consent Final Judgment, including any future modifications, and any reports, plans, specifications and schedules required by the Consent Final Judgment which, upon the approval of each by the DEP, shall be deemed incorporated into and become an enforceable part of this Consent Final Judgment as though each was originally set forth herein.

II. JURISDICTION

A. The DEP is the administrative agency of the State of Florida having the power and duty to protect Florida's air and water resources, and to administer and enforce the provisions of Chapter 403, Florida Statutes, and the rules promulgated thereunder, Florida Administrative Code ("F.A.C.") Title 62 including the rules which Florida has the responsibility to administer and enforce under the federally approved Florida State Implementation Plan (SIP) and the separate Environmental Protection Agency delegation of PSD authority.

B. This Court has jurisdiction over the subject matter herein and over the Parties hereto pursuant to Chapter 403, Florida Statutes.

C. This Court retains jurisdiction over both the subject matter of this Consent Final Judgment and the Parties during the performance of its terms to enforce compliance therewith, if necessary.

III. PARTIES BOUND

This Consent Final Judgment shall apply to and be binding upon the DEP and TAMPA ELECTRIC COMPANY, (hereinafter individually defined as a "Party" or together defined as "Parties") and their successors and assigns. Each person signing this Consent Final Judgment certifies that he or she is authorized to execute the Consent Final Judgment and to legally bind to it the party on whose behalf he or she signs the Consent Final Judgment.

IV. STATEMENT OF FACTS

A. TAMPA ELECTRIC COMPANY owns and is an operator of the Big Bend coal fired electric generation plant in Hillsborough County. Big Bend generates electricity from four steam generating boilers which are designated as Big Bend Unit 1, Big Bend Unit 2, Big Bend Unit 3, and Big Bend Unit 4. TAMPA ELECTRIC COMPANY also owns and is an operator of the Gannon coal fired electric generation plant in Hillsborough County. Gannon generates electricity from six steam generating boilers which are designated as Gannon Unit 1, Gannon Unit 2, Gannon Unit 3, Gannon Unit 4, Gannon Unit 5, and Gannon Unit 6.

B. The DEP has alleged that Tampa Electric Company undertook a number of activities at the Gannon and Big Bend Generating Stations without appropriate regulatory review and permits, in violation of Chapter 403, Florida Statutes, and applicable provisions of the federally approved SIP. These activities include, but are not limited to, the following:

1. TAMPA ELECTRIC COMPANY modified, and thereafter operated, its electric generating units at Big Bend and Gannon, which are coal fired electricity generating power plants in Hillsborough County, Florida, without first obtaining appropriate permits authorizing this construction and without installing the best control technology (BACT) to control emissions of nitrogen oxides, sulfur dioxide, and particulate matter, as required by Florida law.

2. As a result of TAMPA ELECTRIC COMPANY's operation of the power plants, these unlawful modifications and the absence of appropriate controls, sulfur dioxide, nitrogen oxides, and particulate matter have been, and still are being, released into the atmosphere aggravating air pollution locally and downwind from these plants.

3. At various times, TAMPA ELECTRIC COMPANY commenced construction of modifications at Big Bend. These modifications included, but are not limited to: (1) replacement of steam drum internals in Big Bend Units 1 and 2 in 1994

and 1991, respectively; (2) replacement of the waterwall in Big Bend Unit 2 in 1994, and (3) replacement of the high temperature reheater in Big Bend Unit 2 in 1994.

4. Such modifications by TAMPA ELECTRIC COMPANY were done without obtaining a permit from the DEP and without applying BACT for nitrogen oxide, sulfur dioxide and particulate matter as required by Chapter 403, Florida Statutes.

5. At various times, TAMPA ELECTRIC COMPANY commenced construction of modifications to Gannon. These modifications included, but were not limited to: (1) replacement of the furnace floor in Gannon Unit 3 with a new design in 1996; (2) replacement of the cyclone in Gannon Unit 4 in 1994; and (3) replacement of a radiant superheater at Gannon Unit 6 in 1992.

6. Such modifications by TAMPA ELECTRIC COMPANY were done without obtaining a permit from the DEP and without applying BACT for nitrogen oxide, sulfur dioxide and particulate matter as required by Chapter 403, Florida Statutes.

C. Tampa Electric Company has agreed to the entry of the Consent Final Judgment and has agreed to implement the requirements of the Consent Final Judgment without an admission of liability and in recognition of the benefits of resolving litigation and elimination of such related expenses as settlement of the claims set forth in the Complaint, which Tampa Electric Company believes to be disputed claims. Tampa Electric Company neither admits nor denies the facts set forth in the Complaint and in Section IV.B. of this Consent Final Judgment.

V. REQUIREMENTS OF THE CONSENT FINAL JUDGMENT

A. TAMPA ELECTRIC COMPANY shall shut down coal-fired Units 1, 2, and 6 at Gannon Station and repower Units 3, 4, & 5 for gas to be phased-in between

January 1, 2003 and December 31, 2004. The repowered Units shall meet BACT for nitrogen oxide applicable to combined cycle gas turbines with an emission rate of 3.5 ppm. This requirement shall be included as a permit condition issued through the normal process.

B. TAMPA ELECTRIC COMPANY shall evaluate using "zero-ammonia" nitrogen oxide control technology at its Gannon facility. If, by May, 2000, such technology is found by the DEP to be commercially viable, TAMPA ELECTRIC COMPANY shall install such technology on one of the units it intends to repower so long as the incremental capital cost differential above the cost of Selective Catalytic Reduction (SCR) does not exceed $8 million and TAMPA ELECTRIC COMPANY obtains acceptable performance guarantees and remedies from the manufacturer of the technology. The installation shall be performed as part of the repowering process and shall be completed no later than December 31, 2004. In the event that the DEP does not find that the technology is commercially viable, then by December 31, 2004, TAMPA ELECTRIC COMPANY shall spend up to $8 million to demonstrate alternative commercially viable nitrogen oxide reduction technologies for natural gas-fired or coal-fired generating facilities as determined by the DEP and TAMPA ELECTRIC COMPANY.

C. At Big Bend Station, the new scrubber serving Units 1&2 is currently going through performance testing and is scheduled for commercial operation on or about January 1, 2000. It has a guaranteed removal efficiency of 95% but is the first Unit with a large, high velocity tower serving approximately 800 megawatts. TAMPA ELECTRIC COMPANY shall use reasonable commercial efforts to optimize the removal efficiency to achieve a 95% removal efficiency by May 1, 2002 if such rate is not achieved by commercial operation and if necessary, to pursue its available remedies against the vendor.

