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June 30, 1998

HAND DELIVERED

Ms. Blanca S. Bayo, Director
Division of Records and Reporting
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, FL 32399-0850

Re: Petition by Tampa Electric Company for Approval of Cost Recovery for a new Environmental Program, the Big Bend Units 1 and 2 Flue Gas Desulfurization System; FPSC Docket No. 980693-EI

Dear Ms. Bayo:

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

1. Prepared Direct Testimony and Exhibit (CRB-1) of Charles R. Black. 06852-98

2. Prepared Direct Testimony and Exhibit (TLH-1) of Thomas L. Hernandez. 06853-98

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

Thank you for your assistance in connection with this matter.

3

Sincerely,

James D. Beasley

JDB/pp
Enclosures

5 tony cc: All Parties of Record (w/encls.)

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true copy of the foregoing testimony and exhibits filed on behalf of Tampa Electric Company has been furnished by hand delivery (*) or U. S. Mail on this 30th day of June 1998 to the following:

Ms. Grace A. Jaye*
Staff Counsel
Division of Legal Services
Florida Public Service Commission
2540 Shumard Oak Blvd.
Tallahassee, FL 32399-0850

Mr. Joseph A. McGlothlin*
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ATTORNEY

ORIGINAL

TAMPA ELECTRIC

TAMPA ELECTRIC COMPANY

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 980693-EI

TESTIMONY
AND EXHIBIT OF

THOMAS L. HERNANDEZ

BEFORE THE PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

THOMAS L. HERNANDEZ

Q. Please state your name and your business address.

A. My name is Thomas L. Hernandez. My business address is 702 North Franklin Street, Tampa, Florida 33602. I am the Vice President-Regulatory Affairs for TECO Energy, Tampa Electric Company's parent.

Q. What is your educational background and business experience?

A. I graduated from Louisiana State University in August 1982 with a Bachelor of Science degree in Chemical Engineering. My responsibilities at Tampa Electric have included engineering and management positions in Production, Generation Planning and Energy and Market Planning. I was named Director-Fuels and Environmental Services earlier in 1998, and I was named Vice President-Regulatory Affairs for TECO Energy in March of this year.

I have participated in the preparation of key studies supporting the company's proposal in this proceeding. Tampa Electric's planning document to comply with Phase I requirements of the Clean Air Act Amendments of 1990 ("CAAA") and associated cost-effectiveness studies were prepared under my direction and supervision while I was in the position of Manager, Generation Planning. The cost-effectiveness studies used to develop a Phase II CAAA compliance plan was prepared under my direction and supervision while I was in the position of Director, Energy and Market Planning.

Q. Mr. Hernandez, have you previously testified before this Commission?

A. Yes. I testified before this Commission in the last annual planning hearing Docket No. 910004-EU. I also provided a description of Tampa Electric's planning process at the FPSC Staff workshop on March 3, 1994. I also submitted testimony in Docket No. 930551-EI which was the numeric conservation goals proceeding for Tampa Electric. Most recently I testified in Docket No. 960409-EI regarding the prudence of Polk Unit One.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to demonstrate the reasonableness and prudence of Tampa Electric's selection of a flue gas desulfurization ("FGD") system for Big Bend Units 1 & 2 as the company's primary means of satisfying the Phase II requirements of the CAAA. As discussed below, the FGD system is the most viable and cost-effective compliance alternative for meeting the requirements of the CAAA. In addition, I will explain why the Company's proposed regulatory treatment for the FGD system should be approved and why the Commission should conclude that the reasonable and prudent project costs incurred in connection with the FGD Project qualify for cost recovery through the Environmental Cost Recovery Clause ("ECRC"), pursuant to Section 366.8255, Florida Statutes (1997), over a ten year period, beginning when the system is placed in service.

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

A. Yes I have. My Exhibit No. ____ (TLH-1) consisting of four documents (Nos. 1-4) was prepared under my direction and supervision. It consists of detailed information related to Tampa Electric Company's CAAA Phase I and Phase II compliance plans and 1998 Ten Year Site Plan. The documents describe the methods and key planning assumptions used to develop the company's compliance plans and ten-year expansion plan.

FGD System Need

Q. Prior to selecting a Phase II compliance option, what steps did Tampa Electric take to defer the need for additional SO_2 emission mitigation measures?

A. The company is dedicated to the efficient use of energy and has maintained an aggressive conservation program that has reduced the total energy requirements of the system. The company continuously monitors the energy market and purchases capacity and energy when reliable energy sources are available to economically displace system generation from our own resources. Both energy conservation and purchased power effectively reduce SO_2 emissions from the company's system.

Q. How did the company prepare itself to meet Phase II compliance requirements?

A. For Phase II compliance, Tampa Electric reviewed previous studies that supported the Phase I compliance plan. Several options studied in the Phase I evaluation were eliminated as Phase II options because the Phase I study concluded that they were not viable or cost-effective. The remaining options were screened through quantitative and qualitative comparisons for Phase II. The results of these comparisons clearly showed that Big Bend 1 and 2 FGD system provided the greatest savings to the ratepayer on a cumulative present worth revenue requirements (CPWRR) basis. The results of the screening analysis are described in detail in Document No. 2.

Q. Did you perform any tests to verify the viability of the Big Bend Units 1 and 2 FGD option?

A. Yes. After a preliminary determination that the proposed Big Bend Units 1 and 2 FGD system was the most technically viable compliance option, Tampa Electric assessed the economic viability of this option. The capital cost estimates and fuel blending assumptions were evaluated to reflect Tampa Electric's most current data, and the FGD option was again compared to a fuel blending and SO_2 allowance purchase base case scenario. This comparison showed that the FGD system will generate significant savings of $80 million on a CPWRR basis over a twenty year period. In addition, Tampa Electric performed sensitivities to verify the economic viability of the FGD option. These sensitivities included: capital cost, SO_2 allowance market viability, and a deferral analysis.

For the capital cost sensitivity, the CPWRR savings were compared against the base case with 5% and 10% increases in the capital estimate. In both cases, the FGD option showed significant CPWRR savings versus the base case. To examine the SO_2 allowance market viability, Tampa Electric evaluated the CPWRR of scenarios with varying allowance purchase quantities. The FGD option was determined to have the lowest ten-year CPWRR. Tampa Electric therefore concluded that SO_2 allowance purchases alone would not be the most cost effective alternative. A one year deferral analysis concluded that deferral would decrease the CPWRR savings to the ratepayer. In each of these sensitivity analyses, the proposed FGD option remained economically viable compared to the base case. These are described in detail in Document No. 2.

Q. How do the economics of the FGD option compare to those of the other compliance options evaluated by Tampa Electric?

A. Of the various compliance options evaluated by Tampa Electric, the FGD option provides significantly greater CPWRR savings when compared to our base case scenario and nearly twice the expected savings of the next most economical option. The FGD option for Big Bend Units 1 and 2 offers the greatest fuel savings and will provide the greatest benefits to retail customers compared to the other alternatives analyzed.

Q. Are there other benefits associated with the proposed FGD system for Big Bend Units 1 and 2?

A. Yes, as discussed in Mr. Black's testimony, the proposed FGD system for Big Bend Units 1 and 2 has the added benefit of providing more operating flexibility and fuel diversity potential to Tampa Electric's system. The FGD options also minimizes any negative impact to system reliability compared to the blending options since these options resulted in higher capacity derations and additional maintenance outage hours.

Key Planning Assumptions

Q. How did Tampa Electric develop and utilize the cogeneration and wholesale interchange forecasts which it relied upon in its selection of the CAAA Phase II compliance plan?

A. The cogeneration and wholesale interchange forecasts for the cost-effectiveness studies contained in the Phase II compliance document were developed utilizing the same data and methodology contained in Tampa Electric Company's 1998 Ten Year Site Plan (TYSP) filed with the Commission on

April 1 of this year and attached as Document No. 4. Self-service cogeneration capacity and firm and as-available cogeneration purchase power reduce the system generation requirements and results in lower SO_2 emissions. For example, in the year 2000, self-service cogeneration and cogeneration purchase power are projected to reduce system energy requirements by 2,547 GWH. This amount of energy is approximately equivalent to 290 MW of coal-fired capacity from Big Bend unit 1 or 2 operating for every hour of a single year. Although firm and as-available wholesale energy sales increase the system generation requirements, the combined net effect of these sales and the self-service cogeneration and cogeneration purchases results in a decrease in estimated SO_2 emissions.

Q. How did Tampa Electric develop and utilize the demand and energy forecast it relied upon in selecting a CAAA Phase II compliance plan?

A. The system demand and energy forecast utilized in the cost-effectiveness studies is the same forecast and methodology described in detail in section III of Tampa Electric Company's 1998 TYSP. The demand component of the forecast is used to project system supply side capacity requirements to ensure adequate and reliable electric power. This same firm demand is used in system reliability studies in calculating projected reserve margins and is a key element in determining the need for adding new generating capacity to our system. The energy component of the forecast is used to project system generation and purchase power requirements. This same energy forecast is used in calculating expected unserved energy (EUE) and loss-of-load probability (LOLP) for the purpose of projecting system reliability. While both components of the demand and energy forecast are important for planning and operations purposes, the energy forecast and the related economic utilization of all the energy resources on Tampa Electric's system is a particularly important element of the Phase II compliance plan.

Q. How did Tampa Electric develop and utilize the fuel price forecast it relied upon in selecting a CAAA Phase II compliance plan?

A. The specific fuel price forecast utilized in the cost-effectiveness studies are described in detail by Mr. Black. The methodology used in the development of the specific fuel price forecasts is the same as described in section V of Tampa Electric Company's 1998 TYSP. The fuel price forecast and availability and quality of the fuels is a key element of the cost-effectiveness studies because revenue requirement analyses primarily focus on fixed and operating costs to determine the most cost-effective compliance alternative. The projected fuel savings associated with specific compliance alternatives are offset by the capital and O&M costs. The combined net effect of fixed and variable costs results in the cumulative differential revenue requirements on a present worth basis. The FGD option is the most cost-effective compliance alternative due to the significant fuel savings which more than offset the capital costs of constructing and operating the FGD system for both Big Bend Units 1 and 2.

Q. How did Tampa Electric develop and utilize the demand side management (DSM) forecast it relied upon in selecting a CAAA Phase II compliance plan?

A. The DSM forecast utilized in the cost-effectiveness studies is the same forecast and methodology described in detail in section III of Tampa Electric Company's 1998 TYSP. The dispatchable DSM programs contained in the forecast effectively reduce system load requirements at times of system peak when economic supply side capacity is unavailable. These programs do not significantly reduce system energy requirements but do defer the need to construct new generating capacity. The non-dispatchable DSM programs contained in the forecast effectively reduce system load requirements for all hours which result in lower system energy requirements. For example, in the year 2000, non-dispatchable DSM programs are projected to reduce system energy requirements by 415 GWH along with the associated SO_2 emissions. This amount of energy is approximately equivalent to 50 MW of coal-fired capacity from Big Bend Unit 1 or 2 operating for every hour of a single year.

<u>Regulatory Treatment</u>

Q. What regulatory treatment is Tampa Electric proposing for FGD related costs?

A. As noted above, Tampa Electric proposes to recover prudently incurred project related costs through the ECRC over a ten year period, beginning when the FGD system is first placed in service. In the interim, project costs will be tracked and accumulated in AFUDC until the FGD goes into service. We are asking the Commission to concur with Tampa Electric's selection of the FGD option as the most cost-effective compliance alternative and to confirm that all reasonable and prudent costs associated with this project will be recoverable through the ECRC cost recovery mechanism with the capital costs of the project to be recovered over a 10 year period. However, we are not requesting approval of any related FGD system project costs for cost recovery at this time. We recognize that the company will be required to present detailed evidence to support the actual and projected costs associated with the FGD system at a petition in advance of the projection period when the system goes into service and before any project related cost is recovered through the ECRC.

Q. How does Tampa Electric intend to treat costs associated with this project while it is under construction?

A. Tampa Electric will track its costs associated with the construction of the FGD system and accumulate them in AFUDC until the FGD system goes into service. This is consistent with the Commission's Rule 25-6.0141 identifying projects eligible for AFUDC accrual. The proposed FGD system will involve gross additions to plant in excess of 0.5% of the sum of the total balance in Account 101-Electric Plant in Service, and Account 106-Completed Construction not Classified, at the time the project commences. In addition, the project is expected to be completed in excess of one year after the commencement of construction. We request that in approving the project the Commission confirm that this project qualifies for AFUDC accrual under the above-referenced Commission rule.

Q. Why are the costs associated with the proposed construction and operation of a FGD system to serve Big Bend Units 1 and 2 appropriately recovered through the Environmental Cost Recovery Clause?

A. Consistent with the guidelines which this Commission established in Order No. PSC-94-0044-FOF-EI, the FGD related costs; A) will be incurred after April 13, 1993; B) will be incurred on the basis of a legal requirement of the CAAA; and C) are not currently being recovered through base rates or any other cost recovery mechanism.

The FGD system related costs proposed for environmental cost recovery were not among the compliance activities included in the basis for setting base rates in Tampa Electric's last rate case, Docket No. 920324-EI, in 1992. At the time of that rate case, the planned compliance activities for Phase I of the CAAA consisted only of fuel blending with low sulfur coals and allowance purchases.

Q. Why is the ten year cost recovery period proposed by Tampa Electric appropriate?

A. The determination of an appropriate recovery period necessarily involves the exercise of judgment. We believe the use of a ten year recovery period for the proposed FGD system is reasonable under the circumstances. Extending the recovery period beyond ten years, however, would disregard the goal of mitigating potential stranded cost. The Commission has previously recognized that stranded cost mitigation efforts are in the interest of customers and has in the past supported such efforts through reasonable means. We submit that our proposal is consistent with this policy and the Commission's past practice. Lastly, it should be noted that over the ten year recovery period customers who bear these costs will realize a net benefit. The use of a ten year recovery period is also consistent with the composite life of the project equipment used for tax purposes.

Q. Please summarize your testimony.

A. My testimony supports Tampa Electric's selection of a stand alone FGD system serving Big Bend Units 1 and 2 as the company's most viable and cost-effective option for meeting the heightened SO_2 emission limitations of Phase II of the CAAA. I explain our company's need for approval by the Commission of this project as a reasonable compliance means, and a corresponding determination by the Commission that costs prudently incurred by Tampa Electric in implementing this project will and should be eligible for environmental cost recovery beginning in the cost recovery period when the project is placed in service. Finally, my testimony supports the use of a ten year recovery period for the proposed FGD system for Big Bend Units 1 and 2.

Q. Does this conclude your testimony?

A. Yes it does.

TAMPA ELECTRIC COMPANY
DOCKET 980693-EI
WITNESS: HERNANDEZ
EXHIBIT NO._______(TLH-1)

TAMPA ELECTRIC COMPANY

INDEX

MEMORANDUM

SUBJECT: **SO_2 Compliance Plan Evaluation - Phase 1**

DATE: December 16, 1994

FROM: Tom Hernandez

TO: Spence Autry
Bill Cantrell
Gordon Gillette
Hugh Smith
John Smolenski

The attached reference document describes the process used to develop Tampa Electric's SO_2 compliance plan for Phase 1. This document does not reflect the additional studies conducted this year which led to the Big Bend 4 FGD integration project as part of the Phase 1 compliance plan. A separate study is available upon request.

This document has not been provided to any external agency, but may be useful as a reference for any future regulatory or agency requirement.

attachment

ORIGINAL DOCUMENT

TAMPA ELECTRIC COMPANY
CLEAN AIR ACT AMENDMENTS OF 1990
COMPLIANCE PLAN EVALUATION - PHASE I
JANUARY 1994

APPENDICES

EXECUTIVE SUMMARY

Tampa Electric Company is an investor-owned electric utility which serves west central Florida, primarily Hillsborough County, as well as portions of Polk, Pinellas, and Pasco Counties. Currently, Tampa Electric Company serves approximately 477,000 residential, commercial, industrial, and governmental Customers within its service area. Tampa Electric Company's system has an installed net electric generating capacity of 3,329 MW and 22 generating units located at five different sites: Big Bend, Gannon, Hookers Point, Phillips, and Dinner Lake Stations. By July 1996, an integrated gasification combined cycle (IGCC) will be constructed and placed in service in Polk County.

The Acid Rain Program of emissions reductions will evolve in two phases. Phase I of the program begins on January 1, 1995, and continues through December 31, 1999. During Phase I, only a select group of utility generating units will be regulated. Phase II of the program starts on January 1, 2000, and will regulate almost all of the new and existing utility units. Tampa Electric has three units (Big Bend 1-3) which are considered to be Phase I units. The remainder of the Tampa Electric system units, with the exception of Phillips, Dinner Lake, and the existing combustion turbines which are not regulated by Title IV, are considered to be Phase II units.

Tampa Electric is required to comply with the acid rain provisions of the Clean Air Act Amendments of 1990 (CAAA). In Phase I (1995-1999), Tampa Electric plans to meet Phase I SO_2 emission compliance by fuel blending lower sulfur coal with the existing West Kentucky coal on Big Bend 1-3. Tampa Electric may participate in the allowance market for the purpose of reducing overall system costs. This strategy allows Tampa Electric the flexibility to evaluate the allowance market and respond to changes in the demand and energy forecast, low sulfur fuel price forecast and future regulations. Tampa Electric has no requirement with regard to NO_x emission requirements during Phase I.

The total cost of compliance in Phase I is $91 million in 1992 present worth dollars. This cost is the incremental fuel, O&M and capital revenue requirements relative to the Tampa Electric system without complying with the new CAAA requirements.

This document presents the results of a multi-department evaluation of potential control options to comply with the acid rain provisions (Title IV) of the Clean Air Act Amendments of 1990 (CAAA) which occurred in February 1992. This evaluation determined fuel blending to be the most cost effective strategy for Tampa Electric to comply with CAAA in Phase I. Tampa Electric continues to evaluate this decision as well as Phase II compliance options

1. INTRODUCTION

1.1. Tampa Electric's System

Tampa Electric is an investor-owned electric utility. Tampa Electric has five steam-generating plants and four combustion turbine peaking units. By July 1996, an Integrated Gasification Combined Cycle (IGCC) will be constructed and placed in service in Polk County. Tampa Electric's generation mix is 98% coal and 2% oil/natural gas.

1.2. Overview of Regulatory Requirements

The stated purpose of Title IV of the Clean Air Act Amendments of 1990 (CAAA) is to achieve reductions in annual emissions of sulfur dioxide (SO_2) of ten million tons from 1980 emission levels and also establish reductions in the emissions of nitrogen oxides (NO_x). The Acid Rain Program created under Title IV to achieve this nationwide reduction in SO_2 emissions involves allocating a fixed amount of annual allowances which utilities will need in order to emit SO_2. One allowance will be required for each ton of SO_2 emitted. An elaborate control system has been created under Title IV to assign, track, and allow for the trading of allowances. Allowances created by the program and issued to utilities can be bought and sold on the open market. This market approach is designed to add flexibility and lower the overall cost of compliance with the program.

The Acid Rain Program of emissions reductions will evolve in two phases. Phase I of the program begins on January 1, 1995, and continues through December 31, 1999. During Phase I, only a select group of utility generating units will be regulated. Phase II of the program starts on January 1, 2000, and will regulate almost all of the new and existing utility units. Tampa Electric has three units (Big Bend 1-3) which are considered to be Phase I units. The remainder of the Tampa Electric system units, with the exception of the Sebring units and the existing combustion turbines which are not regulated by Title IV, are considered to be Phase II units.

During each of the five years in Phase I, Big Bend Units 1-3 will be required to have one allowance for each ton of SO_2 emitted. Under the Title IV Acid Rain Program, these three units combined will receive 80,085 allowances annually. Unless additional allowances are obtained, the SO_2 emissions from these three units cannot exceed 80,085 tons annually. This represents a reduction of approximately fifty percent (50%) from the 1992 emission level. Without the CAAA, SO_2 emissions from Big Bend 1-3 would be 173,057 tons in 1995. This would lead to a reduction of 92,972 tons of SO_2. The amount of reduction needed in Phase I is shown in Figure 1-1.

The Title IV Acid Rain Program sets requirements for the NO_x limitations on certain types of coal-fired utility units. The utility units to be regulated for NO_x during Phase I are those with tangentially fired or dry wall-fired type boilers. Units with cyclone and/or wet bottom boilers, such as Big Bend Units 1-3, will not be regulated for NO_x emissions in Phase I. Under Title IV, the EPA is required to establish regulations and NO_x limits for these units by January 1, 1997. These limitations, however, will not be in effect until the beginning of Phase II. Therefore, Tampa Electric has no requirements to meet with regard to NO_x compliance during Phase I.

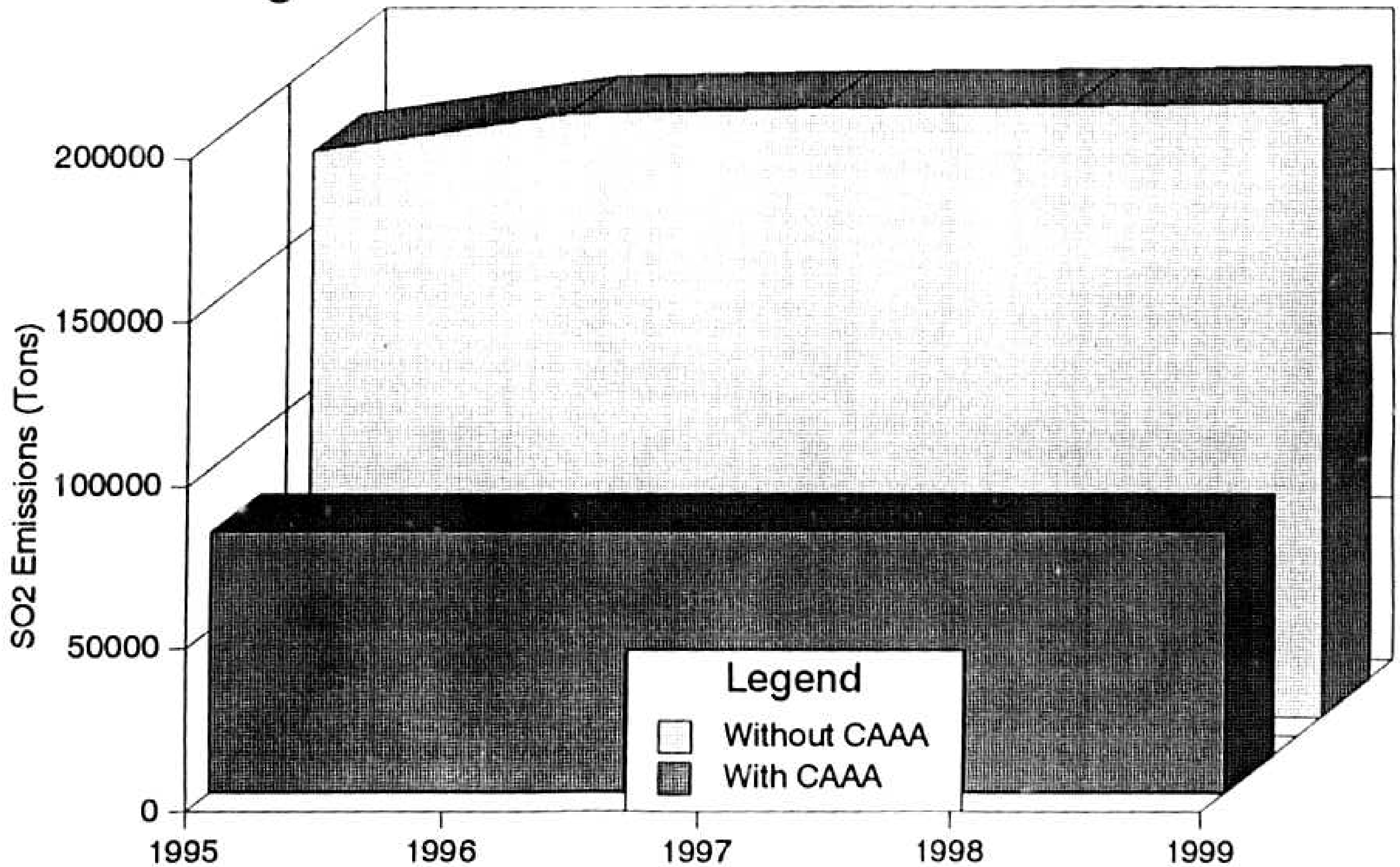
The Title IV Acid Rain Program requires the installation and certification of CEMS to monitor the emissions from each affected Phase I unit. This system must be able to provide quality assured data for SO_2, NO_x, CO_2, or O_2, and volumetric flow. Phase I units must have the CEMS installed, certified, and operating not later than November 15, 1993.

Under Title IV, an Acid Rain Program Phase I permit and Compliance Plan is required. The application for this permit must have been submitted by the owner (or their Designated Representative) no later than February 15, 1993, and EPA action on the permit application was required within six months of the application date.

Figure 1-1

Tampa Electric Company

Big Bend 1-3 Annual Sulfur Dioxide Emissions



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1.3 Overview of Tampa Electric's Integrated Approach

Tampa Electric has closely followed acid rain legislation for several years. A group was formed in 1990 specifically to study Tampa Electric's compliance options. This group was named SPARC, Strategic Planning for Acid Rain Compliance, and consisted of employees from several areas throughout the company. These areas included Energy Resource Planning, Environmental Planning, Fuels, Generation Planning, Production and Rates and Regulatory Control. The expertise each department contributed enabled Tampa Electric to determine the most cost effective compliance plan for Phase I.

The evaluation process was based on a detailed quantitative and qualitative analysis of compliance costs and strategic considerations. An initial screening analysis of numerous compliance methods was conducted to select the most technically and economically viable alternatives. The viable alternatives were combined with consideration of base capital and O&M costs for compliance and the total company business plan to create several compliance scenarios to evaluate.

1.4. Recommended Compliance Plan

These scenarios were analyzed based on system revenue requirements and strategic considerations. The most cost effective and flexible compliance scenario for Tampa Electric is to lower the SO_2 emission rate by blending low Sulfur coal with the existing standard West Kentucky coal. The blend of Low Sulfur coal with standard West Kentucky coal can be adjusted based on changes in load, fuel price, and/or the allowance market. This scenario allows Tampa Electric the flexibility to react to changes in both Phase I and Phase II. This document explains the analysis which was used to support the decision to fuel blend Low Sulfur coal with the existing standard West Kentucky coal.

2. ASSUMPTIONS

2.1 System Assumptions

Several assumptions were used in developing Tampa Electric's Phase I compliance plan. The Economic Planning and Forecasting Section of the company's Resource Planning Department provided the demand and energy projections. This forecast included the most cost effective amount of conservation and load management. The Cogeneration Section of the Resource Planning Department provided projections of net and purchase cogeneration. The Bulk Power Section provided a projection of off-system sales. The Generation Planning Section developed the most cost effective Integrated Resource Plan. The Production Department provided operating characteristics for existing generating units. Capital costs and O&M estimates for different compliance options were provided by the Production Department.

Fuel price and fuel characteristics information for existing fuels and potential compliance fuels was provided by the Fuels Department. To obtain the necessary emission rates (lb SO_2/MBtu), the lower sulfur coals were blended with standard West Kentucky coal. This analysis used supplemental fuel prices for dispatch and production costing. It was assumed that the difference between supplemental and average fuel price is a fixed cost that remains constant for all alternatives as long as the contract minimum volumes remain unchanged.

Appendix A summarizes the basic system assumptions which were used in this analysis. These tables include the demand and energy forecast, load management and conservation forecast, non-compliance supplemental fuel forecast, existing generating facilities (capacity, availability and heat rate), cogeneration forecast and the bulk power forecast.

2.2 Economic and Financial Assumptions

The economic and financial assumptions used to determine the present worth revenue requirements associated with each compliance alternative are summarized in Tables 2-1 and 2-2. Table 2-1 shows cost of capital, capital structure, AFUDC rates, tax rates and discount rate. Table 2-2 shows the economic escalation rates for plant construction, fixed O&M and variable costs.

The assumed book life of a Flue Gas Desulfurization (FGD) system is 30 years and the tax life is 20 years. The assumed book life of the Flue Gas Conditioning (FGC) system is the lesser of the number of years until a FGD is installed on the unit or 30 years. The tax life is equal to the lesser of the book life or 20 years.

Construction lead time for the FGD is 3 years. The construction spending curve is Year 1 .6%, Year 2 44.1% and Year 3 55.3%. Flue Gas Conditioning (FGC) system construction lead time is 1 year.

Table 2 – 1

TAMPA ELECTRIC COMPANY
PHASE I COMPLIANCE PLAN EVALUATION
Economic and Financial Assumptions

Cost of Capital	
Debt	9.25 %
Preferred	7.70 %
Common	13.50 %
Capital Structure	
Debt	43.00 %
Preferred	2.00 %
Common	55.00 %
AFUDC Rate	
1993 – 2002	7.93 %
Taxes	
Effective Tax Rate	37.63 %
ITC Tax Rate	0.00 %
Discount Rate	
1993 – 2002	10.06 %

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Table 2 - 2

TAMPA ELECTRIC COMPANY
PHASE I COMPLIANCE PLAN EVALUATION
Economic Escalation Assumptions

Year	Plant Construction Cost %	Fixed O & M Cost %	Variable O & M Cost %
1993	4.3	4.0	4.0
1994	4.6	4.3	4.3
1995 and Beyond	4.8	4.5	4.5

ECOESC.WK1 (CAAC-001) 10/19/93

NOTE: Plant and O&M rates include inflation and escalation components.

2.3 Compliance Assumptions

Several compliance assumptions were used to perform the analysis. These assumptions were developed based on input from SPARC, the multi-department group formed to evaluate compliance.

1. The following are the emission rates by fuel type for purposes of this study

Gannon Coal	=	1.80 lb SO_2 / MMBtu
Hookers Point Oil	=	1.04 lb SO_2 / MMBtu
Big Bend 4	=	0.35 lb SO_2 / MMBtu
Polk IGCC	=	0.16 lb SO_2 / MMBtu
Existing/Future #2 Oil	=	0.53 lb SO_2 / MMBtu
Existing/Future Natural Gas	=	0.00 lb SO_2 / MMBtu
Big Bend 1-3 Existing Fuel	=	4.66 lb SO_2 / MMBtu
Big Bend 1-3 with FGD Retrofit	=	0.31 lb SO_2 / MMBtu

2. Tampa Electric's affected units in Phase I are Big Bend 1-3. In Phase II, all existing and future units, with the exception of existing combustion turbines, Phillips Station, and Dinner Lake Station, will be affected.

3. Five percent of sulfur in coal will be retained in the collected combustion by-products (flyash, slag, bottom ash).

4. Total load includes projected retail load, wholesale load, and off-system sales.

5. Off-system sales are priced at incremental fuel prices. Capital and O&M costs associated with fuel blending, retrofitting FGD, and CEMS are assumed to be recovered from both retail and partial requirements Customers.

6. Fuel blending Big Bend 1-3 to lower sulfur coals with less than 2.8 (lb SO_2/ MMBtu) emissions will result in a 0.7% decrease ... availability. In addition, a flue gas conditioning system will be needed to maintain desired electrostatic precipitator collection efficiencies.

7. Retrofitting a FGD will result in a 8 MW capacity degradation due to increased station service auxiliary load. The first and second FGD retrofit would be on Big Bend 3 and Big Bend 1, respectively.

8. No carrying cost was associated with the banking of allowances as an operating margin.

9. Substitution / Reduced Utilization units were not used for compliance unless the affected units combined heat input was lower than the 1985-1987 baseline.

3. METHODOLOGY

3.1 Alternative Technology Screening

There are numerous control alternatives available to obtain the necessary sulfur dioxide emissions reductions. The Electric Power Research Institute (EPRI), equipment vendors, fuel suppliers, architect/engineering firms and other utilities are available resources to compile an extensive list of alternatives. However, many of these technologies are not proven on a commercial or utility scale. Additionally, due to Tampa Electric's experience operating coal-fired power plants and a FGD system, there is a high level of confidence in alternatives that incorporate either fuel blending to lower sulfur coal blends or FGD technology.

Several compliance alternatives were screened for application on the Tampa Electric system. Due to the system-wide requirements for CAAA compliance, an attempt to evaluate the full scope of compliance possibilities based on these alternatives offers a tremendous planning challenge. On the Tampa Electric system several thousand potential compliance scenarios could be generated. In order to narrow the range of possibilities a comparison of the capital intensive alternatives was performed using EPRI cost data. Screening curves which compared the levelized cost per SO_2 ton removed for each alternative versus capacity factor were used to eliminate the higher cost alternatives. Those alternatives which remained were analyzed in more detail using both a quantitative and qualitative approach.

3.2 Quantitative Analysis

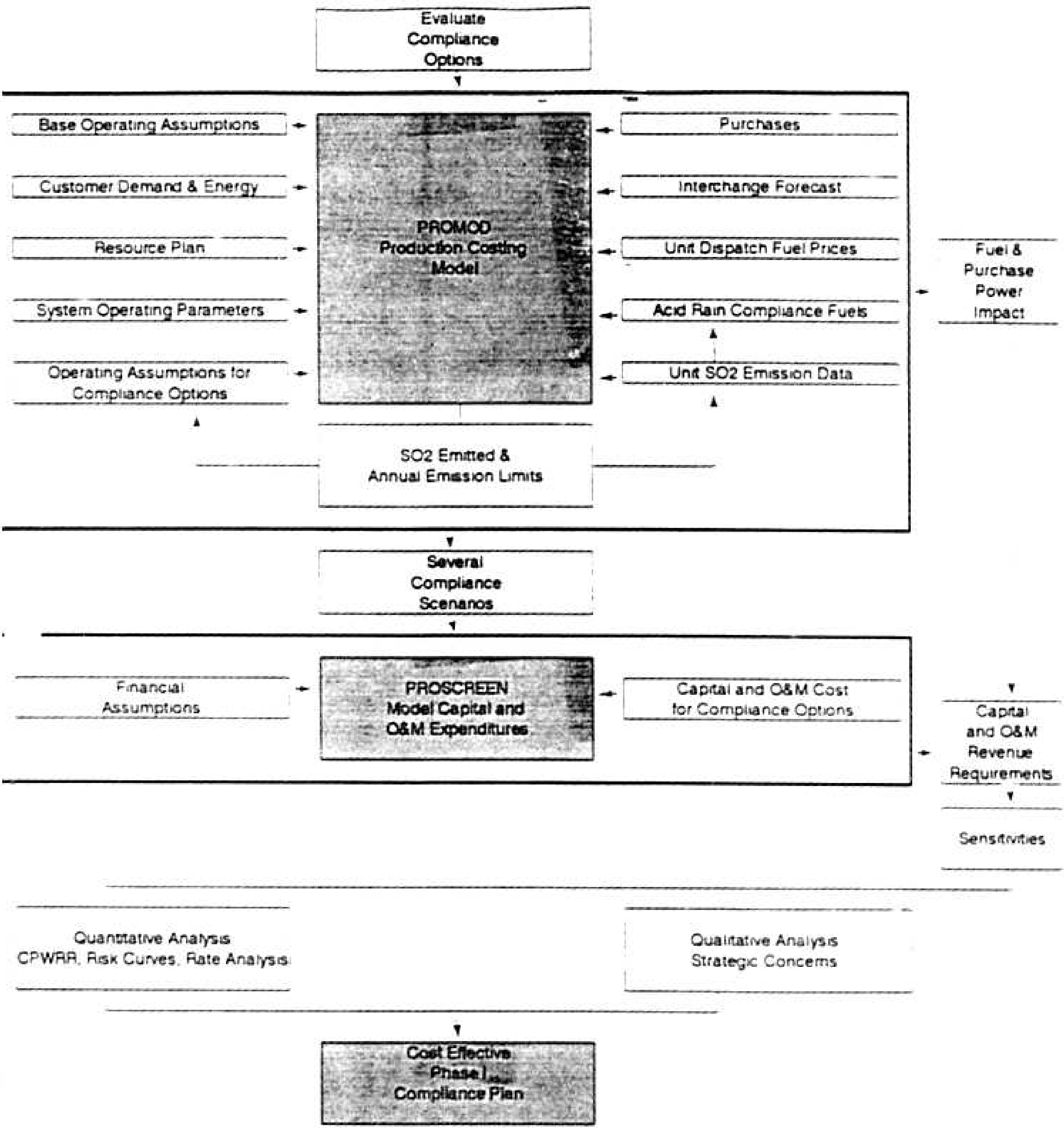
This phase of the evaluation enables a direct quantitative comparison of compliance-related costs based on cumulative present worth revenue requirements and projected average retail rates for each alternative on a total and native load basis The analysis was performed for both total and native load for several reasons Tampa Electric has historically been a seller of electricity and this trend is expected to continue Tampa Electric's retail Customers benefit from off-system sales through more efficient operation of our units and the credit which native load Customers receive from these sales Reducing off-system sales increases recoverable fuel and purchase power expense to native load Customers In addition, Tampa Electric needs to know the amount of lower sulfur coal required to comply for both total and native load in order to develop fuel purchasing strategies Compliance costs were developed on an incremental revenue requirements basis relative to the existing Tampa Electric system prior to the Clean Air Act Amendments of 1990 The cumulative present worth revenue requirements include system fuel and purchase power expense and incremental capital and O&M expense associated with the compliance alternatives and construction of new generating resources

Several compliance alternatives exist for Tampa Electric to comply with the Clean Air Act Amendments of 1990 (Figure 3-1 is flow diagram of the Tampa Electric Phase I compliance methodology) After screening down the number of viable alternatives to a manageable list, the different combinations of the remaining alternatives were identified and a general list of scenarios to evaluate was created

PROMOD, a production costing computer model, was used to determine the fuel & purchase power expense associated with each of the scenarios PROMOD simulates an economic dispatch of the generating system based on incremental production costs. Incorporated in the fuel and purchase power expense is the unit operating characteristic impacts and system dispatch effects associated with the different compliance alternatives. Since dispatch effects can result in varying mix of generating resources to meet the system energy requirements, this process is iterative until a scenario which meets both the system energy requirements and compliance requirements can be determined

Figure 3-1

ACID RAIN COMPLIANCE EVALUATION



Once the compliance scenarios were analyzed using PROMOD, the capital revenue requirements and O&M associated with the compliance alternatives were calculated. Tampa Electric used PROSCREEN to determine these costs. PROSCREEN incorporates Tampa Electric's financial and economic assumptions. Both PROMOD and PROSCREEN are developed by Energy Management Associates based in Atlanta, Georgia.

Sensitivities were included in the analysis to quantify the risk associated with each scenario. Two assumptions which can impact Phase I compliance greatly are the fuel price forecast and the system energy requirements. Sensitivities were evaluated based on a high and low compliance fuel forecast. To evaluate load uncertainty, both total and native load sensitivities were analyzed. Total load includes both firm and non-firm load, whereas native load includes only firm load.

The incremental capital revenue requirements and O&M expenses were combined with the fuel and purchase power expense to determine the total cost of each scenario. The differential nominal and cumulative present worth of the total system revenue requirements was then used to compare each scenario in a given year or a specific period of years. One tool used to evaluate the scenarios is a risk curve. A risk curve is a graph of the differential cumulative present worth of the system revenue requirements of the scenarios against a base scenario.

3.3 Qualitative Analysis

The qualitative analysis attempts to incorporate considerations that are not readily quantified on a cost basis. These considerations include regulatory/legislative issues, operational concern, compliance plan flexibility and public perspective. A favorability rating on a scale of one to seven was used to indicate a degree of favorability for each alternative for a given consideration. This same relative scoring is applied to the economic analysis so that a composite relative cost index and relative risk index can be used for selecting the most cost effective alternatives.

4. RESULTS

4.1 SO_2 Alternative Selection

The initial phase of the evaluation process was to determine the different alternatives available to Tampa Electric to comply with the CAAA. The following is a list of these alternatives, which was compiled using the Electric Power Research Institute (EPRI), equipment vendors, fuel suppliers, architect/engineering firms, and other utilities.

Alternatives

- Fuel blend with lower sulfur coals
- Conversion from coal to residual oil
- Conversion from coal to natural gas
- Coal/natural gas co-firing
- Coal Gasification
- Retire coal unit/Replace with NG Combined Cycle unit
- Retire coal unit/Replace with NG Combustion Turbine
- Retire coal unit/Replace with IGCC unit
- Fluidized Bed Conversion (Repowering)
- FGD (Wet Scrubber)
- FGD (Dry Scrubber-Boiler Injection)
- FGD (Dry Scrubber-Duct Injection)

Special System Alternatives

- Environmental Dispatch

FGD Screening

There are several FGD technologies. Tampa Electric needed to screen these technologies to determine which FGD technology was the most feasible and economical. The FGD options were screened using an EPRI software tool called FGD Cost. This computer model forecasts the total installed cost for any of 26 FGD technologies taking into account site specific performance, operational, construction and economic factors.

FGD Cost models were run for the following 26 FGD technologies

Limestone/Forced Oxidation	Lurgi CFB
Limestone/Wallboard Gypsum	SOXAL
Lime Dual Alkali	MGO
Magnesium Enhanced Lime	Limestone Dual Alkali
Limestone/Inhibited Oxidation	Saarberg Holter
Limestone/DBA	NSP Bubbler
Pure Air/Mitsubishi	Passamaquoddy
CT-121	ISPRA
Lime Spray Dryer	HYPAS
Furnace Sorbent Injection	Damp/ADAVACATE
Duct Sorbent Injection	SO_2 Advanced Retrofit
Duct Spray Dryer	Wellman-Lord
Tampella LIFAC	Economizer Sorbent Inject

These models were performed using Big Bend 3 as the retrofit site. This unit was intuitively the most cost effective site for an FGD retrofit within the Tampa Electric generating system. The Limestone/Wallboard Gypsum model was also run on Big Bend 1 and 2. In addition a reduced group of the above models for both wet and dry systems was run on Gannon 1-6. The results of the modeling indicated that a Limestone/Wallboard Gypsum FGD system on Big Bend 3 would provide the lowest cost per ton of SO_2 reduction of all of the FGD technologies evaluated.

Once it was determined that the Limestone/Wallboard Gypsum FGD system (Wet Scrubber) was the most cost effective FGD technology, all of the other alternatives needed to be analyzed. Due to the magnitude of scenarios which can be developed based on the list of alternatives, screening curves were used to reduce the alternatives to a manageable number. These screening curves compared levelized $/ton removed for each alternative based on a range of capacity factors. These curves screen for a single unit and not for the system.