D. TAMPA ELECTRIC COMPANY shall maximize scrubber utilization on all four boilers at Big Bend. The DEP recognizes the need for shut down for operational reasons.

E. TAMPA ELECTRIC COMPANY shall add nitrogen oxide controls, repower or shut down Units 1 through 3 at Big Bend Station by May 2010 and at Unit 4 at Big Bend Station by May 2007. If SCRs or similar nitrogen oxide controls are installed, BACT for nitrogen oxide will be .10 lbs./mmBTU on Unit 4 and .15 lbs./mmBTU on Units 1, 2, and 3.

F. TAMPA ELECTRIC COMPANY shall undertake a performance optimization study and a BACT analysis of its electrostatic precipitators and make reasonable upgrades to the electrostatic precipitators at Big Bend Station by May 1, 2003, if the study indicates that reasonable upgrades are necessary to obtain performance optimization.

G. TAMPA ELECTRIC COMPANY shall report to DEP on the technical feasibility of installing a particulate matter continuous emissions monitor on one stack at Big Bend by March 1, 2002. If the DEP determines by May 31, 2002 that installation to be technically feasible, TAMPA ELECTRIC COMPANY shall install a particulate matter continuous emissions monitor on one stack at Big Bend station no later than May 1, 2003. Such monitor shall be installed solely for demonstration and informational purposes.

H. TAMPA ELECTRIC COMPANY shall be entitled to retain all sulfur dioxide reduction credits as currently authorized by law and freely trade them as allowed by the acid rain program. These credits were an integral part of the economics of the repowering project. If a credit trading program is developed by state or federal law for nitrogen oxide, TAMPA ELECTRIC COMPANY shall bank such credits obtained from the reductions achieved through the implementation of this Consent Final Judgment, but such credits shall not be eligible for sale to third parties but shall be held for TAMPA ELECTRIC COMPANY's (or any affiliate's) own account.

I. TAMPA ELECTRIC COMPANY shall agree to cooperate with the DEP on its Bay Regional Air Chemistry Experiment BRACE program relating to nitrogen deposition in Tampa Bay, including allowing necessary stack testing access to the DEP, and contributing $2 million dollars to the Hillsborough Environmental Protection Commission (EPC) for use in the BRACE program, in lieu of civil penalties. The DEP will enter into an agreement with EPC to ensure that the funds are spent on the BRACE program. TAMPA ELECTRIC COMPANY shall make the first payment to EPC in the amount of $500,000 by July 1, 2000, and shall pay $500,000 each six months thereafter until the full $2 million dollars has been paid.

J. TAMPA ELECTRIC COMPANY shall collaborate with the DEP to develop and implement State tax policy aimed at emissions reductions and such other supplemental environmental programs which are agreed to by TAMPA ELECTRIC COMPANY and the DEP.

K. TAMPA ELECTRIC COMPANY shall be entitled to relief from the time requirements of this Consent Final Judgment in the event of a force majeure that includes, among other things, delays in regulatory approvals, construction, labor, material or equipment delays, natural gas and gas transportation availability delays, acts of God or other similar events that are beyond the control of the company and not resulting from its owns actions, for the length of time necessarily imposed by the delay.

L. TAMPA ELECTRIC COMPANY shall be released from civil liability for all past New Source Review (NSR) related acts and State Implementation Plan (SIP) violations associated with the Prevention of Significant Deterioration (PSD), New Source Performance Standards (NSPS) and NSR related matters set forth herein and in the Complaint.

M. TAMPA ELECTRIC COMPANY shall also be protected from triggering NSR requirements with respect to repairs, maintenance and physical or operation changes during the term of the Consent Final Judgment which term shall remain effective until the actions required hereunder have been implemented.

N. The DEP shall cooperate with TAMPA ELECTRIC COMPANY and the United States Environmental Protection Agency in an effort to clarify the NSR regulations for repairs, maintenance, physical and operation changes in the future.

O. TAMPA ELECTRIC COMPANY's obligation to implement the emissions reductions and other requirements set forth herein will be conditioned on the receipt of necessary federal, state and local environmental permits, and acceptable regulatory treatment, including cost recovery by the Florida Public Service Commission.

P. DEP will defend the terms of this Consent Final Judgment in any action to which it is a party.

VI. MISCELLANEOUS

A. This Consent Final Judgment embodies the entire agreement and understanding of the Parties and supersedes any and all prior agreements, drafts, arrangements, conversations, negotiations or understandings relating to matters provided for in the Consent Final Judgment.

B. This Consent Final Judgment may be executed in one or more counterparts, each of which will be deemed an original, but all of which together will constitute one and the same instrument.

C. Each provision of the Consent Final Judgment shall be interpreted in such a manner as to be effective and valid under applicable law, but if any provision of the Consent Final Judgment shall be prohibited or invalid under applicable law, such provision shall be ineffective to the extent of such prohibition or invalidity, without invalidating the remainder of such provision or the remaining provisions of the Consent Final Judgment.

D. This Consent Final Judgment is not, and shall not be construed to be, a permit issued pursuant to any federal, State or local law, rule or regulation.

E. If, for any reason, the Court should decline to enter this Consent Final Judgment in the form in which it is lodged, the Consent Final Judgment as lodged is voidable, at the sole discretion of either Party. The Parties agree that because the claims of the DEP contained herein were disputed as to validity and amount, none of the terms of the lodged but voided Consent Final Judgment may be used as evidence in any litigation for any purpose, except with the written consent of TAMPA ELECTRIC COMPANY.

F. Except as provided for herein, there shall be no modifications or amendments of this Consent Final Judgment without written agreement of the Parties to this Consent Final Judgment and approval by the Court.

VII. FINAL JUDGMENT/RETENTION OF JURISDICTION

This Consent Final Judgment constitutes a final judgment in this action. This Court will retain jurisdiction for the purpose of enabling the Parties to apply to the Court at any time for such further order, direction or relief as may be necessary or appropriate for the construction or modification of this Consent Final Judgment, or to effectuate or enforce compliance with its terms, or to resolve disputes.

DONE AND ORDERED IN CHAMBERS this ___ day of ________________,

1999.

ORIGINAL SIGNED

DEC 16 1999

ROBERT H. BONANNO
CIRCUIT JUDGE

____
Circuit Judge

FLORIDA DEPARTMENT OF ENVIRONMENTAL PROTECTION

By: David B. Struhs
Secretary of the Florida Department of Environmental Protection

Date: December 6, 1999

TAMPA ELECTRIC COMPANY

By: John B. Ramil
John B. Ramil
President

Date: December 6, 1999

Appendix B

APPENDIX B

GANNON RESOURCE UTILIZATION STUDY

Overview

Tampa Electric periodically completes resource utilization studies, evaluating various planning and operating alternatives to current operations, with objectives ranging from meeting compliance requirements in the most cost-effective and reliable manner to maximizing operational flexibility and minimizing operational costs. The most recent resource utilization study, involving the Gannon coal units, began in late 1998 and continued into 1999.

In the 1998/99 study, Tampa Electric evaluated various options for Gannon Station designed to address a variety of issues. These issues included: the anticipated designation of the Tampa Bay region as an ozone non-attainment area; the anticipated promulgation of new ambient air standards including fine particulate matter ($PM_{2.5}$); local community environmental issues: the probability of higher natural gas availability (announcements of several proposed pipeline projects had occurred); the reduced efficiency and availability of the aging Gannon units, and the fact that considerable maintenance would be required to maintain acceptable performance levels from these units exacerbating the existing issue with the Environmental Protection Agency (EPA) over its interpretation of maintenance relative to Section 114 of the New Source Review (NSR) Standards

Many alternatives were evaluated in the Gannon utilization study including the following:

- Fuel switching the Gannon units from coal to natural gas;
- Repowering the Gannon coal units;
- Installing flue gas desulfurization (FGD) and selective catalytic reduction (SCR) systems on all of the Gannon coal units;
- Placing Gannon Station on reserve standby and purchasing replacement power to serve Tampa Electric's power requirements; and
- Placing Gannon Station on reserve standby and building replacement generation

Several alternatives were eliminated from further consideration during the initial screening process for various reasons (e.g. cost, technological issues, statewide transmission system reliability issues, etc.). Of the remaining alternatives, the repowering of Gannon Units 3, 4, and 5 was determined to be the most cost-effective alternative while meeting reliability and environmental considerations.

The Gannon utilization study was updated in the fall of 1999 to include NO_X control on the Big Bend coal units as a result of the Consent Final Judgement (CFJ) with the Florida Department of Environmental Protection (DEP) which requires, among other things, the repowering of Gannon Units 3, 4, and 5 by the end of 2004 and the installation of NO_X control technology on the Big Bend coal units beginning in 2007 with completion by the end of 2010. The events leading up to the CFJ are as follows:

> On November 3, 1999, despite Tampa Electric's longstanding efforts to reach a mutually agreeable settlement with the EPA, the Department of Justice (DOJ) sued Tampa Electric and seven other electric utilities on behalf of EPA for alleged violations of the Clean Air Act ("CAA") associated with this NSR issue. At issue are the coal-fired Gannon Units 3, 4, and 6, and Big Bend Units 1 and 2.
>
> Following this federal action, DEP also contended that Tampa Electric had not applied for appropriate air permits for certain unit maintenance projects at Gannon and Big Bend Stations and, therefore, had operated the coal-fired units without Best Available Control Technology (BACT) for NO_X, SO_2, and PM. Following negotiations within the CAA 30-day notice period, DEP and Tampa Electric reached a settlement. On December 7, 1999, DEP and Tampa Electric entered into a CFJ which addresses the DEP claims that Tampa Electric modified and then operated its generating units at Big Bend and Gannon without first obtaining permits authorizing the modifications and without installing BACT to control NO_X, SO_2, and PM.

As a key element of the CFJ, all coal-related assets including coal-handling equipment will be retired. The steam turbines/generators and associated non-coal related equipment from Units 1 and 2 will be shut down and placed on reserve standby coincident with the repowering of Unit 5. Unit 6 will be shut down and placed on reserve standby by the end of 2004. These units will be available to Tampa Electric as future supply-side resource options via repowering to meet the growing demand and energy needs of its customers. The company does not currently have plans to utilize the units, but it may, at some time in the future, repower or convert the units to natural gas if those options prove to be cost-effective.

The study was also updated with the most current planning assumptions initially including minimum reliability criteria of 15 percent firm reserve margin with a minimum 7 percent reserve margin from supply-side resources. The reserve margin criteria of 15 percent was subsequently updated to 20 percent based on the stipulation between the FPSC and the three Florida investor owned utilities to carry a 20 percent reserve margin.

Sensitivities on natural gas commodity prices, transportation prices, and SO_2 allowance treatment were included in the study. The Gannon Repowering Alternative remained the most cost-effective alternative in all of these sensitivities.

Assumptions

Economic and Financial Assumptions

- The economic and financial assumptions used to determine the cumulative present worth revenue requirements (CPWRR) associated with each compliance alternative are summarized in Table B-1. This table shows key parameters such as inflation rates, income tax rates, rates of return, other discount rates, and the allowance for funds used during construction (AFUDC) rate.

- Financial assumptions for each alternative evaluated are provided in Tables B-2a and B-2b.

TABLE B-1
TAMPA ELECTRIC COMPANY
FINANCIAL ASSUMPTIONS

INFLATION/ESCALATION	
O&M	
1999	1.9%
2000	2.1%
2001+	2.3%
CAPITAL	
1999	1.5%
2000	2.0%
2001+	2.2%
TAX RATE	
OTHER TAXES	1.49%
FEDERAL & STATE	38.58%
FINANCIAL CAPITALIZATION RATIOS	
DEBT	41.80%
PREFERRED	0.00%
COMMON EQUITY	58.20%
RATE OF RETURN	
DEBT	7.75%
PREFERRED	10.66%
COMMON EQUITY	12.75%
DISCOUNT RATE	9.41%
AFUDC RATE	7.79%

TABLE B-2a
TAMPA ELECTRIC COMPANY
COST ASSUMPTIONS FOR COMPLIANCE ALTERNATIVES

COMPONENTS OF COMPLIANCE ALTERNATIVES	GANNON REPOWERING UNIT 3/4 & UNIT 5	COMMON FUTURE CTS (IN ALL EXPANSION PLANS)	GANNON REPLACEMENT PLAN FUTURE CC "F" FRAME	GANNON REPLACEMENT PLAN FUTURE CC "G" FRAME
NOMINAL COST * $/kW	$366	$295	$439	$427
ANNUAL FIXED CAPITAL 99$000/unit	$3,454	$0	$2,283	$2,283
ANNUAL FIXED O&M 99$000/unit	$4,600	$368	$3,067	$3,067
VARIABLE O&M 99$/MWH	$0.57	$2.80	$0.57	$0.57
TAX LIFE	20 Years	15 Years	20 Years	20 Years
BOOK LIFE	30 Years	30 Years	30 Years	30 Years
IN-SERVICE DATE	May 2004	Oct 2000	May 2003	Jan 2007