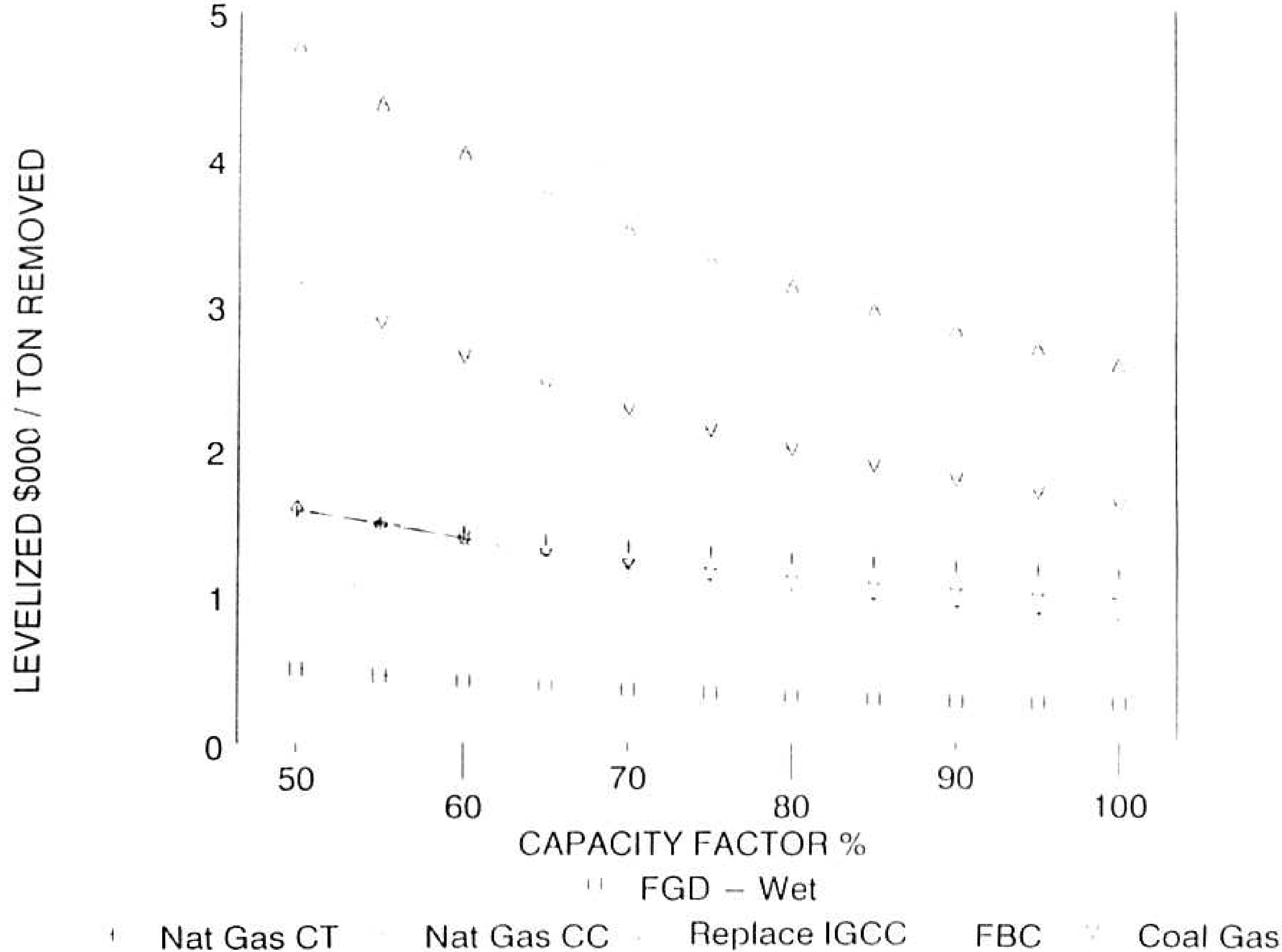
The first curve (Figure 4-1) compares alternatives which involve replacing the boiler or retrofitting a FGD. These alternatives included

- FGD (Wet Scrubber)
- Retire coal unit / Replace with IGCC unit
- Fluidized Bed Conversion
- Retire coal unit / Replace with Natural Gas Combined Cycle
- Retire coal unit / Replace with Natural Gas Combustion Turbine

The FGD (Wet Scrubber) has a SO_2 removal efficiency of 95%. Retiring and replacing a coal unit with IGCC has a removal efficiency of 98% but is very capital intensive. As shown in the curves, the improved removal efficiency over a FGD is not worth the additional capital investment. The Fluidized Bed Conversion has a 80% removal efficiency and is more expensive than the FGD. Retiring and replacing a coal unit with a natural gas combined cycle or a natural gas combustion turbine eliminates sulfur dioxide emission, however, the fuel price associated with natural gas is uncertain and the capital is high. Converting to coal gas involves adding a gasification plant. Removal efficiency is high and so is the capital. The screening curves show that out of these options, the Limestone/Wallboard Gypsum FGD system is the least cost based on levelized $/ton removed.

ACID RAIN COMPLIANCE

ALTERNATIVE SCREENING



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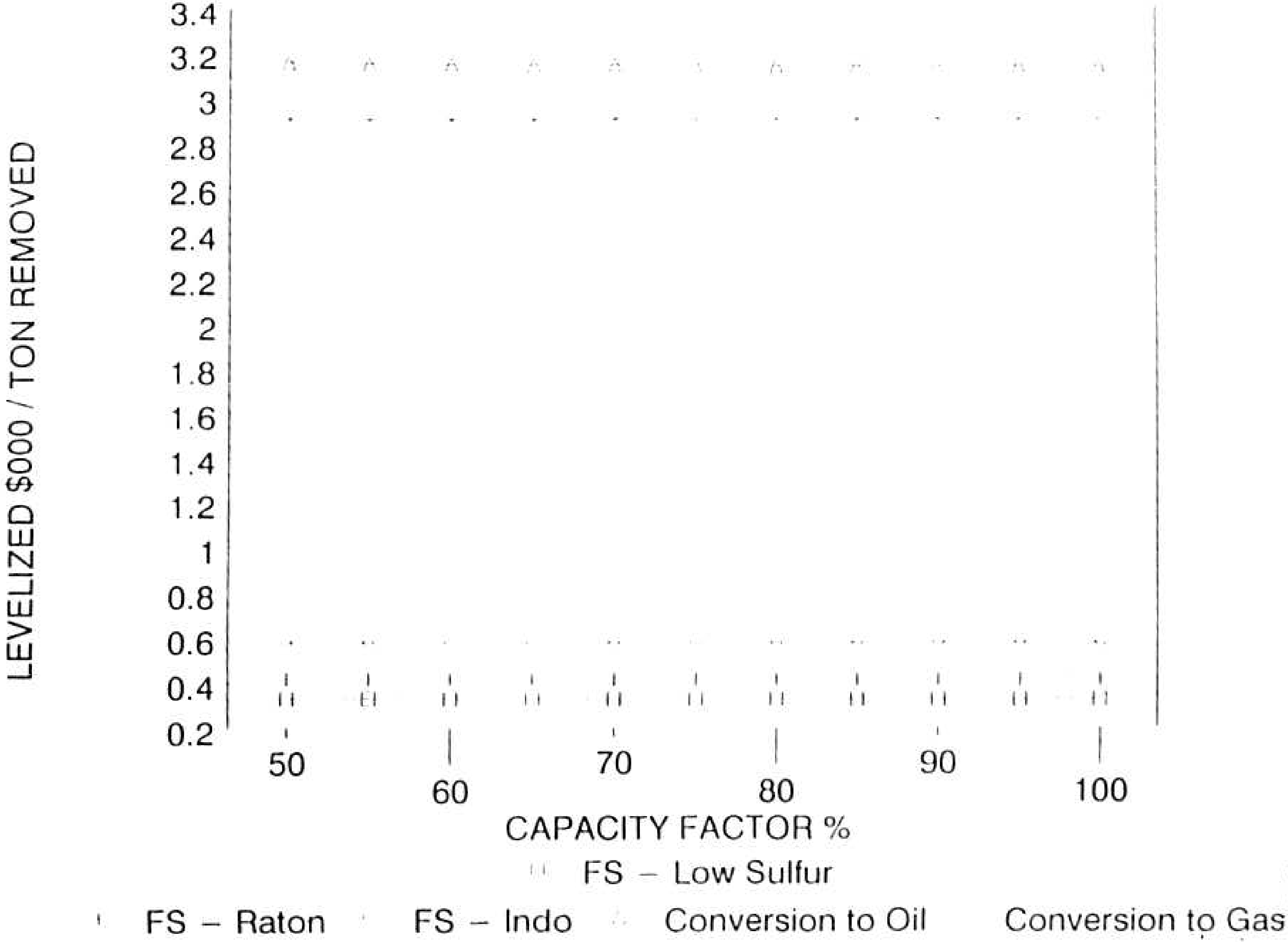
The second screening curve (Figure 4-2) compared the following fuel blending and fuel switching alternatives:

- Fuel blend to Low Sulfur coal
- Fuel blend to Raton
- Fuel blend to Indonesian
- Conversion from coal to residual oil
- Conversion from coal to natural gas

The amount of sulfur removal is dependant upon the amount of sulfur in the fuel. The curve showed that the fuel blending alternatives to lower sulfur coal have the lowest levelized SO_2 removal cost ($/ton). All of the fuel blending to lower sulfur coal alternatives were retained. Due to the uncertainty of the natural gas fuel forecast and the low capital investment, the conversion to natural gas was kept for the detailed analysis along with co-firing coal with natural gas.

ACID RAIN COMPLIANCE

ALTERNATIVE SCREENING



Based on the alternatives which remained after the screening analysis, Tampa Electric combined several alternatives to evaluate the most cost effective Phase I compliance plan Table 4-3 is list of compliance scenarios evaluated by Tampa Electric The analysis was performed over a twenty five year study period to incorporate the impacts of Phase II However, the main emphasis is on Phase I compliance due to the uncertainties in the allowance market, Phase II fuel prices, developing technologies, and developing legislation To evaluate all options on an equal basis, the emission bank at the end of Phase I for all options was kept relatively the same Listed below is a brief description of the compliance alternatives evaluated

4.1.A. Fuel Blending

Fuel blending Big Bend 1-3 existing fuel with a lower sulfur coal is one alternative for complying in Phase I Fuel blending may require some modifications to the unit to maintain desirable boiler operating characteristics Several fuel sources, each with different fuel prices and characteristics associated with them, were analyzed Each fuel source could potentially have a different impact on system dispatch Therefore the blend of low sulfur coal and West Kentucky coals will vary However, the actual blend ratios will depend on unit capabilities and system demand and energy requirements Fuel blending with lower sulfur coal offer fuel flexibility and lower capital investment compared to other alternatives The coals selected in Phase I compliance are expected to be compatible with generating units and existing coal handling and transportation systems

TABLE 4-3

NOTE: This table is in another file: TABLE 4-3 DOC

4.1.B. Flue Gas Desulfurization Retrofit

The most cost effective FGD technology chosen to evaluate against other options is the limestone forced oxidation gypsum producing system. Tampa Electric investigated Phase I FGD retrofit alternatives including three FGD in 1995, two FGD (one in 1995 and one in 1997), one FGD in 1995 and one FGD in 1997. The three FGD scenario was eliminated due to high capital costs, extreme over compliance and site preparation problems. Installing one FGD in 1995 or 1997 still requires additional fuel blending in Phase I. Building more than one FGD is the only way to eliminate the need for more removal on Big Bend 1 and 2 in Phase I. The FGD is assumed to be 98% available and to have a 95% SO_2 removal efficiency.

If Tampa Electric chose to build an FGD prior to 1997, there was a possibility that bonus and extension allowances would have been available in 1995-1996 and 1997-1999, respectively. It was undecided as to how these bonus and extension allowances would be distributed. Tampa Electric joined a group of utilities called the Allowance Pooling Group, which was interested in obtaining bonus and extension allowances. The intent of the group was to pool its resources and distribute the allowances evenly amongst the member utilities. Uncertainty still remained at the time Tampa Electric needed to make a decision on a Phase I FGD retrofit. Therefore, it was decided to eliminate the bonus and extension allowances from the base economic analysis. The bonus and extension allowances were treated as a sensitivity.

4.1.C. Allowance Market

At the time of this analysis, the expected market value of an allowance was over \$400/ton. This value was above Tampa Electric's incremental cost of removal. Therefore Tampa Electric decided not to participate in the allowance market and thus to self comply. As the price of allowances continue to decline, Tampa Electric may use allowance purchases to further lower the cost of compliance.

4.1.D. Natural Gas Conversion

Fuel switching an existing coal unit to natural gas requires relatively lower capital investment and minimal impact to boi' · operating characteristics when compared to retrofitting a FGD system. However, the future price and deliverability of natural gas in sufficient volume to fully dispatch one or more of the Big Bend Units 1-3 was of great concern.

In lieu of selecting any specific natural gas forecast, a break-even analysis was used to calculate what the delivered price of natural gas would have to be to result in the annual revenue requirements equivalent to a Phase I FGD retrofit for Big Bend 3. These revenue requirements include total system capital, O&M and fuel expense. The break-even natural gas price was compared to several external gas forecasts at the time. The resulting break-even price of natural gas was significantly lower than the other gas forecasts and remains lower than existing gas forecasts. This analysis indicated that the total conversion of Big Bend 1-3 from coal to natural gas was not an economically viable alternative.

4.1.E. Coal/Natural Gas Co-firing

An alternative to fuel switching an existing coal unit to natural gas is co-firing, in which gas and coal are burned simultaneously in the same boiler. However, the two fuels are not physically mixed and would require associated burners and auxiliary equipment to use natural gas simultaneously with pulverized coal. Co-firing will reduce sulfur dioxide emissions and may also improve boiler operating characteristics by mitigating slagging and fouling problems, stabilizing burner flames and reducing unborn carbon. Co-firing with natural gas would allow for the use of higher sulfur coal blends and thus less low sulfur coal. However the future price and deliverability of natural gas is still an issue. The determination of a break-even price of natural gas was based on the same methodology described in the Natural Gas Conversion Section. While the combined use of lower cost higher sulfur coal and natural gas increased the break-even price calculated previously, the resulting natural gas price was still lower than other viable natural gas price forecasts. This analysis indicated that co-firing coal and natural gas was not an economically viable alternative.

4.1.F. Environmental Dispatch

The prospect of dispatching generating units on an environmental emissions basis has resulted in a wide range of opinions within the industry. Many have suggested that environmental dispatch is impractical. To implement an environmental dispatch, a utility would have to violate basic system and power operating procedures. Some have interpreted environmental dispatch to entail operating a power system to minimize total emissions or to replace actual system operating costs with some vaguely defined multi-objective function reflecting environmental externalities resulting in significantly higher overall costs.

Others have suggested that environmental dispatch is neither infeasible nor complex in that it only requires incorporating emission costs as a fuel cost adder before deciding on operational strategies. At this point, the industry has no clear consensus on the definition of an environmental dispatch.

A dispatch of the Tampa Electric system to minimize total emissions would require off-loading generation from Big Bend 1-3 and increasing generation at Gannon, Hookers Point, CT's and or power purchases from Hardee Power Station. The CAAA allows, to a certain extent, a shift in burn to other unaffected units in Phase I. If the shift in burn exceeds a specified criteria, other units could become affected, further restricting Tampa Electric's Phase I compliance requirements. Regardless of other units becoming affected in Phase I, a major shift in burn would be cost prohibitive. This approach does not provide a viable or cost effective Phase I compliance methodology for Tampa Electric.

On the other hand, Tampa Electric may consider a form of environmental dispatch. It might be implemented through cost-effective scheduling of the power system, reflecting all supply-side constraints, transmission constraints, demand-side requirements, wholesale requirements, and market conditions (including environmental issues such as emission reduction targets and emission allowance markets). An effective environmental dispatch must explicitly respect all other system operating constraints. It also adds complexity to all future operating decisions.

4.2 SO_2 Compliance Costs

This section presents the results of the economic analysis of the selected compliance scenarios. The cumulative present worth revenue requirements (CPWRR) are provided in 1992$ and are differentials relative to a scenario without the Clean Air Act Amendments of 1990. CPWRR are provided for all sensitivities. Rate impacts in 1995 and 1999 are also provided for native and total load only. These rates are differentials relative to a scenario without the Act.

Tampa Electric analyzed the economics from two perspectives. The first is the relative cost of the scenarios at the end of Phase I. This approach is appropriate since Tampa Electric is focusing on Phase I compliance only and since there are many uncertainties that still remain unanswered for Phase II. However, in order to capture end effects, a twenty five year relative cost comparison was also analyzed. Both of these perspectives were used in the decision matrix.

On a total load basis, at the end of Phase I, Scenario 1 and 2 are the least cost options as shown in Table 4-4. Scenario 6 which has a 1997 FGD retrofit is third in relative cost. The rate impact and revenue requirements follow similar trends. Over the twenty five year study period, the top four least cost scenarios (Scenario 1,2,5 and 6) are only different by less than 0.6%. Even though the FGD case in 1995 is the least cost option, economically, these scenarios are nearly equivalent. The risk curve (Figure 4-5) shows how the scenarios compare over time. All scenarios were compared against the 1995 FGD retrofit scenario. The fuel blending scenario remains least cost until 2018.

Table 4 – 4

Tampa Electric Company
Phase I Compliance Plan Evaluation

Total Load

Scenario	Phase I Description	Phase I Emission Bank	Phase I Inc CPWRR (92 $000)	Phase I Rate Impact (%) 1995	1999	Phase I Relative Cost
1	Fuel Blend BB1–3 to Low Sulfur Coal (Avg Fuel Blend = 2.08 lb SO2 / Mmbtu)	12,802	91,132	2.27	2.71	1
2	Fuel Blend BB1–3 to Utah Coal (Avg Fuel Blend = 2.08 lb SO2 / Mmbtu)	14,681	103,649	2.55	3.07	2
3	Fuel Blend BB1–3 to Raton Basin Coal (Avg Fuel Blend = 2.08 lb SO2 / Mmbtu)	16,750	118,400	2.92	3.47	5
4	Fuel Blend BB1–3 to Gatliff Coal (Avg Fuel Blend = 2.20 lb SO2 / Mmbtu)	14,645	179,991	4.60	5.06	7
5	BB 3 FGD in 1995; BB 1–2 Fuel Blend to Low Sulfur Coal (Avg Fuel Blend = 2.92 lb SO2 / Mmbtu)	12,426	116,773	2.60	3.15	4
6	BB 3 FGD in 1997; BB 1–2 Fuel Blend to Low Sulfur Coal (Avg Fuel Blend = 2.20 lb SO2 / Mmbtu 95–96 and 2.80 lb SO2 / Mmbtu 97–99)	15,981	110,642	2.32	3.35	3
7	BB 3 FGD in 1995; BB 1 FGD in 1997; BB 1–2 Fuel Blend to Low Sulfur Coal (Avg Fuel Blend = 3.00 lb SO2 / Mmbtu 95–96 and 4.66 lb SO2 / Mmbtu 97–99)	30,043	139,629	2.70	3.83	6

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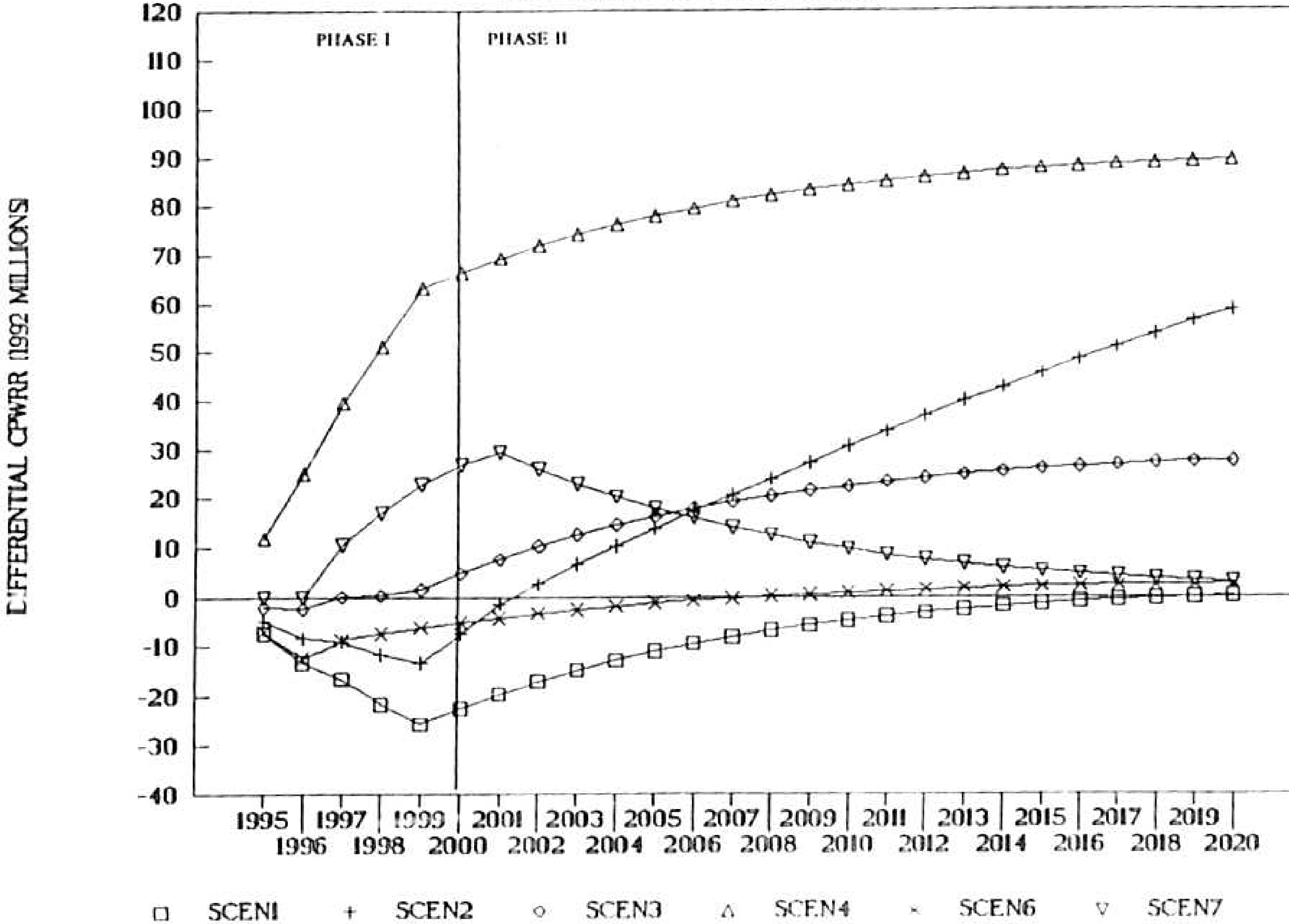
TOTAL LOAD - RISK CURVES

COMPLIANCE COAL BASE CASE



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On a native load basis in Phase I, the relative order is nearly identical to total load except Scenario 6 and 2 switched relative ranking as shown in Table 4-6 Similar to total load, the top four least cost scenarios, Scenario 1,2,5 and 6, are different by only 3% The risk curve (Figure 4-7) shows Scenario 5 as the least cost option after 2014 It should be noted that even though the incremental cost of compliance is less for native load, the CPWRR is less for total load. The incremental cost of compliance is higher for total load due to the fact that off-system sales volume and credit are reduced due to an increase in the dispatch price.

4.3 SO_2 Contingency Analysis

These sensitivity cases provide additional analysis of the total load cases In Table 4-8, compliance (lower sulfur) coal prices are adjusted to represent potential coal market price increases and decreases The risk curves for the high compliance coal prices (Figure 4-9) and the lower compliance coal prices (Figure 4-10) are included

As shown in Figures 4-9 and 4-10, lower compliance coal prices favor fuel blending, while higher compliance coal prices favor FGD retrofits (2 in Phase II) The lower price sensitivity makes Scenario 1 the least cost scenario If the higher price sensitivity were to occur, installation of the 1997 FGD is a better economic choice In the decision matrix both sensitivities were given equal weighting

Table 4 – 6

Tampa Electric Company
Phase I Compliance Plan Evaluation

Native Load

Scenario	Phase I Description	Phase I Emission Bank	Phase I Inc CPWRR (92 $000)	Phase I Rate Impact (%) 1995	1999	Phase I Relative Cost
1	Fuel Blend BB1–3 to Low Sulfur Coal (Avg Fuel Blend = 2.20 lb SO2 / Mmbtu)	19,676	82,755	2.22	2.29	1
2	Fuel Blend BB1–3 to Utah Coal (Avg Fuel Blend = 2.20 lb SO2 / Mmbtu)	20,052	100,909	2.69	2.77	3
3	Fuel Blend BB1–3 to Raton Basin Coal (Avg Fuel Blend = 2.20 lb SO2 / Mmbtu)	20,162	107,808	2.88	2.93	5
4	Fuel Blend BB1–3 to Gatliff Coal (Avg Fuel Blend = 2.30 lb SO2 / Mmbtu)	23,115	165,809	4.20	4.58	7
5	BB 3 FGD in 1995; BB 1–2 Fuel Blend to Low Sulfur Coal (Avg Fuel Blend = 3.20 lb SO2 / Mmbtu)	11,452	105,339	2.[illegible]7	2.64	4
6	BB 3 FGD in 1997; BB 1–2 Fuel Blend to Low Sulfur Coal (Avg Fuel Blend = 2.20 lb SO2 / Mmbtu 95–96 and 3.20 lb SO2 / Mmbtu 97–99)	14,277	100,029	2.28	2.86	2
7	BB 3 FGD in 1995; BB 1 FGD in 1997; BB 1–2 Fuel Blend to Low Sulfur Coal (Avg Fuel Blend = 3.20 lb SO2 / Mmbtu 95–96 and 4.66 lb SO2 / Mmbtu 97–99)	51,522	136,460	2.55	3.77	6

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NATIVE LOAD - RISK CURVES

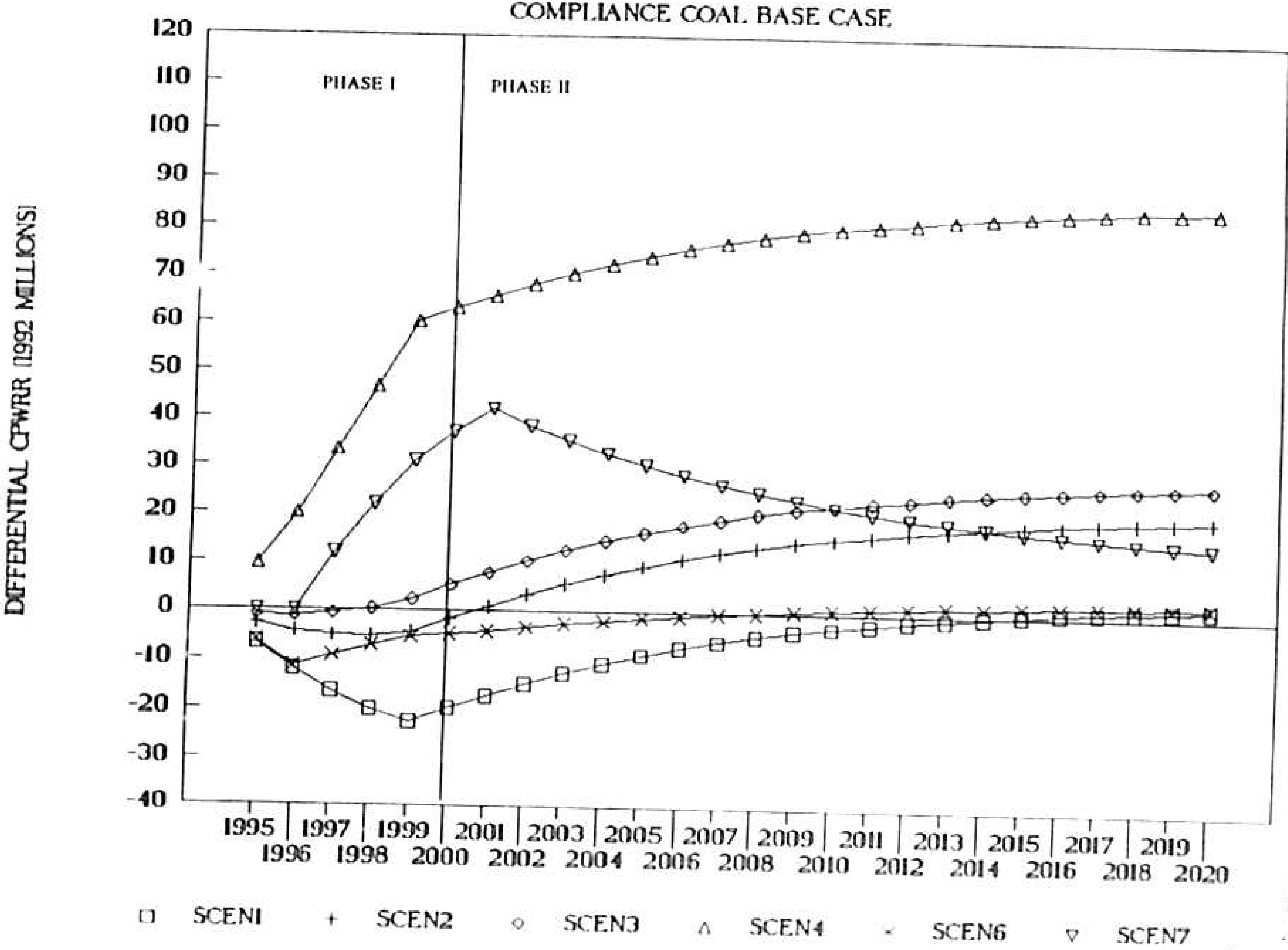

Table 4 – 8

Tampa Electric Company
Phase I Compliance Plan Evaluation

Total Load – Fuel Price Sensitivity

Scenario	Phase I Description	Phase I Emission Bank	High Price Forecast Phase I Inc CPWRR (92 $000)	High Price Forecast Relative Cost	Low Price Forecast Phase I Inc CPWRR (92 $000)	Low Price Forecast Relative Cost
1	Fuel Blend BB1–3 to Low Sulfur Coal (Avg Fuel Blend = 2.08 lb SO2 / Mmbtu)	12,802	140,454	3	76,222	1
2	Fuel Blend BB1–3 to Utah Coal (Avg Fuel Blend = 2.08 lb SO2 / Mmbtu)	14,681	122,513	1	97,668	2
3	Fuel Blend BB1–3 to Raton Basin Coal (Avg Fuel Blend = 2.08 lb SO2 / Mmbtu)	16,750	147,072	5	109,218	4
4	Fuel Blend BB1–3 to Gatliff Coal (Avg Fuel Blend = 2.20 lb SO2 / Mmbtu)	14,645	225,003	7	165,707	7
5	BB 3 FGD in 1995; BB 1–2 Fuel Blend to Low Sulfur Coal (Avg Fuel Blend = 2.92 lb SO2 / Mmbtu)	12,426	139,120	2	110,017	5
6	BB 3 FGD in 1997; BB 1–2 Fuel Blend to Low Sulfur Coal (Avg Fuel Blend = 2.20 lb SO2 / Mmbtu 95–96 and 2.80 lb SO2 / Mmbtu 97–99)	15,981	140,561	4	101,491	3
7	BB 3 FGD in 1995; BB 1 FGD in 1997; BB 1–2 Fuel Blend to Low Sulfur Coal (Avg Fuel Blend = 3.00 lb SO2 / Mmbtu 95–96 and 4.66 lb SO2 / Mmbtu 97–99)	30,043	145,638	6	137,716	6

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TOTAL LOAD - RISK CURVES

COMPLIANCE COAL - HIGH FUEL FORECAST

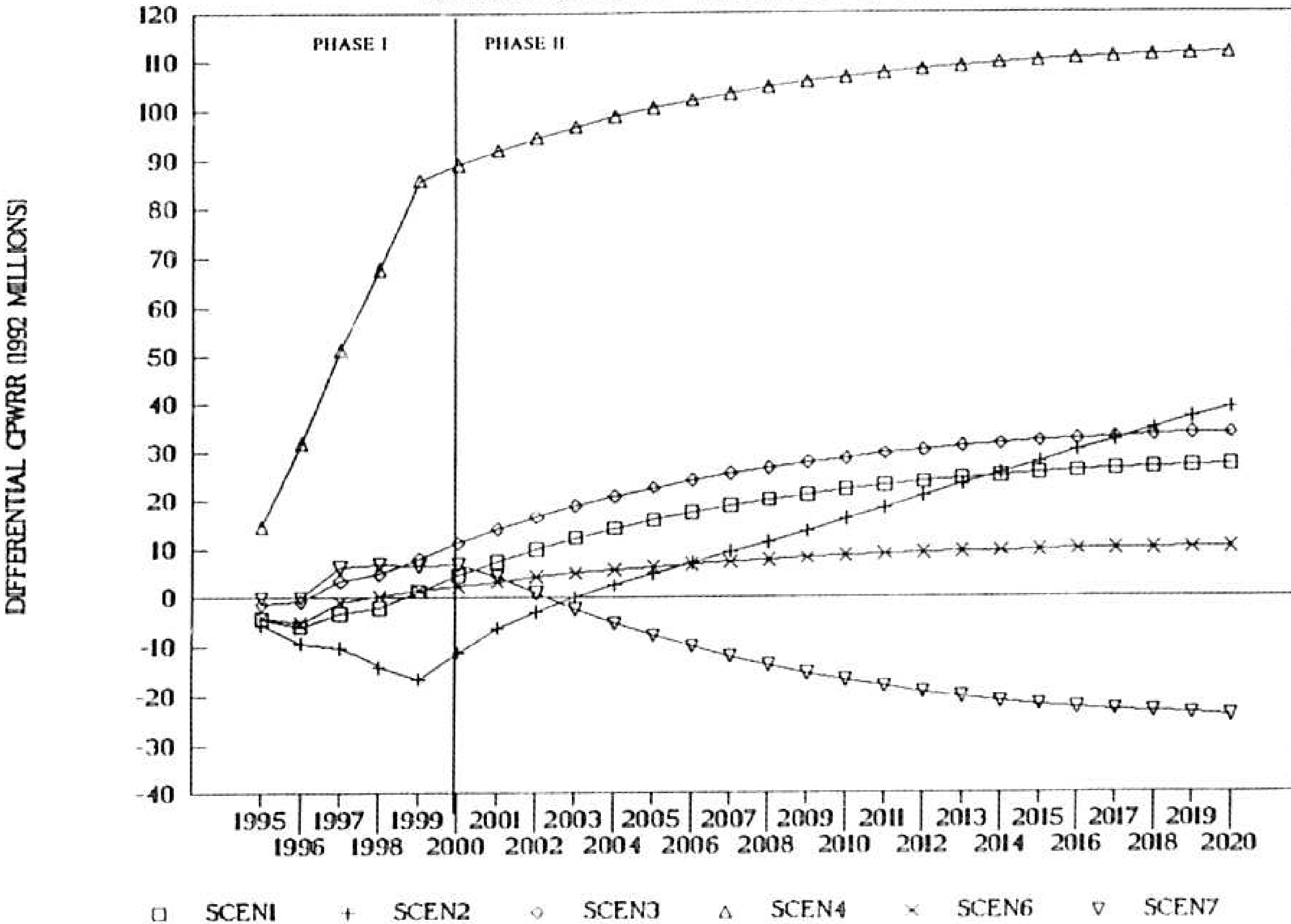
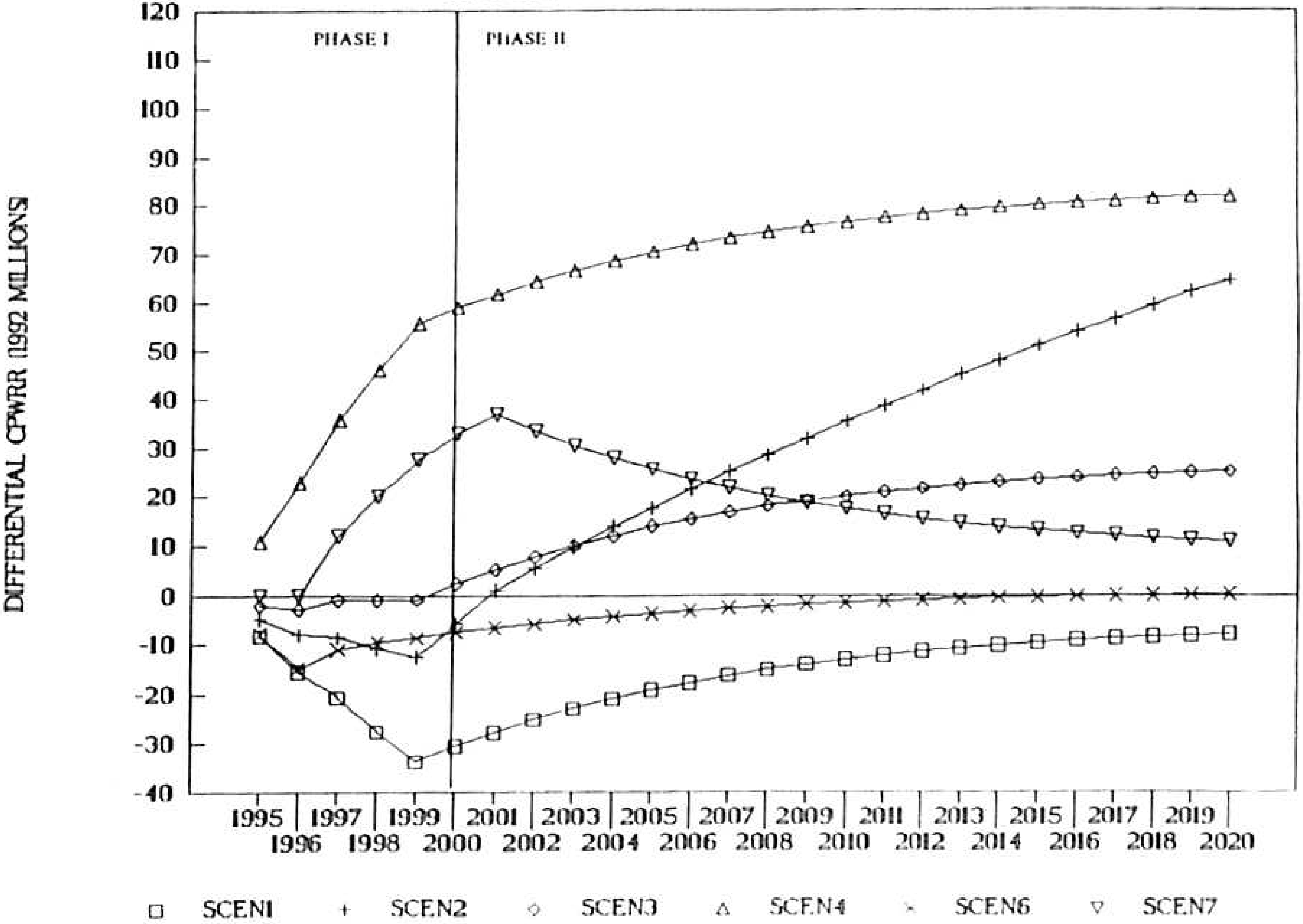


Figure 4 - 10

TOTAL LOAD - RISK CURVES

COMPLIANCE COAL LOW FUEL FORECAST



When bonus and extension allowances were included in the analysis as a sensitivity, the cost of the scenarios with an FGD prior to 1998 decreased by $8.5-$24 million over the 25-year study. Tampa Electric assumed in the analysis that the bonus and extension allowances would be internalized and would be used for compliance as they are received. Scenario 6 provides the least cost Phase I FGD alternative throughout most of Phase II but in Phase I, Scenario 1 is still the least cost scenario (Table 4-11). Based on the analysis, use of FGD in Phase I in order to capture bonus and extension allowances does not pay off until 2005 (Figure 4-12). The uncertainty of receiving these allowances and the pay off does not seem to be a prudent decision. This sensitivity was included in the decision matrix but with a low weight factor.

Table 4 - 11

Tampa Electric Company
Phase I Compliance Plan Evaluation

Total Load - Bonus Allowance Sensitivity

Scenario	Phase I Description	Phase I Emission Bank	Phase I Inc CPWRR (92 $000)	Phase I Relative Cost
1	Fuel Blend BB1-3 to Low Sulfur Coal (Avg Fuel Blend = 2.08 lb SO2 / Mmbtu)	12,802	91,132	1
2	Fuel Blend BB1-3 to Utah Coal (Avg Fuel Blend = 2.08 lb SO2 / Mmbtu)	14,681	103,649	3
3	Fuel Blend BB1-3 to Raton Basin Coal (Avg Fuel Blend = 2.08 lb SO2 / Mmbtu)	16,750	118,400	5
4	Fuel Blend BB1-3 to Gatliff Coal (Avg Fuel Blend = 2.20 lb SO2 / Mmbtu)	14,645	179,991	7
5	BB 3 FGD in 1995; BB 1-2 Fuel Blend to Low Sulfur Coal (Avg Fuel Blend = 3.25 lb SO2 / Mmbtu)	22,717	108,274	4
6	BB 3 FGD in 1997; BB 1-2 Fuel Blend to Low Sulfur Coal (Avg Fuel Blend = 2.95 lb SO2 / Mmbtu 95-96 and 2.80 lb SO2 / Mmbtu 97-99)	18,032	99,823	2
7	BB 3 FGD in 1995; BB 1 FGD in 1997; BB 1-2 Fuel Switch to Low Sulfur Coal (Avg Fuel Blend = 4.66 lb SO2 / Mmbtu 95-96 and 4.66 lb SO2 / Mmbtu 97-99)	61,473	124,964	6

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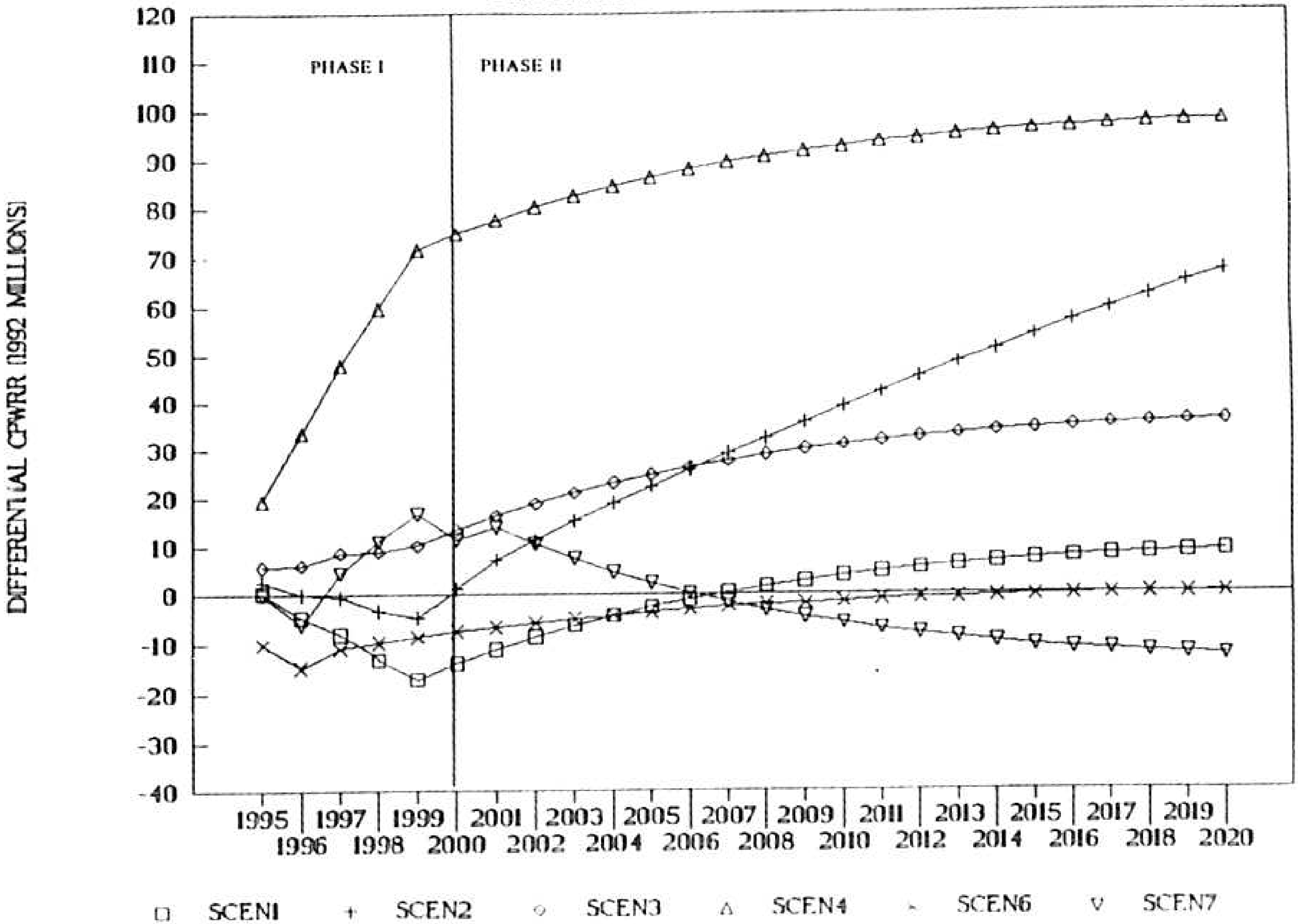
Fig 4 - 12

TOTAL LOAD - RISK CURVES

BONUS ALLOWANCE SENSITIVITY



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4.4 NO_x Compliance Alternatives

NO_x regulation has not been finalized for units with cyclone and/or wet bottom boilers, such as Big Bend Units 1-3. EPA is required to establish regulations and NO_x limits for these units by January 1, 1997. Therefore, Tampa Electric will not have to meet Phase I NO_x requirements. However, Tampa Electric is presently evaluating NO_x reduction technologies.

The NO_x reduction technologies which are presently approaching commercial viability for the Cyclone and Wet Bottom boilers in the Tampa Electric generating system are as follows:

- Selective Catalytic Reduction
- Non-Selective Catalytic Reduction
- Reburn

None of these technologies are presently considered commercially proven on high sulfur coal fired units. Testing of all of these technologies is underway at various utilities across the country both independently and in conjunction with EPRI sponsored research.

With respect to Big Bend 4, a CE tangential fired boiler, the CEM data for that unit indicates that it has averaged an emissions rate for NO_x of approximately 0.459 lb/MMBtu. This is very close to the emissions rate presently set in the CAAA of 0.45 lb/MMBtu and may be achievable through combustion tuning. Combustion tuning is a process by which certain operating variables, namely excess air quantity, burner tilt angles, overfire air port pitch and all angles, coal fineness, etc. are adjusted in an effort to modify the amount of NO_x formed during combustion. Tampa Electric is presently conducting its own study to determine the feasibility of meeting this emission rate through combustion tuning rather than the installation of low NO_x burners.

4.5. Compliance Alternative Considerations

4.5.A. Regulatory/Legislative Climate

Allowance Trading Regulations

The basis of the Acid Rain Program is the allowance trading system At the time of this study there was a great deal of uncertainty in the allowance trading market Major issues included 1) finalizing the EPA regulations that implement the program; 2) finalizing the FERC accounting standards; 3) obtaining a ruling from IRS on whether or not receipt of allowances from EPA is a taxable event, and 4) how each commission will provide for cost recovery for compliance expenditures Many of these issues still remain outstanding

It was expected that the price of allowances would be in excess of $400/ton which is greater than Tampa Electric's internalized Phase I cost of compliance Allowance prices have continued to drop but it is unknown if this trend will continue through Phase I The first EPA auction occurred in March 1993 The average price of allowances in Phase I was $156/ton There is still some activity in the allowance market but new issues continue to impede market activities The ratemaking treatment of SO_2 allowances needs to be resolved Allowance transfers can not be completed until the EPA Allowance Tracking System is operational

Tampa Electric will continue to evaluate the allowance market and will possibly use the purchase of allowances to minimize the use of lower sulfur coals and reduce overall compliance costs Therefore, Tampa Electric will implement a compliance plan which offers the greatest flexibility to demonstrate compliance with internal resources and be responsive to the allowance market if the economics are favorable Due to the reductions required for both existing and future growth in energy requirements, Tampa Electric is not expected to have an excess of allowances for sale.

Cost Recovery

It was expected that the cost recovery mechanism for fuel blending would be more flexible and dynamic than for the cost recovery associated with a FGD system. While it cannot be considered to be automatic, fuel cost can be recovered through the fuel adjustment clause. Currently, an environmental cost recovery clause docket is being discussed by the FPSC. A draft rule was prepared by Staff. This docket will answer questions as to what and how future compliance cost will be recovered. A hearing is scheduled to be held in December 1993. Prior to this docket, it was assumed that capital investment would be included in rate base for cost recovery. This would likely involve rate hearings that could put capital cost recovery at greater risk. A 1997 FGD system will be more desirable than one in 1995, so as not to overlap the Polk IGCC unit construction expenditure schedule.

The fuel cost associated with natural gas would be recovered through the fuel adjustment clause. The capital was expected to be included in rate base. The capital associated with the natural gas option is significantly lower than an FGD retrofit.

The pipeline was not accounted for in the cost analysis for switching to natural gas, but this cost will have to be recovered with an initial capital investment.

NO$_x$ & CO$_2$ Regulations

Title IV, the Acid Rain Program, sets limits on NOx emission rates for specific types of boilers (tangential and dry-bottom) For Phase I, cyclone and wet-bottom boilers (Big Bend 1-3) are not affected for NO_x EPA will promulgate regulations and limits for these units by January 1, 1997 However, these limits would not go into effect until Phase II

The legislation requires that limits be set based on the use of low NO_x burner technology However, this technology is not currently applicable for cyclone and wet-bottom boilers The CAAA requires that any EPA limits for cyclone and wet-bottom boilers need to be achieved at a cost comparable to installing low NO_x burners on tangential and dry-bottom boilers At this point, Big Bend 4, a tangential boiler, will be affected for NO_x in Phase II Depending on the economics, Tampa Electric may not need to comply with NO_x regulations which require reductions from current levels on any other boilers However, should cyclone and wet bottom boilers fall under more stringent NO_x regulations, fuel blending options may become less desirable Combustion modifications that may be needed to efficiently burn lower sulfur coals can also increase NO_x emissions

Several bills have been introduced in Congress that would lead to reductions in carbon dioxide (CO_2) emissions by utilities In addition, the international community is negotiating similar targets and timetables through the United Nations Several of these proposals require stabilization of CO_2 emissions at 1990 levels, by 2005 This could require about a 25 percent reduction in CO_2 emissions from all utility sources, considering new unit additions Reductions in CO_2 are typically accomplished by switching fuels If coal-fired units can switch to oil or gas, CO_2 can be reduced 28 percent and 44 percent, respectively

Blending current coal sources with low sulfur coal for CAAA compliance has no significant CO_2 response

Installation of FGD does increase CO_2 emissions in two ways. First, the dissolution of limestone (calcium carbonate) results in the release of CO_2. These CO_2 emissions are about 1.8 percent greater than a unit without FGD. Also, the station service requirements for a FGD system reduce the net generation by about 2 percent, which must be made up by additional generation (and burning of fossil fuel) at another unit. Therefore, the total increase in CO_2 emissions due to FGD is about 3.8 percent. In order to meet 1990 emission levels, reduction of this additional amount of CO_2 would have to be considered.

Two FGD systems in Phase I limits Tampa Electric's flexibility to respond to CO_2 regulations since this would require a continued commitment to burning coal on those units in order to fully utilize the FGD capital investment.

<u>Air Toxics</u>

As part of the requirements under Title III (Hazardous Air Pollutants) EPA is required to conduct two studies regarding emissions from electric utility steam generating facilities. EPA will then promulgate regulations based on the results of the studies if the Administrator determines that the action is "necessary and appropriate". The first study must focus on hazards to human health that result from the combustion process. This study was to be completed by November 1993, but will not likely be finished before 1995. The second study must examine mercury emissions, their effects on health and the environment, and the technologies for controlling these emissions. This study is required to be completed by November 1994.

Based on the results of these studies, reductions of emissions of mercury and/or other air toxics from electric generating facilities could be required. These emissions reductions may range from no additional reductions to significant reductions.

Compliance strategies based on fuel switching or blending could require the consideration of mercury concentration in coals. In addition, further particulate emission controls may be required (precipitators and/or baghouses), even on oil-fired units.

Compliance strategies using FGD should mitigate some of the mercury/air toxics concerns as recent experience shows that FGD may remove from forty to ninety percent of these emissions.

The World Health Organization has determined sulfuric acid mist to be a Class I carcinogen. This will prompt EPA to set utility SO_3 regulations. They will not need additional legislation to do so due to Class I determination. Any SO_3 or sulfuric acid mist regulations will be met more easily with a FGD system than fuel switching. Most of the proposed lower sulfur fuel switches actually require the injection of SO_3 to maintain precipitator performance.

<u>Water and Combustion By-Products</u>

Current practice for Tampa Electric is to produce a marketable by-product material from the combustion and/or flue gas clean up process. This practice minimizes on-site land use for storage and disposal as well as eliminating off-site disposal costs. Changes in characteristics of different types of coal sources may impact the marketability of the ash by-products. Lack of sufficient on-site disposal capacity would require costly off-site disposal of the ash. In the case of additional FGD, some additional on-site storage capacity may be required, but this by-product should remain marketable and not require off-site disposal.

The potential for disposal problems with the FGD by-products has been mitigated by two proactive opportunities that Tampa Electric has taken advantage of 1) The Big Bend 3 FGD proposal specified a forced oxidation system that will produce commercial grade by-product gypsum, and 2) Tampa Electric signed an agreement with a wallboard manufacturer for sale of all FGD by-product gypsum on a long-term basis, including gypsum from a potential Big Bend 3 FGD system

The use of FGD requires an adequate source of process water The need for using water from a potable water supply can be mitigated by the use of lower grade process water, such as plant recycle water and sewage treatment plant effluent, as is done on Big Bend 4

The treatment and/or disposal of wastewater streams from the use of FGD will require modifications and/or upgrades to existing water treatment facilities This, in turn, will require that new and/or modified environmental permits be obtained in order to construct and operate the FGD system

Blending existing coal sources with lower sulfur coals should not significantly impact current water use and/or disposal issues Switching to fuel sources other than coal should reduce current water use and/or disposal impacts Fuel blending to lower sulfur coals is a concern since there is a risk that the fly ash will be high in calcium and low in iron If the fly ash becomes difficult to market due to these undesirable characteristics, a by-product storage area would be required There is no potential problem with the fly ash from a unit with FGD since it will continue to burn the same coals that Tampa Electric currently uses

4.5.B. Operational Concerns

Generating Unit(s) Operations Upon Implementation

Fuel blending scenarios carry with them the risks associated with availability and suitability. Raton Basin and Indonesian coals are essentially single source coal supplies. Low fusion coals from Utah and the Eastern U.S., along with the Low Sulfur coal, are mined by a small number of operations. With such a limited number of suppliers, there is a possibility that demand could restrict availability and drive up prices.

The suitability of any of these coals also ties into their availability. There is the risk that only the highest cost coal is suitable for use at Big Bend Station. Only if several of these coals are suitable will availability stay high and costs stay competitive.

At the time this analysis was performed, the only lower sulfur coals tested at Big Bend station were Gatliff and Pocahontas. A preliminary test burn was done on the Indonesian coal. The summary of the test burns and results are included in Appendix B. Also included are future test burns. Gatliff coal has been burned at Big Bend with no problems. Fluxing is not necessary and there were no problems with slag tapping on the Big Bend units. There might be a potential problem with the ball mills and wet coal using Gatliff coal. The Pocahontas fuel burned well at Big Bend 2, however, there were some handling problems in the coal yard. The Indonesian coal may have some coal handling problems, however, these problems are manageable.

It should be noted that the lower sulfur coal used in Scenario 5-7 is the Low Sulfur coal. If a different fuel source was used in Scenario 5-7, the total CPWRR would have increased.

Blending with coals with very different characteristics than those presently used at Big Bend may result in higher capital costs in order to burn them They also pose the potential for higher operation and maintenance costs Coals which have similar characteristics to those already used at Big Bend pose a low probability of incurring the type of costs mentioned above They are not completely without risk, however, and may require some additional capital and increased operation and maintenance costs

The level of performance specified for the FGD systems (95% SO_2 removal efficiency and 98% availability) is well within the present day achieved levels There is therefore little risk associated with the levels of SO_2 reduction assumed in the study What risks remain are those associated with the temporary loss of the FGD system due to fire, major equipment failure, etc These risks do not threaten the generation of power but the amount of SO_2 reduction which can be achieved on a particular unit

Burning only natural gas in Big Bend 3 reduces coal handling and preparation expense as well as maintenance for boiler fireside deposits and reduced O&M expense for other auxiliaries Natural gas co-firing can potentially help with slagging and fouling problems Production Department expects that no additional personnel will be needed to operate two FGD systems at Big Bend

Technology Performance

There are approximately thirteen (13) new or advanced FGD processes under development or commercially available None are commercially proven however These systems do not appear to hold any cost advantages for Tampa Electric in the future due to either their heavy reliance on unproven by-product markets for their cost savings or due to site specific constraints There are a large number of innovative FGD processes being investigated which may hold cost savings for the future. However, all of these systems are so far from commercial availability that they will not be ready until well into Phase II Therefore, there is little risk that

Tampa Electric could miss technology advances with early application of an FGD system.

Tampa Electric is currently evaluating a Big Bend 3 integration with the Big Bend 4 FGD. This integration would significantly reduce capital cost and would maintain sulfur dioxide removal efficiency on Big Bend 4. No operation and maintenance or performance differences would be realized as compared to a Big Bend 3 retrofit. The earliest this integration could occur is 1999.

Fuel blending with coals that have not been tested or coals that are unlike existing coals burned at Big Bend have the potential of incurring additional but as yet unidentified problems.

System Compatibility

Tampa Electric's long term coal contracts carry the obligation to utilize coal supplied under contract if reasonably possible There is no obligation on Tampa Electric's part to install FGD in order to satisfy this requirement, but alternative sources of coal must be considered

Contracts with Consol and MAPCO both expire at the end of 1995 Both suppliers have alternate mine sources that might be utilized in fuel blending scenarios

Peabody's contract runs through the year 2004 Alternative low sulfur sources available to Peabody do not appear suitable for use at Big Bend Station Some fuel switching scenarios use insufficient high sulfur coal in blending to enter into such a contract with Peabody

Operating Experience

Tampa Electric has over seven years' experience with a FGD system Tampa Electric's knowledge and FGD operating expertise has resulted in a patent on FGD process modification Tampa Electric has also become very successful compared to other utilities in the marketing and sale of gypsum by-product Since Gatliff coal has been successfully transported, handled, and tested, it has the highest probability of long-term success There is no operating experience with burning only natural gas or co-firing with natural gas

Potential Cost

The FGD costs used for the study are based upon fixed price lump sum bids for the vast majority of the equipment and erection This minimizes the risk associated with potential cost overruns The prices received and under consideration are from bidders who were extremely anxious to receive a Phase I FGD contract (See Appendix C for more information on Tampa Electric's RFP) Their prices are believed to be well below market value Therefore, there is a risk that Tampa

Electric may not receive such favorable pricing in the future should the FGD option be rejected or delayed.

The Indonesian fuel source will require additional cost based on preliminary test burns. A new unloading system, modifications at Davant (the main coal transportation terminal for Tampa Electric), and new ball mills may be necessary. Flue gas conditioning units will be necessary in all scenarios in Phase I except 7 and 9. These costs were included in the analysis. Future coal contracts will have to be negotiated in all scenarios. Natural gas alternatives will require large capital investments prior to 1995 for pipelines, gas distribution systems, and new burners. There would be additional costs for a second FGD system in Phase I (Scenario 7) since no detailed engineering work has been done to prepare for it.

4.5.C Compliance Plan Flexibility

Implementation Schedule

A schedule was established in order to have a FGD system in-service in 1995. In order to meet a 1/1/95 FGD in-service, a contract had to be awarded no later than May 15, 1992 or else $3.5 million in additional cost would be incurred. Scenario 5 and 7 were less favorable than other scenarios since they required Tampa Electric to make a decision immediately without knowing all the results of the test burns or the allowance market. Scenario 6 allowed Tampa Electric time to review the test burns and evaluate the allowance market. The risk associated with Scenario 6 is whether the FGD suppliers will agree to set construction costs (with escalation). Fuel blending with Gatliff coal will work and obtaining the additional coal should not be a problem. Scenario 8 and 9 are a concern because Tampa Electric might not be able to build the pipeline in sufficient time or have sufficient capacity on the statewide FGT grid to assure 1995 compliance. Scenario 9 and 10 offer some flexibility because they allow Tampa Electric to burn three fuels (higher sulfur coal, lower sulfur coal and natural gas) depending on fuel and allowance markets However, permitting and operational restrictions could affect the actual flexibility

Unit vs System Specific

Units which are converted to gas or retrofitted with FGD will limit Tampa Electric's options due to the large capital investments required Fuel blending all three units at Big Bend gives Tampa Electric the flexibility to burn different blends in each boiler that may benefit certain unit operating characteristics

Two FGD systems force Tampa Electric to burn only one coal blend in the remaining unit If fuel blending with Gatliff coal is chosen, there might be a concern that Tampa Electric will have nine units that are dependent on the same fuel source

Allowance Market Sensitivity

The allowance market is very uncertain and therefore the best option was to position ourselves to take advantage of the developing market Fuel blending scenarios allow Tampa Electric the flexibility to evaluate the allowance market and reduce lower sulfur coal purchases if the cost of allowances are less than Tampa Electric's incremental cost of compliance Scenario 7 produces additional allowances that can be used in Phase II Scenario 6 allows Tampa Electric the option to look at how the market matures and react to it Scenario 9 also gives flexibility since several different fuel sources can be burned to adjust to the market

Response to Regulatory Requirement Changes

Fuel blending allows some flexibility to adjust to Regulatory Requirement changes unless mercury/air toxics are regulated. Natural gas options can allow units to burn natural gas or high sulfur coals. One FGD system takes away some of the responsiveness to gas. Two FGD systems take away almost all flexibility to switch to gas or low sulfur coals.

4.5.D. Public Perspective

Several groups such as the Department of Environmental Protection, Florida Public Service Commission, environmental groups, wholesale Customers, retail Customers, and the general public may have differing opinions of any alternative selected by Tampa Electric. Potential "non-American" fuel sources and FGD vendors may invite criticism. Adding two FGD systems in Phase I might lead to questions as to whether both can be justified. Some environmental groups prefer FGD and others do not. Generally, the retail Customers will want the least cost option.

The results of our economic analyses of the most feasible compliance scenarios show cost impacts of 3-5 percent for Phase I. This is considerably lower than the original 20 percent value estimated based on the initially proposed CAAA. While still a rate increase, we can show how prudent assessment of compliance decisions in the fuel and/or FGD markets has resulted in significant reduction in both SO_2 and cost. Compliance with this major legislation at a cost much lower than in other states will be a more positive issue for Customer opinion.

5. CONCLUSIONS

In developing the most cost effective alternative to comply with the statutory and environmental requirements associated with the Clean Air Act Amendments of 1990, Tampa Electric considered compliance costs as well as strategic concerns An initial screening analysis produced a manageable number of viable alternatives for detailed eco.. mic and strategic analyses A decision matrix was developed to determine the Relative Cost Index and Relative Risk Index for selected alternatives to facilitate both tabular and graphical comparisons

5.1 Decision Matrix

The decision matrix is an analytical tool for comparing and selecting an optimal plan from several alternatives Each alternative is ranked based on pre-determined criteria with assigned weighting factors A composite score or index is calculated for each alternative by multiplying the assigned ranking by the appropriate weighting factor for the criteria and summing the values for each category The combined scores indicate the relative strength of each alternative on both a quantitative and qualitative basis The quantitative analysis is based on comparing the cumulative present worth of the revenue requirements for each alternative The qualitative analysis considers several key strategic issues and how each alternative would affect Tampa Electric's position upon implementation

5.1.A Weight Factors

The weight factors are assigned by the evaluation team to establish the relative importance of the criteria in determining the most cost effective alternative The team based the weighting factors on a 100 point scale and assigned 65 points for the economic analysis and 35 points for strategic considerations (Table 5-1) A higher weighting was assigned for the economic analysis since the compliance costs are based on detailed engineering studies while the strategic considerations are based on judgment and perception The assigned weighting factors within the economic category indicate an emphasis on Phase I costs and less emphasis on potential bonus allowances associated with FGD alternatives

5.1.B Relative Ranking

The relative ranking of each alternative is determined by the evaluation team for each criteria based on a seven point scale. A rank of 1 indicates the most favorable or preferred alternative and a rank of 7 indicates the least favorable alternative. Values between 1 and 7 are used to identify significant differences among the alternatives. A forced distribution for the ranking is not used since there are key criteria that are required for a comprehensive analysis but may not reflect significant differences among the alternatives. In this situation the relative ranking may be within a smaller range of values.

Supplemental worksheets were developed to facilitate the ranking of the strategic considerations. The worksheets identify supporting issues for each sub-category that enabled the team to assign the weight factors and the relative ranking of each alternative.

5.2 Relative Cost vs. Relative Risk Index

The decision matrix enabled the team to evaluate each alternative on a quantitative and qualitative basis. The composite score for each category determines the Relative Cost Index and Relative Risk Index. These two dimensionless indices are then graphically compared for each alternative in Table 5-2. The graph indicates that Alternative 1 offers the most cost effective compliance plan for Tampa Electric.

Tampa Electric Company
Phase I Compliance Strategy Evaluation
SO2 Compliance Alternatives

Ranking Criteria	Most Favorable - - > / Least Favorable - - >	Weight Factor	Scenario 1	Scenario 2	Scenario 3	Scenario 4	Scenario 5	Scenario 6	Scenario 7	Scenario 8	Scenario 9	Scenario 10
CPWRR BASIS												
Total load	Phase I	15	1	2	4	6	4	3	5	7	6	2
	Phase II	10	1	5	4	6	1	2	2	7	6	7
Native load	Phase I	10	1	2	4	6	3	2	5	7	6	2
	Phase II	5	1	3	4	6	1	1	2	7	6	7
Higher Price Compliance Coal		10	3	3	4	6	2	2	1	5	5	5
Lower Price Compliance Coal		10	1	5	3	6	2	2	3	5	5	5
Bonus Allowances		5	3	5	4	6	2	2	1	5	5	5
SUBTOTAL		65	95	220	250	390	155	140	200	405	365	280
STRATEGIC CONSIDERATIONS												
Regulatory/Legislative Climate		9	4	6	5	7	6	4	7	2	1	3
Operational Concerns		8	5	6	5	4	2	3	2	5	7	5
Plan Flexibility		10	3	3	3	3	5	4	7	6	6	4
Public Perspective		8	3	5	4	6	3	3	3	5	5	4
SUBTOTAL		35	130	172	147	173	144	124	173	158	165	139
TOTAL SCORE		100	225	392	397	563	299	264	373	563	530	419
RELATIVE RANK			1	4	4	7	3	2	4	7	6	5

Tampa Electric Company
Phase I Compliance Strategy Evaluation
SO2 Compliance Alternatives

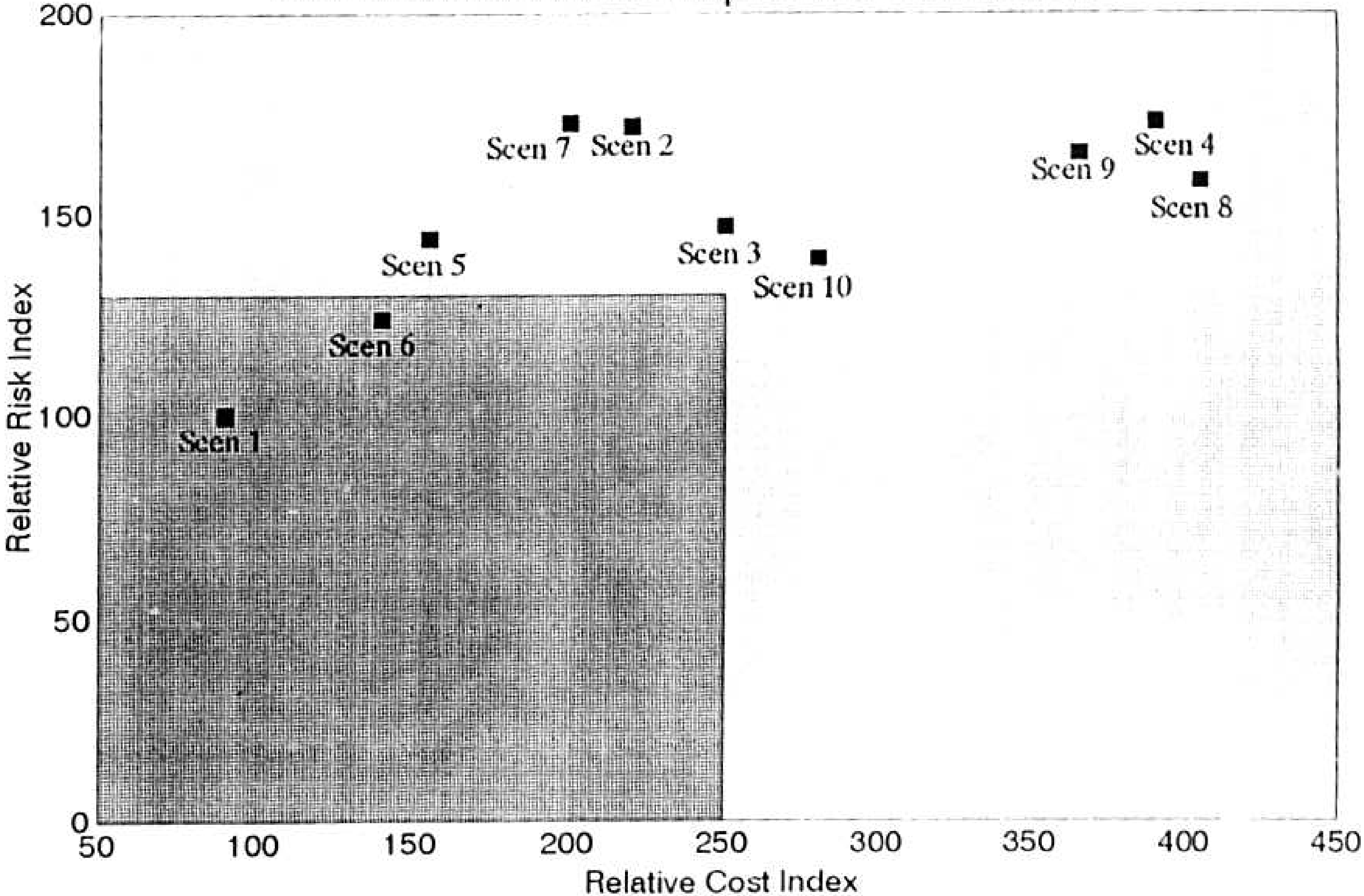
Strategic Considerations Worksheet

Ranking Criteria	Most Favorable -> 1 Least Favorable -> 7	Weight Factor	Scenario 1	Scenario 2	Scenario 3	Scenario 4	Scenario 5	Scenario 6	Scenario 7	Scenario 8	Scenario 9	Scenario 10
REGULATORY/LEGISLATIVE CLIMATE			4	6	5	7	6	4	7	2	1	3
Allowance Trading Regulation		10	3	3	3	4	5	4	6	1	1	2
Cost Recovery		25	2	3	3	5	5	4	7	4	4	3
NOx & CO2 Regulations		20	4	4	4	4	5	5	6	2	1	3
Air Toxics		25	6	6	6	6	3	3	2	1	1	3
Water & Combustion By-Products		20	4	5	4	4	4	4	4	2	1	3
SUBTOTAL		100	390	435	415	475	430	395	485	215	175	290
OPERATIONAL CONCERNS			5	6	5	4	2	3	2	5	7	5
Generating Unit(s) Operations Upon Implementation		25	4	5	4	3	2	3	2	4	6	5
Technology Performance		15	3	5	4	3	2	2	2	4	6	5
System Compatibility		20	3	5	4	3	2	2	2	6	7	5
Operating Experience		15	4	5	4	3	2	3	2	6	7	5
Potential Costs		25	5	6	5	4	2	2	2	3	4	3
SUBTOTAL		100	390	525	425	325	200	240	200	445	585	450
PLAN FLEXIBILITY			3	3	3	3	5	4	7	6	6	4
Implementation Schedule		25	2	2	2	1	6	3	6	7	7	3
Unit vs System Specific		15	3	3	3	3	4	4	5	4	4	3
Allowance Market Sensitivity		20	3	3	3	4	2	1	7	3	3	4
Response to Regulatory Requirement Changes		15	3	3	3	3	5	4	7	5	6	4
SUBTOTAL		75	200	200	200	195	325	215	470	370	385	260

Figure 5-2

Tampa Electric Company

SO2 Emissions Compliance Scenarios



5.3 Recommendation of Appropriate Compliance Plan

Tampa Electric conducted a comprehensive evaluation of viable alternatives to comply with the sulfur dioxide limitations of Title IV of the Clean Air Act Amendments of 1990. The most cost effective scenario that provides the most flexibility for Phase I compliance is fuel blending Low Sulfur coal with the existing standard West Kentucky coal on Big Bend 1-3. This scenario allows Tampa Electric the ability to react to changes in both Phase I and II. The blend of Low Sulfur coal with standard West Kentucky coal can be adjusted based on changes in load, the allowance market and our generating system. It allows Tampa Electric time to determine how future developments in the CAAA will impact our system and to continue to make cost effective decisions.

5.4 Compliance Plan Implementation Schedule

Tampa Electric is currently negotiating Low Sulfur coal contracts for the period 1995-1999 and is continuing to test burn coals for Phase II. Tampa Electric is continuing to evaluate the allowance market to determine if the incremental cost of compliance is below the market price. This will enable Tampa Electric to lower the total cost of compliance. The Big Bend 1-3 CEMS have been installed, certified, and are operational. Tampa Electric will continue to evaluate Phase II SO_2 compliance options, NO_x regulations and limits and NOx compliance technologies.

APPENDIX A

Table A – 1

TAMPA ELECTRIC COMPANY

PHASE I COMPLIANCE PLAN EVALUATION

Demand and Energy Forecast

Summer Peak Demand							Winter Peak Demand							Net Energy for Load			
System		Wholesale	Retail				System		Wholesale	Retail				System		Wholesale	Retail
Year	Total System Load (MW)	Sebring Load (MW)	Total Retail Load (MW)	Interruptible Load (MW)	Load Mgmt. (MW)	Firm Load (MW)	Year	Total System Load (MW)	Sebring Load (MW)	Total Retail Load (MW)	Interruptible Load (MW)	Load Mgmt. (MW)	Firm Load (MW)	Year	Net Energy for Load (GWH)	Net Energy for Load (GWH)	Net Energy for Load (GWH)
1993	2,812	45	2,767	228	88	2,496	1992/93	3,140	59	3,081	210	210	2,720	1993	13,996	184	13,812
1994	2,879	47	2,832	224	93	2,562	1993/94	3,217	62	3,155	207	222	2,788	1994	14,326	190	14,136
1995	2,953	48	2,905	224	99	2,630	1994/95	3,298	64	3,234	206	234	2,858	1995	14,724	195	14,529
1996	3,023	49	2,974	220	104	2,699	1995/96	3,376	65	3,311	202	246	2,928	1996	15,089	200	14,889
1997	3,096	51	3,045	216	109	2,771	1996/97	3,455	67	3,388	199	258	2,998	1997	15,469	205	15,264
1998	3,167	52	3,115	211	114	2,842	1997/98	3,534	69	3,465	195	270	3,069	1998	15,849	210	15,639
1999	3,239	53	3,186	207	119	2,913	1998/99	3,617	72	3,545	191	282	3,144	1999	16,234	215	16,019
2000	3,316	55	3,261	206	125	2,985	1999/00	3,699	74	3,625	189	294	3,216	2000	16,654	220	16,434
2001	3,388	56	3,332	202	129	3,057	2000/01	3,779	76	3,703	186	304	3,289	2001	17,058	226	16,832
(1993-01) AAGR	2.4%	2.8%	2.3%			2.6%		2.3%	3.2%	2.3%			2.4%		2.5%	2.6%	2.5%

DAEFCST.WK1 (CAAC-001) 10/26/93

Table A - 2

TAMPA ELECTRIC COMPANY
PHASE I COMPLIANCE PLAN EVALUATION
Load Management and Conservation Forecast

Summer			Winter			Energy	
Year	Load Management (MW)	Conservation (MW)	Year	Load Management (MW)	Conservation (MW)	Year	Conservation & Load Management (GWH)
1993	88	41	1992/93	210	268	1993	190
1994	93	45	1993/94	222	292	1994	206
1995	99	50	1994/95	234	322	1995	223
1996	104	52	1995/96	246	348	1996	237
1997	109	54	1996/97	258	378	1997	253
1998	114	58	1997/98	270	412	1998	266
1999	119	59	1998/99	282	447	1999	282
2000	125	61	1999/00	294	485	2000	297
2001	129	61	2000/01	304	525	2001	312
(93-01) AAGR	4.9%	5.1%		4.7%	8.8%		6.4%

TMECST.WK1 (CAAC 001) 10/19/93

Table A - 3

TAMPA ELECTRIC COMPANY
PHASE I COMPLIANCE PLAN EVALUATION
Cogeneration Forecast

	Winter Peak Demand – MW				Summer Peak Demand – MW			Energy – GWH		
Year	Firm Purchases	Net	Total	Year	Firm Purchases	Net	Total	Purchases	Net	Total
1992/93	39	317	355	1993	39	317	355	323	2,154	2,476
1993/94	51	323	373	1994	51	323	373	419	2,196	2,615
1994/95	51	322	372	1995	51	322	372	419	2,181	2,600
1995/96	51	325	375	1996	51	325	375	420	2,208	2,628
1996/97	51	328	378	1997	51	328	378	419	2,223	2,642
1997/98	51	331	381	1998	51	331	381	419	2,244	2,663
1998/99	51	334	384	1999	51	334	384	419	2,265	2,684
1999/00	51	331	381	2000	51	331	381	420	2,260	2,680
2000/01	51	334	384	2001	51	334	384	419	2,275	2,694

COGFCST.WK1 (CAAC-001) 10/25/93

* Total may not add due to rounding.

Table A – 4

TAMPA ELECTRIC COMPANY
PHASE I COMPLIANCE PLAN EVALUATION
Existing Generating Facilities
As of October 1, 1992 and Beyond

Plant	Unit No.	Location	Type	Fuel Primary	Fuel Alt.	Fuel Transportation Primary	Fuel Transportation Alt.	Commercial In-Service (Mo/Yr)	Net Capability Summer (MW)	Net Capability Winter (MW)
									1,187	1,189
GANNON	1	Hills. County	FS	C	NO	WA	RR	09/57	119	119
	2	4/30S/19E	FS	C	NO	WA	RR	11/58	119	119
	3		FS	C	NO	WA	RR	10/60	160	160
	4		FS	C	NO	WA	RR	11/63	184	184
	5		FS	C	NO	WA	RR	11/65	227	227
	6		FS	C	NO	WA	RR	10/67	363	363
CT	1		CT	LO	NO	WA	NO	03/69	15	17
									213	213
HOOKERS POINT	1	Hills. County	FS	HO	NO	WA	NO	07/48	34	34
	2	19/29S/19E	FS	HO	NO	WA	NO	06/50	34	34
	3		FS	HO	NO	WA	NO	08/50	34	34
	4		FS	HO	NO	WA	NO	10/53	43	43
	5		FS	HO	NO	WA	NO	05/55	68	68
									1,825	1,875
BIG BEND	1	Hills. County	FS	C	NO	WA	NO	10/70	406	406
	2	9/31S/19E	FS	C	NO	WA	NO	04/73	407	416
	3		FS	C	NO	WA	NO	05/76	426	430
	4		FS	C	NO	WA	NO	02/85	441	446
CT	1		CT	LO	NO	WA	NO	02/69	15	17
CT	2		CT	LO	NO	WA	NO	11/74	65	80
CT	3		CT	LO	NO	WA	NO	11/74	65	80
									51	52
DINNER LAKE	1	Highlands Co.	FS	NG	HO	PL	TK	12/66	11	12
PHILLIPS	1	Highlands Co.	D	HO	NO	TK	NO	06/83	18.5	18.5
	2		D	HO	NO	TK	NO	06/83	18.5	18.5
HRSG	3		HRSG	WH	NO	NO	NO	06/83	3	3
								SYSTEM TOTAL	3,276	3,329

Table A – 5

TAMPA ELECTRIC COMPANY
PHASE I COMPLIANCE PLAN EVALUATION
Existing Generation Facilities
Availability and Heat Rate

Unit		Phase I Average Availability (Including Planned Maintenance) (%)	Annual Average * Heat Rate (Btu/KWh)
GANNON	1	84.30	10,910
	2	84.20	11,190
	3	69.50	10,920
	4	76.00	10,541
	5	75.30	10,050
	6	84.10	10,047
	CT 1	61.77	21,370
HOOKERS POINT	1	72.69	12,993
	2	72.69	12,948
	3	72.69	13,113
	4	72.69	15,908
	5	72.69	13,390
BIG BEND	1	79.36	9,946
	2	79.50	9,990
	3	80.06	9,605
	4	80.78	9,929
	CT 1	61.77	21,371
	CT 2	66.77	15,709
	CT 3	66.77	15,731
DINNER LAKE		74.35	16,856
PHILLIPS	1	76.69	10,539
	2	76.69	10,539
POLK	CT	92.30	12,271

AVHR.WK1 (CAAC–001) 10/25/93

* The annual average heat rate is for the year 1995.

Table A – 6

TAMPA ELECTRIC COMPANY
PHASE I COMPLIANCE PLAN EVALUATION
Expansion Plan

Year	Expansion Plan
1995	ACT
1996	HRSG/CG
1997	--
1998	--
1999	CT
2000	CT
2001	HRSG
2002	CT
2003	CT/HRSG
2004	CT
2005	CT
2006	CT
2007	CT
2008	--
2009	CT
2010	CT
2011	--

EXPLAN WK1 (CAAC-001) 10/19/93

ACT Advanced Combustion Turbine

CT Combustion Turbine

HRSG Heat Recovery Steam Generator/Steam Turbine

CG Coal Gasifier

Table A – 7

TAMPA ELECTRIC COMPANY
PHASE I COMPLIANCE PLAN EVALUATION
Current Fuel Sources Supplemental Fuel Prices

Year	Price Per Unit (¢/MMBtu)								
	Big Bend 1–3	Big Bend 4	Gannon 1–4	Gannon 5–6	Polk 1	#6 Oil L.S.	#6 Oil H.S.	#2 Oil	Natural Gas
1993	149.68	143.79	215.62	215.19	154.31	348.06	365.52	529.73	307.51
1994	158.97	151.57	227.15	226.71	163.67	404.96	428.92	595.68	371.91
1995	165.05	160.41	235.49	235.03	170.32	483.66	516.04	669.46	433.24
1996	171.41	165.10	244.06	243.58	176.98	497.03	531.12	691.50	446.94
1997	178.59	171.41	253.86	253.37	184.48	529.87	566.68	737.72	476.95
1998	186.06	178.59	263.65	263.14	192.18	564.34	603.94	786.27	517.03
1999	193.86	186.06	274.18	273.65	200.48	601.64	644.39	838.83	552.42
2000	202.41	193.86	285.69	285.14	209.90	643.27	689.40	897.51	596.46
2001	212.05	202.41	297.33	296.75	220.35	689.12	738.83	962.14	652.40

SUPPFUEL.WK1 (CAAC-001) 10/19/93

APPENDIX B

THE EVALUATION OF COAL SUPPLY OPTIONS FOR CLEAN AIR ACT AMENDMENT OF 1990 COMPLIANCE

A SUPPLEMENT TO

TAMPA ELECTRIC COMPANY

CLEAN AIR ACT AMENDMENT OF 1990

COMPLIANCE PLAN EVALUATION - PHASE I

INTRODUCTION

Since the passage of the Clean Air Act Amendment in October 1990, Tampa Electric has been heavily involved in the process of evaluating options for achieving compliance with the new law. The evaluation process has involved many different departments at Tampa Electric. It has been dynamic, constantly evolving and changing as the various options are developed in scope and refined in detail. After an extensive analysis, it was decided in August of 1992 that blending existing coal sources with low sulfur coal was the most cost effective alternative for compliance. This fuel blending would be implemented at Big Bend 1-3 only and a sulfur level of 2.2 lb of SO_2 or less would need to be met.

With that as a given, this report deals with Tampa Electric's efforts to develop a fuel blending strategy that will take into account all the factors involved in the transition to a low sulfur coal compliance plan. The report is an effort to commit to writing, the thoughts and reasons for the decisions that eventually led Tampa Electric to the place it is today in the development of this plan.

General Guidelines/Constraints to the Fuel Strategy

In the development of a fuel blending strategy, many parameters influenced the decisions made which limited the alternatives available. An explanation of the critical parameters are listed and explained below.

1. Tonnage Needed

   It was determined that the tonnage needed for Phase I compliance only would be sought. The Phase II constraints of even lower SO_2 emissions coupled with several other possible emission limits of NO_x, etc., made the planning for Phase II compliance appear to be different and therefore may require a different strategy. The Phase I time frame extends from 1/1/95 through 12/31/99 inclusive.

The projected amount of BTU's for these three units is 7.816 x 10 to the 13th power BTU's for 1995, which is divided approximately evenly between the three units. Assuming an average heat content of 12,000 BTU per pound coal, total tonnage needed is approximately 1.1 million tons per unit. This will be approximately the same for the 1995 through 1999 time frame with slight variances due to outage schedules, etc. (needs for the units are specified in BTU's due to large variation in heat content of the coals to be considered).

In summary, the tonnage needed will be approximately 3.3 MTPY of a 12,000 BTU/lb coal or equivalent BTU total through the 1995 through 1999 time frame inclusive.

2. <u>Existing Long Term Contracts</u>

Tampa Electric currently has several coal contracts for Big Bend 1-3 which extend into the 1995 through 1999 time frame. These contracts are for high-sulfur West Kentucky type coal. The contract requirements are as follows:

COMPANY	MINE	SEAM	LBS SO_2	EXPIRES	TONNAGE
Consol	Humphrey	Pitts #8	4.25	12/31/95	450,000
Mapco	Dotiki	W. KY #8	4.47	12/31/95	450,000
Peabody	IC/Pyro	W. KY #9	4.75	12/31/04	750,000

The total burn for Big Bend 1-3 for 1992 was 3.276 million tons. These three contracts were 50% of the total burn of 1992 and will be 49% of the projected burn of 1995. After 1995 the Peabody contract will account for 23% of total burn. These contracts will greatly affect how much low sulfur coal can be bought and also how low the sulfur must be. (i.e. if Tampa Electric buys, 2.0 lb/SO_2 coal, no high sulfur coal can be bought). If Tampa Electric buys 1.0 lb SO_2 coal, only 966,000 tons of high sulfur coal can be bought. Therefore the resolution of the contracts will be required in order to determine the low sulfur tonnage requirements.

In summary, low sulfur needs will be somewhere between 1.7 and 3.3 MTPY depending on the resolutions of the high sulfur long term contracts.

3. Number of required Low Sulfur suppliers

Knowing that Tampa Electric will need between 1.7 and 3.3 MTPY, the question arises as to how many suppliers should this tonnage be divided between. Since there are no guidelines specifically addressing this issue, Tampa Electric will use its own general guidelines as to what it considers best at this time. First, not all the tonnage should come from one supplier because we would not want the entire fuel blending strategy to be dependent on one company or on one mine. Also, we would not want to be dependent upon one coal region of the U.S. or one foreign country for similar reasons. If there was a strike or a natural disaster, etc. that affected an area, we would want to have other replacements available in other coal producing regions. Therefore, we want to have low sulfur coal coming in from a minimum of two different areas of the country or world, each with a minimum of two similar suppliers in each area.

The similar suppliers would also be necessary if Tampa Electric is to have competitive bid proposals solicited in each area to ensure Tampa Electric is getting the best price possible.

Finally, Tampa Electric has decided on approximate contract size limits. A contract should not be for more than 1.5 MTPY (to allow room for more than one supplier). Also, no contract should be for less than 250,000 TPY (not feasible to do test burn for less tonnage).

Concerning the maximum number of suppliers possible, Tampa Electric is constrained by the inventory limitations of the coal yard at the Big Bend station. Ideally, Big Bend would like to have one large stockpile of all the same type of coal. This would provide the maximum inventory possible for the coal yard space available. As the coal yard is divided into individual stockpiles, the total amount of coal that can be stockpiled on-site becomes less, due to space needed between the piles and the angle of repose for the coal. Big Bend has been maintaining four individual piles which fill the coal yard. One pile is the coal for

Big Bend 4 which will need to be kept separate The other three piles are for Big Bend 1-3 and are for coals of varying sulfur content Recently Big Bend decreased the size of two piles and made an area to stockpile test burn coals This increased the number of individual stockpiles in the yard to five Big Bend felt that this was the maximum number of piles possible while maintaining an adequate inventory and a manageable y_ d

After the onset of Phase I, Big Bend will be required to maintain a separate stockpile for Big Bend 4 (a scrubbed unit burning mostly high sulfur Illinois #6 coal). Also, it appears Big Bend will continue to burn some amount of high sulfur West Kentucky type coal This will allow for a maximum of three other stockpile areas available for different low sulfur coals It appears that the coals which will eventually be used in the plan will have vastly different characteristics

Tampa Electric would like to maintain control of the blending of the various coals on-site at Big Bend At Big Bend, the coals from the coal yard are fed individually into blending bins which then feed coal into the plant The blending bins allow for the precise blending of up to four different coals simultaneously By doing the blending on-site, Tampa Electric retains the ability and maximum flexibility to control SO_2 emissions and maintain operational control of the blends If a coal changed (i.e. increase in ash, moisture, and fusion), the yard can adjust blends quickly and therefore avert possible problems in the units Therefore, at the present time, we will consider only individual piles of very similar coals at the Big Bend plant

In summary, Tampa Electric is looking for a minimum of two low sulfur coal supplies and a maximum of three They should be from different coal producing regions and have a minimum of two suppliers in each area to provide bidding opportunities

4. Coal Type

The various coals of the world can be generally ranked into four categories, namely:

		Approx. BTU Range
1.)	Lignite	4,000 - 8,300
2.)	Sub-bituminous	8,300 - 11,500
3.)	Bituminous	10,500 - 15,000
4.)	Anthracite	15,000 +

Big Bend 1-3 burn bituminous coals with heating values in the 11,000 to 13,000 BTU per pound range. Lignites are not considered as a viable fuel source for Tampa Electric due to the low BTU content. Anthracite comprises less than 2% of the total United States coal reserves and would be very expensive. Therefore, only the sub-bituminous and bituminous coals of the world were considered.