* Nominal costs are based on winter unit capabilities and do not include AFUDC and Transmission & Distribution

TABLE B-2b
TAMPA ELECTRIC COMPANY
COST ASSUMPTIONS FOR PURCHASE POWER ALTERNATIVE

PURCHASED POWER ALTERNATIVE	VALUE
Levelized Capacity Component	73.99 $/kW-YR
Energy Component (2003$)	26.07 $/MWH
Wheeling Component (2003$)	17.9 $/kW-YR
CAPITALIZATION RATIOS	
Debt	75.0%
Common Equity	25.0%
RATE OF RETURN	
Debt	8.5%
Common Equity	15.0%
Risk Adjustment Factor Per Standard & Poor's Method	25.0%

Fuel Assumptions

- For the Gannon Repowering Alternative, natural gas availability was assumed to be 100 percent. However, 100,000 MMBtu/day of firm gas was assumed for the Gannon Repowering Alternative with 50,000 MMBtu/day dedicated to the first repowered unit and 50,000 MMBtu/day dedicated to the subsequent repowered units.

- Natural gas transportation costs of $0.55/MMBtu and $0.80/MMBtu were used for the base case and high transportation case sensitivity, respectively.

- The fuel assumptions for existing and future units were based on the company's current Fuel and Interchange Forecast for year 2000 and beyond.

- The purchase power fuel availability was assumed to be 100 percent with firm transportation. This assumes that the power provider would not have dual fuel capability.

Environmental Control Technology Assumptions

- Sargent & Lundy was contracted to prepare a study to develop more detailed capital cost estimates, along with schedule, staffing requirements, O&M costs, and thermodynamic performance for the repowering alternative. In addition, another study was performed by Sargent & Lundy to develop cost estimates for retrofitting Gannon Units 5 and 6 with FGD systems and SCR's for use in the previously mentioned environmentally adjusted alternative. The results of this FGD/SCR study were extrapolated for developing estimates for all of the Gannon units.

- Although the NO_X control technology to be utilized with the Big Bend coal units has not yet been determined, an estimated cost of installing SCRs on these units was substituted for the purpose of this analysis.

Load Assumptions

- Load forecasts used in the analysis are from the company's 2000 Fuel and Interchange Forecast.

Unit Operating Assumptions

- Unit operating parameters used in the analysis are from the company's 2000 Fuel and Interchange Forecast

- Operating assumptions for each alternative evaluated are provided in Table B-3.

TABLE B-3
TAMPA ELECTRIC COMPANY
OPERATING ASSUMPTIONS

COMPONENTS OF COMPLIANCE ALTERNATIVES	WINTER CAPACITY MW	SUMMER DERATION MW	HEAT RATE* Mbtu/MWh	EQUIVALENT AVAILABILITY FACTOR** %
GANNON REPOWERING				
UNIT 3/4	802	91	7.050	91.0%
UNIT 5	796	98	7.080	91.0%
EXISTING GANNON STATION				
UNIT 1	114	0	11.909	75.6%
UNIT 2	113	0	12.028	66.5%
UNIT 3	155	10	11.413	81.1%
UNIT 4	189	10	11.047	69.8%
UNIT 5	242	10	10.196	75.2%
UNIT 6	392	20	10.376	72.2%
COMMON FUTURE CT'S *(In all expansion plans)*	180	25	10.580	94.0%
GANNON REPLACEMENT PLAN				
FUTURE CC'S				
USING GE "F" FRAME CT'S	523	78	7.081	91.0%
USING WESTINGHOUSE "G" FRAME CT'S	675	103	6.590	91.0%

* Heat rates of Gannon Repowering Units 3/4 and 5 are higher heating values (HHV) and based on average ambient temperatures
* EAF's are based on Winter Capacity

Purchased Power Assumptions

- The incremental capital cost of maintaining transmission system reliability of the transmission grid associated with placing Gannon Station on reserve standby was estimated conservatively at $71 million (20-year CPW in 1999 dollars). This assumes the medium case scenario with firm purchased power being provided from several areas with peninsular Florida.

- In addition to these transmission capital costs required to maintain transmission system reliability, further investigation and consultation with Power Technologies Inc. (PTI) indicates that significant bulk transmission system reactive power devices will be required for TEC or Florida system voltage support. Based on preliminary estimates, these devices could cost as much as $50 million (20-year CPW in 1999 dollars). Because a detailed analysis of these requirements has not been made, this economic cost was not included in this assessment.

- In evaluating impacts to the state transmission system related to this project, it became apparent that transmission losses will increase well above the amount accounted for by utility transmission tariff loss percentages. Contractual tariff losses were included in the analysis and were quantified with an effective loss rate of 2.17%. However, actual incremental transmission losses throughout the state will greatly exceed this contractual rate. As this is not an actual economic cost to Tampa Electric, it was not included in this assessment.

- Generic assumptions for an IPP-financed combined cycle plant were used to calculate the price of replacement power.

- For the purposes of determining wheeling charges, transmission impacts, and transmission losses associated with replacement power, the power was assumed to be purchased from several power projects throughout Florida that are associated with various independent power producers (i.e. Duke/New Smyrna Beach, Okeechobee Generating Company, Reliant, Constellation and Panda). A percentage, estimated for each project, was utilized to calculate weighted average wheeling charges, transmission losses, and transmission impacts.

- A financial risk adjustment was included in the cost of purchased power to capture the impact on the company related to the financial risk associated with entering a long-term contract for purchased power.

Repowering Assumptions

- Gannon Units 3, 4, and 5 were selected to be repowered based on the generation requirements for meeting expansion plan criteria, the physical operating characteristics of the existing equipment, and the overall condition and age of the existing units.