5. Availability of Coal

Developing a compliance strategy based on the burning of low sulfur coals, the coals to be considered have to be available not only during the five (5) years of Phase I (1995-1999) in the quantities needed, but also in the 1992 through 1994 time frame in limited quantities to allow for test burns. Test burns are required for any major purchases of coal different than those already being burned. Therefore, companies that do not have existing production available for sale of a coal were not considered. Also, the mine(s) must have production capacity available for sale during the 1995-1999 time frame of at least 250,000 tons per year and up to 1.5 million tons per year.

In summary, only existing coal mines with coal available for sale in the quantities Tampa Electric needs were considered.

6. Specifications for the coal(s)

The units affected, namely Big Bend 1-3 have the following specifications.

Big Bend Units	Gross Rating	Type	Initial Operation
1	420 MW	PC - wet bottom	October 1970
2	420 MW	PC - wet bottom	April 1973
3	435 MW	PC - wet bottom	May 1976

Big Bend 1-3 have been operating for over sixteen (16) years Tampa Electric during that time has gathered a lot of operating experience on what coal specifications are needed to have the units operate properly These coal specifications, listed below, are also used in the coal bid solicitations for Big Bend standard coal for spot coal purchases

("As Received" quality)		Big Bend Specification
Moisture (%)	Maximum	10
Ash (%)	Maximum	9
Lb Ash/MMBtu*	Maximum	7 6
Volatile (%)	Nominal	30
Fixed Carbon (%)	Nominal	40
BTU/lb	Minimum	1,500
Sulfur (%)	Maximum	2 9
Lb So_2/MMBtu	Maximum	4 7
Chlorine Content (%)	Maximum	0 25
Hardgrove Grindability Index	Range	50-60
Ash Fusion Temp (°F)		
(reducing atmosphere)		
Softening (H=W)		2050-2300
T-250 (°F)		2275-2475

Size (inches)***	Range	2 X 0

* lb ASH/MMBtu= $\frac{\%ASH \times 10{,}000}{BTU/LB}$

** lb SO_2/MMBtu= $\frac{\%S \times 19{,}000}{BTU/LB}$

*** **Size and Percentage Range**

Size Range	Percentage Range
2" x 1¼"	10% to 25%
1¼" x ¼"	40% to 80%
¼" x 0"	10% to 45%

The one exception to the above specifications is the sulfur which must be less than 2.0 lb SO_2. In fact, the sulfur level will probably need to be much lower (i.e. 1.0 lb SO_2 coal allows Tampa Electric to burn only 960,000 tons of the high sulfur coal now under contract in 1995 or Tampa Electric would need 1.26 lb SO_2 coal to burn all the 750,000 tons under the Peabody contract in the 1996 through 1999 time frame).

Also critical to the analysis is the ash mineral analysis. The ash mineral analysis lists the compounds and the percentage of each compound that comprises the ash in the boiler as the coal is burned. The characteristics of each of these compounds and the interactions between compounds dictates how the ash behaves in the boilers. Some of the critical factors of the ash for Big Bend are:

1. Melting temperature of the ash (H=W 2050 to 2300°F)
2. Viscosity of the molten ash (T-250 of 2275°- 2475°F)
3. Slagging index (low or medium)
4. Fouling index (low or medium)

The last important consideration is the salability of the ash. Tampa Electric presently sells its bottom ash and fly ash as by-products to industrial customers. This ability to sell the ash is critical, because by doing so, we avoid expensive disposal costs We also avoid the long term liability of building and owning the refuse disposal site Therefore, the ash must meet the following criteria to ensure is marketability

Flyash - CaO content less than 10%
- Fe_2O_3 content greater than 10%
- L.O.I. below 7%

Bottom ash - black color - glassy
- not friable - no fines
- size consist (50% greater than 14 mesh)

Coals that do not meet the specifications by a small amount were evaluated on a case-by-case basis to determine if the problem(s) were insurmountable

One method of overcoming a problem with meeting coal specifications is to make capital improvements Though there are not a lot of things a utility can do to change a unit's operating characteristics, there are some capital improvements or modifications that can help in some areas (i e a harder grind coal can be compensated for by adding additional pulverizer capacity or wall blowers could be installed to compensate for a coal that has a tendency to cause slagging problems) Generally, these solutions are costly and the results are not guaranteed. Time and capital constraints also make this generally not a good alternative

A second method of overcoming a problem with the coal specification criteria is to blend coals, though the final results are not always predictable Test burns are required to ensure the results are acceptable

In summary, the units require coals that meet a tight band of criteria for proper operation Minor deviations from these specifications can be solved through capital modifications, which generally tend to be expensive, or by blending, which must be proven in test burns

Once the general guidelines and constraints were established, we reviewed the currently available low fusion, low sulfur coals that met Big Bend's criteria and also the general guidelines and constraints The search was conducted on a state by state basis In the effort to identify the desired coals that were available over 650 mines were evaluated representing all the coal producing regions of the continental United States These 650 mines represents all the mines known by Tampa Electric to exist in the United States as of the beginning of 1991

Compliance Coal Test Burn Committee

A committee was formed for the purpose of planning the low sulfur test burns It was comprised of individuals from the Big Bend station, Production Services, Production Engineering and the Fuels Department Meetings were held regularly on a 3-4 week interval during the time of the short term test burns and occasionally during the long term test burn The meetings generally consisted of each department reporting on the status of their work for the test burn Also discussed was each departments' responsibilities for the succeeding test burns

Overall, the committee was charged with the task of executing the Tampa Electric philosophy of a test burn program

1 Short term tests of coals to initially demonstrate compatibility, followed by long term tests of the best coals to demonstrate complete technical acceptability

2 Due to operating requirements that all units be fully operational at maximum capacity during high load seasons, test burns can only be scheduled during off peak periods of the year These off peak periods are for several months during the spring and fall season

3 Tampa Electric was time constrained in its ability to test burn coals (To be burning a coal on 1-1-95 would require Tampa Electric to start receiving shipments by the 3rd quarter of 1994 This is to allow time to buildup acceptable stockpile levels of the new coal) To be receiving coal in the 3rd quarter of 1994, Tampa Electric should have a contract in place by the 1st quarter of 1994 This is to allow time for the supplier to get ready to ship on these new contracts To

have new contracts in place by the 1st quarter of 94, would probably require 6 months of negotiating time. Therefore, contract negotiating would start in the 3rd quarter of 1993. Since the long term test burns will take approximately three months each and can only be done one at a time during certain months of the spring and fall seasons, the start of the long term test burn must begin no later than mid-1992. This means that seven short term test burns are all we can get in by mid-1992.

4 The test burns were evaluated on a technical basis initially. This was later combined with an economic (cost) assessment for a final score for each coal being considered.

Foreign Coal

Big Bend station's location on the water in central Florida allows for the possibility of a foreign coal supply option. Developments in this area have been and will continue to be monitored. Tampa Electric has also done several test burns over the last fifteen years of foreign coal which appeared feasible based on their specifications. Test burns have been conducted on coal from Poland, South Africa, and Australia. These test burns, which occurred at either the Gannon or Big Bend plants or both, had bad results.

During the last several years, there have been new coal developments in the countries of Columbia, Venezuela, and Indonesia. Tampa Electric has evaluated these options and decided to test burn coal from Indonesia. This was due to its compatibility with most of the Big Bend specs, but also because of several unique characteristics, namely a 0.1% sulfur level and an average ash content of 1.0%.

Overall, the foreign coal option will have a small role, if any at all, in Tampa Electric fuel blending strategy. Tampa Electric does not feel that it would be prudent to have a major part of the fuel blending plan totally dependent on foreign supply due to the reliability risk associated with situations involving political unrest, etc., which supplies from a foreign country might be subjected Tampa Electric will, instead, concentrate on coal supplies available within the continental United States

U S Coal

The United States has many geographical areas underlain with various qualities of coal To simplify the explanation of the various regions, a map of the United States (see Map no 1) was divided into eight geographical areas of similar coal types

1 Appalachian Coal Area - Area No 1

The Appalachian Coal area underlies or is parallel to most of the Appalachian mountains extending from northwestern Pennsylvania to central Alabama This area is one of the largest and most productive coal regions The coals are bituminous is grade and vary in the amount of sulfur The area has hundreds of mines varying in size from under 10,000 tons per year to multi-million ton per year operations

Two coals were picked from this area as test burn candidates The first was a Blue Gem seam coal from southeastern Kentucky The second was a Pocahontas #3 seam coal from western Virginia (explanation of test burn results included in next section)

2 Gulf Coast Lignite Province - Area II

This area extends from the Texas-Mexico border to the southern part of Alabama The coal occurs primarily as lignite with average as received values of approximately 7,000 BTU Only one mine was found with values above 8,000 BTU The mine is located near the Texas-Mexico border and had an HGI value of 28-30, which is unacceptably hard

No coals were picked for test burns from this region

3. Illinois Basin - Area III

The Illinois Basin covers Illinois, part of Indiana and extends into western Kentucky. The coals are bituminous in rank with a high sulfur content normal from 3% to 5%. A few areas have been found with sulfur values below 2.5% but unfortunately, the fusion temperatures are marginal at best.

One coal was picked from this area as a test burn candidate. The coal is an Illinois #6 seam mine located in south central Illinois.

4. Western Interior Region - Area IV

The Western Interior Region covers parts of Iowa, Missouri, Kansas, and Oklahoma and extends into Arkansas. The coals are bituminous in rank. The lower sulfur seams are generally thin and therefore very expensive. Also they are difficult to transport due to transportation constraints.

No coals were picked for test burns from this area.

5. Powder River Basin - Area V

The Power River Basin is located in the northeast quadrant of Wyoming and extends into southeastern Montana. It is one of the largest and most productive basins in the western U.S. with coal seams of 100 feet in thickness. The coals are sub-bituminous in rank and consistent in quality. Coal quality is approximately 29% moisture, 6% ash, 0.5% sulfur and 8,500 BTU's. The mines in the basin are very large and highly productive.

Major problems with the Powder River Basin coals are the high moisture (29%) and low BTU's (8,500). Also the ash mineral analysis shows a high Sodium Oxide content (1.5%), a high Calcium Oxide content (23%) and a low T-250 (2,190°).

The beneficiated PRB coals were also explained The benefication process generally lowers the moisture from 29% to a 2-10% range and raises the BTU's from 8,500 to a 11,000 - 12,000 BTU range In some coals the volatiles are lowered The ash mineral analysis stays the same as the original coal

Tampa Electric had been interested in doing a test burn of a beneficiated PRB coal Several companies which had demonstration plants under construction were contacted for estimated dates of start up These dates were either too late to be considered or kept slipping until it became too late to try a test burn At that point a PRB coal was test burned instead

One coal was picked from this area for a test burn The coal was from a mine located south of Gillette Wyoming in the Roland seam

6 Green River/Hanna Basin Region - Area VI

This region covers the southern half of Wyoming and extends into northern Colorado The majority of the coal is sub-bituminous in rank but the operating mines are generally in the bituminous areas The quality of the operating mines averages 9,500 to 11,000 BTU, sulfur values, though below 2 0 lb SO_2, average higher than similar coals in other areas

Moisture tends to be high for bituminous coal, averaging 13-18% Also coals tend to have either a high Calcium Oxide content (15-25%) or high T-250 temperatures

No coals were picked from this region for a test burn

7. Unita Basin - Area VII

The Unita Basin extends from west central Colorado into and through central Utah. The coal is bituminous in rank. The BTU values are between 11,000 and 12,500 and the sulfur content is low with values generally between 0.7 and 1.0 lb SO_2.

The coals of the Book Cliffs region of the Unita Basin tend to have above spec fusion and T-250 temperatures. The remaining coals of the Unita Basin are located in the Wasatch Plateau and are lower fusion coals having fairly high Calcium Oxide of 15-20%.

One coal was chosen from this area for test burning. It was from a mine in the Wasatch Plateau operating in the Lower O'Conner seam.

8. Black Mesa/San Juan Basin - Area VIII

The Black Mesa Field is located in the northeast corner of Arizona and the San Juan Basin in on the northwest quadrant of New Mexico. The coal rank is predominately sub-bituminous. The BTU's are generally between 8,000 - 10,800.

Existing mines have either high ash values (14-27%) or are located away from existing railroads. The bituminous coals are thin, discontinuous and generally remote with a long truck-haul (plus 75 miles) to the nearest rail line.

No coal was picked from this area for a test burn.

9. Raton Basin - Area IX

The Raton Basin is a relatively small basin located in northern New Mexico and southern Colorado. The coal is bituminous in rank. Quality is good with a washed product averaging 6% moisture, 10% ash, 0.5% sulfur and 12,500 BTU.

There are only two significant operating coal mines in the basin The ash fusion and T-250 temperatures of these coals are slightly higher (than Tampa Electric's desired specs)

One coal was picked for a test burn from this area The mine is located in southern Colorado and is mining the Maxwell seam

Short Term Test Burns

As mentioned previously, Tampa Electric considers the test burning of any coal supply essential before it can be considered as a potential fuel source Even though the Big Bend fuel specifications give a good indication that a fuel will burn successfully in the boilers, they are not always successful in predicting the behavior and characteristics of the slag in the boilers This can severely effect the acceptability of the fuel Tampa Electric selected six low-sulfur coals from various regions of the U.S and one foreign low-sulfur coal Coals were selected from each region (and from the coals in the region) which Tampa Electric felt had the best chance of successfully completing a test burn and therefore potentially becoming a viable fuel supply source

The test burns were planned to be of a short duration (approximately 2 weeks in length) The best two or three coals, assuming that many burned successfully, would then be scheduled for a long term test burn of 8-12 week duration The purpose of the short term test burn was to do a brief intensive evaluation in order to quickly screen out coals that had major problems without risking inventories of coal which may not be usable The long term test burns would then give a complete picture under a long term burning scenario

Since it is assumed that we will be burning some amount of the high sulfur coal (approximate 4 66 lb SO_2) from western Kentucky under the existing long term contracts, each test burn coal was blended with this high sulfur coal The blend percentage of test coal for each test burn was adjusted to an approximately 2.2 lb SO_2 blend, unless other test burn coal characteristics prevented the unit from operating at that blend percentage

Tampa Electric designated Big Bend Unit 2 for doing the short term test burns. A flue gas conditioning system was installed on this unit to help the electrostatic precipitator operate during burning of the low sulfur coal. The first short term test burn was conducted in late 1990 and the seventh was completed in early 1992.

Each test burn has a detailed report written to document and expla.. the procedures used and the results obtained. This report provides a brief explanation of the results of each test burn.

Test Burns

Objective

The objective of the test burn program at Big Bend Station was to identify coals that could be used to meet the Phase I requirements of the Clean Air Act Amendment of 1990 and also satisfy generation needs. Accomplishing this objective involved three steps.

1. A laboratory analysis was performed on each candidate coal. Major concerns were ash fusion temperatures, heating value, sulfur content, and ash content.

2. Those coals deemed satisfactory were test burned in one of the Big Bend units for a period of approximately two weeks. This particular time period was chosen because it allowed for an initial screening without committing to a large supply of coal. This procedure was not adopted until the third test burn since the first two coals were deemed to be very low risk to reliable plant operations.

3. Those coals which passed the two week screening period were subjected to a longer test burn period, typically in the neighborhood of 60 days. This permitted a longer observation period in order to judge the coal's suitability for Phase I compliance.

In order to meet Phase I requirements for sulfur dioxide emissions as well as meeting generation needs, coals containing an average 2.2 lb SO_2/MMBtu were required. This was achieved by blending the test coal with coal currently used at Big Bend Station.

The following table summarizes all test burns conducted at Big Bend Station. The variability in the blend ratio is due to variability of the sulfur content of the test coals. Those coals containing less sulfur required less blending.

Summary of Test Burns at Big Bend Station							
		Blend Ratio					
Test Coal	Units	% Test Coal	% Existing Coal	From	To	Tons (test coal)	Results
Pocahontas	2	50	50	10/01/90	03/18/90	90,071	Unsatisfactory
Gatliff		100	100	04/16/91	05/04/91	54,464	Satisfactory
Indonesian	2	50	50	01/29/92	02/06/92	24,243	Satisfactory
Wyoming	2	60	40	02/17/92	02/26/92	23,527	Satisfactory
Wyoming	3	60	40	08/28/92	09/29/92	69,806	Satisfactory
Wyoming	2	60	40	10/23/92	11/23/92	56,880	Satisfactory
Utah	2	65	35	03/18/92	03/31/92	31,696	2nd test required
Utah	2	65	35	05/17/93	06/26/93	81,120	Unsatisfactory
Utah	3	65	35	06/25/93	06/26/93	4,160	Unsatisfactory
Utah	3	65	35	08/06/93	08/11/93	6,240	Unsatisfactory
Utah	1	75	25	06/02/93	06/16/93	31,200	Unsatisfactory
Rend Lake	2	100	100	05/06/92	05/15/92	47,810	Unsatisfactory
Rend Lake	2	25	75	04/24/93	05/03/93	20,985	Unsatisfactory
PRB	2	25	75	06/10/92	06/15/92	12,181	Unsatisfactory

Pocahontas

The coal came from the Virginia Pocahontas mine located in Virginia and was purchased from Island Creek Coal Company. The extremely friable nature of the coal produced severe material handling problems, both in the coal yard as well as the fuel ductwork within the plant.

Because of the friable nature of the coal, it consisted of mostly fine material. Excess fine material is undesirable because of the large amount of surface afforded for moisture absorption. Wet, fine material is prone to caking out in ductwork which leads to pluggage in the ductwork. This occurred several times during the test burn. One such occurrence required 12 hours to remove the pluggage. During this time, capacity was restricted by approximately 100 MW due to the unavailability of the affected equipment.

This coal was also a problem in the coal yard. The large percentage of fines caused the coal to behave like a fluid. Thus, it would tend to flow away from the stockpile. This was aggravated by typical afternoon rain showers. Following each rain storm, the coal had to be retrieved from the drainage ditches surrounding the coal yard.

Gatliff

This coal came from eastern Kentucky and was supplied by TECO Coal. With the exception of an increase in unburned carbon losses, performance of the coal was acceptable. Compared to other coals used at Big Bend Station, Gatliff coal is harder, making it more difficult to grind. This manifests itself in a deterioration in coal fineness, of which the immediate impact is an increase in the unburned carbon content of the fly ash. Whereas 5% inburned carbon in the flyash is typical for the coals normally used at Big Bend Station, 8% was typical during the Gatliff test burn. It is important to maintain low unburned carbon content in the fly ash, as this directly impacts fly ash marketability.

Indonesian

This coal came from the island of Borneo and was purchased from P. T. Adaro of Indonesia. Performance of the coal was satisfactory. Characteristically, this coal has a low heating value in the neighborhood of 8,800 Btu/pound. This limits the amount that can be used because of the need to achieve a composite product with a heating value of at least 11,200 Btu/pound necessary for rated mill capacity. Blending this coal to a 2.2 lb SO_2/MMBtu product with no capacity restriction was possible for Big Bend 1 and 2. However, because of Big Bend 3's higher generating capacity, blending to 2.2 lb SO_2/MMBtu would result in a capacity reduction of approximately 30 MW.

Wyoming

This coal came from the Golden Eagle Mine, located in Trinidad, Colorado, and was purchased from Basin Resources, Inc. This coal did exhibit a slightly higher than normal slagging tendency which can be dealt with through changes in boiler operating procedures. Overall, this coal was satisfactory.

Utah

This coal came from the Skyline Mine and was purchased from Coastal Corporation. A decision on the suitability of this coal was deferred after the first test burn because of some unrelated equipment problems, making the outcome unclear. However, after extended use afforded by the second test burn, it became clear that the coal was unsatisfactory due to its excessive slagging nature.

Rend Lake

This coal came from the Rend Lake Mine and was purchased from Consol Coal Company. This test burn was deemed unsuitable due to excessive slagging. Based on the guidelines established for the qualification program, the second test burn would not have been undertaken based on the poor results of the first test burn. It was only because of the belief that the failure of the first test burn may have been due to ash incompatibility between the Rend Lake and blend coal (25% component) that a second test was attempted. The second test burn was done using 100% Rend Lake coal. Unfortunately, the experience of the first test burn was repeated.

Powder River Basin

This coal came from the Rochelle Mine located near Bill, Wyoming and was purchased from Peabody Holding Company. Almost immediately upon introduction of this coal into the boiler, performance deteriorated to the point where the unit capability was limited to 335 MW (gross), representing a 100 MW restriction. The coal was judged as unsatisfactory.

Comparison of Short Term Test Burns

At the completion of the seven short term test burns, it appeared that five of the seven coals burned successfully. Since Tampa Electric desired to only test up to three coals on an extended basis, a method of determining the best three was needed. This was solved through the use of ranking charts.

1. Ranking Chart (technical)

   A technical ranking chart (see chart No. 1) was developed by Tampa Electric in order to objectively compare the coals. The chart was based upon a list of factors which covered the important concerns of a coal for all departments. The factors were weighted based on each factors' overall importance. These factors and their corresponding weight percentages were developed by the Compliance Coal Test Burn Committee. The committee, after developing the chart, then ranked each coal from 1 to 5 (5 being the best) for each factor on the chart. In the Coal Supply part of the chart, the coals were compared to each other. In the Boiler Operations and By Products areas, the coals were ranked against how the plant personnel felt a successful coal should perform.

2. Ranking Chart (Cost)

   A second chart (see chart No. 2) was set up to rank fuel costs. The total delivered cost of each coal was calculated on a cents per million BTU basis. A ranking index was assigned with the highest costs coal being 1 and the lowest being 5.

3. Final Ranking

   The results of the technical and cost rankings were than combined on a weighted basis, the cost factor at 40% and the technical factor at 60%. The combination of these indexes became the grand total score for each coal. The coals were then ranked 1 to 7, based on the results (see chart No. 2).

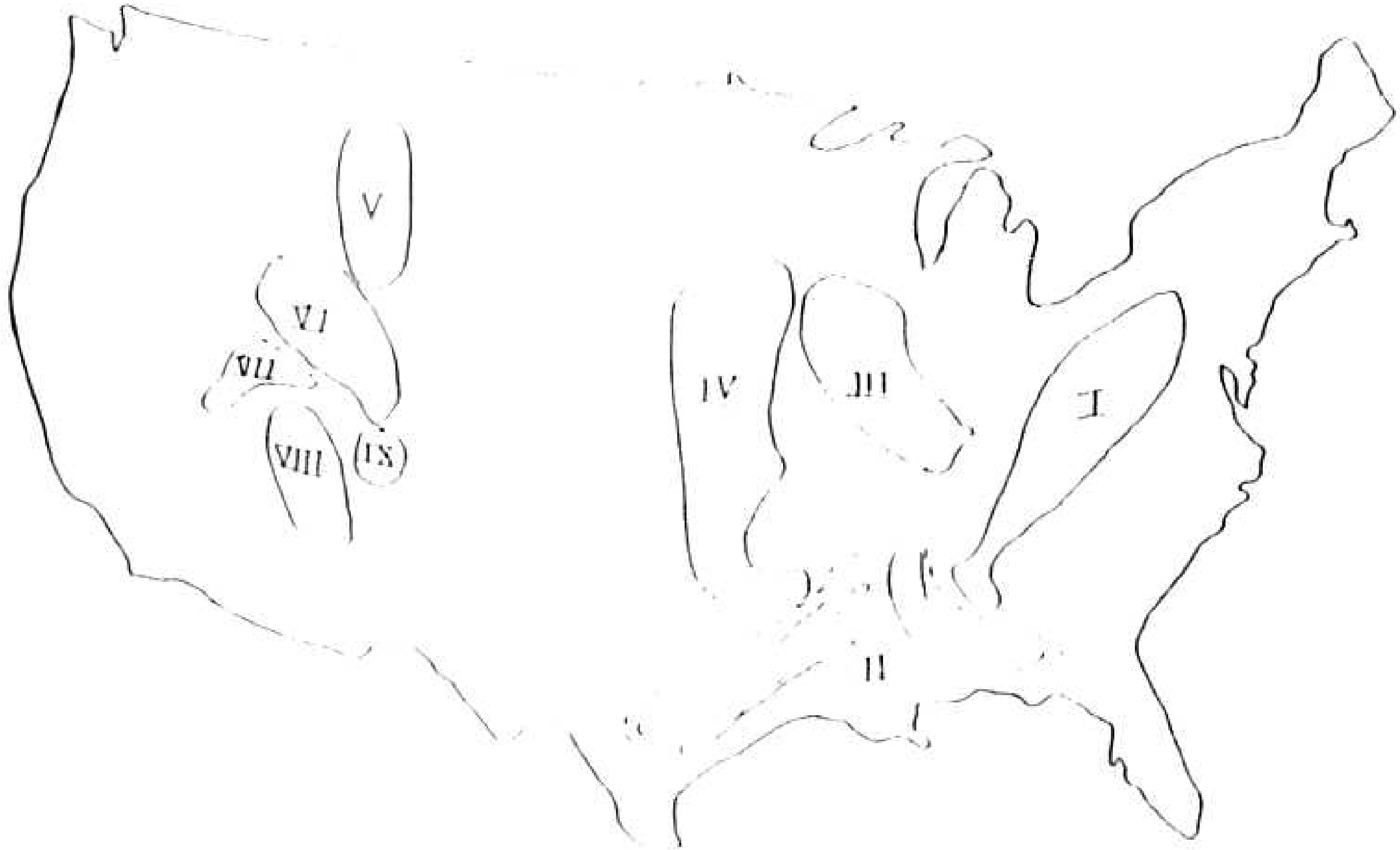
Existing Long Term Contract Disposition

Tampa Electric is negotiating with its long term contract suppliers concerning the disposition of their high sulfur contracts for the 1995 time frame and beyond Tampa Electric needs to reduce the contracted high sulfur tonnage on the basis of being unable to burn this much high sulfur coal and still meet the 2.2 lb SO_2 limit.

Summary

Tampa Electric's strategy for complying with the Phase I requirements of the CAA Amendment centers on fuel blending Big Bend 1-3 to coal blends averaging less than 2.2 lb SO_2 per MMBtu The blends will be a combination of high sulfur Western Kentucky coal blended with low fusion very low (<1.0 lb SO_2) sulfur coals A minimum of two and a maximum of three contracts with low sulfur suppliers from different geographic regions are planned The new low sulfur coals will complete successful short and long term test burns Next Tampa Electric will solicit coal supply proposals from similar coal suppliers in each region to ensure the best prices possible

U.S. COAL FIELDS



MAP NO. 1

COST & FINAL RANKING OF CANDIDATE COALS

		Pocahontas	Galltll	Utah	Raton Basin	Indonesian	Rend Lake	Powder Rive
1992 DELIVERED FUEL PRICE C/MMBTU		235.57	234.86	180.14	175.58	167.28	147.14	152.33
COST RANKING		1.00	1.03	3.28	3.47	3.81	4.64	4.42
TECHNICAL RANKING		2.86	3.17	3.52	4.20	3.06	2.93	2.22
COST WEIGHTING FACTOR	40.0%	0.40	0.41	1.31	1.39	1.52	1.86	1.77
TECHNICAL WEIGHTING FACTOR	60.0%	1.71	1.90	2.11	2.52	1.84	1.76	1.33
GRAND TOTAL SCORING		2.11	2.31	3.42	3.91	3.36	3.61	3.10
FINAL RANKING		7	6	3	1	4	2	5

TECHNICAL RANKING OF CANDIDATE COALS

FACTOR	WT %	Pocahontas RANKING	Gatliff RANKING	Utah RANKING	Raton Basin RANKING	Indonesian RANKING	Rend Lake RANKING	Powder River RANKING
COAL SUPPLY (Weight: 30%)								
Reliability of Supply	10.5%	2	3	3	3	3	4	5
Competitiveness of Fuel & Transportation	9.0%	2	1	3	4	4	5	5
Handling Properties (Fines, Long-term Storage, Moisture, Chute Pluggage)	10.5%	2	3	5	5	1	4	2
Subtotal	30.0%	0.60	0.72	1.11	1.20	0.78	1.29	1.19
BOILER OPERATIONS (Weight: 50%)								
Processing (HGI, Low Btu, etc.)	12.5%	4	4.5	5	5	3	1	1
Tapping	5.0%	5	5	5	5	5	5	5
Slagging	12.5%	5	5	5	5	5	1	1
Fouling (Upper Furnace and Back Pass)	10.0%	–	–	–	–	–	–	–
Precipitator Performance	10.0%	4	4	3	5	5	4	4
Subtotal	50.0%	1.78	1.84	1.80	2.00	1.75	0.90	0.90
BY-PRODUCTS (Weight: 20%)								
Flyash Marketability	13.0%	1	2	2	5	3	3	1
Slag Marketability	7.0%	5	5	5	5	2	5	–
Subtotal	20.0%	0.48	0.61	0.61	1.00	0.53	0.74	0.13
Total Score	100.0%	2.86	3.17	3.52	4.20	3.06	[illegible]	2.22
Technical Ranking		6	3	2	1	4	5	7

HWS92 - I coalfact wk3

APPENDIX C

APPENDIX C

FCD REQUEST FOR PROPOSAL

In order to obtain accurate FGD cost information for our compliance planning and to maintain a viable Phase I FGD compliance option Tampa Electric initiated an engineering effort to secure bids for an FGD system to retrofit to Big Bend 3 Tampa Electric issued a Request for Proposal (RFP) for Architect/Engineering Services in February 1991 to a short list of five bidders Proposals were received from the following

United Engineers & Constructors
Stone & Webster Engineering Corporation
EBASCO Inc.
Gilbert & Associates
Sargent & Lundy

Stone & Webster Engineering Corp. was selected as the lowest evaluated cost supplier of engineering services Radian Corporation was also retained to act as a special FGD consultant and to aid in the preparation of specific process related sections of the specification They were also responsible for assisting Tampa Electric in the evaluation of A/E's with respect to their FGD experience and to review the process related portions of the FGD vendors proposals

Conceptual engineering and a specification were completed for a Retrofit FGD system Tampa Electric issued an RFP for a wet limestone, forced oxidized, commercial grade gypsum FGD system in September 1991 Bids were sought from a short list of five FGD suppliers The vendor and the type of wet limestone system bid were as follows

General Electric Environmental Services Inc	(Open spray tower type)
Riley Stoker Corp.	(Open spray tower type)
Asea Brown Bovarei	(Open spray tower type)
Pure Air	(Cocurrent packed tower type)
Noell Inc	(Double-loop counter current packed tower type)

The bids were received from all five bidders on November 13, 1991 The proposals were evaluated by Tampa Electric, Radian Corporation (FGD consultant), and Stone & Webster Engineering Corp. (Architect/Engineer). The lowest evaluated cost proposal was then used in our compliance planning for further analysis of the FGD compliance option versus other methods of compliance

TAMPA ELECTRIC COMPANY

CAAA PHASE II COMPLIANCE

May 1998

Table of Contents

EXECUTIVE SUMMARY

Tampa Electric Company is an investor-owned electric utility which serves retail customers in Hillsborough and portions of Polk, Pinellas and Pasco Counties. Currently, Tampa Electric Company serves nearly 525,000 residential, commercial, industrial and public authority Customers within its service area. Tampa Electric Company's system has an installed net electric generating capacity of 3,629 MW and 23 generating units located at six different sites: Big Bend, Gannon, Hookers Point, Phillips, Dinner Lake and Polk.

The Acid Rain Program of the Clean Air Act Amendments of 1990 (CAAA), set as its primary goal the reduction of annual SO2 emissions by 10 million tons below 1980 levels. To achieve these reductions, the law requires a two-phase program which reduces the allowable SO2 emissions from fossil fuel-fired power plants. Phase I of the program began on January 1, 1995 and continues through December 31, 1999.

Phase II of the program begins on January 1, 2000 and further reduces annual SO2 emissions from Phase I plants. Phase II also sets restrictions on smaller plants fired by coal, oil and gas encompassing over 2,000 units in all. The program affects existing fossil fueled utility generating units with an output capacity greater than 25 MW and all new utility units. Units on Tampa Electric's system affected by Phase I are Big Bend Units 1, 2 and 3. Big Bend Unit 4 was designated as a substitution unit by Tampa Electric in Phase I SO2 compliance. Phase II SO2 compliance affects Big Bend, Gannon and Polk coal units as well as Hookers Point and future fossil fueled generating units. Phillips Station, Dinner Lake and existing combustion turbines are not affected.

This document presents the results of a multi-departmental evaluation of potential control options for Tampa Electric to comply with SO2 emission regulations for Phase II of the CAAA. Tampa Electric previously conducted an extensive study for Phase I compliance, with a follow-up study recommending integration of Big Bend Unit 3 with the existing Big Bend Unit 4 Flue Gas Desulfurization (FGD) system and fuel blending at Big Bend Units 1 and 2. The Big Bend Unit 3 Integration was completed and system placed in service June 1995 which further reduced the amount of SO2 allowance purchases and also reduced Tampa Electric's purchases of higher cost lower sulfur coal. For Phase II, Tampa Electric incorporated results from the previous study and developed several compliance alternatives. A screening process was used 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 Flue Gas Desulfurization System for Big Bend Units 1 and 2 was determined to be the most cost effective SO2 compliance alternative for Tampa Electric's system. This document outlines the assumptions, analyses and other corroborating data which support the selection of this alternative.

1 INTRODUCTION

1.1 Tampa Electric's System

Tampa Electric has six generating plants, consisting of fossil steam units, combustion turbine peaking units, diesel units and an integrated gasification combined cycle (IGCC) unit. The six generating plants include Big Bend, Gannon, Hookers Point, Dinner Lake, Phillips and Polk. Big Bend and Gannon consist of both steam-generating units and combustion turbine units.

Coal-fired generation continues to be the most economical fuel alternative for satisfying Tampa Electric's energy requirements. Tampa Electric has eleven coal-fired units. Ten of these units are fired with pulverized coal, while the Polk IGCC unit is fired with synthetic gas produced from gasified coal and other carbonaceous fuels. This technology integrates state-of-the-art environmental processes for creating a clean fuel gas from a variety of feedstock with the efficiency benefits of combined cycle generation equipment.

Generating units at Hookers Point and Phillips are residual oil-fired units. Dinner Lake is fueled by natural gas and oil, but is currently on long-term reserve standby. The four combustion turbines at Big Bend and Gannon Stations use distillate oil as the primary fuel. Total net system generation in 1997 was 17,734 GWh produced by 98% coal and 2% oil-fired generation.

1.2 Overview of Regulatory Requirements

The Acid Rain Program created under Title IV of the Clean Air Act Amendments of 1990 (CAAA) sets as its primary goal the reduction of annual SO2 emissions by 10 million tons below 1980 levels, to be achieved over a two-phase period. The primary goal of the Program is to achieve a nationwide reduction in SO2 emissions, which involves allocating a fixed number of annual SO2 emission allowances to utilities. In order to emit SO2, one allowance is required for each ton of SO2 emitted.

Phase I of the CAAA began in 1995 and affects mostly coal-burning electric utility plants. Phase II of the program begins January 1, 2000, and further restricts annual emissions from Phase I generating plants. The program affects existing utility generating units with an output capacity of greater than 25 MW and all future utility generating units.

1.3 Compliance Strategy

Tampa Electric began its CAAA compliance plan in 1990 and sought input from several areas of the company. In 1994, the SO2 Compliance Plan Evaluation - Phase I was completed. This plan reviewed several options to comply with the first phase of the CAAA. As part of an on-going effort to reduce compliance costs and meet compliance requirements in the most cost effective manner, this plan was followed by an integration study which indicated that integrating Big Bend Unit 3 with the existing Big Bend Unit 4 Flue Gas Desulfurization (FGD) system in conjunction with fuel blending and allowance purchases was the best option for compliance for Phase I of the CAAA. Tampa Electric continued its efforts to develop appropriate compliance options for the CAAA Phase II SO2

Electric continued its efforts to develop appropriate compliance options for the CAAA Phase II SO2 requirements. By incorporating the results of previous studies and the successful operation of the Big Bend Unit 4/Big Bend Unit 3 FGD system integration, Tampa Electric developed viable options to meet the more stringent Phase II regulations. The preliminary analyses demonstrated that a stand-alone FGD system at Big Bend Units 1 and 2 was the most cost effective option. These analyses also incorporated sensitivities in key planning assumptions including fuel, capital costs and other pertinent issues.

The compliance plan described in this document does not address any specific plans for NOX reductions which may be required under the CAAA Phase II NOX requirements. Tampa Electric is currently evaluating alternatives for NOX compliance. Tampa Electric will be implementing other capital commitments to achieve NOX compliance, however the NOX related costs that will be incurred do not affect the selection of the FGD system as the most cost effective alternative.

2 PHASE II COMPLIANCE SCREENING

2.1 Assumptions

2.1.1 System Assumptions

Several assumptions were used in developing Tampa Electric's Pha... II compliance plan. The Energy and Market Planning Department provided demand and energy projections. Their projections included combinations of proven conservation and load management programs that reduced the growth in system energy requirements. The Cogeneration Services Department provided projections of net and purchased cogeneration which reduces system generation requirements. The Bulk Power Department provided assumptions for wholesale interchange. The Energy and Market Planning Department also developed the most cost effective Integrated Resource Plan to maintain system reliability with addition of future generating plants and DSM energy resources. The Energy Supply Department provided operating characteristics for existing generating units. Capital costs and operations and maintenance (O & M) expense estimates for the various compliance options were also developed by the Energy Supply Department.

Fuel price and fuel characteristics information for various fuel types were provided by the Fuels Department. This compliance analysis used supplemental fuel prices for unit dispatch and average fuel prices for production costing.

2.1.2 Economic and Financial Assumptions

The economic and financial assumptions used to determine the present worth revenue requirements associated with each compliance alternative are summarized in Table 2-1. This table shows key parameters such as inflation rates, income tax rates, capitalization ratios, rates of return, other discount rates and the allowance for funds used during construction (AFUDC) rate.

2.1.3 Compliance Assumptions

Several operating assumptions were developed by the project team, as well as other departments throughout the company to support the engineering and economic evaluation.

1) Tampa Electric's affected Phase II units include all existing and future units; Phillips, Dinner Lake Station and existing and future combustion turbines are not included.

2) Five percent of sulfur in coal will be retained in the collected combustion products (flyash, slag and bottom ash).

3) Total load includes projected retail load and firm wholesale sales.

4) Fuel blending with lower sulfur coals may result in decreased unit availability, net heat rate degradations or decreased net unit capacity. These impacts were quantified for each compliance alternative.

5) Retrofitting an FGD system or the integration of additional units with the existing FGD system may result in decreased unit availability due to the maintenance schedule, net heat rate degradations or decreased net unit capacity. These impacts were quantified for each FGD option.

TABLE 2-1
TAMPA ELECTRIC COMPANY
PHASE II COMPLIANCE ANALYSIS
SCREENING FINANCIAL ASSUMPTIONS

INFLATION	
PRODUCTION	3.0%
NON-PRODUCTION	3.0%
INCOME TAX RATE:	
STATE	5.50%
FEDERAL	35.00%
EFFECTIVE	38.58%
CAPITALIZATION RATIOS:	
DEBT	41.50%
PREFERRED	0.00%
EQUITY	58.50%
RATE OF RETURN:	
DEBT	8.00%
PREFERRED	7.25%
EQUITY	12.75%
DISCOUNT RATE	9.50%
AFUDC RATE	7.79%

2.2 Methodology

2.2.1 Quantitative Analysis

This stage of the evaluation compares the related costs of each compliance alternative based on cumulative present worth revenue requirements, and the benefit-to-cost ratio (BCR). Compliance costs were developed on an incremental revenue requirements basis relative to the base case (fuel blending) assumptions. The cumulative present worth revenue requirements (CPWRR) include system fuel and purchased power expense, incremental capital, incremental O&M 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 scenarios. PROMOD simulates an economic dispatch of Tampa Electric's generating system based on incremental production costs. In addition to fuel and purchased power expense, PROMOD simulates the unit operating characteristic impacts, and system dispatch effects associated with different compliance alternatives. Since dispatch results can create varying mixes of generating resources to meet system energy requirements, the process is repeated until a scenario which meets both the system energy requirements and compliance requirements is determined.

Once the compliance scenarios production costs were developed, capital revenue requirements and incremental O&M expense associated with the compliance alternatives were calculated.

Incremental capital revenue requirements and O&M expenses were combined with fuel and purchased power expense to determine the total cost of each alternative.

2.2.2 Qualitative Analysis

The qualitative analysis incorporates parameters that are not readily measurable on a cost basis. Operational concerns, compliance plan flexibility and several risk factors were among various parameters considered. Eight specific categories were identified as being critical for each alternative. Each category was assigned a weighting factor of 1 - 4. The alternatives were assessed based on the importance of each category and received a score of +1, -1 or 0. The weighting factors were then multiplied by the score for each category and totaled to give the net assessment for each alternative.

2.3 Screening Assessments

Tampa Electric began developing its Phase II SO2 compliance options based on the study performed for Phase I compliance. In the Phase I study, an extensive investigation was conducted to address the feasibility of alternate technologies, various FGD technologies, various fuel blends and conversion alternatives. Most of the options evaluated during the Phase I study were eliminated from further consideration because they were not technologically viable or practical. The options chosen for the final screening for Phase II compliance included the following:

1) Fuel blending

2) Flue Gas Desulfurization Retrofit

   a) Integration of Big Bend Unit 2 with the existing Big Bend Unit 3 and 4 FGD System.

   b) Construction of a stand alone FGD System for Big Bend Units 1 and 2.

   c) Construction of an FGD System utilizing ammonia at Gannon Station.

   d) Construction of an FGD System utilizing limestone at Gannon Station.

3) Natural Gas Replacement

4) Coal/Natural Gas Co-firing

5) Purchased Power Options

2.3.1 Fuel Blending

Fuel blending at Gannon and Big Bend with lower sulfur coal is one alternative for compliance in Phase II. Fuel blending may require some modification to the units in order to maintain adequate boiler operating conditions. Some units may incur capacity derations, net heat rate degradations or decreased availability. Several fuel sources, each with different prices and characteristics, were analyzed. Each fuel source could potentially have different impacts on unit operating characteristics and system dispatch. Therefore, the blend of low sulfur coals with design coals (coal types that best fit the operating characteristics of a particular unit), will vary based on unit capabilities and system demand and energy requirements. Fuel blending with lower sulfur coal reduces system fuel flexibility and increases operating risk but has lower capital revenue requirements compared to other alternatives. Tampa Electric's principal strategy for Phase I SO2 compliance is fuel blending. This alternative is the base case to which the other alternatives were compared.

2.3.2 Flue Gas Desulfurization Retrofit

A Limestone Flue Gas Desulfurization system consists of equipment to provide capability to remove sulfur dioxide from the flue gas generated by the combustion of coal. The flue gas is directed to an absorber tower where it is treated with a slurry spray of limestone and water. The SO2 in the flue gas is absorbed by the water to form an acid which is then neutralized by the dissolved calcium carbonate (limestone). The reaction of the SO2 and calcium carbonate produces calcium sulfite which is then oxidized in situ by the introduction of air into the reaction tank. The product of this forced oxidation is calcium sulfate (gypsum) which then precipitates out of solution. The resulting gypsum slurry is then dehydrated to produce a near dry gypsum cake which is sold as a raw material, predominately to wallboard producers.

In the case of an ammonia FGD system, ammonia is employed as the absorption material in place of limestone. The ammonia reacts with SO2 to form ammonium sulfate, a key ingredient in fertilizer. Ammonium sulfate can be sold to fertilizer companies for their processing facilities.

Four FGD retrofit options were identified for Phase II SO2 compliance. These options include the integration of Big Bend Unit 2 into the existing FGD system, the construction of a stand-alone FGD system for Big Bend Units 1 and 2, and the construction of a stand-alone FGD system for Gannon Units 4, 5 and 6. For each of these FGD options, a limestone-based system was evaluated. In addition, an ammonia FGD system was considered for Gannon Units 4, 5 and 6. Each alternative was assumed to have an in-service date of January 1, 2000. A description of each of these options as well as the operating and financial assumptions are provided in Tables 2-2, 2-3 and 2-4.

Each of the FGD system options provides significant fuel savings that result from switching from low to high sulfur coal. Operational benefits are realized as well. Switching from low sulfur to high sulfur coal enables Tampa Electric's system to operate more cost effectively while continuing to meet environmental standards since the high sulfur coal more closely represents the design fuels of Tampa Electric's coal-fired units. To determine the economic viability of each of the FGD options, the quantitative and qualitative analyses described previously were applied.

2.3.3 Natural Gas Replacement

Replacement of existing coal-fired generation with new, natural gas-fired generation was also evaluated. This option is not a cost-effective alternative at Big Bend Station due to the need to retain and maintain the coal handling system for the remaining coal-fired units. Retirement and replacement of the coal-fired units with new natural gas-fired generation are possible options. However, the revenues from the sale of the existing units, O&M savings and operational efficiency improvements do not offset the higher fuel cost of natural gas and the high capital cost of the replacement units. Therefore, replacement of existing coal-fired units with new, natural gas-fired generation was identified as not economically viable.

TABLE 2-2

TAMPA ELECTRIC COMPANY

PHASE II COMPLIANCE ANALYSIS

SCREENING SCENARIO DESCRIPTIONS

SCENARIO	DESCRIPTION
BASE	• BB3 & 4 scrubbed by the existing BB4 FGD System. • BB1 & 2 utilize fuel blending to meet Phase I and Phase II SO_2 requirements. • Gannon 1-6 fuel blend to meet Phase II SO_2 requirements, resulting in capacity restrictions and availability impacts on GN 1-4. • Assumes 20,000 allowances purchased each year.
GANNON AMMONIA	• Construction of new, stand aloneFGD system for Gannon 4, 5, and 6. • Design would consist of one scrubber tower with a new stack located on top of the absorber tower. • Ammonia used as reagent to produce a granular grade Ammonium Sulfate by-product. • No redundancy of equipment. • Assumes 20,000 allowances purchased each year.
GANNON LIMESTONE	• Similar to Gannon ammonia FGD system with the exception that Limestone is used as the reagent to produce an agricultural quality Gypsum as the by-product. • Assumes 20,000 allowances purchased each year.
BB2 INTEGRATION	• Integration of BB2 into the existing BB4 FGD System. • Existing stack modifications rather than new stack construction. • Limestone reagent will be used to produce a wallboard quality Gypsum by-product. • Assumes 20,000 allowances purchased each year.
BIG BEND 1 - 2 STAND ALONE	• Construction of new, stand alone FGD system for BB1 & 2. • New stack would be constructed. • Limestone reagent will be used produce a wallboard quality Gypsum by-product. • No balanced draft modifications will be made to the boilers. • Assumes up to 20,000 allowances purchased each year.

TABLE 2-3

TAMPA ELECTRIC COMPANY

PHASE II COMPLIANCE ANALYSIS

OPERATING ASSUMPTIONS

	BASE	GANNON 4, 5, & 6 LIMESTONE	GANNON 4, 5, & 6 AMMONIA	BIG BEND 2 INTEGRATION	BIG BEND 1 - 2 STANDALONE
COMBINED FGD AVAILABILITY & EFFICIENCY					
BB4	95%	95%	95%	94%	95%
BB3	86%	86%	86%	-----	86%
BB2&3	-----	-----	-----	86%	-----
BB1&2	-----	-----	-----	-----	93%
GN4-6	-----	88%	88%	-----	-----
CAPACITY DERATION	10 MW on GN 1 9 MW on GN 2 14 MW on GN 3 19 MW on GN 4	12 MW total on GN 4, 5, & 6	14 MW total on GN 4, 5, & 6	13 MW on BB2	14 MW total on BB1 & 2
CAPACITY IMPROVEMEN.S	-----	19 MW on GN 4	19 MW on GN 4	None	10 MW on GN 1 9 MW on GN 2 14 MW on GN 3 19 MW on GN 4
HEAT RATE DEGRADATIONS	2% on GN 1-4	1 48% on GN 4, 5, & 6	1 72% on GN 4, 5, & 6	3 02% on BB2	1.62% on BB1 & 2
HEAT RATE IMPROVEMENTS	-----	2% on GN 4	2% on GN 4	None	2% on GN 1-4
UNIT AVAILABILITY IMPACTS DUE TO FUEL BLENDS	9 more outage days each on GN 1-4 2-3 more outage days each on GN 5&6	9 less outage days on GN 4 2-3 less outage days each on GN 5&6	9 less outage days on GN 4 2-3 less outage days each on GN 5&6	None	9 less outage days each on GN 1-4 2-3 less outage days each on GN 5&6
OUTAGE SCHEDULE MODIFICATIONS	-----	None	None	Modified in 1999 & 2000	None

TABLE 2-4

TAMPA ELECTRIC COMPANY

PHASE II COMPLIANCE ANALYSIS

PRELIMINARY SCREENING COST ASSUMPTIONS

	BIG BEND 2 INTEGRATION	BIG BEND 1-2 STAND ALONE	GANNON 4, 5, & 6 LIMESTONE	GANNON 4, 5, & 6 AMMONIA
CAPITAL COST (96$000)	$17,300	$73,000	$63,125	$68,225
CAPITAL SAVINGS (96$000)	$0	$0	$2,000	$2,000
NET CAPITAL COST (96$000)	$17,300	$73,000	$61,125	$66,225
ANNUAL O&M EXPENSE (96$000)	$150	$750	$1,190	$1,450
ANNUAL REAGENT TONS	135,000	270,000	229,000	69,600
REAGENT COST (96$/Ton)	$7.18	$7.18	$20.00	$190.00
ADDITIONAL DBA (96$/yr)	$100,000	$200,000	None	None
ANNUAL BY-PRODUCT TONS	250,000	500,000	480,000	267,000
BY PRODUCT SALES (96$/Ton)	$2.50	$2.50	$1.50	$80.00
TAX LIFE	20 YR	20 YR	20 YR	20 YR
BOOK LIFE	30 YR	30 YR	30 YR	30 YR
IN SERVICE DATE	01/01/2000	01/01/2000	01/01/2000	01/01/2000

2.3.4 Coal/Natural Gas Co-firing

An alternative to fuel switching an existing coal unit to natural gas is co-firing, in which case gas and coal are burned simultaneously in the same boiler. However, the two fuels are not physically mixed and would require additional burners and auxiliary equipment to use natural gas in unison with pulverized coal. Co-firing will reduce sulfur dioxide emissions and may also improve boiler operating characteristics by mitigating slagging and fouling problems, stabilizing burner flames and reducing unburned carbon. However, because co-firing requires the maintenance of two fuel systems (coal and gas), this option does not realize savings from the retirement of coal equipment. Tampa Electric currently forecasts the price of natural gas to be significantly higher than coal, hence no fuel savings would result from this option. Since this alternative produces no savings to offset the associated capital expenditures, it was identified as not economically viable.

2.3.5 Purchased Power Options

Tampa Electric considered purchased power as an option for complying with CAAA Phase II SO2 emission requirements. As a result of the FGD screening, it was estimated that approximately 800 MW of firm capacity would have to be purchased by TEC to displace SO2 emissions of its coal generation and be within the compliance requirements of Phase II.

The 1997 Florida Regional Coordinating Council (FRCC) Reliability Assessment was used as the basis of an analysis to determine the availability of firm capacity within Peninsular Florida. Beginning in the year 2000 and continuing through 2006, reserve margins in Peninsular Florida range from 19% to 16% in the summer and 16% to 13% for the winter. A purchase of a firm 800 MW from Peninsular Florida would reduce reserve margins below 15% for summer and winter in almost every year of the forecast. Table 2-5 uses reserve margin data from the 1997 FRCC Reliability Assessment to show the effect of an 800-MW firm purchase on the region's capacity reserves. A firm purchase of this size was considered impracticable as a Phase II compliance strategy for Tampa Electric based on the potential impact it would have on Peninsular Florida's reliability.

2.4 Screening Results

This section presents the results of the economic analysis of the various compliance alternatives. The cumulative present worth revenue requirements (CPWRR) are provided in 1996 dollars and are differentials relative to the base case fuel blending scenario. CPWRRs are provided for all sensitivities along with estimated residential rate impacts. A Benefit-to-Cost Ratio (BCR) was also determined for each option to assess relative economics.

Table 2-6 provides a summary of the results of the quantitative analysis. The results show that the Big Bend Units 1 and 2 stand-alone FGD option demonstrates the greatest relative benefit. This option has the greatest CPWRR savings, provides the most benefits to retail ratepayers and has the second highest BCR of the options evaluated. A graph of the CPWRR for each option is also provided in Figure 2-1.

Table 2-7 shows the results of the qualitative analysis. The screening risk decision matrix shows that the best option is the Big Bend Units 1 and 2 stand alone FGD. This option provides coal source flexibility, is a proven technology in which Tampa Electric is experienced, and benefits retail ratepayers.

Because the Big Bend Units 1 and 2 stand alone FGD system demonstrated the best economics with the least amount of risk, it was concluded that this option was the best alternative for Phase II SO2 compliance.

TABLE 2-5

FRCC Reserves

Summer Reserves

	Firm Reserve Margin	Reserve Capacity Above 15% Firm Reserve Margin	Firm Capacity Reserves		Firm Capacity Reserves w/ 800 MW Firm Purchase		
			Installed Capacity	DSM	Installed Capacity	DSM	Reserve Margin
	(%)	(MW)	(MW)	(MW)	(MW)	(MW)	(%)
2000	19	1281	3308	3074	2508	3074	16
2001	17	835	2890	3156	2090	3156	15
2002	18	980	3102	3180	2302	3180	16
2003	16	498	2616	3271	1816	3271	14
2004	17	624	2777	3331	1977	3331	15
2005	16	516	2760	3357	1960	3357	14
2006	16	215	2533	3382	1733	3382	13

Winter Reserves

	Firm Reserve Margin	Reserve Capacity Above 15% Firm Reserve Margin	Firm Capacity Reserves		Firm Capacity Reserves w/ 800 MW Firm Purchase		
			Installed Capacity	DSM	Installed Capacity	DSM	Reserve Margin
	(%)	(MW)	(MW)	(MW)	(MW)	(MW)	(%)
1999/00	16	191	1739	3893	939	3893	13
2000/01	15	45	1680	3925	880	3925	13
2001/02	15	98	1731	4039	931	4039	13
2002/03	14	-339	1290	4154	490	4154	12
2003/04	14	-569	1127	4201	327	4201	12
2004/05	14	-441	1329	4256	529	4256	12
2005/06	13	-929	923	4305	123	4305	11

Data was taken from the FRCC's **1997 Reliability Assessment**

TABLE 2-6

TAMPA ELECTRIC COMPANY

PHASE II COMPLIANCE ANALYSIS

10 YEAR SUMMARY

CASE	2000 - 2009 Differential CPWRR (96$000)	Benefit Cost Ratio	Relative Benefit
BB2 FGD INTEGRATION	(19,021,435)	2.14	3
BB1 & 2 STAND ALONE	(60,487,860)	1.86	1
GN 4, 5, & 6 LIMESTONE	(16,027,073)	1.27	4
GN 4, 5, & 6 AMMONIA	(35,577,741)	1.45	2

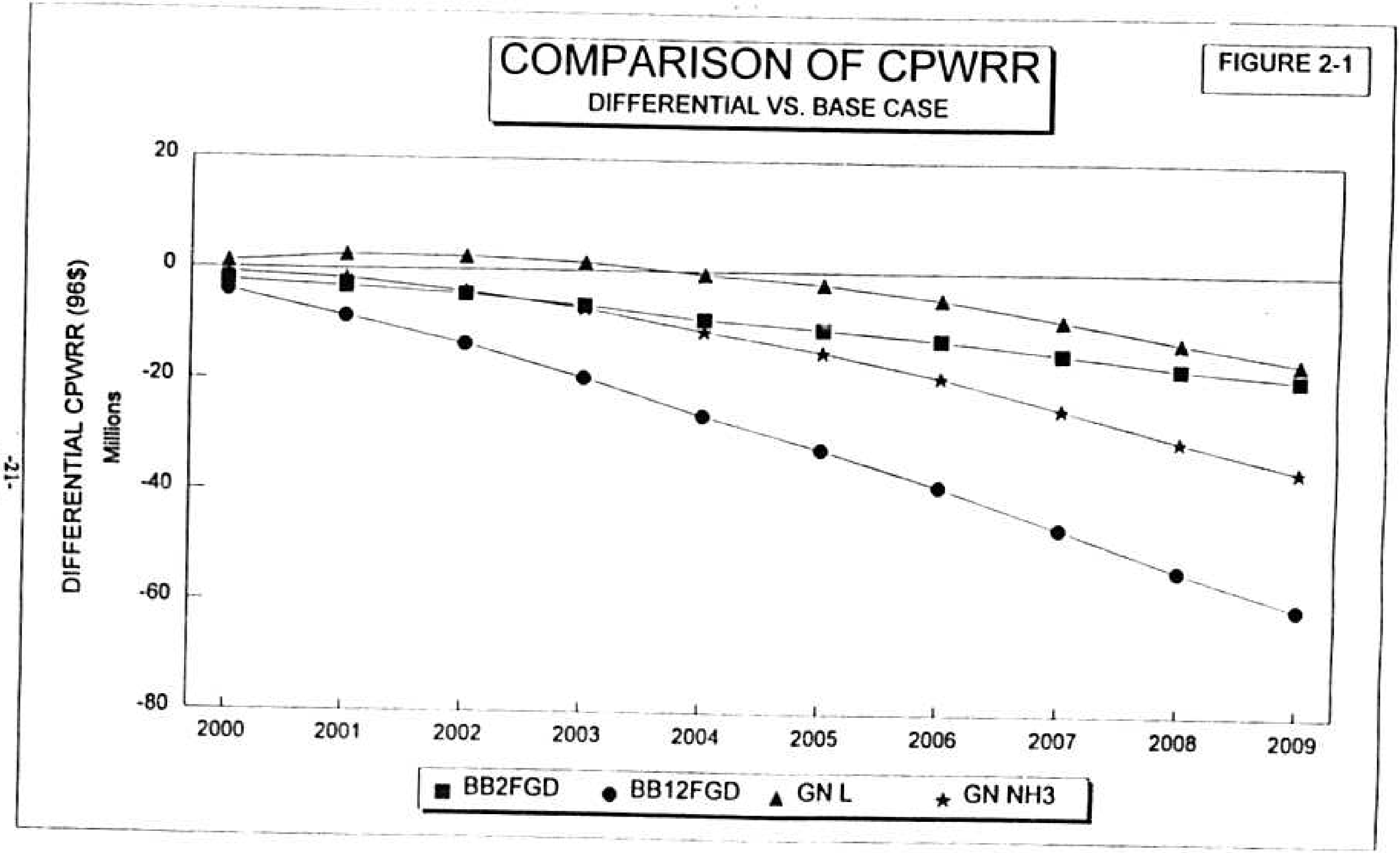

COMPARISON OF CPWRR
DIFFERENTIAL VS. BASE CASE
FIGURE 2-1
DIFFERENTIAL CPWRR (96$)
Millions
20
0
-20
-40
-60
-80
2000
2001
2002
2003
2004
2005
2006
2007
2008
2009
BB2FGD
BB12FGD
GN L
GN NH3

TABLE 2-7

TAMPA ELECTRIC COMPANY

PHASE II COMPLIANCE ANALYSIS

SCREENING RISK MATRIX

Key Objective	Weighting Factor	Base Fuel Blending	Big Bend 2 Integration	Big Bend 1&2 Stand Alone	Gannon 4,5,6 Limestone	Gannon 4,5,6 Ammonia
Provides Coal Source Flexibility	4	-1	0	1	1	1
Operational/Technology/Safety Implications	4	-1	-1	1	0	-1
Capital Investment	3	1	1	-1	-1	-1
Competitive Position	3	-1	0	1	1	1
Dependence on SO2 Allowance Purchases	2	-1	-1	1	0	0
Impact on Retail Rates (Fuel/ECRC)	2	-1	0	1	1	-1
Impact on Short-Term Earnings	1	-1	0	1	1	1
Dependence on By-Product Market Impact on Local Market	1	1	0	-1	-1	-1
Weighted Positive Impact		4	3	16	10	8
Weighted Negative Impact		-16	-6	-4	-4	-10
NET ASSESSMENT (Weighted)		-12	-3	12	6	-2

3. BIG BEND 1&2 FGD ANALYSES

As discussed in Chapter 2, the screening analysis concluded that a stand alone FGD system at Big Bend Units 1 and 2 was the best option for Phase II SO2 compliance. To ensure that this option was prudent given a wide range of contingencies, Tampa Electric performed a series of additional analyses incorporating various sensitivities which are summarized in Section 3.3. These additional analyses include sensitivities on capital cost, incremental O&M expense, allowance market variability, fuel prices, project deferral, and asset amortization. In addition, the base case and the FGD alternative were updated with Tampa Electric's most current assumptions, summarized in the following sections.

3.1 Base Case Assumptions

Tampa Electric's base case compliance plan incorporates low sulfur fuel blends and SO2 allowance purchases. The fuel blends for each coal unit were set at a fixed percentage, with the exception of Big Bend Units 1 and 2. The blends for these two units were varied each year in order to meet the compliance cap. The blends consist of high, medium and low sulfur coals. Due to operational requirements, Big Bend Units 1 and 2 are restricted to a maximum of 80 to 90% low sulfur coal in any given year. Tampa Electric plans to purchase approximately 25,000 allowance credits during each year of Phase II. These additional credits will help provide fuel flexibility and allow the affected units to burn a higher percentage of design fuels. Some low sulfur coals may impact the unit availabilities, net unit capacities, or unit heat rates. These impacts have been accounted for in the base case assumptions.

3.2 Big Bend 1&2 FGD Alternative Assumptions

The FGD alternative assumes that Big Bend Units 1 and 2 would burn high sulfur coal and would be scrubbed at 95% efficiency with 98% system availability. This option results in all coal units at Big Bend Station being scrubbed. Because Tampa Electric is restricted to a system SO2 cap, the scrubbing of Big Bend Station allows Gannon units to burn a higher sulfur blend and still meet the system SO2 cap. Hence, fuel savings are realized at both Gannon and Big Bend stations. Furthermore, by blending higher sulfur coal at Gannon, those units are able to mitigate some of the operational derations associated with burning low sulfur coals.

The capital cost of the FGD system is estimated to be approximately $90 million (including AFUDC). This estimate is based on the conceptual design and a detailed cost estimate performed by an outside consulting firm. The annual incremental O&M expense of the FGD system is estimated to be approximately $3.5 million based on Tampa Electric's past experience in fuel blending and operation of the existing FGD system. Other financial assumptions, including any revisions to other assumptions regarding the FGD system case are summarized in Tables 3.1 and 3.2.

TABLE 3-1

TAMPA ELECTRIC COMPANY

PHASE II COMPLIANCE ANALYSIS

BASE CASE & FGD CASE
FINANCIAL ASSUMPTIONS

INFLATION	
PRODUCTION	2.80%
NON-PRODUCTION	3.00%
INCOME TAX RATE:	
STATE	5.50%
FEDERAL	35.00%
EFFECTIVE	38.58%
CAPITALIZATION RATIOS:	
DEBT	40.00%
PREFERRED	0.00%
COMMON EQUITY	60.00%
RATE OF RETURN:	
DEBT	7.75%
COMMON EQUITY	12.75%
DISCOUNT RATE	9.55%
AFUDC RATE	7.79%

TABLE 3-2
TAMPA ELECTRIC COMPANY
PHASE II COMPLIANCE ANALYSIS
BB1&2 FGD COST ASSUMPTIONS

	BIG BEND 1-2 STAND ALONE FGD SYSTEM
CAPITAL COST* (Nominal $000)	$89,271
ANNUAL O&M EXPENSE (Yr 2000 $000)	$1,167
ANNUAL REAGENT COST (Yr 2000 $000)	2,322
TAX LIFE	See pg. 27
BOOK LIFE	10 YR
IN SERVICE DATE	07/01/2000

*Includes AFUDC.

3.2.1 Financial Assumptions

Tax-Life

The tax life for pollution control facilities added to units built prior to 1976 is eligible for special tax treatment under Section 169 of the Internal Revenue Code. The benefit of this election is to effectively reduce the tax life of the equipment. Research indicates that this project may be eligible for a 5-year tax life on up to 60% of the asset value. The remaining value would be depreciated over a 20-year Modified Accelerated Cost Recovery System (MACRS) life. This shortened tax life generates additional value through deferred taxes.

Recovery Period

The company will accumulate project costs, including AFUDC, in Account 107 - Construction Work In Progress (CWIP) until the project is placed in service. At that time, the company will begin cost recovery through the environmental clause. The company requests the approval of a ten-year period to amortize the project cost to expense to match the period of greatest fuel cost savings to the ratepayers. The use of a 10-year recovery period recognizes that the FGD system is not being built to serve incremental load on Tampa Electric's system but, instead, will enable the company to comply with a regulatory mandate and achieve the intangible benefits of cleaner air. Significant fuel savings will flow from this project relative to the base case scenario. Using a 10 year recovery period will enable Tampa Electric to recoup the cost of the equipment over a reasonable period of time while producing net benefits to customers. This is a conservative approach and one which will better prepare Tampa Electric to deal with increasing uncertainties in the electric industry. This proposal benefits the ratepayers through fuel cost savings and maintains a conservative approach to capital recovery of a major expenditure late in the life of two generating units.

Capital Cost

The revised capital cost estimate is $82.4 million. This figure does not include AFUDC. Total cost including AFUDC is approximately $90 million.

Incremental O&M Costs

O&M costs represent approximately $3.5 million per year in 2000 dollars. This figure is comprised of approximately $2.32 million in reagents (limestone and dibasic acid) and approximately $1.17 million in plant O&M. Both values are expected to escalate at a rate of 3% per year.

3.3 Contingency Analyses

Several sensitivities were performed to verify the economic viability of the Big Bend Units 1 and 2 FGD option. The sensitivities include: capital cost, SO2 allowance market viability, fuel price sensitivity and a deferral analysis.

3.3.1 Capital Sensitivity

Figure 3-1 shows the impacts of increased capital costs to the viability of the Big Bend Units 1 and 2 FGD alternative. Sensitivities were analyzed for a 5% and 10% variation to the assumed capital cost. The increased capital expense would decrease the benefits of the FGD system; however, the FGD system is still a more economically viable alternative than the fuel blending base case.

3.3.2 Allowance Market Viability

Because the cost of SO2 allowances in Phase II is expected to be low compared to the cost of low sulfur coal, Tampa Electric would expect to purchase allowances as part of a fuel blending plan, but would restrict that quantity to 25,000 allowances per year as mentioned in Section 3.1. To quantify the potential benefits of increasing the amount of allowances purchased in a fuel blending plan, an analysis was performed to determine the CPWRR of several fuel blend/allowance purchase plans versus the FGD alternative. The results of this analysis are presented in Figure 3-2. The results shown indicate that the FGD system provides greater benefits than increasing the purchased quantity of allowances.

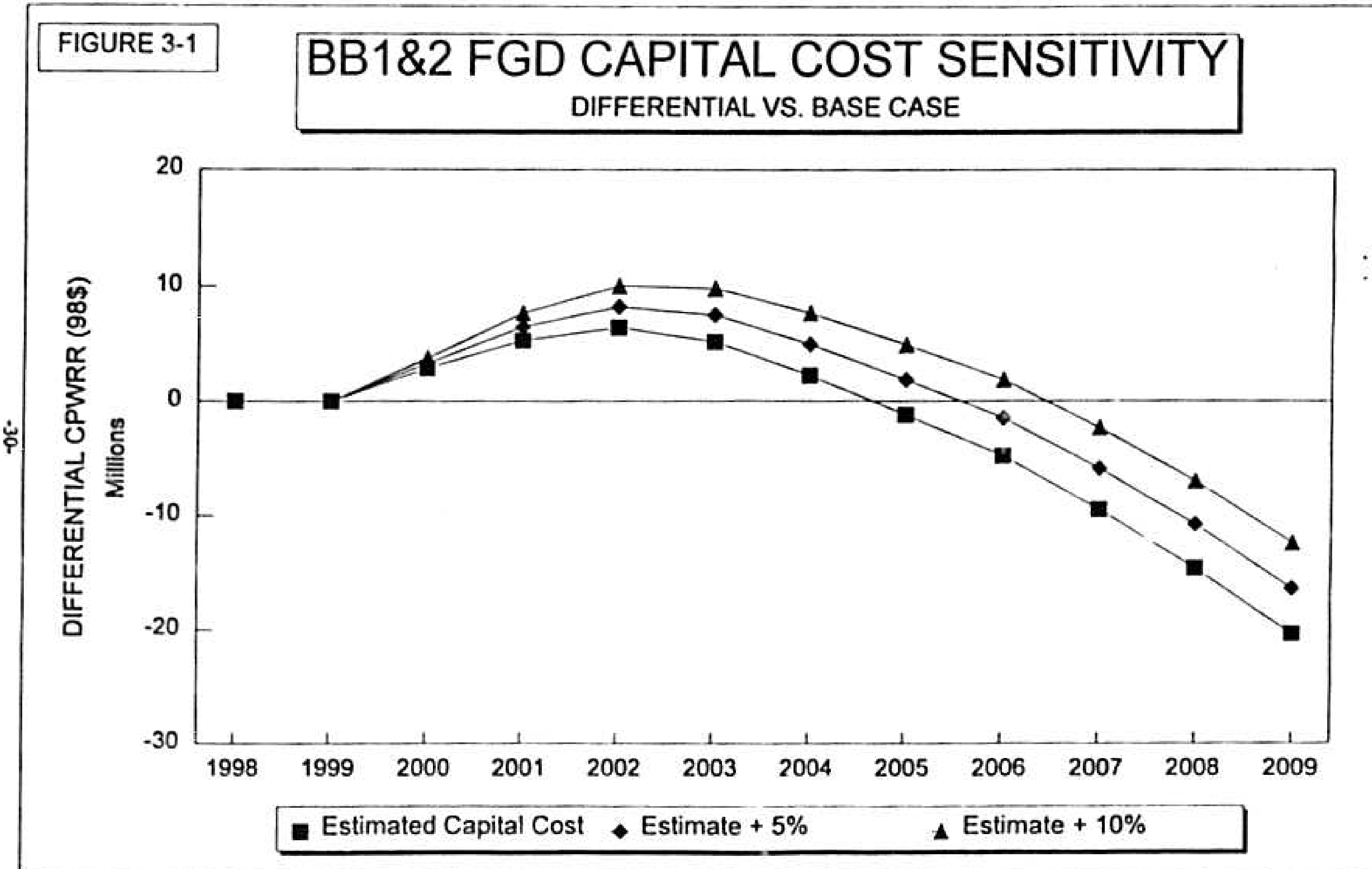
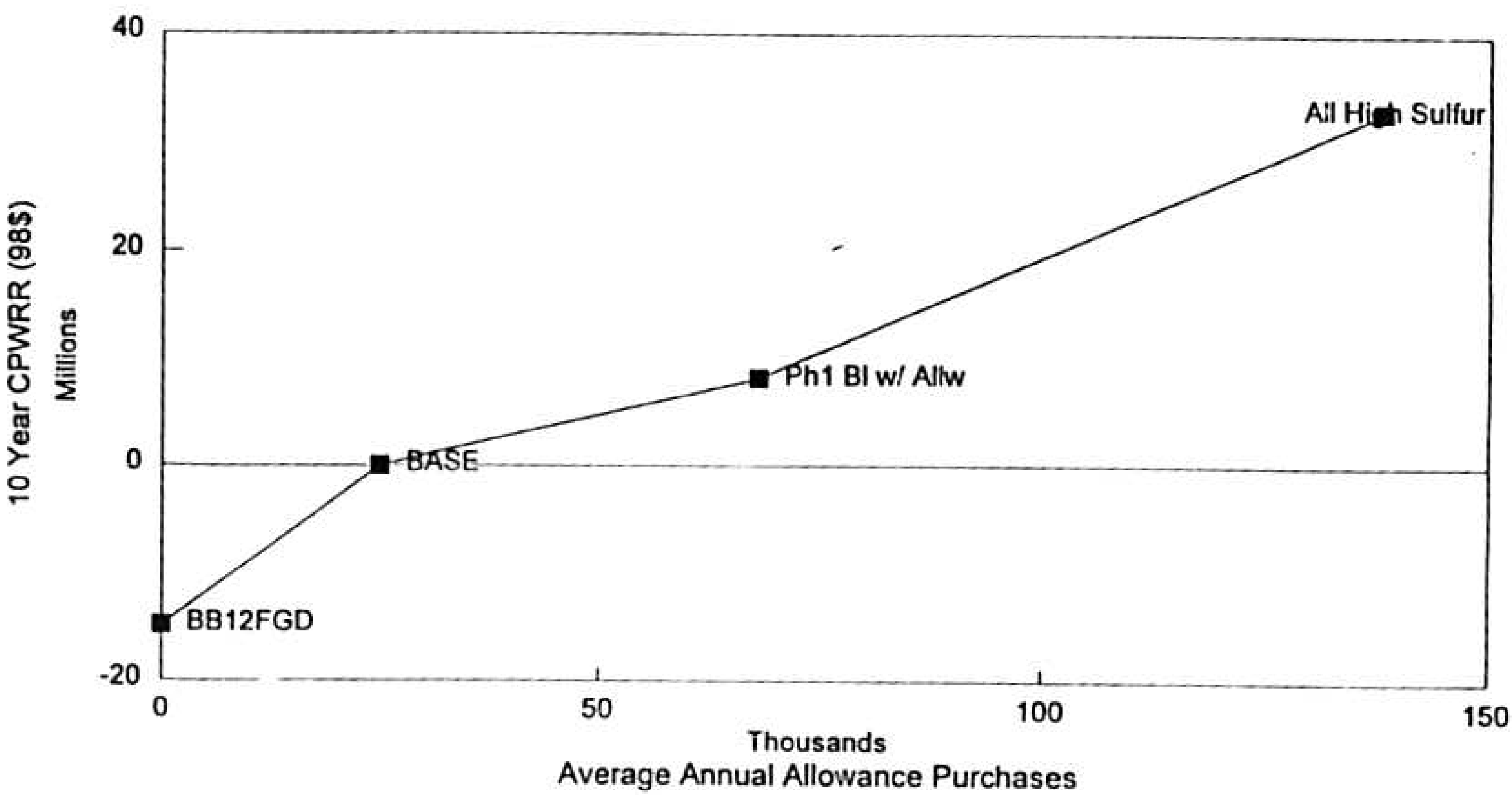


FIGURE 3-1
BB1&2 FGD CAPITAL COST SENSITIVITY
DIFFERENTIAL VS. BASE CASE
DIFFERENTIAL CPWRR (98$)
Millions
20
10
0
-10
-20
-30
1998
1999
2000
2001
2002
2003
2004
2005
2006
2007
2008
2009
Estimated Capital Cost
Estimate + 5%
Estimate + 10%

FIGURE 3-2

OPTIMIZATION OF ALLOWANCE PURCHASES

BB1&2 FGD ANALYSIS



136.

3.3.3 Fuel Price Sensitivity

The fuel benefits provided by the FGD system are dependent on the differences in cost between low and high sulfur coals, i.e., the greater the differential in costs, the greater the fuel benefits of the FGD system. To evaluate the risk associated with Tampa Electric's low/high sulfur coal price forecasts, a comparison was made of the Tampa Electric forecast versus available database resources. In a comparison of fuel price forecasts, it was observed that the company's forecast for high sulfur coal was higher than other forecasts. The Tampa Electric forecast for low sulfur coal was lower than other forecasts. Therefore, the differential in fuel costs was concluded to be conservative when compared to other industry forecasts. In addition, it was demonstrated that the fuel cost differential in the Tampa Electric forecast escalated at a slower rate than the other forecasts, thus re-enforcing the conservative approach. The results of these comparisons are provided in Figures 3-3 and 3-4.

3.3.4 Deferral Analysis

To determine the impact of delaying the project, a one-year deferral was analyzed. For this analysis, it was assumed that capital costs would escalate 2.8% for each year of deferral, but the annual cash flow distribution of the fuel savings would remain the same. The results of this analysis are provided in Figure 3-5 and show that the deferral would be more costly on a CPWRR basis.

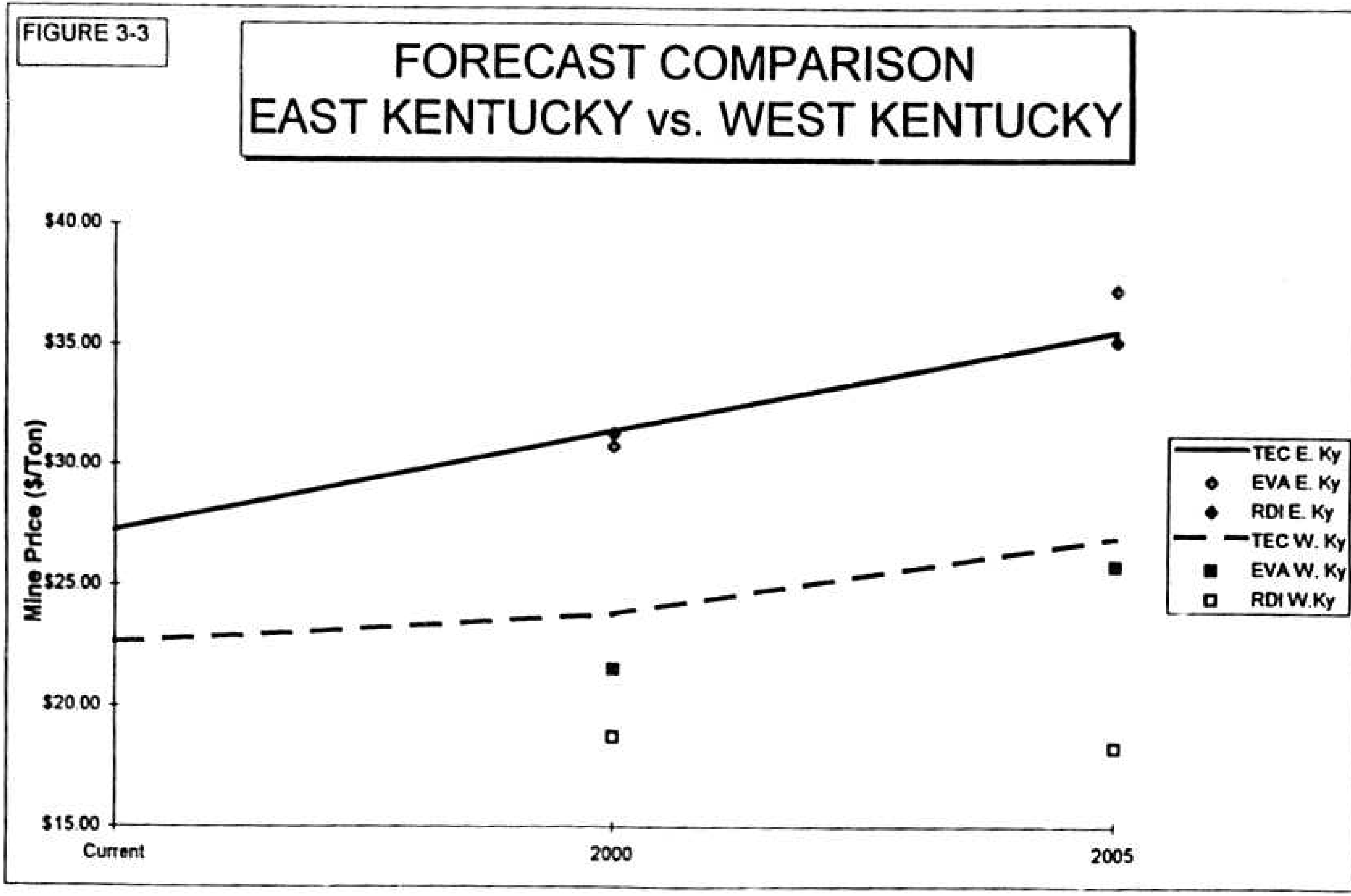
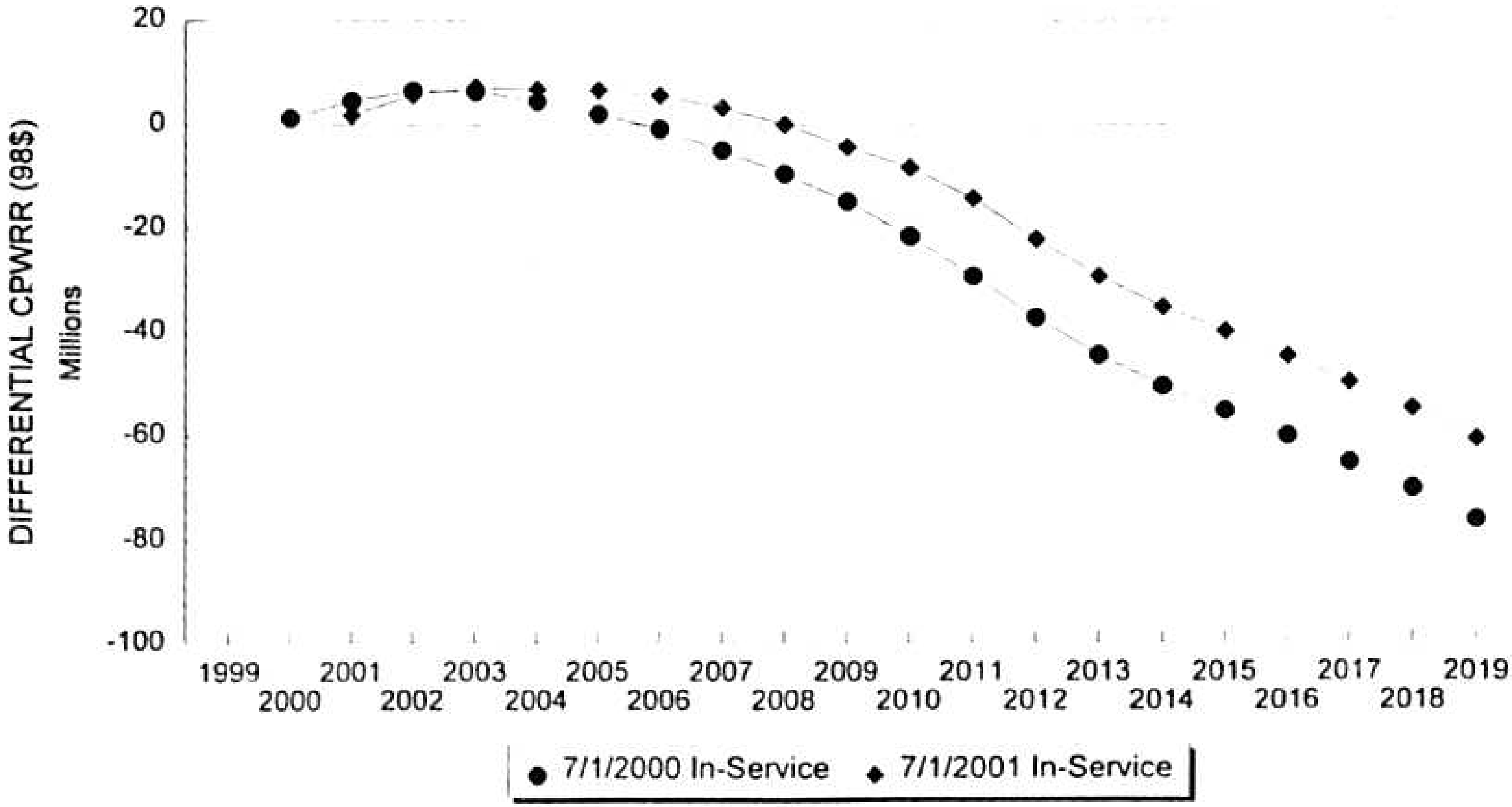


FIGURE 3-3
FORECAST COMPARISON
EAST KENTUCKY vs. WEST KENTUCKY
$40.00
$35.00
$30.00
$25.00
$20.00
$15.00
Mine Price ($/Ton)
Current
2000
2005
TEC E. Ky
EVA E. Ky
RDI E. Ky
TEC W. Ky
EVA W. Ky
RDI W.Ky

FIGURE 3-5

DEFERRAL ANALYSIS
DIFFERENTIAL VS. BASE CASE



3.4 Compliance Considerations

3.4.1 On-going Compliance Strategy

In choosing its compliance strategy, Tampa Electric will continue to evaluate the SO2 allowance market. Tampa Electric will continue to incorporate allowance purchases to minimize the use of lower sulfur coals in its efforts to reduce overall compliance costs and balance these purchases with our role in the community. Therefore, Tampa Electric proposes to implement a compliance plan which offers the greatest flexibility to meet compliance requirements with internal resources and be responsive to the allowance market if the economics are favorable while still operating in an environmentally prudent manner.

3.4.2 Operational Concerns

The fuel blending base case requires extremely low sulfur coal blends which would result in precipitator problems and opacity restrictions. These impacts were demonstrated during test burns. In addition, higher Loss on Ignition (LOI), slagging and fouling problems and maintenance difficulties are anticipated with these low sulfur blends.

3.4.3 Public Perspective

Opinions of the Florida Department of Environmental Protection, Florida Public Service Commission, environmental organizations, Customers, both wholesale and retail as well as the general public are likely to vary regarding the most appropriate method for Tampa Electric to comply with the SO2 emissions reductions required under Phase II of Title IV of the CAAA of 1990. The construction of an integrated FGD system for Big Bend Units 1 and 2 allows Tampa Electric to burn a wide range of coals in an environmentally sound manner consistent with Phase II requirements, and at the least cost to our Customers. The more costly option of using more expensive lower sulfur fuels, or reliance on the use of allowances instead of emissions reductions to meet the Phase II requirements, are much less likely to be well-received by the public.

The results of the economic analyses of available Phase II compliance alternatives clearly show that construction of an FGD system for Big Bend Units 1 and 2 provides the lowest cost impact to our Customers. In addition, the innovative approach to the design and development of the FGD system will allow Tampa Electric to construct the FGD system at a price competitive with other FGD systems. Tampa Electric's ability to keep construction costs low is aided by the fact that many components of the FGD system are existing and may only need modification rather than totally new construction. Compliance with the CAAA in the most cost effective manner, coupled with the advantages described above, suggests that this compliance option is more likely to be viewed positively by our Customers.

4 CONCLUSION

In developing the most cost effective alternative to comply with the statutory and environmental requirements associated with Phase II of the Clean Air Act Amendments of 1990, Tampa Electric examined compliance costs as well as other environmental concerns.

4.1 Recommendation of Appropriate Compliance Plan

Based on the data compiled, the construction of a Flue Gas Desulfurization System for Big Bend Units 1 and 2 is the best option for compliance with the Clean Air Act Amendment Phase II SO2 requirements. Although the capital revenue requirement for this project compared to the other options is higher, the overall benefits to the ratepayer are much more significant than with the other alternatives. This strategy reduces Tampa Electric's SO2 emissions and introduces enough fuel flexibility to allow our ratepayers to realize significant fuel savings.

4.2 Compliance Plan Implementation Schedule

Tampa Electric proposes to proceed on a very aggressive schedule to accomplish having the FGD System in-service in the year 2000. Although Tampa Electric is targeting the FGD system to be operational by January 1, 2000, a July 1, 2000 in-service date may be more realistic. Tampa Electric will submit a petition in May 1998, to the Florida Public Service Commission for approval of cost recovery for this project. Simultaneously, environmental permitting will proceed. Tampa Electric plans to submit required environmental permit applications in June 1998. Based on communications with the Department of Environmental Protection, Tampa Electric anticipates the release to initiate construction to be received in September 1998. All project environmental permits should be obtained by December 1999.