- The configuration of the repowered units is as follows: The first phase of the repowering includes integrating three new dual-fuel (natural gas and oil) fired GE 7FA combustion turbines and three new heat recovery steam generators (HRSGs) with the existing Gannon Unit 5's steam turbine. The second phase of the repowering includes integrating three more new GE 7FA combustion turbines and three new HRSGs with the two existing steam turbines associated with Gannon Units 3 and 4.

- The capital costs associated with the existing Gannon Station were considered sunk costs, and were treated as such in the determination of customer rates and overall revenue requirement impacts. However, the impact of recovering these dollars on a faster schedule (due to the advanced retirement date) than previous life estimates was factored into the analysis.

Methodology

Initial Screening

Early in the resource utilization study many alternatives were screened on a qualitative and quantitative basis to determine those alternatives that were the most feasible options, overall. Those alternatives that failed to meet environmental acceptability, economics, technical feasibility, operational criteria, maintainability, and reliability were eliminated. This phase of the study resulted in a set of feasible alternatives that were considered in the more detailed economic analysis.

Alternatives Evaluated

A description of the Gannon utilization study alternatives chosen by Tampa Electric for quantitative evaluation are listed below. The generation expansion plans associated with each alternative are shown in Table B-4.

1) **Environmentally Adjusted Alternative**
This alternative has an all-CT expansion plan. It also includes the installation of environmental equipment that meets the more stringent interpretations of the NSR standards proposed by the EPA. The environmental equipment includes the addition of FGD and SCR systems on all of the Gannon coal units.

In this alternative, NO_X control technology is installed on the Big Bend coal units beginning in 2007 with completion by the end of 2010.

2) **Gannon Repowering Alternative**
The Gannon Repower Alternative meets the more stringent interpretations of the NSR standards proposed by the EPA and the requirements of the CFJ by repowering Gannon Units 3, 4, and 5 with natural gas-fired technology by the end of 2004. The first phase of the repowering includes integrating three new dual-fuel (natural gas and oil) fired GE 7FA combustion turbines and three new HRSGs with the existing Gannon Unit 5's steam turbine. The second phase of the repowering includes integrating three more new GE 7FA combustion turbines and three new HRSGs with the two existing steam turbines associated with Gannon Units 3 and 4. The Gannon Repowering Alternative also includes the installation of SCR systems for all of the CTs utilized in the repowering.

In this alternative, NO_X control technology is installed on the Big Bend coal units beginning in 2007 with completion by the end of 2010.

3) **Gannon Non-Repower Replacement Alternative**
The Gannon Non-Repower Replacement Alternative meets the more stringent interpretations of the NSR standards proposed by the EPA by

retiring the existing Gannon coal assets by 2004 and replacing the retired generation with on-site GE 7FA combined cycle technology. The replacement units were all equipped with SCRs.

This alternative also includes NO_X control technology on the Big Bend coal units beginning 2007 with completion by the end of 2010.

4) **Purchased Power Alternative**

The Purchased Power Alternative meets the more stringent interpretations of the NSR standards proposed by the EPA by retiring the Gannon coal-fired units and purchasing capacity and energy to meet system demand and energy requirements. The transmission cost of maintaining the reliability of the transmission grid associated with the placing Gannon Station on reserve standby was included in this alternative. An adjustment to the cost of purchased power was made to reflect the financial risk to Tampa Electric associated with entering a long-term contract for purchased power.

This alternative also includes NO_X control technology on the Big Bend coal units beginning 2007 with completion by the end of 2010.

TABLE B-4
TAMPA ELECTRIC COMPANY
EXPANSION PLANS FOR EACH COMPLIANCE ALTERNATIVE

YEAR	ENVIRONMENTALLY ADJUSTED ALTERNATIVE	GANNON REPOWERING ALTERNATIVE	GANNON NON-REPOWERING REPLACEMENT ALTERNATIVE	PURCHASED POWER ALTERNATIVE
2000	HPS CT2B Polk CT (Oct)	HPS CT2B Polk CT (Oct)	HPS CT2B Polk CT (Oct)	HPS CT2B Polk CT (Oct)
2001	—	—	—	—
2002	Polk CT (May)	Polk CT (May)	Polk CT (May)	Polk CT (May)
2003	Polk CT (May)	Repower 5 (May) LTRS Gannon 1 & 2	Gannon "F" CC Polk CT LTRS Gannon 1, 2, & 5	Firm purchase to replace Gannon Repowering Alternative
2004	Polk CT (May)	Repower 3 & 4 (May) LTRS Gannon 6	2 ea - Gannon "F" CC LTRS Gannon 3, 4, & 6	Firm purchase to replace Gannon Repowering Alternative
2005	Polk CT (May)	Polk CT	—	Polk CT
2006	—	Polk CT	Polk CT	Polk CT
2007	Future Site CT		Future Site "G" CC	
2008	Future Site CT	Polk CT		Polk CT
2009	Future Site CT	Future Site CT		Future Site CT

Economic Analysis

The analysis compares the related costs of each utilization alternative based on incremental CPWRR. The relative costs were developed on an incremental basis relative to the Environmentally Adjusted Alternative assumptions. The CPWRR include system fuel and purchase power expense, incremental generation capital, incremental transmission and distribution capital, incremental O&M expense, incremental SO_2 allowance costs, depreciation, working capital, incremental transmission losses, transmission wheeling expense and other incremental costs associated with the compliance alternatives and construction of new generating resources.

PROMOD, a production costing computer model, was used to determine fuel and purchased power expense associated with each of the alternatives. PROMOD simulates an economic dispatch of Tampa Electric's generating system based on incremental production costs. In addition to fuel and purchase power expense, PROMOD simulates the unit operating characteristic impacts, and system dispatch effects associated with different compliance alternatives.

PROSCREEN, another planning model, was used to develop incremental capital revenue requirements, SO_2 allowance costs and incremental O&M expense associated with each alternative. The incremental capital revenue requirements and incremental O&M expenses were added to the fuel costs, purchase power expense, incremental transmission wheeling expense, and incremental transmission system losses expense to determine the total revenue requirements of each alternative. Also incorporated were Gannon Station coal working capital reductions, depreciation timing impact associated with the earlier retirement of coal-related Gannon Station assets and the financial risk adjustment associated with purchased power contracts.

The financial risk adjustment was included in the cost of purchased power to capture the impact on the company of the financial risk associated with entering a long term contract for purchased power. This adjustment reflects the additional cost associated with maintaining the higher equity amounts required by rating agencies in order to maintain the financial strength needed to justify current bond ratings. The financial risk adjustment was calculated using Standard and Poors methodology which imputes purchased power capacity payments as a debt equivalent. The financial adjustment represents the imputed cost of this higher source of capital that replaces lower cost debt.