PHASE II COST EFFECTIVENESS STUDY

The Phase II cost effectiveness study compared system revenue requirements of the Big Bend 1 and 2 FGD System versus a compliance plan incorporating low sulfur fuel blends with SO_2 allowance purchases. The revenue requirements were compared in year 2000 dollars over ten year , twenty year, and twenty-five year periods.

The capital cost of the FGD system was assumed to be \$89.3 million (including AFUDC). The annual O&M expense of \$3.5 million includes \$1.17 million in O&M and \$2.3 million in reagent costs. This study assumed an in-service date of July 1, 2000.

Fuel prices were consistent with the 1998 Ten Year Site Plan. In the fuel blending case, Big Bend Units 1 and 2 would burn a blend of low and medium sulfur coals to meet Phase II requirements. In the FGD case, these units would be scrubbed with a 95% efficiency and 98% FGD availability, therefore burning 100% high sulfur coal.

The Phase II cost effectiveness study concluded that a system present worth revenue requirement savings of approximately \$18 million (10 year), \$80 million (20 year), \$96 million (25 year) would result from the FGD case.

TECO

TAMPA ELECTRIC

TEN-YEAR SITE PLAN FOR ELECTRICAL GENERATING FACILITIES AND ASSOCIATED TRANSMISSION LINES

JANUARY 1998 TO DECEMBER 2007

PHASE II COST EFFECTIVENESS STUDY

The Phase II cost effectiveness study compared system revenue requirements of the Big Bend 1 and 2 FGD System versus a compliance plan incorporating low sulfur fuel blends with SO_2 allowance purchases. The revenue requirements were compared in year 2000 dollars over ten year , twenty year, and twenty-five year periods.

The capital cost of the FGD system was assumed to be $89.3 million (including AFUDC). The annual O&M expense of $3.5 million includes $1.17 million in O&M and $2.3 million in reagent costs. This study assumed an in-service date of July 1, 2000.

Fuel prices were consistent with the 1998 Ten Year Site Plan. In the fuel blending case, Big Bend Units 1 and 2 would burn a blend of low and medium sulfur coals to meet Phase II requirements. In the FGD case, these units would be scrubbed with a 95% efficiency and 98% FGD availability, therefore burning 100% high sulfur coal.

The Phase II cost effectiveness study concluded that a system present worth revenue requirement savings of approximately $18 million (10 year), $80 million (20 year), $96 million (25 year) would result from the FGD case.

TEN-YEAR SITE PLAN FOR ELECTRICAL GENERATING FACILITIES AND ASSOCIATED TRANSMISSION LINES

January 1998 to December 2007

TAMPA ELECTRIC COMPANY
Tampa, Florida

April 1998

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TEN-YEAR SITE PLAN FOR ELECTRICAL GENERATING FACILITIES AND ASSOCIATED TRANSMISSION LINES

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Tampa, Florida

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TAMPA ELECTRIC COMPANY
CODE IDENTIFICATION SHEET

Unit Type:	CT	=	Combustion Turbine
	CC	=	Combined Cycle
	CG	=	Coal Gasifier
	D	=	Diesel
	FS	=	Fossil Steam
	HRSG	=	Heat Recovery Steam Generator
	IGCC	=	Integrated Gasification Combined Cycle
	ST	=	Steam Turbine
Unit Status:	P	=	Planned
	T	=	Regulatory Approval Received
Fuel Type:	BIT	=	Bituminous Coal
	C	=	Coal
	PC	=	Petroleum Coke
	HO	=	Heavy Oil (#6 Oil)
	LO	=	Light Oil (#2 Oil)
	NG	=	Natural Gas
	WH	=	Waste Heat
Environmental:	CL	=	Closed Loop Water Cooled
	CLT	=	Cooling Tower
	EP	=	Electrostatic Precipitator
	FQ	=	Fuel Quality
	LS	=	Low Sulfur
	SC	=	Scrubber
	OLS	=	Open Loop Cooling Water System
	OTS	=	Once-Through System
	NO	=	Not Required
Transportation:	PL	=	Pipeline
	TK	=	Truck
	RR	=	Railroad
	WA	=	Water
Other:	N	=	None

CHAPTER I

DESCRIPTION OF EXISTING FACILITIES

Description of Electric Generating Facilities

Tampa Electric has six generating plants, consisting of fossil steam units, combustion turbine peaking units, diesel units, and an integrated gasification combined cycle unit. The six generating plants include Big Bend, Gannon, Hookers Point, Dinner Lake, Phillips, and Polk. Big Bend and Gannon consist of both steam-generating units and combustion turbine units.

Generation by coal continues to be the most economical fuel alternative for satisfying Tampa Electric's energy requirements. Tampa Electric has eleven coal-fired units. Ten of these units are fired with pulverized coal, while the Polk unit is fired with synthetic gas produced from gasified coal and other carbonaceous fuels. The Polk unit is an integrated gasification combined cycle unit (IGCC). This technology integrates state-of-the-art environmental processes for creating a clean fuel gas from a variety of feedstocks with the efficiency benefits of combined cycle generation equipment.

Generating units at Hookers Point and Phillips are residual oil fired units. Dinner Lake is fueled by natural gas and oil and is currently on long term reserve standby. The four combustion turbines at Big Bend and Gannon Stations use distillate oil as the primary fuel. Total net system generation in 1997 was 17,734 GWh produced by 98% coal and 2% oil-fired generation.

Schedule 1

TABLE 1-1
Existing Generating Facilities
As of December 31, 1997

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
				Fuel		Fuel Transport		Alt Fuel	Commercial	Expected	Gen. Max.	Net Capability	
Plant Name	Unit No.	Location	Unit Type	Pri	Alt	Pri	Alt	Days	In-Service Mo/Yr	Retirement Mo/Yr	Nameplate KW	Summer MW	Winter MW
Big Bend		Hillsborough Co. 14/31S/19E									1,998,000	1,852	1,919
	1		FS	C	N	WA	N	0	10/70	Unknown	445,500	421	421
	2		FS	C	N	WA	N	0	4/73	*	445,500	416	428
	3		FS	C	N	WA	N	0	5/76	*	445,500	428	438
	4		FS	C	N	WA	N	0	2/85	*	486,000	442	447
	CT1		CT	LO	N	WA	TK	0	2/69	*	18,000	15	17
	CT2&3		CT	LO	N	WA	TK	0	11/74	*	157,500	130	160
Dinner Lake**		Highland Co. 12-055									12,500	11	11
	1		FS	NG	HO	PL	TK	2	12/66	Unknown	12,500	11	11
Gannon		Hillsborough Co. 4/30S/19E									1,319,880	1,180	1,187
	1		FS	C	N	WA	RR	0	9/57	Unknown	125,000	114	114
	2		FS	C	N	WA	RR	0	11/58	*	125,000	101	108
	3		FS	C	N	WA	RR	0	10/60	*	179,520	155	155
	4		FS	C	N	WA	RR	0	11/63	*	187,500	169	179
	5		FS	C	N	WA	RR	0	11/65	*	239,360	227	232
	6		FS	C	N	WA	RR	0	10/67	*	445,500	382	382
	CT1		CT	LO	N	WA	TK	0	3/69	*	18,000	15	17
Hookers Pt.		Hillsborough Co. 19/29S/19E									232,600	207	215
	1		FS	HO	N	WA	N	0	7/48	01/03*	33,000	32	34
	2		FS	HO	N	WA	N	0	6/50	01/03*	34,500	32	34
	3		FS	HO	N	WA	N	0	8/50	01/03*	34,500	32	34
	4		FS	HO	N	WA	N	0	10/53	01/03*	49,000	41	43
	5		FS	HO	N	WA	N	0	5/56	01/03*	81,600	70	70
Phillips		Highland Co. 12-055									42,030	37	37
	1		D	HO	N	TK	N	0	6/83	Unknown	19,215	17	17
	2		D	HO	N	TK	N	0	6/83	Unknown	19,215	17	17
	3 ***		HRSG	WH	N	N	N	0	6/83	Unknown	3,600	3	3
Polk		Polk Co. 2,3/32S/23E									326,299	250	250
	1		IGCC	C	LO	WA/TK	TK	0	9/96	Unknown	326,299	250	250
											TOTAL	3,807	3,839

* This is currently being reviewed by Tampa Electric Company

** Unit placed on long-term reserve standby 03/01/94

*** Unit on full forced outage with an undetermined return to service date

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TABLE 1-2
Existing Generating Facilities/Land Use and Investment

	Land Area		Plant Capital Investment ($000)			
Plant Name	Total Acres	In Use Acres	Land	Structures & Improvements	Equipment	Total [1]
Hookers Point Station	25	25	$ 438	$ 7,867	$ 45,061	$ 53,366
Big Bend Station	1,124	1,124	5,147	157,914	852,843	1,015,904
Francis J. Gannon Station	213	213	1,556	60,942	389,843	452,341
Dinner Lake - Sebring	2	2	15	134	3,487	3,636
Phillips - Sebring	36	36	179	288	59,356	59,823
Combustion Turbine - Gannon	1	1	0	75	1,753	1,828
Combustion Turbines - Big Bend	75	75	834	1,516	21,138	23,488
Miscellaneous Production [2]	47	47	94	6,661	5,749	12,504
Polk Power Station	4,347	4,347	18,919	110,782	385,061	514,767
TOTALS			$27,182	$346,184	$1,764,291	$2,137,657

[1] Dollar values rounded to the nearest $1,000.

[2] Power Plant Services, Production Service Complex, Production Warehouse, Central Testing Lab, Production Training Facilities

TABLE 1-3
Existing Generating Facilities/Environmental Considerations for Steam Generating Units

		Flue Gas Cleaning			
Plant Name	Unit	Particulate	SO_x	NO_x	Cooling Type
Francis J. Gannon	1	EP	LS	NR	OTS
	2	EP	LS	NR	OTS
	3	EP	LS	NR	OTS
	4	EP	LS	NR	OTS
	5	EP	LS	NR	OTS
	6	EP	LS	NR	OTS
	CT 1	NR	LS	NR	---
Hookers Point	1	NR	LS	NR	OTS
	2	NR	LS	[illegible]	OTS
	3	NR	LS	NR	OTS
	4	NR	LS	NR	OTS
	5	NR	LS	NR	OTS
Big Bend	1	EP	(1)	NR	OTS
	2	EP	(1)	NR	OTS
	3	EP	SC	(2)	(4)
	4	EP	SC	(3)	(4)
	CT 1	NR	LS	NR	---
	CT 2	NR	LS	NR	---
	CT 3	NR	LS	NR	---
Dinner Lake	1	NR	FQ	NR	OTS
Phillips	1	NR	FQ	(2)	CLT
	2	NR	FQ	(2)	CLT
	HRSG 3	NA	NA	NA	NA
Polk	IGCC 1	NR	AGR	NI	OLS

CLT = Cooling Tower
CT = Combustion Turbine
EP = Electrostatic Precipitator
FQ = Fuel Quality
LS = Low Sulfur
SC = Scrubber
OTS = Once-Through System
HRSG = Heat Recovery Steam Generator
IGCC = Integrated Gasification Combined Cycle
AGR = Acid Gas Removal
NI = Nitrogen Injection
CR = Cooling Reservoir
OLS = Open Loop Cooling Water System
NA = Not Applicable
NR = Not Required

December 31, 1997 Status.
Source: Tampa Electric Company

(1) Big Bend Units 1 - 4 operate under an SO_2 emissions cap which limits the emissions from these four units in total. Coal blending of units 1 and 2 along with the scrubbing of units 3 and 4 are used to meet the limits established for these units.
(2) NO_x controlled through unit operation.
(3) NO_x controlled through unit design and operation.
(4) OTS with fine mesh screens to minimize entrainment.

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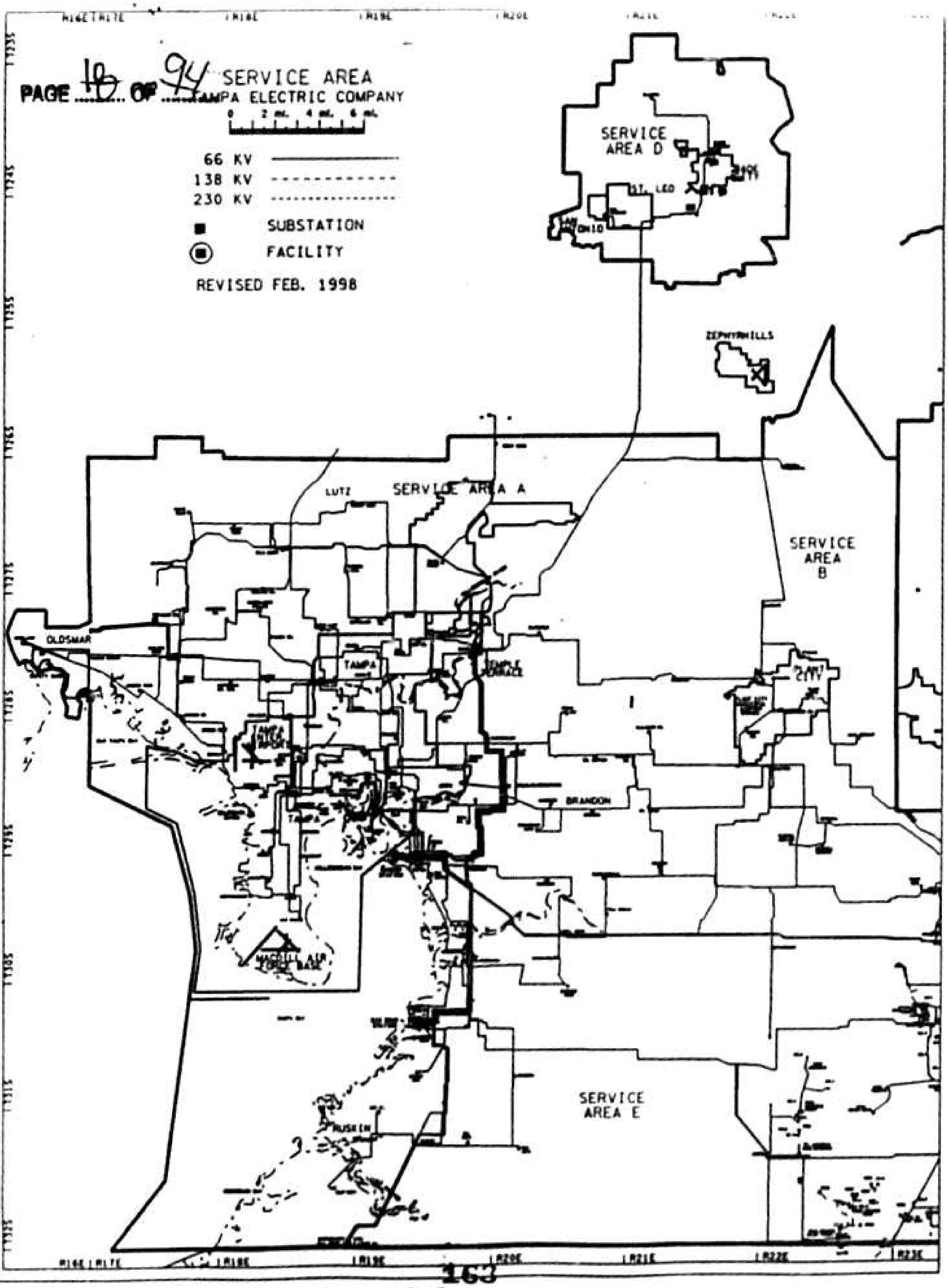
SERVICE AREA
TAMPA ELECTRIC COMPANY
0 2 mi. 4 mi. 6 mi.
66 KV
138 KV
230 KV
SUBSTATION
FACILITY
REVISED FEB. 1998
SERVICE AREA D
ST. LEO
ZEPHYRHILLS
SERVICE AREA A
LUTZ
SERVICE AREA B
OLDSMAR
TAMPA
TEMPLE TERRACE
PLANT CITY
BRANDON
MACDILL AIR FORCE BASE
SERVICE AREA E
RUSKIN
R16E R17E
R18E
R19E
R20E
R21E
R22E
R23E

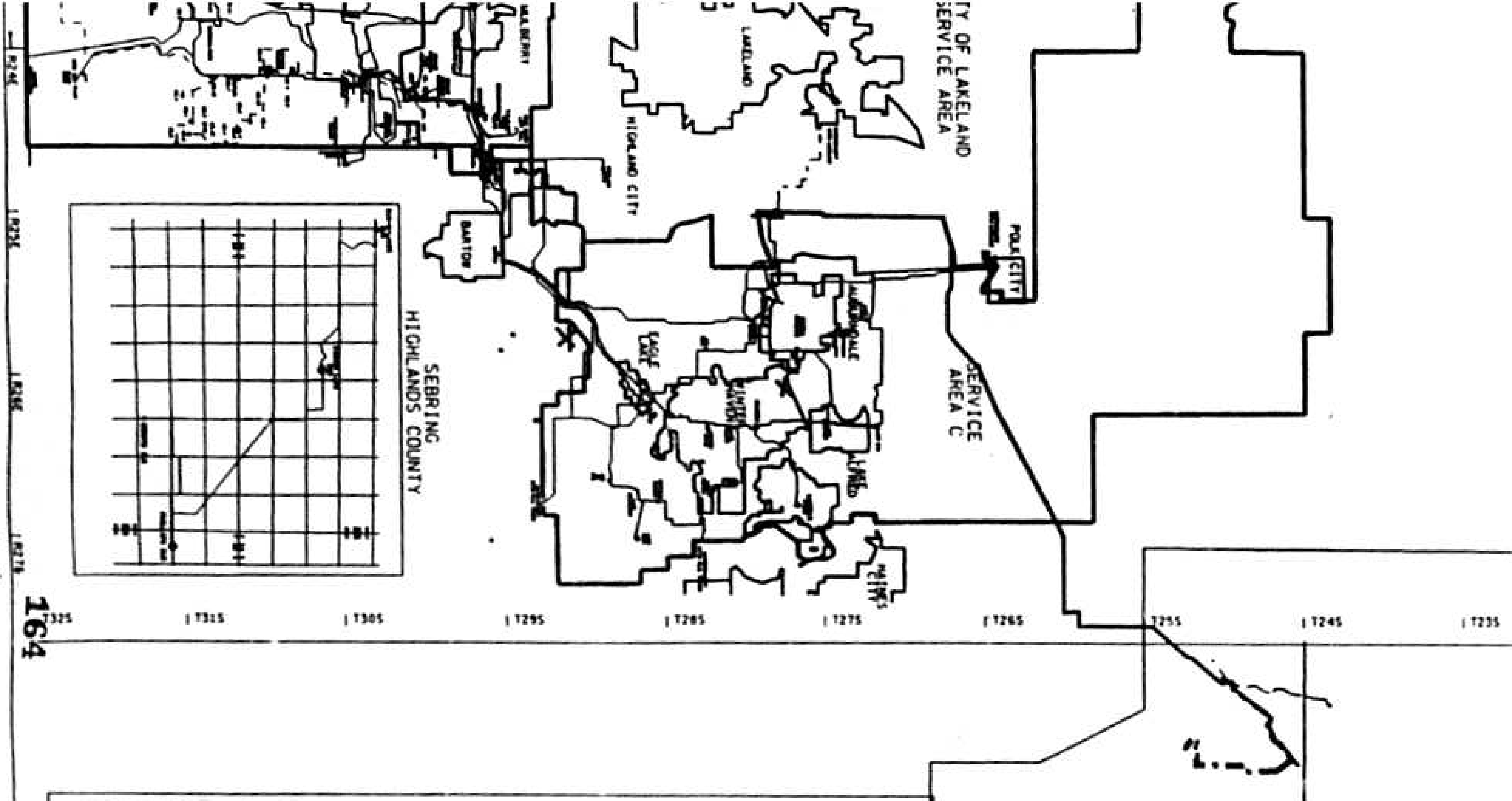

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FIGURE I-1

TAMPA ELECTRIC RETAIL CUSTOMER SERVICE AREA

SOURCE: TAMPA ELECTRIC.

TAMPA ELECTRIC COMPANY

TEN YEAR SITE PLAN
FOR ELECTRICAL GENERATING FACILITIES
AND ASSOCIATED TRANSMISSION LINES

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CHAPTER II

FORECAST OF ELECTRIC POWER, DEMAND, AND ENERGY CONSUMPTION

Schedule 2.1

TABLE II-1
History and Forecast of Energy Consumption and
Number of Customers by Customer Class
(Page 1 of 3)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
	Rural and Residential					Commercial		
Year	Population**	Members Per Household	GWH	Average* No. of Customers	Average KWH Consumption Per Customer	GWH	Average* No. of Customers	Average KWH Consumption Per Customer
1988	809,468	2.5	4,967	383,717	12,944	3,814	48,713	78,295
1989	822,621	2.5	5,214	393,278	13,258	4,062	49,780	81,599
1990	834,054	2.5	5,412	401,172	13,490	4,231	50,287	84,137
1991	843,203	2.5	5,507	407,235	13,523	4,274	50,774	84,177
1992	853,990	2.5	5,560	412,970	13,463	4,333	51,727	83,767
1993	866,134	2.5	5,706	420,051	13,584	4,432	52,492	84,432
1994	879,069	2.5	5,947	427,594	13,908	4,583	53,482	85,692
1995	892,874	2.5	6,352	436,091	14,566	4,710	54,375	86,621
1996	910,855	2.5	6,607	445,664	14,825	4,815	55,479	86,790
1997	929,507	2.4	6,500	456,175	14,249	4,902	56,981	86,029
1998	950,614	2.4	6,875	465,019	14,784	5,176	57,845	89,481
1999	969,417	2.4	7,054	474,487	14,867	5,345	58,881	90,776
2000	987,815	2.4	7,230	483,883	14,942	5,516	59,995	91,941
2001	1,004,237	2.4	7,412	492,563	15,048	5,688	61,135	93,040
2002	1,019,371	2.4	7,594	500,128	15,184	5,861	62,064	94,435
2003	1,032,494	2.4	7,777	507,557	15,322	6,035	62,995	95,801
2004	1,045,493	2.4	7,959	514,996	15,454	6,208	63,889	97,169
2005	1,057,775	2.4	8,141	522,393	15,584	6,379	64,771	98,485
2006	1,069,717	2.4	8,320	529,793	15,704	6,549	65,652	99,753
2007	1,081,556	2.4	8,496	537,142	15,817	6,720	66,545	100,984

December 31, 1997 Status.

* Average of end-of-month customers for the calendar year.
** Hillsborough County population.

Schedule 2.2

TABLE II-1
History and Forecast of Energy Consumption and
Number of Customers by Customer Class
(Page 2 of 3)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	Industrial				Street &	Other Sales	Total Sales
		Average* No. of	Average KWH Consumption	Railroads and Railways	Highway Lighting	to Public Authorities	to Ultimate Consumers
Year	GWH	Customers	Per Customer	GWH	GWH	GWH	GWH
1988	2,749	561	4,900,178	0	40	856	12,426
1989	2,672	536	4,985,075	0	40	907	12,896
1990	2,818	518	5,440,154	0	41	934	13,436
1991	2,669	515	5,182,524	0	42	963	13,455
1992	2,625	509	5,157,171	0	43	991	13,552
1993	2,236	509	4,392,927	0	45	1,028	13,447
1994	2,278	511	4,457,926	0	46	1,078	13,932
1995	2,362	491	4,810,591	0	51	1,125	14,600
1996	2,305	504	4,573,413	0	53	1,150	14,929
1997	2,465	612	4,027,778	0	53	1,170	15,090
1998	2,340	640	3,656,250	0	56	1,244	15,691
1999	2,487	640	3,885,938	0	58	1,285	16,229
2000	2,478	640	3,871,875	0	61	1,326	16,611
2001	2,461	640	3,845,313	0	63	1,368	16,992
2002	2,441	640	3,814,063	0	65	1,410	17,371
2003	2,421	640	3,782,813	0	66	1,453	17,752
2004	2,398	640	3,746,875	0	68	1,497	18,130
2005	2,376	640	3,712,500	0	69	1,535	18,500
2006	2,354	640	3,678,125	0	71	1,574	18,868
2007	2,329	640	3,639,063	0	72	1,613	19,230

December 31, 1997 Status.

* Average of end-of-month customers for the calendar year.

Schedule 2.3

TABLE II-1
History and Forecast of Energy Consumption and
Number of Customers by Customer Class
(Page 3 of 3)

(1) Year	(2) Sales for Resale GWH	(3) Utility Use++ & Losses GWH	(4) Net Energy** for Load GWH	(5) Other* Customers (Average No.)	(6) Total* No. of Customers
1988	0	725	13,151	3,448	436,439
1989	0	809	13,704	3,563	447,157
1990	0	569	14,005	3,695	455,672
1991	129	695	14,279	3,736	462,260
1992	214	671	14,437	3,790	468,996
1993	246	807	14,500	3,958	477,010
1994	163	636	14,731	4,111	485,698
1995	212	870	15,682	4,241	495,198
1996	399	760	16,088	4,391	506,038
1997	507	731	16,328	4,583	518,368
1998	382	860	16,933	4,674	528,178
1999	389	888	17,506	4,769	538,777
2000	331	911	17,853	4,864	549,381
2001	382	932	18,306	4,966	559,303
2002	348	953	18,672	5,069	567,902
2003	372	973	19,097	5,175	576,367
2004	382	996	19,508	5,284	584,809
2005	373	1,015	19,888	5,394	593,198
2006	369	1,035	20,272	5,480	601,565
2007	329	1,058	20,617	5,567	609,894

December 31, 1997 Status.

* Average of end-of-month customers for the calendar year.
** Output to line including energy supplied by purchased cogeneration.
*** Values shown may be affected by rounding.
++ Utility Use and Losses include accrued sales.

Schedule 3.1

TABLE II-2
History and Forecast of Summer Peak Demand
Base Case
(Page 1 of 3)

(1) Year	(2) Total	(3) Wholesale+	(4) Retail	(5) Interruptible	(6) Residential Load Management	(7) Residential Conservation	(8) Comm./Ind. Load Management #	(9) Comm./Ind. Conservation	(10) Net Firm Demand	
1988	2,476	0	2,476	221	75	18	1	7	2,154	
1989	2,555	0	2,555	315	71	19	2	9	2,205	*
1990	2,630	0	2,630	311	72	20	4	9	2,245	*
1991	2,717	39	2,678	265	71	23	1	9	2,309	
1992	2,821	50	2,771	294	77	25	3	10	2,366	*
1993	2,912	60	2,852	273	91	28	6	11	2,453	*
1994	2,823	69	2,75[illegible]	200	97	31	8	11	2,409	*
1995	2,981	81	2,90[illegible]	170	98	34	8	16	2,574	
1996	3,089	92	2,997	234	98	42	18	16	2,589	
1997	3,107	106	3,001	225	89	55	17	18	2,597	
1998	3,201	112	3,089	217	105	61	46	20	2,640	
1999	3,292	128	3,164	233	109	66	60	22	2,674	
2000	3,380	128	3,252	230	112	71	75	25	2,739	
2001	3,491	139	3,352	228	116	76	90	27	2,814	
2002	3,591	140	3,451	225	119	80	107	30	2,890	
2003	3,707	141	3,566	222	123	85	123	31	2,983	
2004	3,806	141	3,665	219	126	89	140	34	3,057	
2005	3,892	130	3,762	217	129	93	158	35	3,130	
2006	3,[illegible]1	130	3,861	215	132	97	176	38	3,203	
2007	4,060	111	3,949	212	135	101	195	39	3,267	

December 31, 1997 Status.

* Not coincident with system peak.
** Values shown may be affected by rounding.
\+ Includes sales to FPC, Wauchula, Ft. Meade, St. Cloud and Reedy Creek.
\# Commercial/Industrial Load Management includes Standby Generator.

Schedule 3.1

TABLE II-2
History and Forecast of Summer Peak Demand
High Case
(Page 2 of 3)

(1) Year	(2) Total	(3) Wholesale+	(4) Retail	(5) Interruptible	(6) Residential Load Management	(7) Residential Conservation	(8) Comm./Ind. Load Management #	(9) Comm./Ind. Conservation	(10) Net Firm Demand	
1988	2,476	0	2,476	221	75	18	1	7	2,154	
1989	2,555	0	2,555	315	71	19	2	9	2,205	*
1990	2,630	0	2,630	311	72	20	4	9	2,245	*
1991	2,717	39	2,678	265	71	23	1	9	2,309	
1992	2,821	50	2,771	294	77	25	3	10	2,366	*
1993	2,912	60	2,852	273	91	28	6	11	2,453	*
1994	2,823	69	2,754	200	97	31	8	11	2,409	*
1995	2,981	81	2,900	170	98	34	8	16	2,574	
1996	3,089	92	2,997	234	98	42	18	16	2,589	
1997	3,107	106	3,001	225	89	55	17	18	2,597	
1998	3,221	112	3,109	220	106	61	46	20	2,656	
1999	3,335	128	3,207	240	110	66	60	22	2,709	
2000	3,441	128	3,313	240	114	72	75	25	2,787	
2001	3,576	140	3,436	241	118	77	91	27	2,882	
2002	3,702	141	3,561	241	121	82	107	30	2,980	
2003	3,853	142	3,711	240	125	86	123	31	3,106	
2004	3,975	142	3,833	240	129	91	140	34	3.199	
2005	4,099	131	3,968	238	133	96	158	35	3,308	
2006	4,222	131	4,091	238	137	100	176	38	3,402	
2007	4,337	113	4,224	237	140	104	195	39	3,509	

December 31, 1997 Status.

- * Not coincident with system peak.
- ** Values shown may be affected by rounding.
- \+ Includes sales to FPC, Wauchula, Ft. Meade, St. Cloud and Reedy Creek.
- \# Commercial/Industrial Load Management includes Standby Generator.

Schedule 3.1

TABLE II-2
History and Forecast of Summer Peak Demand
Low Case
(Page 3 of 3)

(1) Year	(2) Total	(3) Wholesale+	(4) Retail	(5) Interruptible	(6) Residential Load Management	(7) Residential Conservation	(8) Comm./Ind. Load Management #	(9) Comm./Ind. Conservation	(10) Net Firm Demand	
1988	2,476	0	2,476	221	75	18	1	7	2,154	
1989	2,555	0	2,555	315	71	19	2	9	2,205	*
1990	2,630	0	2,630	311	72	20	4	9	2,245	*
1991	2,717	39	2,678	265	71	23	1	9	2,309	
1992	2,821	50	2,771	294	77	25	3	10	2,366	*
1993	2,912	60	2,852	273	91	28	6	11	2,453	*
1994	2,823	69	2,754	200	97	31	8	11	2,409	*
1995	2,981	81	2,900	170	98	34	8	16	2,574	
1996	3,089	92	2,997	234	98	42	18	16	2,589	
1997	3,107	106	3,001	225	89	55	17	18	2,597	
1998	3,189	112	3,077	215	105	60	46	20	2,631	
1999	3,257	128	3,129	226	108	65	60	22	2,648	
2000	3,324	128	3,196	220	111	70	75	25	2,695	
2001	3,413	138	3,275	215	115	75	90	27	2,753	
2002	3,487	139	3,348	209	117	79	107	30	2,806	
2003	3,589	140	3,449	204	120	83	123	31	2,888	
2004	3,651	140	3,511	200	122	87	140	34	2,928	
2005	3,723	129	3,594	195	125	91	158	35	2,990	
2006	3,773	129	3,644	192	127	95	176	38	3,016	
2007	3,814	109	3,705	187	130	98	195	39	3,056	

December 31, 1997 Status.

* Not coincident with system peak.
** Values shown may be affected by rounding.
\+ Includes sales to FPC, Wauchula, Ft. Meade, St. Cloud and Reedy Creek.
\# Commercial/Industrial Load Management includes Standby Generator.

Schedule 3.2

TABLE II-3
History and Forecast of Winter Peak Demand
Base Case
(Page 1 of 3)

(1) Year	(2) Total	(3) Wholesale+	(4) Retail	(5) Interruptible	(6) Residential Load Management	(7) Residential Conservation =	(8) Comm./Ind. Load Management #	(9) Comm./Ind. Conservation	(10) Net Firm Demand
1988/89	2,584	0	2,584	242	127	168	1	17	2,029
1989/90	2,712	0	2,712	178	107	183	0	19	2,345 *
1990/91	2,422	0	2,422	227	139	196	0	20	1,840
1991/92	2,815	53	2,762	294	151	207	1	21	2,088
1992/93	2,886	63	2,823	281	168	221	4	23	2,126
1993/94	2,737	69	2,668	181	177	241	7	25	2,037
1994/95	3,244	74	3,170	240	227	270	8	25	2,400
1995/96	3,449	98	3,351	152	245	311	8	29	2,606
1996/97	3,439	109	3,330	228	237	313	18	26	2,508
1997/98**	3,521	114	3,407	197	245	350	30	27	2,558
1998/99	3,625	129	3,496	211	254	387	42	28	2,574
1999/00	3,721	129	3,592	209	263	421	54	29	2,616
2000/01	3,823	141	3,682	207	272	454	67	29	2,653
2001/02	3,908	141	3,767	204	280	487	81	30	2,685
2002/03	4,019	143	3,876	203	288	519	95	31	2,740
2003/04	4,115	143	3,972	201	296	551	109	31	2,784
2004/05	4,204	132	4,072	198	304	582	124	32	2,832
2005/06	4,302	133	4,170	196	312	611	139	33	2,879
2006/07	4,391	113	4,278	193	319	640	155	34	2,937
2007/08	4,476	114	4,362	192	327	668	155	35	2,985

December 31, 1997 Status.

* Not coincident with system peak.
\+ Includes sales to FPC, Wauchula, Fort Meade, St. Cloud and Reedy Creek.
\# Commercial/Industrial Load Management includes Standby Generator.
** Forecasted Values: 1997/98 - 2007/08.
*** Values shown may be affected by rounding.
= Residential conservation includes code changes.

TABLE II-3
History and Forecast of Winter Peak Demand
High Case
(Page 2 of 3)

(1)	(2) *	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Year	Total	Wholesale+	Retail	Interruptible	Residential Load Management	Residential Conservation =	Comm./Ind. Load Management #	Comm./Ind. Conservation	Net Firm Demand
1988/89	2,584	0	2,584	242	127	168	1	17	2,029
1989/90	2,712	0	2,712	178	107	183	0	19	2,345
1990/91	2,422	0	2,422	227	139	196	0	20	1,840
1991/92	2,815	53	2,762	294	151	207	1	21	2,088
1992/93	2,886	63	2,823	281	168	221	4	23	2,126
1993/94	2,737	69	2,668	181	177	241	7	25	2,037
1994/95	3,244	74	3,170	240	227	270	8	25	2,400
1995/96	3,449	98	3,351	152	245	311	8	29	2,606
1996/97	3,439	109	3,330	228	237	313	18	26	2,508
1997/98**	3,541	114	3,427	200	246	351	30	27	2,573
1998/99	3,662	129	3,533	216	256	389	42	28	2,602
1999/00	3,780	129	3,651	218	266	426	54	29	2,658
2000/01	3,894	142	3,752	219	276	461	67	29	2,700
2001/02	4,014	142	3,872	219	285	496	81	30	2,761
2002/03	4,146	144	4,002	220	295	531	95	31	2,830
2003/04	4,261	144	4,117	219	304	566	109	31	2,888
2004/05	4,391	133	4,258	218	314	599	124	32	2,971
2005/06	4,511	135	4,376	217	323	632	139	33	3,032
2006/07	4,644	115	4,529	215	332	664	155	34	3,129
2007/08	4,764	114	4,650	216	341	696	155	35	3,207

December 31, 1997 Status.

* Not coincident with system peak.
\+ Includes sales to FPC, Wauchula, Fort Meade, St. Cloud and Reedy Creek.
\# Commercial/Industrial Load Management includes Standby Generator.
** Forecasted Values: 1997/98 - 2007/08.
*** Values shown may be affected by rounding.
= Residential conservation includes code changes.

Schedule 3.2

TABLE II-3
History and Forecast of Winter Peak Demand
Low Case
(Page 3 of 3)

(1) Year	(2) Total	(3) Wholesale+	(4) Retail	(5) Interruptible	(6) Residential Load Management	(7) Residential Conservation =	(8) Comm./Ind. Load Management #	(9) Comm./Ind. Conservation	(10) Net Firm Demand
1988/89	2,584	0	2,584	242	127	168	1	17	2,029
1989/90	2,712	0	2,712	178	107	183	0	19	2,345
1990/91	2,422	0	2,422	227	139	196	0	20	1,840
1991/92	2,815	53	2,762	294	151	207	1	21	2,088
1992/93	2,886	63	2,823	281	168	221	4	23	2,126
1993/94	2,737	69	2,668	181	177	241	7	25	2,037
1994/95	3,244	74	3,170	240	227	270	8	25	2,400
1995/96	3,449	98	3,351	152	245	311	8	29	2,606
1996/97	3,439	109	3,330	228	237	313	18	26	2,508
1997/98**	3,510	114	3,396	195	244	349	30	27	2,551
1998/99	3,594	129	3,465	206	252	384	42	28	2,553
1999/00	3,672	129	3,543	200	260	416	54	29	2,584
2000/01	3,754	140	3,614	196	267	447	67	29	2,608
2001/02	3,825	140	3,685	191	274	478	81	30	2,631
2002/03	3,907	142	3,765	188	281	508	95	31	2,662
2003/04	3,979	142	3,837	183	288	537	109	31	2,689
2004/05	4,049	131	3,918	179	295	565	124	32	2,723
2005/06	4,111	132	3,979	175	301	591	139	33	2,740
2006/07	4,174	111	4,063	171	307	616	155	34	2,780
2007/08	4,234	114	4,120	170	313	641	155	35	2,806

December 31, 1997 Status.

* Not coincident with system peak.
\+ Includes sales to FPC, Wauchula, Fort Meade, St. Cloud and Reedy Creek.
\# Commercial/Industrial Load Management includes Standby Generator.
** Forecasted Values: 1997/98 - 2007/08.
*** Values shown may be affected by rounding.
= Residential conservation includes code changes.

TABLE II-4
History and Forecast of Annual Net Energy for Load - GWH
Base Case
(Page 1 of 3)

(1) Year	(2) Total	(3) Residential Conservation =	(4) Comm./Ind. Conservation	(5) Retail	(6) Wholesale +	(7) Utility Use & Losses	(8) Net Energy for Load	(9) Load Factor % **
1988	12,529	93	10	12,426	0	725	13,151	57.1
1989	13,013	105	12	12,896	0	809	13,705	57.7
1990	13,564	111	17	13,436	0	569	14,005	60.8
1991	13,591	117	19	13,455	129	695	14,279	60.0
1992	13,697	123	22	13,552	214	671	14,437	58.3
1993	13,603	131	26	13,446	246	808	14,500	56.8
1994	14,102	141	29	13,932	163	636	14,731	59.6
1995	14,803	162	41	14,600	212	870	15,682	55.2
1996	15,181	195	57	14,929	399	760	16,088	53.1
1997	15,382	228	64	15,090	507	731	16,328	57.8
1998	16,025	260	74	15,691	382	860	16,933	55.0
1999	16,604	291	84	16,229	389	888	17,506	55.4
2000	17,026	321	94	16,611	331	911	17,853	54.6
2001	17,445	350	103	16,992	382	932	18,306	54.8
2002	17,863	379	113	17,371	348	953	18,672	54.5
2003	18,282	407	123	17,752	372	973	19,097	54.3
2004	18,6[illegible]6	434	132	18,130	382	996	19,508	54.0
2005	19,102	460	142	18,500	373	1,015	19,888	53.9
2006	19,504	485	151	18,868	369	1,035	20,272	53.8
2007	19,901	510	161	19,230	329	1,058	20,617	53.4

December 31, 1997 Status.

** Load Factor is the ratio of total system average load to peak demand.
\+ Includes sales to FPC, Wauchula, Ft. Meade, St. Cloud and Reedy Creek.
= Residential conservation includes code changes.

Schedule 3.3

TABLE II-4
History and Forecast of Annual Net Energy for Load - GWH
High Case
(Page 2 of 3)

(1) Year	(2) Total	(3) Residential Conservation =	(4) Comm./Ind. Conservation	(5) Retail	(6) Wholesale +	(7) Utility Use & Losses	(8) Net Energy for Load	(9) Load Factor % **
1988	12,529	93	10	12,426	0	725	13,151	57.1
1989	13,013	105	12	12,896	0	809	13,705	57.7
1990	13,564	111	17	13,436	0	569	14,005	60.8
1991	13,591	117	19	13,455	129	695	14,279	60.0
1992	13,697	123	22	13,552	214	671	14,437	58.3
1993	13,603	131	26	13,446	246	808	14,500	56.8
1994	14,102	141	29	13,932	163	636	14,731	59.6
1995	14,803	162	41	14,600	212	870	15,682	55.2
1996	15,181	195	57	14,929	399	760	16,088	53.1
1997	15,382	228	64	15,090	507	731	16,328	57.8
1998	16,147	261	74	15,812	383	866	17,061	55.1
1999	16,835	293	84	16,458	391	901	17,750	55.6
2000	17,368	324	94	16,950	333	927	18,211	54.8
2001	17,899	354	103	17,442	385	954	18,781	55.2
2002	18,447	385	113	17,949	352	981	19,282	54.8
2003	19,016	414	123	18,479	377	1,009	19,865	54.7
2004	19,583	444	132	19,007	388	1,037	20,432	54.6
2005	20,135	472	142	19,521	380	1,064	20,965	54.4
2006	20,704	499	151	20,054	377	1,092	21,523	54.5
2007	21,276	527	161	20,588	338	1,120	22,046	54.0

December 31, 1997 Status.

** Load Factor is the ratio of total system average load to peak demand.
+ Includes sales to FPC, Wauchula, Ft. Meade, St. Cloud and Reedy Creek.
= Residential conservation includes code changes.

TABLE II-4
History and Forecast of Annual Net Energy for Load - GWH
Low Case
(Page 3 of 3)

(1) Year	(2) Total	(3) Residential Conservation =	(4) Comm./Ind. Conservation	(5) Retail	(6) Wholesale +	(7) Utility Use & Losses	(8) Net Energy for Load	(9) Load Factor % **
1988	12,529	93	10	12,426	0	725	13,151	57.1
1989	13,013	105	12	12,896	0	809	13,705	57.7
1990	13,564	111	17	13,436	0	569	14,005	60.8
1991	13,591	117	19	13,455	129	695	14,279	60.0
1992	13,697	123	22	13,552	214	671	14,437	58.3
1993	13,603	131	26	13,446	246	808	14,500	56.8
1994	14,102	141	29	13,932	163	636	14,731	59.6
1995	14,803	162	41	14,600	212	870	15,682	55.2
1996	15,181	195	57	14,929	399	760	16,088	53.1
1997	15,382	228	64	15,090	507	731	16,328	57.8
1998	15,950	259	74	15,617	381	857	16,856	54.9
1999	16,424	289	84	16,051	388	882	17,320	55.2
2000	16,740	318	94	16,328	329	898	17,555	54.4
2001	17,046	346	103	16,597	379	913	17,889	54.6
2002	17,361	373	113	16,875	345	929	18,149	54.2
2003	17,657	399	123	17,135	368	944	18,447	53.9
2004	17,940	425	132	17,383	377	959	18,718	53.6
2005	18,205	449	142	17,614	367	972	18,953	53.3
2006	18,472	472	151	17,849	362	986	19,197	53.3
2007	18,717	494	161	18,062	321	999	19,382	52.7

December 31, 1997 Status.

** Load Factor is the ratio of total system average load to peak demand.
\+ Includes sales to FPC, Wauchula, Ft. Meade, St. Cloud and Reedy Creek.
= Residential conservation includes code changes.

Schedule 4

TABLE II-5
Previous Year and 2-Year Forecast of Peak Demand and Net Energy for Load by Month

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	1997 Actual		1998 Forecast		1999 Forecast	
Month	Peak Demand MW	NEL GWH	Peak Demand MW	NEL GWH	Peak Demand MW	NEL GWH
January	3,439	1,257	3,521	1,278	3,625	1,318
February	2,445	1,103	3,188	1,161	3,284	1,198
March	2,442	1,287	2,751	1,220	2,837	1,260
April	2,512	1,189	2,644	1,250	2,723	1,295
May	3,107	1,443	2,973	1,514	3,059	1,574
June	3,090	1,530	3,201	1,609	3,292	1,665
July	3,079	1,601	3,170	1,680	3,259	1,737
August	3,076	1,625	3,179	1,692	3,269	1,752
September	2,968	1,542	3,172	1,584	3,262	1,638
October	2,725	1,344	2,899	1,392	2,983	1,437
November	2,111	1,134	2,807	1,282	2,895	1,321
December	2,585	1,273	3,094	1,271	3,192	1,311
TOTAL		16,328		16,933		17,506

December 31, 1997 Status.

Schedule 5

TABLE II-6
History and Forecast of Fuel Requirements

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
	Fuel Requirements		Units	Actual 1996	Actual 1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
(1)	Nuclear		Trillion BTU	0	0	0	0	0	0	0	0	0	0	0	0
(2)	Coal*		1000 Ton	7,795	8,021	7,952	7,669	7,507	7,703	7,683	7,930	7,813	8,090	8,147	8,270
(3)	Residual	Total	1000 BBL	412	427	287	306	419	572	768	128	146	155	163	171
(4)		Steam	1000 BBL	333	345	245	261	362	485	661	0	0	0	0	0
(5)		CC	1000 BBL	79	82	41	45	58	87	108	128	146	155	163	171
(6)		CT	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(7)		Diesel	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(8)	Distillate	Total	1000 BBL	256	319	287	320	385	417	486	665	872	894	1,002	1,105
(9)		Steam	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(10)		CC	1000 BBL	210	250	208	233	241	240	240	239	239	239	239	239
(11)		CT	1000 BBL	46	70	79	87	145	177	246	427	633	656	763	866
(12)		Diesel	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(13)	Natural Gas	Total	1000 MCF	0	0	0	0	0	0	0	1,623	3,100	3,526	4,602	5,295
(14)		Steam	1000 MCF	0	0	0	0	0	0	0	0	0	0	0	0
(15)		CC	1000 MCF	0	0	0	0	0	0	0	0	0	0	0	0
(16)		CT	1000 MCF	0	0	0	0	0	0	0	1,623	3,100	3,526	4,602	5,295
(17)	Other (Specify)														
(18)	Petroleum Coke		1000 Ton	176	111	237	566	581	592	584	582	582	593	590	592

December 31, 1997 Status.

* Coal energy source includes an alternative fuel source consisting of a shredded tire/coal blend fuel for Gannon.
** Values shown may be affected by rounding.
*** All values exclude ignition.

Schedule 6.1

TABLE II-7
History and Forecast of Net Energy for Load by Fuel Source
(Page 1 of 2)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
	Energy Sources		Units	Actual 1996	Actual 1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
(1)	Annual Firm Interchange		GWh	5	(125)	(599)	203	262	192	254	441	511	525	562	622
(2)	Nuclear		GWh	0	0	0	0	0	0	0	0	0	0	0	0
(3)	Coal*		GWh	17,225	17,033	17,570	16,330	16,001	16,379	16,343	16,843	16,649	17,170	17,254	17,544
(4)	Residual	Total	GWh	182	188	124	132	180	248	330	85	97	103	108	114
(5)		Steam	GWh	129	136	96	102	142	190	259	0	0	0	0	0
(6)		CC	GWh	53	52	28	30	38	58	72	85	97	103	108	114
(7)		CT	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(8)		Diesel	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(9)	Distillate	Total	GWh	162	202	180	200	226	236	260	366	486	495	557	609
(10)		Steam	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(11)		CC	GWh	146	178	153	171	177	176	176	175	176	175	175	175
(12)		CT	GWh	16	24	27	30	49	60	84	192	310	320	382	434
(13)		Diesel	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(14)	Natural Gas	Total	GWh	0	0	0	0	0	0	0	139	269	308	418	479
(15)		Steam	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(16)		CC	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(17)		CT	GWh	0	0	0	0	0	0	0	139	269	308	418	479
(18)	Other (Specify)														
(19)	Petroleum Coke Generation		GWh	492	310	663	1,585	1,627	1,658	1,636	1,629	1,679	1,660	1,653	1,657
(20)	Net Interchange		GWh	(2,441)	(1,734)	(1,448)	(1,338)	(883)	(875)	(627)	(890)	(618)	(857)	(782)	(890)
(21)	Purchased Energy from Non-														
(22)	Utility Generators		GWh	464	453	444	394	441	468	476	483	484	483	483	483
(23)	Net Energy for Load		GWh	16,088	16,328	16,933	17,506	17,853	18,306	18,672	19,097	19,508	19,888	20,272	20,617

December 31, 1997 Status.

* Coal energy source includes an alternative fuel source consisting of a shredded tire/coal blend fuel for Gannon.
** Values shown may be affected by rounding.

Schedule 8.2

TABLE II-7
History and Forecast of Net Energy for Load by Fuel Source
(Page 2 of 2)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
	Energy Sources		Units	Actual 1996	Actual 1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
(1)	Annual Firm Interchange		%	0	(1)	(4)	1	1	1	1	2	3	3	3	3
(2)	Nuclear		%	0	0	0	0	0	0	0	0	0	0	0	0
(3)	Coal*		%	107	104	104	93	90	89	88	88	85	86	85	85
(4)	Residual	Total	%	1	1	1	1	1	1	1	0	0	1	1	1
(5)		Steam	%	1	1	1	1	1	1	1	0	0	0	0	0
(6)		CC	%	0	0	0	0	0	0	0	0	0	1	1	1
(7)		CT	%	0	0	0	0	0	0	0	0	0	0	0	0
(8)		Diesel	%	0	0	0	0	0	0	0	0	0	0	0	0
(9)	Distillate	Total	%	1	1	1	1	1	1	1	2	2	2	3	3
(10)		Steam	%	0	0	0	0	0	0	0	0	0	0	0	0
(11)		CC	%	1	1	1	1	1	1	1	1	1	1	1	1
(12)		CT	%	0	0	0	0	0	0	0	1	2	2	2	2
(13)		Diesel	%	0	0	0	0	0	0	0	0	0	0	0	0
(14)	Natural Gas	Total	%	0	0	0	0	0	0	0	1	1	2	2	2
(15)		Steam	%	0	0	0	0	0	0	0	0	0	0	0	0
(16)		CC	%	0	0	0	0	0	0	0	0	0	0	0	0
(17)		CT	%	0	0	0	0	0	0	0	1	1	2	2	2
(18)	Other (Specify)														
(19)	Petroleum Coke Generation		%	3	2	4	9	9	9	9	9	8	8	8	8
(20)	Net Interchange		%	(15)	(11)	(9)	(8)	(5)	(5)	(3)	(5)	(3)	(4)	(4)	(4)
(21)	Purchased Energy from Non-														
(22)	Utility Generators		%	3	3	3	2	2	3	3	3	2	2	2	2
(23)	Net Energy for Load		%	100	100	100	100	100	100	100	100	100	100	100	100

December 31, 1997 Status

* Coal energy source includes an alternative fuel source consisting of a shredded tire/coal blend fuel for Gannon.

** Values shown may be affected by rounding.

CHAPTER III

FORECAST OF ELECTRIC POWER DEMAND

Tampa Electric Company Forecasting Methodology

The Customer, Demand and Energy Forecast is the foundation from which the integrated resource plan is developed. Recognizing its importance, Tampa Electric Company employs state-of-the-art methodologies for carrying out this function. The primary objective in this procedure is to blend proven statistical techniques with practical forecasting experience to provide a projection which represents the highest probability of occurrence.

This chapter is devoted to describing Tampa Electric Company's forecasting methods and the major assumptions utilized in developing the 1998-2007 forecast. The data tables in Chapter II outline the expected customer, demand, and energy values for the 1998-2007 time period.

Retail Load

The Tampa Electric Company retail demand and energy forecast is the result of five separate forecasting methods:

1. detailed end-use model (demand and energy);
2. multiregression model (demand and energy);
3. trend analysis (demand and energy);
4. phosphate analysis (demand and energy); and
5. conservation programs (demand and energy management).

The detailed end-use model, SHAPES, is the company's most sophisticated and primary forecasting model. As shown in Figure III-1, the first three forecasting methods are blended together to develop a demand and energy projection, excluding phosphate load. Phosphate demand and energy is forecasted separately and then combined in the final forecast. Likewise, the effect of Tampa Electric Company's conservation, load management, and cogeneration programs is incorporated into the process by subtracting their expected reduction in demand and energy from the forecast.

1. Detailed End-Use Model

The SHAPES model was developed jointly by Tampa Electric Company, Tech Resources (formerly part of the Battelle Memorial Institute), and New Energy Associates and is the foundation of the demand and energy forecasting process. SHAPES projects annual energy consumption for the service area and load profiles by end-use for typical and extreme (peak) days. The model has two major sections. The first section is the regional economic-demographic model, entitled REGIS, which generates population, households, income, and employment projections which are used in the second part of the model, called SHAPES.

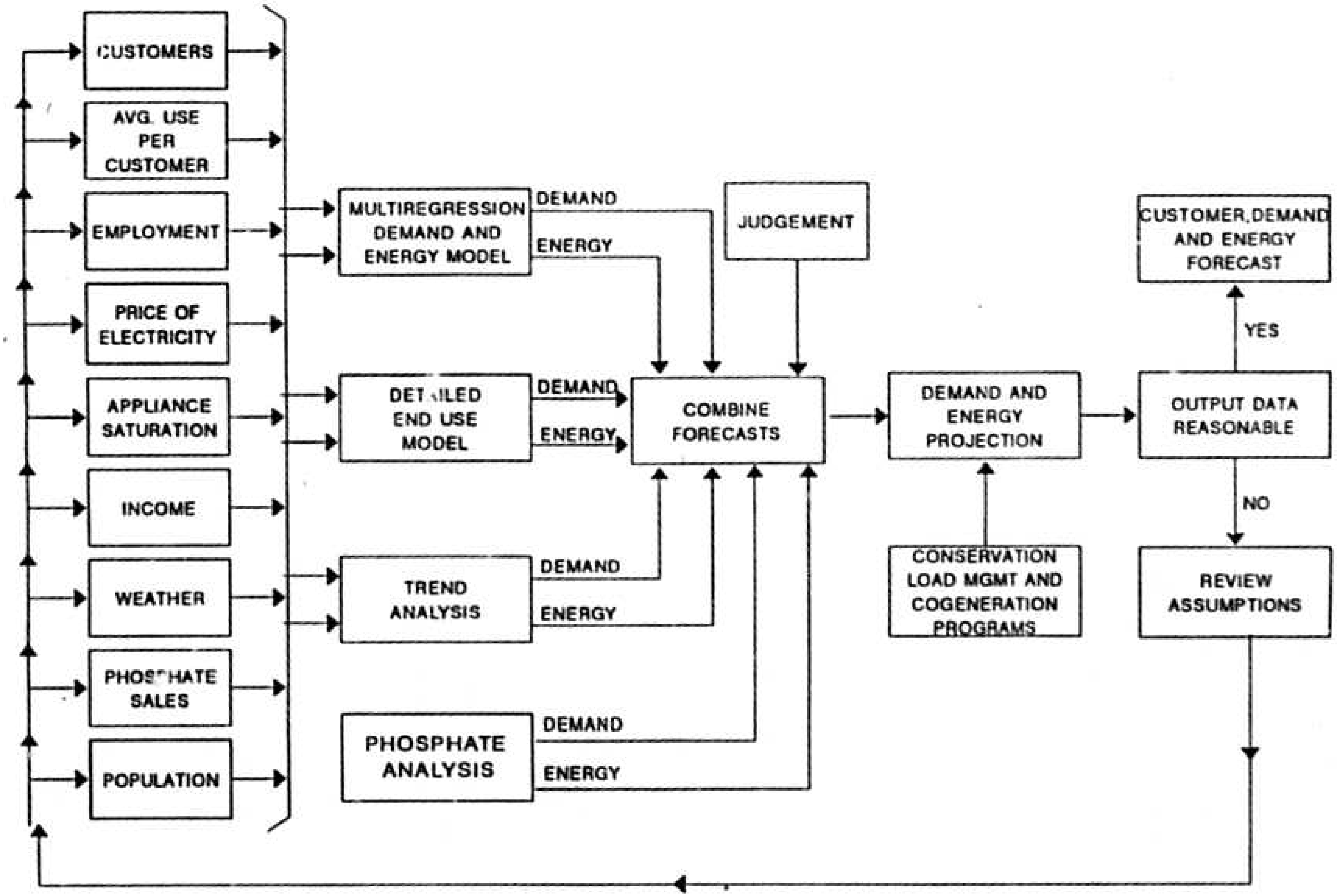


FIGURE III-1

Figure III-1

TAMPA ELECTRIC COMPANY CUSTOMER, DEMAND AND ENERGY FORECAST PROCESS

SOURCE: TAMPA ELECTRIC COMPANY

TAMPA ELECTRIC COMPANY
Ten-Year Site Plan
For Electrical Generation Facilities
And Associated Transmission Lines

As an option, the parameters furnished by REGIS may be replaced with other forecasts, such as the University of Florida's population projections. The SHAPES portion of the model consists of two parts: (1) a demand section, and (2) an energy section. The demand section calculates hourly demands including peak demands based on temperature profiles for normal and extreme conditions. The energy section forecasts residential energy use by appliance, commercial consumption by end-use and building type, and energy used in the industrial and miscellaneous sectors.

REGIS

Since electricity consumption, peak demand, and load shapes depend to a large extent on the nature and level of economic activity, the first step in system demand and energy requirements forecasting is to project the economic and population base of the service area. The economic-demographic model consists of approximately twenty equations with four major components including migration and demographic, housing, labor, and income.

Population is developed through the migration/demographic component of the model which uses a cohort-survival approach as its foundation. More specifically, Hillsborough County population is partitioned into age groups and "aged" over time through the application of birth and death rates. Migration, the most significant component of population change in the service area, is calculated as a function of the relative economic opportunities in the local area and the general health of the overall economy. The population estimates are converted to residential customers by applying household formation rates to each age group. The housing sector determines the stock of housing that relates to the residential customer forecasts.

The labor market and income components are combined to determine service area employment and income. In the labor sector, employment for four manufacturing categories plus the commercial and governmental sectors is projected. Employment is then combined with the wage equation of the income sector to determine local earnings. Since earnings represent 70 to 75% of total personal income, this is an important input for deriving regional personal income.

SHAPES

The power model is comprised of four major sectors: (1) residential, (2) commercial, (3) industrial, and (4) miscellaneous (governmental, street lighting, and transmission and distribution line losses). This structure emphasizes the projection of hourly demand values by end-use based on month, day type, and temperature. Repeating these calculations for each hour of the day and for all consumption units yields the daily load curve of the system. The energy consumption for any period is calculated by summing demand in each hour in the period for all end-uses.

More specifically, the basic equation upon which the model is based is:

$$D_{ij} = \Sigma N_i \bullet C_i \bullet F_{ij}$$

where:

D_{ij} = Demand at hour j by end-use component i;

N_i = Number of use components of type i;

C_i = Connected load per use component i;

F_{ij} = Fraction of connected load of use component i which is operating at hour j.

In the residential sector, the energy consuming units are the major household appliances. A list of the seventeen appliances treated explicitly in the model is provided in Table III-1. The appliance stock in a given year is influenced by the number of households, the mix of dwelling unit types, and family income. The latter two variables are used to derive saturation levels for each appliance which combined with the number of households, results in the total number of units of a given appliance.

Looking at these two factors in more detail, data analysis indicates that saturation levels for certain appliances vary significantly according to housing type. To capture these differences, the occupied housing stock or number of households is partitioned into single family, multi-family, and mobile home categories. In addition, it was determined that certain appliance saturations are related to the individual household's income level. Those appliances having this characteristic included room air conditioners, electric clothes dryers, clothes washers, and dishwashers. Projections of housing mix and per capita income, therefore, were utilized in developing saturation rates for these appliance categories.

To capture the trend of including ranges, central air conditioning, electric water heating, electric space heating or electric heat pumps as standard items in new construction, penetration rates representing the percent of new housing with these features were used to project saturation levels for these appliances. Finally, certain appliances such as television sets and refrigerators have already achieved full saturation. Future saturation levels are similar to present rates except for quality shifts or intercategory adjustments from standard to frost free refrigerators and black and white to color television.

The second major factor in the demand estimation equation is the connected load of the appliance, which was developed from company and industry studies. The last factor in the equation is the use factor or the probability of the appliance operating at a given time.

TABLE III-1. Appliances Treated Explicitly In End-Use Model

Electric Range
Refrigerator - Frost Free
Refrigerator - Standard
Freezer - Frost Free
Freezer - Standard
Dishwasher
Clothes Washer
Electric Dryer
Electric Water Heater
Microwave Oven
TV-Color
TV-Black and White
Lighting
Room Air Conditioner
Central Air Conditioner
Electric Space Heating
Electric Heat Pump

SOURCE: Tampa Electric Company

In the model, appliances can be separated into two groups: temperature insensitive and temperature sensitive. Those appliances which are temperature insensitive have use factors which vary by day type, month, and hour. Thus, the usage of these appliances is characterized by 1,152 use factors (12 months x 24 hours x 4 day types). These four day types are Sunday, Monday, Tuesday-Friday, and Saturday. For temperature-sensitive appliances, which include air conditioners, electric space heaters, and electric heat pumps, the monthly use factors are replaced by a set of factors which vary with respect to time and temperature. Therefore, the energy consumption of these appliances is a function of temperature, time, and day type. These temperature-related use factors are combined with monthly temperature probability matrices to calculate energy requirements over that period.

The model is capable of developing a residential as well as a system demand profile for each hour of each day type for all twelve months. In order to calculate peak demand, a temperature profile representing the expected hottest or coldest day must be input into the model. An average day load profile for each month can also be developed by supplying an average temperature for every hour.

The commercial sector of the model forecasts energy and demand by building type by end-use. This sector estimates energy intensity by end-use for each building type in terms of kWh per square foot of floor space. The forecast of building type square footage can be developed within the model using the REGIS employment forecast by building type and estimates of projected floor space per employee.

In addition, end-use saturation rate estimates are developed from surveys of the service area's commercial customers by building type. The original survey of this sector was performed by Xenergy, Inc. during 1994 as part of commission-sanctioned research into the cost effectiveness of commercial DSM programs. In the future, Tampa Electric expects to survey its commercial customers regarding their end-use saturations by fuel type, building type, employment, square footage, and vintage age and demolition rate of the equipment stock on a semiannual basis.

From the calculation of energy, commercial demand is determined by allocating annual consumption to the hours of the day through use factors. However, the commercial sector contains both temperature-sensitive and insensitive end-uses. The temperature-sensitive use patterns are a function of temperature and time. Therefore, peak demand is calculated, as in the residential sector, by specifying extreme temperatures to represent severe weather conditions.

The nine end-uses and eleven building types that are included in Tampa Electric's commercial floorspace building type model are listed in Table III-2.

TABLE III-2. Commercial Floorspace Model End-Uses and Building Types

End-Uses:

Air Conditioning	Miscellaneous
Cooking	Refrigeration
Exterior Lighting	Ventilation
Heating	Water Heating
Interior Lighting	

Building Types:

Colleges	Offices
Groceries	Retail
Health Care	Restaurants
Hospitals	Schools
Lodging	Warehouses
Miscellaneous	

The industrial and miscellaneous sectors of the model are less detailed than the residential and commercial customer classes due to a lack of connected load data. The industrial class is disaggregated into four major groups representing different levels of energy intensiveness. These include Food Products (SIC 20); Tobacco, Printing, etc. (SIC 21, 23, 24, 25, 27, 37, 39); Fabricated Metals, etc. (SIC 26, 29, 30, 34, 35, 36, 38); and Basic Industries (SIC 32, 33). In each sector, annual energy consumption is computed by multiplying energy use per employee times projected employment. Monthly energy consumption is calculated by allocating the annual energy to the corresponding month using historic ratios of monthly-to-annual consumption. Once monthly energy is computed, it is further broken down by hour for each of the four day types. That is, a use factor is applied which denotes the fraction of each month's energy that is consumed in a given hour. These use factors were developed from hourly billing data available for major industrial customers in each of the four categories.

The miscellaneous sector includes street lighting, sales to public authorities, and transmission and distribution line losses. For street lighting and public authorities, sales are expressed as a function of the number of residential customers, and demand is calculated using an allocation method similar to the industrial and commercial sectors.

The model also allows for price elasticity adjustments which represent the change in electric consumption resulting from changes in the relative price of electricity. In order to capture the price effect, an adjustment factor is applied to the annual consumption. The adjustment factor for a given year is a time-dependent weighted average of short and long-run elasticity. The general mathematical form of the consumption adjustment equation is as follows:

$$C_n = C_0 * \text{(Price Elasticity Adjustment Factor)}$$

where:

C_n = Consumption at the price level in year n, adjusted for price changes in years 0 to n.

C_0 = Consumption at the base year price level, that is, assuming no price changes.

The Adjustment Factor is given by the following:

Price Elasticity Adjustment Factor

$$\left(\frac{P_1}{P_0}\right)^{E_n} \cdots \left(\frac{P_i}{P_{i-1}}\right)^{E_{n-i+1}} \cdots \left(\frac{P_n}{P_{n-1}}\right)^{E_1}$$

where:

P_i = Price of electricity in period i (i = 1 to n).

E_i = Price elasticity coefficient expressed as a time-dependent weighted average of the short and long-run elasticity coefficients (i = 1 to n)

This relationship can be expressed as follows:

$$E_i = E_S + W_i(E_L - E_S)$$

where:

E_S = Short-run elasticity

E_L = Long-run elasticity

W_i = Weighting factor, $0 \le W_i \le 1$; $W_1 = 0$, $W_i = 1$ for $i \ge 12$.

The above relationship warrants two important observations. First, the price elasticity adjustment factor that is applied to a given year incorporates the effects of price changes not only for the given year but also for previous years. Second, the elasticity coefficient that is applied to a given year's price change increases numerically over time, gradually rising from the short-term elasticity value to the long-term. Therefore, each price increase or decrease has a lasting effect on future consumption patterns.

In the residential sector, each of the specific appliances was assigned a short-run and long-run elasticity. This was accomplished by partitioning the major appliances into three groups whose change in consumption due to price changes was considered to be either low, medium, or high (Table III-3). In certain cases, these elasticities were assigned subjectively while in other cases they were based upon studies by National Economic Research Associates (NERA) and the Electric Power Research Institute (EPRI). In addition, the resulting coefficients have the mathematical property that their combined effect, which represents the average residential elasticity coefficient, closely approximates the results of NERA and EPRI research. Therefore, their cumulative effect is in accord with extensive statistical analysis. The elasticity factors used for the commercial and industrial categories were also developed from these studies.

TABLE III-3. Sensitivity of Consumption to Price

Appliances with Low Assumed Price Sensitivity:

Refrigerator	Frost Free Standard
Freezer	Frost Free Standard
TV	Color Black and White

Appliances with Medium Assumed Price Sensitivity:

Electric Range
Clothes Washer
Electric Water Heater
Microwave Oven
Lighting

Appliances with High Assumed Price Sensitivity:

Dishwasher
Electric Dryer
Room Air Conditioner
Central Air Conditioner
Electric Space Heating
Electric Heat Pump

SOURCE: Based on studies by National Economic Research Associates and the Electric Power Research Institute.

Another factor influencing residential energy consumption is the movement toward more energy-efficient appliances. The forces behind this development include market pressures for more energy-efficient technologies and the appliance efficiency standards enacted by the state and federal governments. The efficiency goals affect the usage associated with new additions to the appliance stock.

It should be noted that the base year appliance energy consumption is influenced by both price effects and efficiency improvements. Thus, while some appliances are assumed to be rather price insensitive, their individual consumption levels decrease due to efficiency improvements.

2. Multiregression Demand and Energy Model

The retail multiregression forecasting model is a nine-equation model with two major sections. The energy section forecasts energy sales by the six major customer categories. The demand section forecasts peak load other than phosphate for both summer and winter. The regression technique is a more sophisticated approach than trend analysis as it attempts to examine those factors which influence load.

The selection of appropriate variables to include in the multiregression model equations is an extensive process that begins with the identification of variables that affect demand and energy. Those variables which can not be reasonably quantified or forecast are dismissed from the process. Results from regressions using the remaining variables are evaluated to determine which variables perform best. As a result, the chosen equations are both statistically and theoretically appropriate.

The basic series that make up the regression method are supplied by Tampa Electric Company, the U.S. Bureau of Labor Statistics, the U.S. Bureau of Economic Analysis, the U.S. Geological Survey, the Federal Reserve Board, the National Oceanic and Atmospheric Administration, and the University of Florida's Bureau of Economic and Business Research. All projections of the independent variables in these equations are consistent with those used in the end-use model.

Demand Section

The demand section consists of three regression equations for load other than phosphate. One equation is for the base load which, by definition, is that load on the system that is independent of temperature. The remaining two equations describe the summer peak temperature-sensitive demand and the winter peak temperature-sensitive demand. From regression analysis, the following relationships have been determined.

1.
Base Load = 70.159 + 4.3389 * # Residential Customers - 3707.9 * ¢/kWh (lagged 1 year)
(t = 35.8) (t = -3.7)

$\bar{R}$-Squared = .97 DW = 1.9

2.
Temperature Sensitive Demand (Summer) = (F° - 65) (20.718 + 0.1106 * # A/Cs - 244.53 * ¢/kWh (lagged 2 periods))
(t = 25.5) (t = -4.9)

$\bar{R}$-Squared = .91 DW = 1.9

3.
Temperature Sensitive Demand (Winter) = (65 - F°) (-0.9842 + 0.13284 * # Electric Heaters)
(t = 24.2)

$\bar{R}$-Squared = .89 DW = 1.4

The Variables are defined as follows:

Base Load	The temperature-insensitive component of demand (MW).
Temperature-Sensitive Demand	The load component (MW) which is affected by heating or air conditioning on the system.
# Residential Customers	The average number of residential customers (in thousands).
¢/kWh	Tampa Electric Company's average cost of electricity per kWh adjusted for inflation.
F° (Summer)	Average 24-hour temperature for the day of the system peak load.
F° (Winter)	Peak hour temperature at the time of the system peak load.
# A/Cs	Number of residential air conditioners (in thousands) calculated by multiplying residential customers by cooling saturation levels.
# Electric Heaters	Number of residential electric heaters (in thousands) calculated by multiplying residential customers by electric heating saturation levels.

Energy Section

The energy section of the retail multiregression model consists of six equations that estimate future energy by the major customer classes (residential, commercial, industrial other than phosphate, phosphate, sales to public authorities, and street and highway lighting.) These equations are listed below.

1.
Average Residential Usage = 6045.7 + 51.226 * Chg in Personal Inc. Per Capita (t = 2.3) (lagged 1 year) - 563.6 * ¢/kWh (lagged 1 year) (t = -8.9) + 1.06167 * Total Degree Days (t = 4.5) + 8362.9 * Htg/Cooling Saturation (t = 19.1)

$\bar{R}$-Squared = .94 DW = 1.7

2.
Commercial Energy Sales = -75.95 + 13.813 * Residential Customers (t = 23.2) - 583.0 * ¢/kWh (lagged 1 year) (t = -4.1)

$\bar{R}$-Squared = .99 DW = .94

3.
Other Industrial Energy Sales = 334.44 + 5.933 * Ind Prod Index (t = 7.7) - 88.7825 *Chg. in ¢/kWh (lagged 1 year) (t = -1.7) - 138.1 * Trade Dummy Variable (t = -6.2)

$\bar{R}$-Squared = .70 DW = 1.7

4.
Phosphate Energy Sales = 1135.2 + 51.242 * U.S. Phosphate Mining (t = 10.3) - 331.39 * ¢/kWh (lagged 1 year) (t = -3.3)

$\bar{R}$-Squared = .84 DW = 1.0

5\.

Sales to Public Authorities	= 530.50 + 2.4514 • Residential Customers - 251.11 • Chg in ¢/kWh		
		(t = 10.9)	(t = -4.4)

$\bar{R}$-Squared = .98 DW = 1.1

6\.

Street Lighting	= - 29.073 + 0.10370 • Population	
		(t = 34.8)

$\bar{R}$-Squared = .98 DW = .70

The Variables are defined as follows:

Population	Hillsborough County Population (in thousands).
Residential Customers	Service Area Residential Customers (in thousands).
Chg in Personal Inc. Per Capita	Percent change in real personal income per capita in Hillsborough County.
Htg/Cooling Saturation	Weighted average of heating and cooling saturation rates.
Total Degree Days	Sum of heating and cooling degree days (billing cycle adjusted).
Ind Prod Index	Industrial Production Index (1992 = 100).
U.S. Phosphate Mining	U.S. mining production (in millions of metric tons).
¢/kWh	Cost per kWh for a given customer class adjusted for inflation.
Chg in ¢/kWh	Percent change in cost per kWh for a given customer class adjusted for inflation.
Trade Dummy Variable	Dummy variable representing import substitution of local basic industries production.

3. Trend Analysis

The role of trend analysis in the Tampa Electric Company forecasting process has changed as the stability of fuel prices and supplies has decreased. The present economic and political environment throughout the world has contributed to changing energy consumption patterns resulting in a need for more sophisticated forecasting techniques. Trending provides a useful check for the more intricate methods used by the company in developing the Customer, Demand, and Energy Forecast.

The primary strength of trend analysis is simplicity. When applied to series with stable growth patterns, this method is easy to use and is readily understood by those outside the forecasting process. The need for historical data is minimal, compared to other methods, and the need for external forecasts is alleviated as time is the only predictive variable. However, weaknesses are also a function of this simplicity. The use of time as the only explanatory variable limits the ability of the process to reflect changing economic conditions. Given the limitations of this technique, it can still be used to identify time trends, and it provides a familiarity with the data that aids in evaluating forecasts from other methods.

Trend analysis is applied to several variables including:

1. population;
2. residential customers;
3. system peak demand;
4. residential energy sales;
5. commercial energy sales;
6. industrial energy sales;
7. street lighting energy sales;
8. sales to public authorities; and
9. average usage per customer.

The implementation of trend analysis involves establishing a mathematical relationship between the independent variable (time) and the dependent variable. A forecast can be constructed by entering a future year into the equation. Evaluating the data over different time periods allows one to identify changes in the trend over time. Once trend estimates for the various components are established, they can be combined to yield a total sales forecast.

4. Phosphate Demand and Energy Analysis

Because Tampa Electric Company's phosphate customers are relatively few in number, the Bulk Power & Market Development and Cogeneration Services Departments have obtained detailed knowledge of industry developments including:

1. knowledge of expansion and close-out plans;
2. familiarity with historical and projected trends;
3. personal contact with industry personnel;
4. governmental legislation;
5. familiarity with worldwide demand for phosphate products;
6. knowledge of phosphate ore reserves; and
7. correlation between phosphate rock production and energy consumption.

These departments' familiarity with industry dynamics and their close working relationship with phosphate company representatives forms the basis for a survey of the phosphate customers to determine their future energy and demand requirements. This survey is the foundation upon which the phosphate forecast is based. Further inputs are provided by the multiregression model's phosphate energy equation and discussions with industry experts.

5. Conservation, Load Management and Cogeneration Programs

Tampa Electric has developed conservation, load management, and cogeneration programs to achieve four major objectives:

1. to defer capital expansion, particularly production plant construction;
2. to reduce marginal fuel cost by managing energy usage during higher fuel cost periods;
3. to give customers some ability to control their energy usage and decrease their energy costs, and
4. to pursue the cost-effective accomplishment of ten-year demand and energy goals established by the Florida Public Service Commission (FPSC) for the residential and commercial/industrial sectors.

The company's current DSM plan contains a mix of proven, mature programs that focus on the market place demand for their specific offerings. Additionally, we have developed residential and commercial mail-in audits designed to more economically target customers who have the potential to benefit significantly from our energy management programs. The following is a list that briefly describes the company's programs:

1. Heating and Cooling - Encourages the installation of high-efficiency heating and cooling equipment.

2. Load Management - Reduces weather-sensitive heating, cooling, water heating, and pool pump loads through a radio signal control mechanism. In addition, a commercial/industrial program is in effect.

3. Energy Audits - The program is a "how to" information and analysis guide for customers. Six types of audits will be available in 1998 to Tampa Electric customers; three types are for residential class customers and three types for commercial/industrial customers.

4. Ceiling Insulation - An incentive program for existing residential structures which will help to supplement the cost of adding additional insulation.

5. Commercial Indoor Lighting - Encourages investment in more efficient lighting technologies within existing commercial facilities.

6. Standby Generator - A program designed to utilize the emergency generation capacity of commercial/industrial facilities in order to reduce weather sensitive peak demand.

7. Conservation Value - Encourages investments in measures that are not sanctioned by other programs.

8. Duct Repair - An incentive program for existing homeowners which will help to supplement the cost of repairing leaky heating and cooling air ducts.

9. Cogeneration - A program whereby large industrial customers with waste heat or fuel resources may install electric generating equipment, produce their own electrical requirements and/or sell their surplus to the company.

In addition, the Energy Answer Home and Street and Outdoor Lighting programs were completed in 1987 and 1990, respectively.

The 1997 demand and energy savings achieved by our conservation and load management programs are listed in Table III-4.

TABLE III-4
Comparison of Achieved MW and GWh Reductions With Florida Public Service Commission Goals

Residential

	Winter Peak MW Reduction			Summer Peak MW Reduction			GWh Energy Reduction		
Year	Total Achieved	Commission Approved Goal	% Goal	Total Achieved	Commission Approved Goal	% Goal	Total Achieved	Commission Approved Goal	% Goal
1995	24.0	36.0	66.7%	2.7	12.0	22.5%	12.2	21.0	58.1%
1996	56.7	72.0	78.8%	10.6	23.0	46.1%	28.3	41.0	69.0%
1997	79.2	107.0	74.0%	16.9	35.0	48.3%	43.6	60.0	72.7%

Commercial/Industrial

	Winter Peak MW Reduction			Summer Peak MW Reduction			GWh Energy Reduction		
Year	Total Achieved	Commission Approved Goal	% Goal	Total Achieved	Commission Approved Goal	% Goal	Total Achieved	Commission Approved Goal	% Goal
1995	5.1	2.0	255.0%	5.0	7.0	71.4%	11.7	29.0	40.3%
1996	13.1	5.0	262.0%	15.2	13.0	116.9%	27.4	59.0	46.4%
1997	14.4	7.0	205.7%	18.6	20.0	93.0%	42.0	90.0	46.7%

Combined Total

	Winter Peak MW Reduction			Summer Peak MW Reduction			GWh Energy Reduction		
Year	Total Achieved	Commission Approved Goal	% Goal	Total Achieved	Commission Approved Goal	% Goal	Total Achieved	Commission Approved Goal	% Goal
1995	29.1	38.0	76.6%	7.7	19.0	40.5%	23.9	50.0	47.8%
1996	69.8	77.0	90.6%	25.8	36.0	71.7%	55.7	100.0	55.7%
1997	93.6	114.0	82.1%	35.5	55.0	64.5%	85.6	150.0	57.1%

To support the demand and energy savings filed as part of its plan, Tampa Electric Company developed its Monitoring and Evaluation (M&E) plan in response to requirements filed in Docket No. 941173-EG. The M&E plan was designed to effectively accomplish the required objective with prudent application of resources. Generally speaking, the M&E plan has as its focus two distinct areas: process evaluation and impact evaluation. Process evaluation examines how well a program has been implemented including the efficiency of delivery and customer satisfaction regarding the usefulness and quality of the services delivered. Impact evaluation is an evaluation of the change in demand and energy consumption achieved through program participation. The results of these evaluations give Tampa Electric Company insight into the direction that should be taken to refine delivery processes, program standards, and overall program cost-effectiveness.

Wholesale Load

Tampa Electric's wholesale sales consist of sales contracts with the City of Wauchula, the City of Fort Meade, Florida Power Corp., the City of St. Cloud, and the Reedy Creek Improvement District.

Since Tampa Electric's sales to Wauchula and Fort Meade will vary over time based on the strength of their local economies, a multiple regression approach similar to that used for forecasting Tampa Electric's retail load has been utilized. Under this methodology, three equations have been developed for each municipality for forecasting energy and peak demand. These equations are shown on the following two pages.

WAUCHULA MULTIREGRESSION EQUATIONS

1.

Average Customer Usage = 2923.9 - 120.2 * Change in ¢/kWh (t = -1.5) + 0.0687 * Per Capita Income (t = 3.9) + 1.770 * Cooling Degree Days (t = 21.1) + 2.58 * Heating Degree Days (t = 7.4)

$\bar{R}$-Squared = .96 DW = 1.9

2.

Winter Peak Demand = - 11.972 + 0.00839 * Total Customers (t = 14.0) + 0.176 * Heating Degree Days (t = 8.5)

$\bar{R}$-Squared = .90 DW = 1.9

3.

Summer Peak Demand = - 6.339 + 0.00605 * Total Customers (t = 12.0) + 0.177 * Cooling Degree Days (t = 3.9) - 0.260 * Change in ¢/kWh (lagged one month) (t = -1.5)

$\bar{R}$-Squared = .85 DW = 1.3

The Variables are defined as follows:

Change in ¢/kWh	Change in average cost per kWh adjusted for inflation.
Per Capita Income	Real per capita income (seasonally adjusted).
Total Customers	The average number of total customers.
Heating Degree Days	65 degrees less the average 24-hour temperature.
Cooling Degree Days	Average 24-hour temperature less 65 degrees.

FORT MEADE MULTIREGRESSION EQUATIONS

1.

Average Customer Usage = 914.20 - 63.42 * ¢/kWh + 0.115 * Change in Per Capita Income + 1.122 * Cooling Degree Days + 1.480 * Heating Degree Days

(t = -2.0) (t = 2.2) (t = 11.8) (t = 4.1)

$\bar{R}$-Squared = .87 DW = 1.9

2.

Winter Peak Demand = - 11.025 + 0.00713 * Total Customers + 0.1181 * Heating Degree Days

(t = 5.4) (t = 4.7)

$\bar{R}$-Squared = .78 DW = 1.5

3.

Summer Peak Demand = - 2.970 + 0.00460 * Total Customers + 0.1190 * Cooling Degree Days - 0.2733 * ¢/kWh

(t = 5.0) (t = 2.6) (t = -2.3)

$\bar{R}$-Squared = .86 DW = 1.5

The Variables are defined as follows:

¢/kWh	Average cost per kWh adjusted for inflation.
Change in Per Capita Income	Change in real per capita income (seasonally adjusted).
Total Customers	The average number of total customers.
Heating Degree Days	65 degrees less the average 24-hour temperature.
Cooling Degree Days	Average 24-hour temperature less 65 degrees.

For the remaining wholesale customers, future sales for a given year are based on the specific terms of their contracts with Tampa Electric.

Base Case Forecast Assumptions

Retail Load

1. Detailed End-Use Model

Numerous assumptions are inputs to the detailed end-use model of which the more significant ones are listed below.

1. Population and Residential Customers;
2. Commercial and Industrial Employment;
3. Per Capita Income;
4. Housing Mix;
5. Appliance Saturations;
6. Price Elasticity;
7. Price of Electricity;
8. Appliance Efficiency Standards; and
9. Weather.

Population/Residential Customers

The residential customer forecast is the starting point from which the demand and energy projections are developed. The most important factor in the customer forecast is the service area population estimate. The population estimate is based on Hillsborough County projections supplied by the University of Florida's Bureau of Economic and Business Research (BEBR), which are in the form of high, medium, and low forecasts. The REGIS model is utilized to determine where within the given range popuiation growth is likely to be. For the 1997-2007 period, Hillsborough County population is expected to increase at a 1.5% average annual rate. This rate is slightly above the BEBR's medium forecast of 1.4% per year over this same period.

Household formation trends supplied by the U.S. Bureau of the Census are applied to the Hillsborough population projections to arrive at Hillsborough County households. Finally, service area household forecasts are determined by adjusting the Hillsborough County figures to reflect the relationship between service area and Hillsborough County residential customers. Since 1970, households in the service area have expanded at a faster rate than population due to a decline in household size. This decline in persons per household has been the result of lower birth rates, higher divorce rates, the postponement of marriage by young adults, and an aging overall population. During the next ten years (1998-2007), persons per household are expected to fall at an annual rate of 0.4 percent. Therefcre, the household growth rate is expected to continue to exceed the population expansion rate in the service area over the next ten years.

Commercial and Industrial Employment

Commercial and industrial employment assumptions are utilized in computing energy and demand in their respective sectors. It is imperative that employment growth be consistent with the expected population expansion and unemployment levels. REGIS, which interrelates these important variables, ensures this consistency. In addition, forecasts from outside consulting firms also provide input into formulating these assumptions. For the 1997-2007 period, commercial employment is assumed to rise at a 1.9% average annual rate while industrial employment growth of 1.6% per year is expected.

Per Capita Income, Housing Mix, Appliance Saturations

The stock of appliances, which comprises the nucleus of SHAPES' residential sector, is determined by multiplying the number of households by the saturation rate for each appliance. The assumptions for real per capita income growth and housing mix are critical in computing these saturations since many of the appliances are influenced by income levels and the type of housing (single, multi-family, mobile home) in the service area. The housing mix and per capita income growth rates for the local area are based on forecasts from REGIS as well as from outside consulting services. For the 1997-2007 period, real per capita income is expected to increase at a 1.5% average annual rate.

Price Elasticity/Price of Electricity

Price elasticity measures the rate of change in the demand for a product, electricity in this case, that results from a change in its relative price. The expected elasticity effect can be quantified by multiplying this factor by the assumed change in the real price of electricity (See Page III-8). During the 1970s, price elasticity played a major role in slowing demand and energy growth due to the sharp increase in the price of electricity resulting from an explosion in fuel costs. Since 1981, an easing in fuel price pressures has been an important factor in keeping electricity cost changes below the general pace of inflation. Over the next decade, this pattern is expected to continue as the price of electricity should increase at a rate slower than other products and services.

Appliance Efficiency Standards

Another factor influencing residential energy consumption is the movement toward more efficient appliances. The forces behind this development include market pressures for more energy-saving devices and the appliance efficiency standards enacted by the state and federal governments. The efficiency goals affect the usage associated with new additions to the appliance stock.

Weather

Since weather is the most difficult input to project, historical data is the major determinant in developing temperature profiles. For example, monthly profiles used in calculating energy consumption are based on ten years of historical data. In addition, the temperature profiles used in projecting the winter and summer system peak are based on an examination of the minimum and maximum temperatures for the past forty years plus the temperatures on peak days for the past fifteen to twenty years.

2. Multiregression Demand and Energy Model

The multiregression model utilizes assumptions which are common to SHAPES. These assumptions include future inputs for population, residential customers, income, saturation levels for air conditioners/heaters, and the price of electricity. In all cases where the multiregression and SHAPES models use common input variables, the assumptions for these inputs are the same and result in forecasts which are consistent and comparable.

Wholesale Load

Wauchula and Ft. Meade projections are developed from regression equations which, in turn, are driven by forecasts of customers, real per capita income, and the real price of electricity. For the 1998-2007 period, total customers are projected to expand at a 1.6% and 1.2% annual rate, respectively. Also, real per capita income for both cities is projected to grow annually at a pace of 1.5% and 1.4%, respectively.

High and Low Scenario Forecast Assumptions

Retail Load

The high and low peak demand and energy projections represent alternatives to the company's base case outlook. The high band represents a more optimistic economic scenario than the base case (most likely scenario) with greater expected growth in the areas of customers, employment, and income. The low band represents a less optimistic scenario than the base case with a slower pace of service area growth.

The assumptions related to the high, low, and base peak demand and energy cases are presented in Table III-5. For all other assumptions, including weather and price elasticity, the assumptions remain the same as in the base case scenario.

Wholesale Load

Likewise, high and low forecast scenarios are developed for wholesale customers Wauchula and Fort Meade. For these two municipalities, the assumptions that varied under the alternative scenarios include total customers, real price of electricity, and real per capita income. The bandwidth for the high/low forecasts assumptions are 0.4%, 0.5%, and 0.5%, respectively.

History and Forecast of Energy Use

A history and forecast of energy consumption by customer classification are shown in Table II-1 (Schedules 2.1 - 2.3) and Figure III-2.