The units to be repowered in the Gannon Repowering Alternative were selected based on the generation requirements for meeting expansion plan criteria, the physical operating characteristics of the existing equipment, and the overall condition and age of the existing units.

Study Results

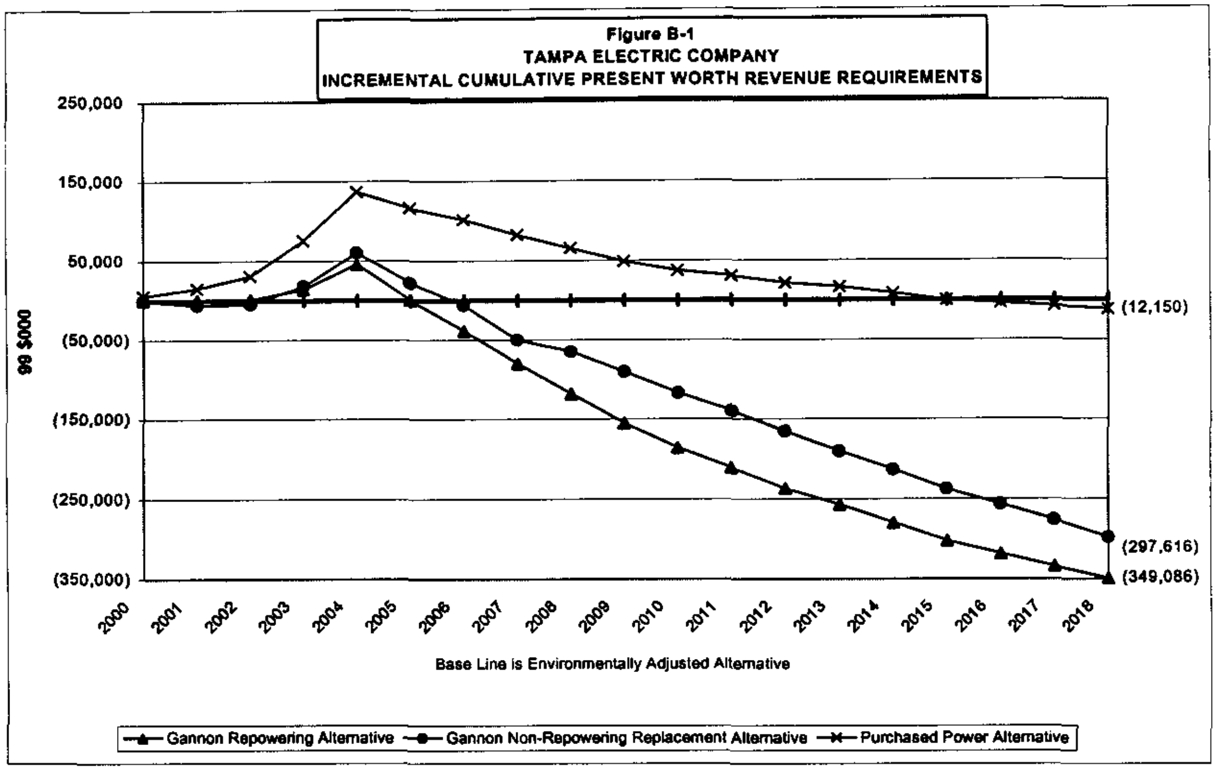
Base Analysis

The incremental CPWRR in 1999 dollars for all of the alternatives evaluated are provided in Figure B-1. These incremental CPWRR are differentials to the Environmentally Adjusted Alternative and provide a graphical summary of the results from the quantitative analysis. The analysis concluded that the Gannon Repowering Alternative was the most cost-effective option for environmental compliance.

The Environmentally Adjusted Alternative was used as the basis for comparison to each of the other alternatives. The incremental CPWRR of the other alternatives show a savings relative to the Environmentally Adjusted Alternative over the study period.

The incremental CPWRR of the Purchased Power Alternative was $337.0 million higher than the Gannon Repowering Alternative. This is due primarily to the transmission costs associated with maintaining transmission reliability after Gannon Station is placed on reserve standby.

The Gannon Non-Repower Replacement Alternative was $51.5 million higher in cost than the Gannon Repowering Alternative. Although this option resulted in lower overall fuel costs due to the higher efficiency of the "G" technology included in the expansion plan, the fuel savings were not great enough to offset the higher capital costs and O&M expense of the Gannon Non-Repower replacement alternative. The capital costs were higher due to expansion plan differences and because the plan did not make use of existing equipment at Gannon Station (i.e. steam turbines). Higher O&M expense was associated with this expansion plan. In the optimization of the expansion plan for this alternative, "G" combined cycle technology was restricted from the early years of the planning window due to technology risk.



Sensitivities

To ensure that the Gannon Repowering Alternative was prudent given a wide range of contingencies, Tampa Electric completed a series of additional analyses incorporating various sensitivities. These additional analyses include sensitivities on lower SO_2 allowance prices and higher natural gas transportation and commodity prices. The results of these sensitivities on the Gannon Repowering Alternative are provided in Figures B-2, B-3, and B-4.

The lower SO_2 allowance price sensitivity assumed that the forecasted price of an allowance would eventually drop to a value that approaches the operating cost of an FGD system on a $/Ton basis. Remarketing excess SO_2 allowances was assumed in the base analysis of each alternative. By lowering the market value of these allowances, the credit back to the customer is reduced and, therefore, the overall revenue requirements are higher. Relative to the Environmentally Adjusted Alternative, the lower SO_2 allowance reduced the differential CPWRR by approximately $12.0 million for the Gannon Non-Repowering Alternative and by $13.2 million dollars for the Gannon Repowering Alternative. The incremental CPWRR of the Purchased Power Alternative was increased by approximately $13.2 million making it the highest cost alternative at $1 million over the CPWRR of the Environmentally Adjusted Alternative.

In the higher natural gas transportation sensitivity, transportation costs for Tampa Electric's gas-fired units were assumed to be higher by 25 cents per MMBtu over the base assumption. Relative to the Environmentally Adjusted Alternative, this increase in transportation cost reduced the CPWRR savings by approximately $36.6 million for the Gannon Non-Repowering Alternative and by $40.3 million dollars for the Gannon Repowering Alternative. The Purchased Power Alternative assumed 100 percent firm natural gas whereas the repowering and non-repower replacement alternatives assumed a combination of firm and interruptible gas. Therefore, the increase to the CPWRR of the Purchased Power Alternative was greater at approximately $57.0 million. This increase changed the order of the alternatives making the Purchased Power Alternative higher in cost by $44.8 million relative to the Environmentally Adjusted Alternative.

The high natural gas sensitivity used a high price forecast for the commodity only. A significant impact to the CPWRR of each alternative resulted from raising the natural gas price. The incremental CPWRR increased by $200.5 million for the Gannon Non-Repowering Alternative and by $207.9 million dollars for the Gannon Repowering Alternative. The incremental CPWRR of the Purchased Power Alternative was increased by approximately $211.6 million dollars and exceeded the CPWRR of the Environmentally Adjusted Alternative by $199.4 million. The relative order of the Gannon Non-Repowering and Gannon Repowering alternatives remained the same.

Through all sensitivities the Gannon Repowering Alternative remained the most cost-effective alternative. This was expected considering that each alternative included natural gas-fired combined cycle technology and, therefore, would be impacted similarly by the natural gas and SO_2 allowance sensitivities.

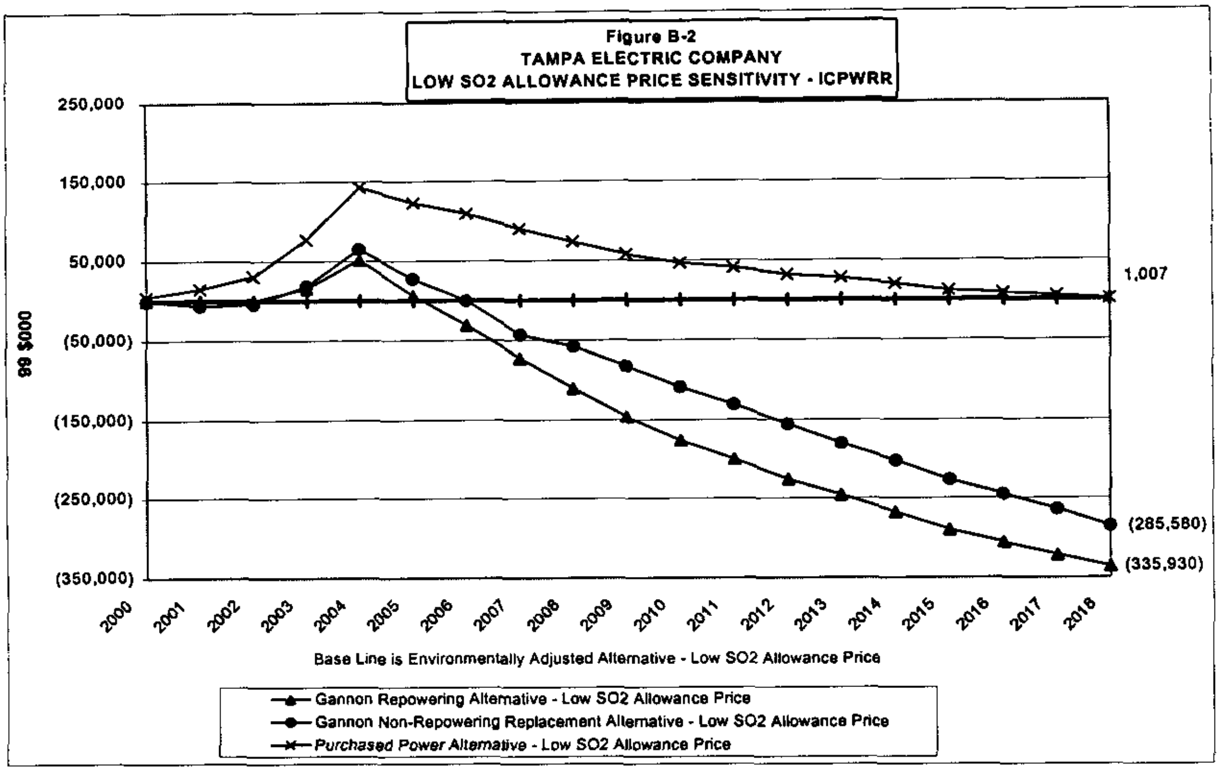


Figure B-2
TAMPA ELECTRIC COMPANY
LOW SO2 ALLOWANCE PRICE SENSITIVITY - ICPWRR
250,000
150,000
50,000
(50,000)
(150,000)
(250,000)
(350,000)
99 $000
2000 2001 2002 2003 2004 2005 2006 2007 2008 2009 2010 2011 2012 2013 2014 2015 2016 2017 2018
1,007
(285,580)
(335,930)
Base Line is Environmentally Adjusted Alternative - Low SO2 Allowance Price
Gannon Repowering Alternative - Low SO2 Allowance Price
Gannon Non-Repowering Replacement Alternative - Low SO2 Allowance Price
Purchased Power Alternative - Low SO2 Allowance Price

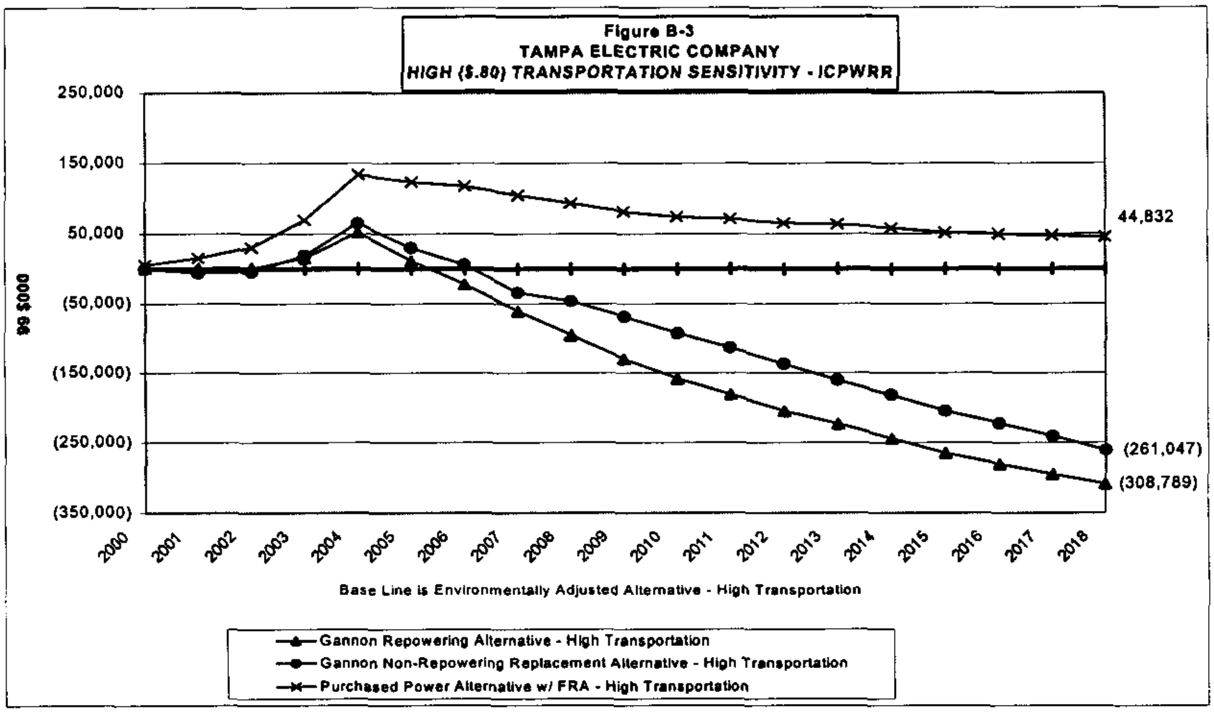
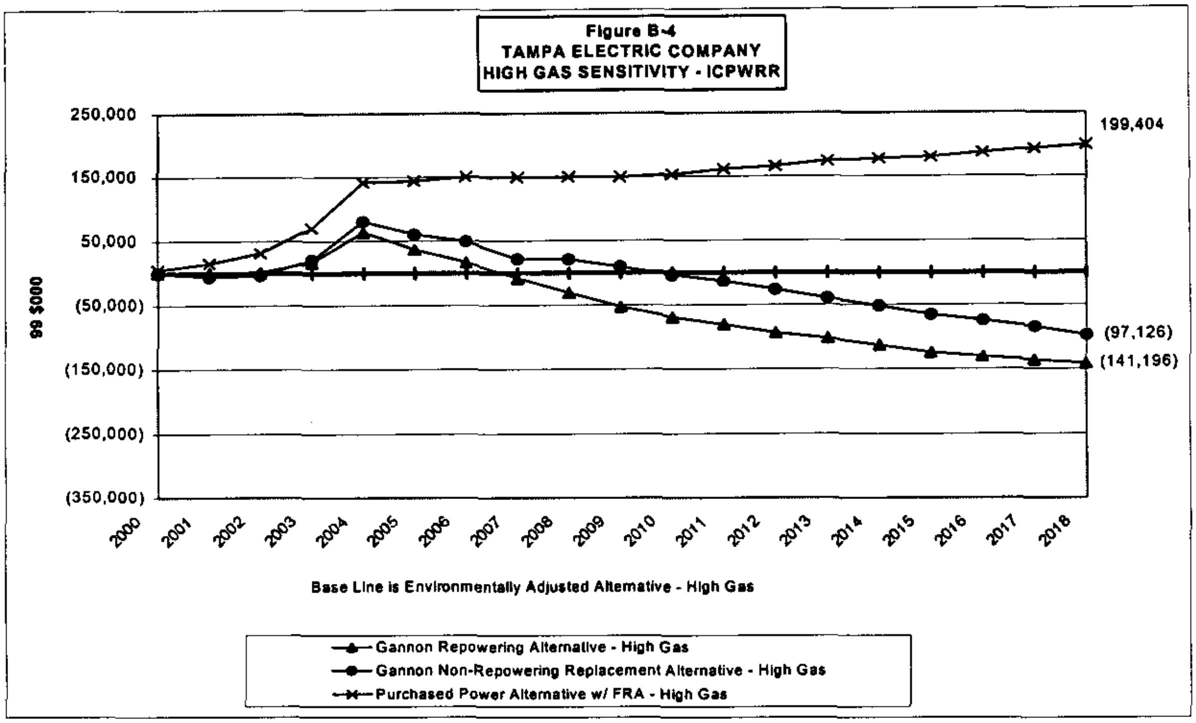


Figure B-3
TAMPA ELECTRIC COMPANY
HIGH ($.80) TRANSPORTATION SENSITIVITY - ICPWRR
250,000
150,000
50,000
(50,000)
(150,000)
(250,000)
(350,000)
99 $000
2000 2001 2002 2003 2004 2005 2006 2007 2008 2009 2010 2011 2012 2013 2014 2015 2016 2017 2018
44,832
(261,047)
(308,789)
Base Line is Environmentally Adjusted Alternative - High Transportation
Gannon Repowering Alternative - High Transportation
Gannon Non-Repowering Replacement Alternative - High Transportation
Purchased Power Alternative w/ FRA - High Transportation



Conclusion

The Gannon Repowering Alternative has been shown to be the most cost-effective option for Tampa Electric's customers when compared to other alternatives. This alternative has significantly lower CPWRR, both annually and over the entire study period, in the base analysis and each sensitivity evaluated.

This alternative would result in significant reductions in SO_2, NO_X, and PM as shown in Figures 7.1, 7.2, and 7.3, respectively, of the Compliance Plan. It is anticipated that emissions of SO_2, NO_X, and PM would be reduced as much as 80 percent, 85 percent, and 45 percent below 1997 levels, respectively. The Gannon Repowering Alternative is also a key component of Tampa Electric's agreement with DEP and meets the more stringent interpretation of the NSR proposed by the EPA.

From a reliability standpoint, this alternative addresses several issues. The issues of reduced efficiency and availability of aging coal units and meeting the incremental power requirements are addressed by installing highly efficient and reliable natural gas-fired combined cycle technology.

The Gannon Repowering Alternative maintains the reliability of the peninsular Florida transmission system in a cost-effective manner and has, overall, the lowest impact to Tampa Electric's transmission system. Significant expenditures would be required to maintain transmission system reliability if an alternative were selected that necessitated placing Gannon Station on reserve standby (i.e. purchasing replacement power or building replacement capacity at a different site).

Tampa Electric's utilization study concluded that the Gannon Repowering Alternative provides Tampa Electric's customers with the most cost-effective option for significantly reducing emissions while maintaining system reliability, statewide transmission grid reliability, and maximizing operational flexibility.