Retail Energy

For 1997-2007, retail energy sales are projected to rise at a 2.5% annual rate. The major contributors to growth will continue to be the commercial, governmental, and residential categories. As a group, these three sectors will be increasing at a 3.0% annual rate.

In contrast, industrial sales are expected to decline over this period. Non-phosphate industrial consumption should register an annual gain over the coming years. However, this will be more than offset by a drop in phosphate sales due to an increase in self-service cogeneration and the southward migration of mining activity. This pattern reflects the changing American economy where the service sector is expanding at a rapid pace relative to manufacturing activity.

The combination of service area income growth and a declining real price of electricity has resulted in rising average residential usage in recent years. Over the 1998-2007 period, usage is anticipated to maintain this upward path based on expectations of continuing economic gains and a downward drift in the real price of electricity.

TABLE III-5. Economic Outlook Assumptions (1997-2007) For Retail Load Forecast

	Average Annual Growth Rate		
	BASE CASE	LOW GROWTH SCENARIO	HIGH GROWTH SCENARIO
Residential Customers	1.7%	1.3%	2.1%
Employment	1.5%	1.1%	1.9%
Real Per Capita Income	1.5%	1.0%	2.0%
Real Price of Electricity	-1.6%	-1.1%	-2.1%

Source: Tampa Electric Company

Wholesale Energy

Wholesale energy sales to FMPA, FPC, Wauchula, Ft. Meade, St. Cloud, and Reedy Creek of 1,141 GWh are expected in 1998, 389 GWh in 1999, and 331 GWh in 2000. Sales are expected to remain in the 320-380 GWh range for 2001-2007.

History and Forecast of Peak Loads

Historical and base, high, and low scenario forecasts of peak loads for the summer and winter seasons are presented in Tables II-2 and II-3 (Schedules 3.1 and 3.2), respectively. For the 1998-2007 period, Tampa Electric's base case retail firm peak demand for the winter and summer are expected to advance at annual rates of 1.5% and 2.4%, respectively. In addition, base, high, and low scenario forecasts of NEL are listed in Table II-4 (Schedule 3.3).

Monthly Forecast of Peak Loads for Years 1 and 2

A monthly forrcast of retail peak loads (MW) and net energy for load (GWh) for years 1 and 2 of the forecast is provided in Table II-5 (Schedule 4).

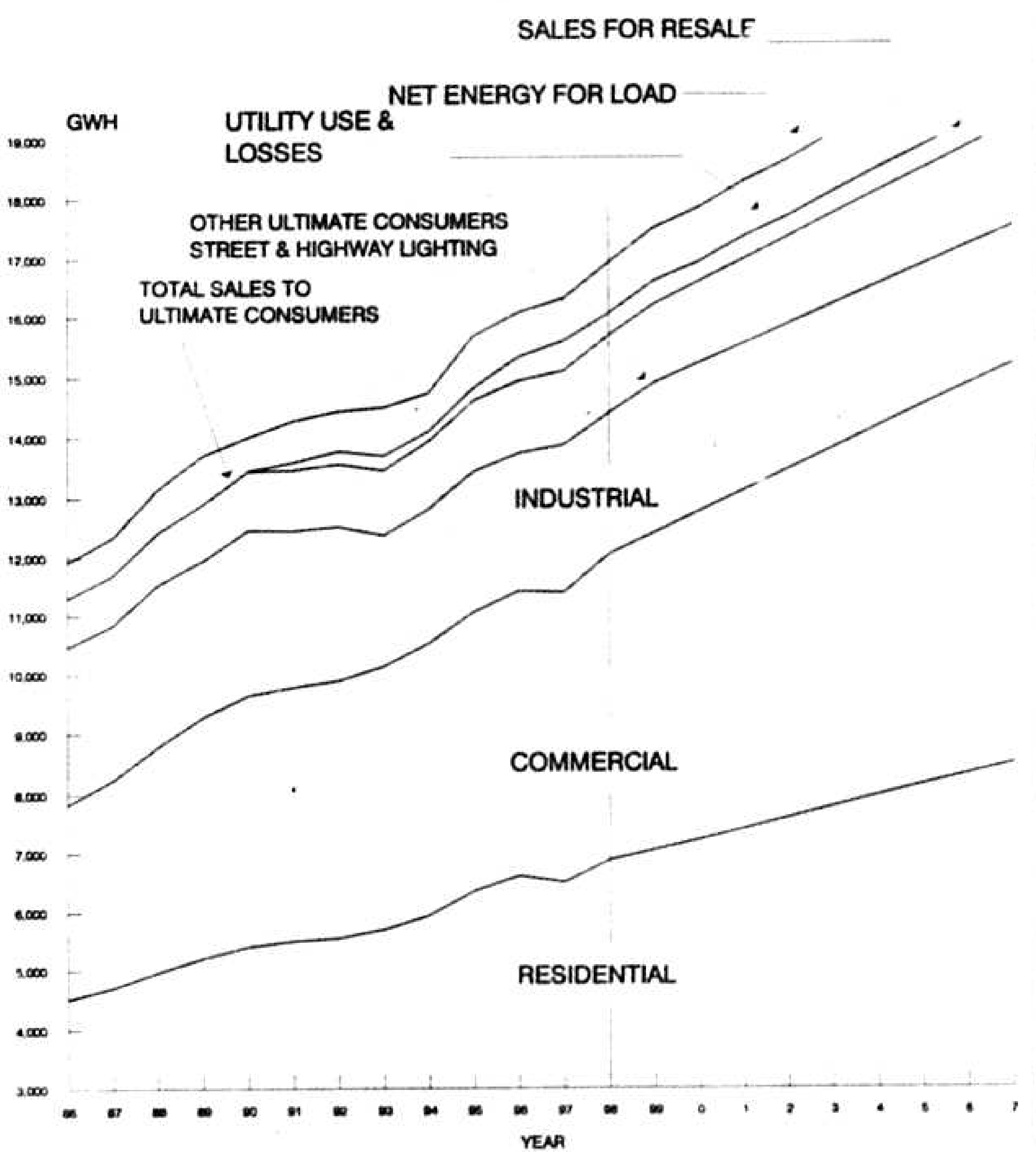


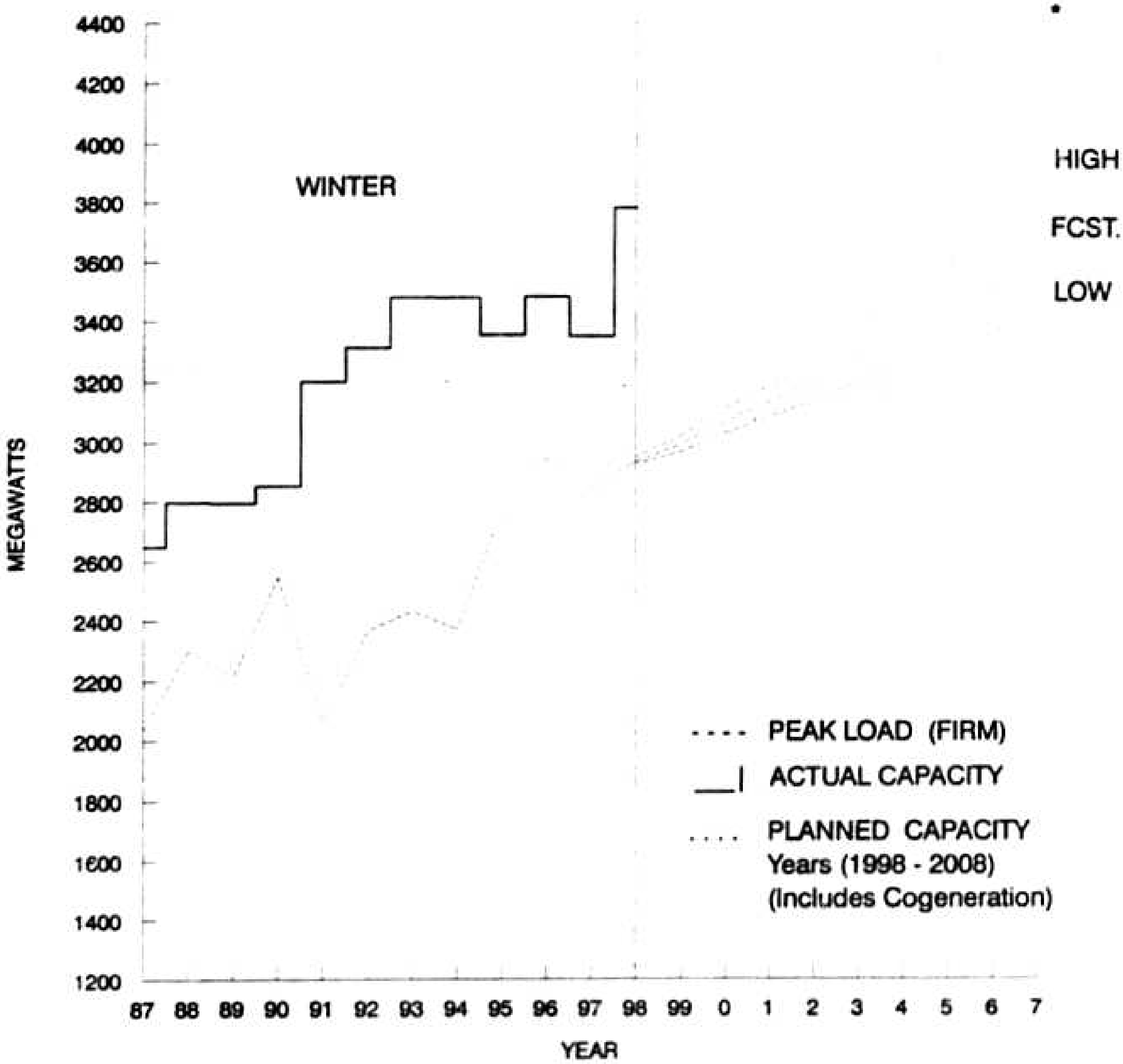
Figure III-2

HISTORY AND FORECAST OF ENERGY USE

TAMPA ELECTRIC COMPANY
Ten-Year Site Plan
For Electrical Generating Facilities
And Associated Transmission Lines

SOURCE: TAMPA ELECTRIC COMPANY

FIGURE III-3 HISTORY & FORECAST OF LOAD AND CAPACITY ADDITIONS
Page 1 of 2

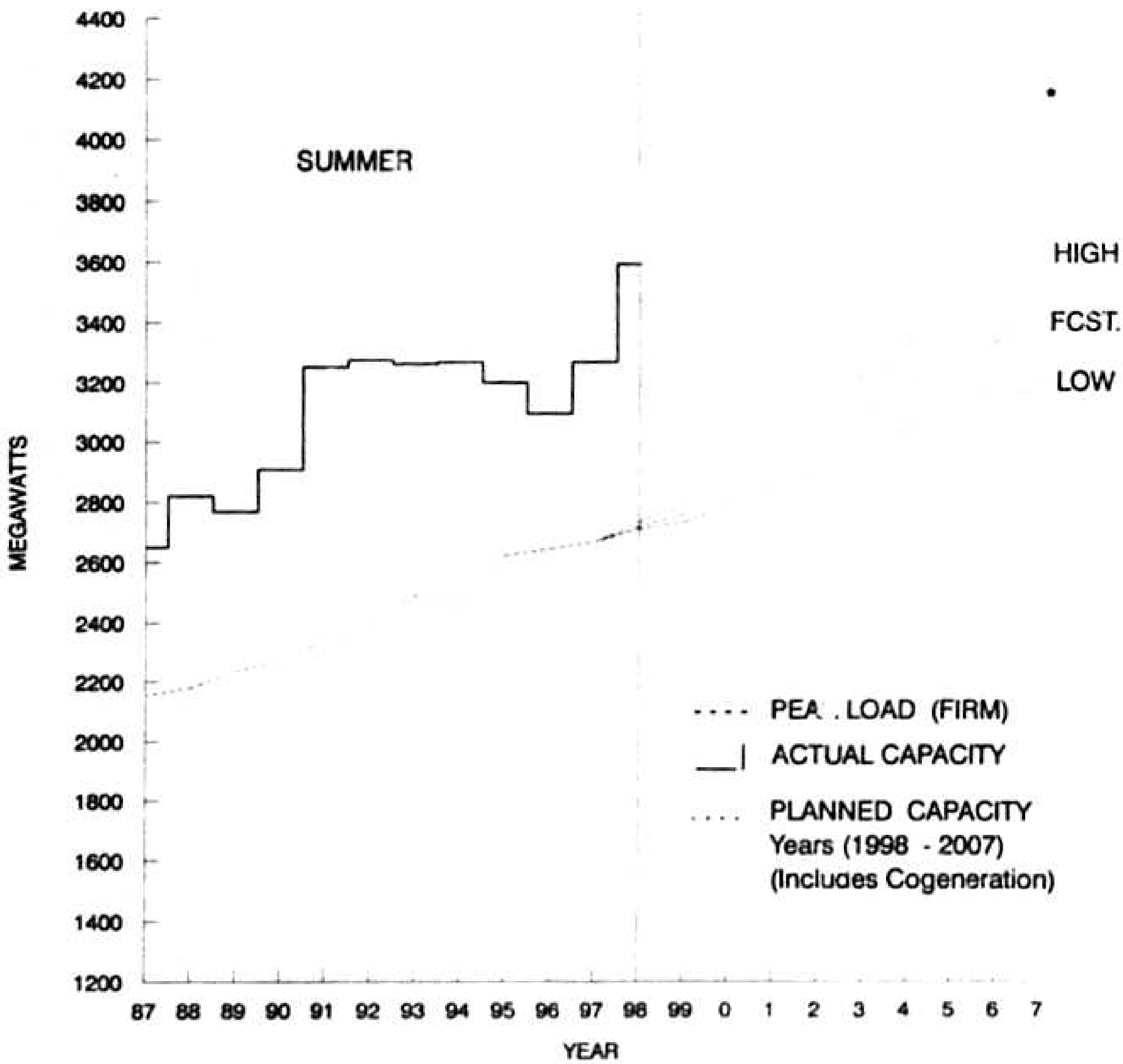


* AGREES WITH SCHEDULE 7.2, COL. 6

Ten-Year Site Plan
For Electrical Generating Facilities
And Associated Transmission Lines

PAGE 48 OF 94

FIGURE III-3 HISTORY & FORECAST OF LOAD AND CAPACITY ADDITIONS
Page 2 of 2



* AGREES WITH SCHEDULE 7.1 , COL. 6

Ten-Year Site Plan
For Electrical Generating Facilities
And Associated Transmission Lines

CHAPTER IV

FORECAST OF FACILITIES REQUIREMENTS

The proposed generating facility additions and changes shown in Table IV-3 integrate demand side management programs and alternative generation technologies with traditional generating resources to provide economical, reliable service to Tampa Electric Company's customers. To achieve this objective, various energy resource plan alternatives comprised of a mixture of generating technologies, purchased power, and cost-effective demand side management programs are developed. These alternatives are analyzed with existing generating capabilities to develop a number of energy resource options which meet Tampa Electric's future system demand and energy requirements. A detailed discussion of Tampa Electric Company's integrated resource planning process is included in Chapter V.

The results of the analysis provide Tampa Electric Company with a plan that is cost-effective while maintaining system reliability and balancing other engineering, business, and industry issues. The new capacity additions are shown in Table IV-3. Additional capacity is first needed in 2003, based on an analysis of system reliability, the incorporation of the FPSC demand side management goals, projected system demand and energy requirements, purchase power, and the existing Tampa Electric generating system. To meet the expected system demand and energy requirements over the next ten years, combustion turbines are planned for service in 2003, 2004, and 2006. These dual-fuel combustion turbines will be fired by natural gas and distillate oil. For purposes of this study, Hookers Point Station is assumed to be retired in January 2003, and Tampa Electric's long-term purchase power contract with Hardee Power Partners Limited remains at 297 MW summer net capability and 360 MW winter net capability for the entire study period. Some of the assumptions and information that impact the plan are discussed below. Additional assumptions and information are discussed in Chapter V.

Cogeneration

Tampa Electric Company plans for 444 MW of cogeneration capacity operating in its service area in 1998. Self-service capacity of 236 MW (net) is used by cogenerators to serve internal load requirements, 62 MW are purchased by Tampa Electric on a firm contract basis, and 6 MW are purchased on a non-firm as-available basis. By 2007, the cogeneration capacity within our service area is expected to increase to 472 MW. This total will consist of 253 MW of self-service capacity, 62 MW of firm capacity purchases by Tampa Electric, and 7 MW of non-firm as-available purchases by Tampa Electric. During 1998, Tampa Electric has entered into transmission wheeling agreements with four of its cogeneration customers, supplying a total of 154 MW of firm contract capacity to two other utilities in the state. By 2007, this total is expected to decrease to 145 MW.

Fuel Requirements

A forecast of fuel requirements and energy sources is shown in Tables II-6 and II-7, respectively. As shown in these tables, Tampa Electric Company plans to continue to use coal as the primary fuel for most of its generating requirements. Alternative fuels were considered and have been incorporated when appropriate to achieve a low cost fuel strategy which benefits Tampa Electric's customers while meeting environmental emissions requirements. The Polk Unit 1 IGCC unit utilizes syngas as the primary fuel with No. 2 oil as the back-up. The syngas will be produced from five demonstration fuels during the first three years of commercial operation to satisfy their demonstration requirements. The demonstration fuels include coal and a coal/petroleum coke blend. Following the demonstration period, Tampa Electric Company plans to utilize a coal/petroleum coke blend to produce syngas. This blend will result in the IGCC unit being the lowest incremental cost resource on Tampa Electric Company's system. Coal, including coal/petroleum coke blends, will provide approximately 94%-98% of the fuel requirements for Tampa Electric's total generation and 88%-93% of total system requirements. This fuel strategy, which makes use of this nation's most abundant domestic fuel, is both practical and cost-effective and minimizes exposure to a disruption in fuel supply or market price volatility.

Clean Air Act Amendments of 1990

The primary focus of Title IV of the Clean Air Act Amendments is a nationwide reduction of sulfur dioxide and nitrogen oxide emissions from existing electric utilities and non-utility sources. The potential impact of other amendments in the Act on the generating system has not been included in this Ten-Year Site Plan. Tampa Electric Company has three generating units, Big Bend Units 1-3, which are Phase I (1995-1999) affected units under Title IV of the Clean Air Act Amendments of 1990. Big Bend Unit 4 was identified as a substitution unit under Title IV of the Clean Air Act Amendments and brought under Phase I compliance requirements. The designation of Big Bend Unit 4 as a Phase I Unit provided an integrated approach for achieving SO_2 compliance for Big Bend Station. Tampa Electric Company currently maintains compliance with the Phase I emission limitations by using blends of low sulfur coal, a small quantity of purchased sulfur dioxide allowances, and integration of Big Bend Unit 3 flue gas with the Big Bend Unit 4 flue gas desulfurization system (FGD). In Phase II (2000-beyond), all of Tampa Electric's units are affected under Title IV except existing combustion turbines, Phillips Station, and Dinner Lake. To cost-effectively comply with Phase II emission standards, Tampa Electric will continue to evaluate the use of low sulfur coal blends, sulfur dioxide allowances, and flue gas scrubbing.

<u>Interchange Sales and Purchases</u>

Tampa Electric interchanges sales include Schedule D and Partial Requirements (PR) service agreements with several utilities and a Schedule G contract with Seminole Electric Cooperative, Inc. (SEC) for non-firm capacity and energy.

Tampa Electric has a long term purchase power contract for capacity and energy with Hardee Power Partners Limited (a TECO Power Services Corporation). The contract involves a shared-capacity agreement with SEC, whereby Tampa Electric plans for the full net capability of the Hardee Power Station during those times when SEC plans for the full availability of Seminole Units 1 and 2 and the SEC Crystal River Unit 3 allocation, and reduced availability during times when Seminole Units 1 and 2 are derated or unavailable due to planned maintenance. A firm capacity sale from Tampa Electric's Big Bend Station Unit No. 4 is made available, on a limited energy usage basis, to Hardee Power Partners Limited for resale to SEC.

In addition to the above sales and purchases, Tampa Electric also has Schedule J service agreements for the interchanges/sale of as-available power with/to thirteen utilities in Florida and Georgia.

Wholesale power sales and purchases are included in Tables II-2, II-3, II-4, II-5, II-6, II-7, IV-1, and IV-2.

Schedule 7.1

Table IV-1
Forecast of Capacity, Demand, and Scheduled Maintenance at Time of Summer Peak

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
	Total Installed Capacity	Firm Capacity Import	Firm Capacity Export		Total Capacity Available	System Firm Summer Peak Demand	Reserve Margin Before Maintenance		Scheduled Maintenance	Reserve Margin After Maintenance	
Year	MW	MW	MW	QF MW	MW	MW	MW	% of Peak	MW	MW	% of Peak
1998	3,493 *	297	(262)	62	3,590	2,833	757	27%	123	634	22%
1999	3,493	297	(176)	62	3,676	2,890	786	27%	15	771	27%
2000	3,493	297	(147)	62	3,706	2,963	742	25%	169	573	19%
2001	3,493	297	(147)	62	3,705	3,057	648	21%	0	648	21%
2002	3,493	297	(147)	62	3,705	3,140	565	18%	15	550	18%
2003	3,434	297	0	62	3,793	3,239	554	17%	0	554	17%
2004	3,582	297	0	62	3,941	3,321	620	19%	108	512	15%
2005	3,582	297	0	62	3,941	3,388	553	16%	0	553	16%
2006	3,730	297	0	62	4,089	3,468	621	18%	0	621	18%
2007	3,730	297	0	62	4,089	3,518	571	16%	0	571	16%

December 31, 1997 Status

NOTE:

1. Capacity import includes the Purchase Agreement with TECO Power Services (TPS) beginning in 1993. Availability of this capacity is subject to back-up requirements for Seminole Electric Cooperative.
2. Capacity export includes 145 MW of Big Bend 4 which will be sold to TECO Power Services, on a limited basis, for use by Seminole Electric Cooperative. Capacity export also includes a firm D transaction to New Smyrna Beach of 18 MW in 1998 and 19 MW in 1999 as well as a Schedule J transaction with New Smyrna Beach of 10 MW in 1998 and 1999 which is treated as firm for expansion planning purposes. Capacities shown in table include losses.
3. Capacity export includes a firm D transaction to Florida Municipal Power Agency of 85 MW for the summer of 1998. For periods beyond calendar year 1998, Tampa Electric plans to fulfill the FMPA capacity obligation via firm power purchases.
4. The QF column accounts for cogeneration that will be purchased under firm contracts.

* Does not include 11 MW from Dinner Lake unit which was placed on long-term reserve standby 03/01/94, nor 3 MW from Phillips HRSG which is on full forced outage with an undetermined return to service date.

** Values may be affected by rounding.

Table IV-2

Forecast of Capacity, Demand, and Scheduled Maintenance at Time of Winter Peak

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
	Total Installed Capacity	Firm Capacity Import	Firm Capacity Export	QF	Total Capacity Available	System Firm Winter Peak Demand	Reserve Margin Before Maintenance		Scheduled Maintenance	Reserve Margin After Maintenance	
Year	MW	MW	MW	MW	MW	MW	MW	% of Peak	MW	MW	% of Peak
1997-98	3,615 *	360	(261)	62	3,776	3,049	727	24%	34	693	23%
1998-99	3,615	360	(160)	62	3,877	3,118	759	24%	34	725	23%
1999-00	3,615	360	(161)	62	3,876	3,195	681	21%	34	647	20%
2000-01	3,615	360	(147)	62	3,890	3,277	613	19%	34	579	18%
2001-02	3,615	360	(147)	62	3,890	3,343	547	16%	34	513	15%
2002-03	3,580	360	0	62	4,002	3,433	569	17%	0	569	17%
2003-04	3,760	360	0	62	4,182	3,509	673	19%	0	673	19%
2004-05	3,760	360	0	62	4,182	3,578	604	17%	0	604	17%
2005-06	3,940	360	0	62	4,362	3,655	707	19%	0	707	19%
2006-07	3,940	360	0	62	4,362	3,724	638	17%	0	638	17%

December 31, 1997 Status

NOTE:

1. Capacity import includes the Purchase Agreement with TECO Power Services (TPS) beginning in 1993. Availability of this capacity is subject to back-up requirements for Seminole Electric Cooperative.

2. Capacity export includes 145 MW of Big Bend 4 which will be sold to TECO Power Services, on a limited basis, for use by Seminole Electric Cooperative. Capacity export also includes a firm D transaction to Reedy Creek Improvement District of 27 MW in 1998, 13 MW in 1999, and 14 MW in 2000. Capacities shown in table include losses.

3. Capacity export includes a firm D transaction to Florida Municipal Power Agency of 85 MW for the summer of 1998. For periods beyond calendar year 1998, Tampa Electric plans to fulfill the FMPA capacity obligation via firm power purchases.

4. The QF column accounts for cogeneration that will be purchased under firm contracts.

* Does not include 11 MW from Dinner Lake unit which was placed on long-term reserve standby 03/01/94, nor 3 MW from Phillips HRSG which is on full forced outage with an undetermined return to service date.

** Values may be affected by rounding.

Schedule 8

Table IV-3
Planned and Prospective Generating Facility Additions

Plant Name	Unit No.	Location	Type	Fuel Primary	Fuel Alternate	Const. Start Mo/Yr	Commercial In-Service Mo/Yr	Expected Retirement Mo/Yr	Gen. Max. Nameplate kW	Net Capability Summer MW	Net Capability Winter MW	Fuel Trans. Primary	Fuel Trans. Alternate	Status
Polk	2	Polk Co.	CT	NG	LO	1/01	1/03	unknown	unknown	148	180	PL	TK	P
	3	Polk Co.	CT	NG	LO	1/02	1/04	unknown	unknown	148	180	PL	TK	P
	4	Polk Co.	CT	NG	LO	1/04	1/06	unknown	unknown	148	180	PL	TK	P

December 31, 1997 Status

SCHEDULE 9

TABLE IV-4
(Page 1 of 3)

STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
UTILITY: TAMPA ELECTRIC COMPANY

(1)	PLANT NAME AND UNIT NUMBER	POLK UNIT 2
(2)	CAPACITY	
	A. SUMMER	148
	B. WINTER	180
(3)	TECHNOLOGY TYPE	COMBUSTION TURBINE
(4)	ANTICIPATED CONSTRUCTION TIMING	
	A. FIELD CONSTRUCTION START-DATE	JAN 2001
	B. COMMERCIAL IN-SERVICE DATE	JAN 2003
(5)	FUEL	
	A. PRIMARY FUEL	NATURAL GAS
	B. ALTERNATE FUEL	DISTILLATE OIL
(6)	AIR POLLUTION CONTROL STRATEGY	N/A
(7)	COOLING METHOD	N/A
(8)	TOTAL SITE AREA [2]	APPROXIMATELY 4,347 ACRES
(9)	CONSTRUCTION STATUS	PROPOSED
(10)	CERTIFICATION STATUS	N/A
(11)	STATUS WITH FEDERAL AGENCIES	N/A
(12)	PROJECTED UNIT PERFORMANCE DATA	
	PLANNED OUTAGE FACTOR (POF)	1.7
	FORCED OUTAGE RATE (FOR)	3.4
	EQUIVALENT AVAILABILITY FACTOR (EAF)	95.0
	RESULTING CAPACITY FACTOR (%) [1]	20.3
	AVERAGE NET OPERATING HEAT RATE (ANOHR) [1]	11,241 Btu/kWh
(13)	PROJECTED UNIT FINANCIAL DATA	
	BOOK LIFE (YEARS)	30
	TOTAL INSTALLED COST (IN-SERVICE YEAR $/kW)	272.32
	DIRECT CONSTRUCTION COST ($/kW)	228.70
	AFUDC AMOUNT ($/kW)	20.66
	ESCALATION ($/kW)	22.96
	FIXED O&M (2003 $/kW-YR)	3.25
	VARIABLE O&M (2003 $/MWh)	1.98
	K-FACTOR [1]	1.617

[1] BASED ON IN-SERVICE YEAR.
[2] REPRESENTS TOTAL POLK SITE.

SCHEDULE 9

TABLE IV-4
(Page 2 of 3)
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
UTILITY: TAMPA ELECTRIC COMPANY

(1)	PLANT NAME AND UNIT NUMBER	POLK UNIT 3
(2)	CAPACITY	
	A. SUMMER	148
	B. WINTER	180
(3)	TECHNOLOGY TYPE	COMBUSTION TURBINE
(4)	ANTICIPATED CONSTRUCTION TIMING	
	A. FIELD CONSTRUCTION START DATE	JAN 2002
	B. COMMERCIAL IN-SERVICE DATE	JAN 2004
(5)	FUEL	
	A. PRIMARY FUEL	NATURAL GAS
	B. ALTERNATE FUEL	DISTILLATE OIL
(6)	AIR POLLUTION CONTROL STRATEGY	N/A
(7)	COOLING METHOD	N/A
(8)	TOTAL SITE AREA [2]	APPROXIMATELY 4,347 ACRES
(9)	CONSTRUCTION STATUS	PROPOSED
(10)	CERTIFICATION STATUS	N/A
(11)	STATUS WITH FEDERAL AGENCIES	N/A
(12)	PROJECTED UNIT PERFORMANCE DATA	
	PLANNED OUTAGE FACTOR (POF)	1.7
	FORCED OUTAGE RATE (FOR)	3.4
	EQUIVALENT AVAILABILITY FACTOR (EAF)	95.0
	RESULTING CAPACITY FACTOR (%) [1]	19.1
	AVERAGE NET OPERATING HEAT RATE (ANOHR) [1]	11,151 Btu/kWh
(13)	PROJECTED UNIT FINANCIAL DATA	
	BOOK LIFE (YEARS)	30
	TOTAL INSTALLED COST (IN-SERVICE YEAR $/kW)	279.94
	DIRECT CONSTRUCTION COST ($/kW)	228.70
	AFUDC AMOUNT ($/kW)	21.24
	ESCALATION ($/kW)	30.00
	FIXED O&M (2004 $/kW-YR)	3.35
	VARIABLE O&M (2004 $/MWh)	2.04
	K-FACTOR [1]	1.624

[1] BASED ON IN-SERVICE YEAR.
[2] REPRESENTS TOTAL POLK SITE.

SCHEDULE 9

TABLE IV-4
(Page 3 of 3)
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
UTILITY: TAMPA ELECTRIC COMPANY

(1)	PLANT NAME AND UNIT NUMBER	POLK UNIT 4
(2)	CAPACITY	
	A. SUMMER	148
	B. WINTER	180
(3)	TECHNOLOGY TYPE	COMBUSTION TURBINE
(4)	ANTICIPATED CONSTRUCTION TIMING	
	A. FIELD CONSTRUCTION START DATE	JAN 2004
	B. COMMERCIAL IN-SERVICE DATE	JAN 2006
(5)	FUEL	
	A. PRIMARY FUEL	NATURAL GAS
	B. ALTERNATE FUEL	DISTILLATE OIL
(6)	AIR POLLUTION CONTROL STRATEGY	N/A
(7)	COOLING METHOD	N/A
(8)	TOTAL SITE AREA [2]	APPROXIMATELY 4,347 ACRES
(9)	CONSTRUCTION STATUS	PROPOSED
(10)	CERTIFICATION STATUS	N/A
(11)	STATUS WITH FEDERAL AGENCIES	N/A
(12)	PROJECTED UNIT PERFORMANCE DATA	
	PLANNED OUTAGE FACTOR (POF)	1.7
	FORCED OUTAGE RATE (FOR)	3.4
	EQUIVALENT AVAILABILITY FACTOR (EAF)	95.0
	RESULTING CAPACITY FACTOR (%) [1]	18.5
	AVERAGE NET OPERATING HEAT RATE (ANOHR) [1]	11,095 Btu/kWh
(13)	PROJECTED UNIT FINANCIAL DATA	
	BOOK LIFE (YEARS)	30
	TOTAL INSTALLED COST (IN-SERVICE YEAR $/kW)	295.83
	DIRECT CONSTRUCTION COST ($/kW)	228.70
	AFUDC AMOUNT ($/kW)	22.44
	ESCALATION ($/kW)	44.69
	FIXED O&M (2006 $/kW-YR)	3.55
	VARIABLE O&M (2006 $/MWh)	2.16
	K-FACTOR [1]	1.639

[1] BASED ON IN-SERVICE YEAR.
[2] REPRESENTS TOTAL POLK SITE.

Schedule 10

Table IV-5
Status Report and Specifications of Proposed Directly Associated Transmission Lines

(1)	Point of Origin and Termination:	N/A
(2)	Number of Lines:	N/A
(3)	Right-of-Way:	N/A
(4)	Line Length:	N/A
(5)	Voltage:	N/A
(6)	Anticipated Construction Timing:	N/A
(7)	Anticipated Capital Investment:	N/A
(8)	Substations:	N/A
(9)	Participation with Other Utilities:	N/A

Tampa Electric has no plans to construct transmission lines which correspond to proposed generating facilities.

CHAPTER V

OTHER PLANNING ASSUMPTIONS AND INFORMATION

Transmission Constraints and Impacts

Assessments of Tampa Electric transmission system performance are based upon planning studies completed in 1997 in support of Tampa Electric's transmission expansion plan. These studies are performed annually with the results of the study varying due to updates in load projections, planning criteria, and operating flexibility. Based on existing studies and Tampa Electric's current transmission construction program, Tampa Electric anticipates no transmission constraints on our system which violate the submitted performance criteria contained in the Generation and Transmission Reliability Criteria section of this document.

Expansion Plan Economics and Load Sensitivity

The overall economics and cost-effectiveness of the plan were analyzed as stated in Tampa Electric's Integrated Resource Planning process. This process is discussed in detail later in this chapter. Sensitivity analyses using high and low bands of the base case load forecast yielded generation expansion plans that were significantly different from the base case plan of one combustion turbine in each of the years 2003, 2004, and 2006. Optimization based on the low load forecast deferred the 2004 combustion turbine two years and moved the third combustion turbine out of the ten-year planning window. The expansion plan based on the high load forecast begins one year earlier than the base plan and includes two combustion turbines and two combined cycle units.

Fuel Forecast and Sensitivity

Product price for actual and forecast data for the purpose of deriving base, high, and low forecast pricing is done by careful analysis of actual price and current and previous forecasts obtained by various consultants and agencies. These sources include the Energy Information Administration, American Gas Association, Cambridge Energy Research Associates, Resource Data International, Coal Markets Weekly, Coal Daily, Energy Ventures Analysis, Inc., and coal, oil, natural gas, and propane pricing publications and periodicals which include: Coal Outlook, Inside FERC, Natural Gas Week, Platt's Oilgram, and the Oil and Gas Journal.

The high and low fuel price projections represent alternative forecasts to the company's base case outlook. The high price projection represents the effect of oil and natural gas prices escalating 10% above the base case on a monthly basis to the year 2000.

The low price scenario represents the effect of oil and natural gas prices escalating 10% below the product price of the base case on a monthly basis to the year 2000. Annual high and low case price projections after 2000 are based on the company's internal general approach using information provided by consultants combined with internal fuel markets analysis.

With a large percentage of fuel utilized by the company being coal, only base case forecasts are prepared for coal fuels. Base case analysis and forecasts include a large number of coal sources and diverse qualities. The individual price forecasts contained within the base forecast capture the market pressures and sensitivities that would otherwise be reflected in high and low case scenarios.

Expansion plan fuel sensitivity analyses were performed using high/low gas and oil price forecasts. The base case expansion plan did not change as a result of substitution of the base fuel forecast with the low fuel forecast. The expansion plan based on the high fuel forecast, however, did vary from the base plan in that the last unit selected was a combined cycle unit instead of a combustion turbine.

Expansion Plan Sensitivity Constant Fuel Differential

Even though Tampa Electric does not recognize, as a viable forecasting method, the arbitrary development of a fuel forecast by fixing the price differential between non-linked fuels, an expansion plan fuel sensitivity was performed by holding the differential between oil/gas and coal constant. The base case expansion plan did not change as a result of this change in the fuel price forecast. This result was expected because Tampa Electric Company's base case expansion plan consists of combustion turbines. These dual-fuel combustion turbines will be fired by natural gas and distillate oil. Because this sensitivity lowers Tampa Electric Company's natural gas and oil price forecasts and Tampa Electric Company's future resources are fired by natural gas and oil, it results in the same base case plan.

Generating Unit Performance Modeling

Tampa Electric Company models generating unit performance in the Generation and Fuel (GAF) module of PROSCREEN, a computer model developed by New Energy Associates. This module is a tool to evaluate long-range system operating costs associated with particular generation expansion plans. Generating units in the GAF are characterized by several different performance parameters. These parameters include capacity, heat rate, unit derations, planned maintenance weeks, and unplanned outage rates. The unit performance projections that are modeled are based on historical data trends, engineering judgement, time since last planned outage, and recent equipment performance. Specifically, unit capacity and heat rate projections are based on historical unit performance test values which are adjusted as needed for current unit conditions. Planned outage projections are modeled two ways. The first five years of planned outages are based on a forecasted outage schedule, and the planned outages for the balance of the years are based on an average of the first five years.

The five-year outage schedule is based on unit-specific maintenance needs, material lead time, labor availability, budget constraints, and the need to supply our customers with power in the most economical manner. Unplanned outage rate projections are based on an average of three years of historical data adjusted, if necessary, to account for current unit conditions.

<u>Financial Assumptions and Sensitivities</u>

Tampa Electric makes numerous financial assumptions as part of the preparation for its Ten-Year Site Plan process. These assumptions are based on the current financial condition of the company, the market for securities, and the best available forecast of future conditions. The primary financial assumptions include the FPSC-approved Allowance for Funds Used During Construction (AFUDC) rate, capitalization ratios, financing cost rates, tax rates, and FPSC-approved depreciation rates.

- Per the Florida Administrative Code, an amount for AFUDC is recorded by the company during the construction phase of each capital project. This rate is set by the FPSC and represents the cost of money invested in the applicable project while it is under construction. This cost is capitalized, becomes part of the project investment, and is recovered over the life of the asset. The AFUDC rate assumed in the Ten-Year Site Plan represents the company's currently approved AFUDC rate.
- The capitalization ratios represent the percentages of incremental long-term capital that are expected to be issued to finance the capital projects identified in the Ten-Year Site Plan.
- The financing cost rates reflect the incremental cost of capital associated with each of the sources of long-term financing.
- Tax rates include federal income tax, state income tax, and miscellaneous taxes including property tax.
- Depreciation represents the annual cost to amortize over its useful life the total original investment in a plant item less net salvage value. This provides for the recovery of plant investment. The assumed book life for each capital project within the Ten-Year Site Plan represents the average expected life for that type of investment.

Sensitivities were performed by taking the top ranked resource plans and analyzing them with respect to varying financial assumptions, using PROSCREEN. Each financial assumption was tested by increasing and decreasing the financial assumption by one percent. The capital, operating and maintenance, and fuel costs for each resource plan were analyzed. The variation in the financial assumptions had no impact on the base plan within the ten year planning window because the top ranked plans were identical through year 200[illegible].

Integrated Resource Planning Process

Tampa Electric Company's Integrated Resource Planning process was designed to evaluate demand side and supply side resources on a fair and consistent basis to satisfy future energy requirements in a cost-effective and reliable manner, while considering the interests of utility customers and shareholders. A flow diagram of the overall process is shown in Figure V-1.

The initial pass of the process incorporates a reliability analysis to determine timing of future needs, and an economic analysis to determine what resource alternatives best meet future system demand and energy requirements. In this pass, a demand and energy forecast which excludes incremental DSM programs is developed. Then a supply plan based on the system requirements which excludes incremental DSM is developed. This interim supply plan becomes the basis for potential avoided unit(s) in a comprehensive cost-effective analysis of the DSM programs. Once the cost-effective DSM programs are determined, the system demand and energy requirements are revised to include the effects of these programs on reducing system peak and energy requirements. The process is repeated to incorporate the DSM programs and supply side resources. The same planning and business assumptions are used to develop numerous combinations of DSM and supply side resources that account for variances in both timing and type of resources added to the Tampa Electric Company system.

The cost-effectiveness of DSM programs is based on the following standard Commission tests: the Rate Impact Measure (RIM), the Total Resource Cost (TRC), and the Participants Tests. Using the Commission's standard cost-effectiveness methodology, each measure is evaluated based on different marketing and incentive assumptions. Utility plant avoidance assumptions for generation, transmission, and distribution are used in this analysis. All measures that pass the RIM, TRC, and Participants Tests in the DSM analysis are considered for utility program adoption. Each adopted measure is quantified into annual kW/kWh savings and is reflected in the demand and energy forecast. Measures with the highest RIM values are generally adopted first.

Tampa Electric Company evaluates DSM measures using a spreadsheet developed to meet the Commission's prescribed cost-effectiveness methodology.

Generating resources to be considered are determined through an alternative technology screening analysis which is designed to determine the economic viability of a wide range of generating technologies for the Tampa Electric Company service area. Geographic viability, weather conditions, public acceptance, economics, lead-time, environmental acceptability, safety, and proven demonstration and commercialization are used as criteria to screen the generating technologies to a manageable number.

The technologies which pass the screening are included in a supply side analysis which examines various supply side alternatives for meeting future capacity requirements. These include modifying existing units by repowering or over-pressure operation and delayed retirements. Other supply resources such as constructing new unit additions, firm power purchases from other generating entities, joint ownership of generating capacity, and modifications of the transmission system to increase import capability are included in the analysis.

Tampa Electric Company uses the PROVIEW module of PROSCREEN, a computer model developed by New Energy Associates, to evaluate the supply side resources. PROVIEW uses a dynamic programming approach to develop an estimate of the time and type of capacity additions which would most economically meet the system demand and energy requirements. Dynamic programming compares all feasible combinations of generating unit additions which satisfy the specified reliability criteria and determines the schedule of additious which have the lowest revenue requirements. The model uses production costing analysis and incremental capital and O&M expenses to project the revenue requirements used to rank each plan.

A detailed cost analysis for each of the top ranked resource plans is performed using the Capital Expenditure and Recovery module and the Generation and Fuel module of PROSCREEN. The capital expenditures associated with each capacity addition are obtained based on the type of generating unit, fuel type, capital spending curve, and in-service year. The fixed charges resulting from the capital expenditures are expressed in present worth dollars for comparison. The fuel and the operating and maintenance costs associated with each scenario are projected based on economic dispatch of all the energy resources on our system. The projected operating expense, expressed in present worth dollars, is combined with the fixed charges to obtain the total present worth of revenue requirements for each alternative plan.

Sensitivity analysis of the top ranked plans from the economic analysis is used to determine the relative impact of various assumptions on the robustness of the base plan. These sensitivities involve parameters which are greatly influenced by the action and decisions of organizations other than Tampa Electric Company. The sensitivities include system load and energy requirements, fuel prices, and financial assumptions. These sensitivities are developed by using the top plans, which are chosen based on economics and a variety of supply side options, and analyzing them in scenarios to determine the most economically viable plan under all scenarios.

Strategic Concerns

Strategic issues which affect the type, capacity, and/or timing of future generation resource requirements are analyzed. These issues such as competitive pressures, environmental legislation, and plan acceptance are not easily quantified. Therefore, a strategic analysis is conducted to compare the overall performance of each alternative resource plan under each issue. The strategic issues and economic analysis are combined to ensure that an economically viable expansion plan is selected which has the flexibility for the company to respond to future technological and economic changes.

The tool used to combine the strategic issues and economic analysis is a decision matrix. The decision matrix is used to compare and select the most cost-effective plan. Each alternative resource plan is analyzed on both a quantitative and qualitative basis. The quantitative analysis is based on comparing the cumulative present worth of revenue requirements for each alternative for both the base and sensitivity assumptions. The qualitative analysis considers these previously mentioned strategic issues. Each alternative is ranked based on pre-determined criteria and the sum of the values for each category. The combined scores indicate the relative strength of each alternative on both a quantitative and qualitative basis.

The results of the analysis provide Tampa Electric Company with a plan that is cost-effective while maintaining flexibility and adaptability to a dynamic regulatory and competitive environment. The new capacity additions are shown in Table IV-3. To meet the expected system demand and energy requirements over the next ten years and cost-effectively maintain system reliability, combustion turbines are planned for November of 2002, 2003, and 2005. These combustion turbines will be dual-fueled by natural gas and distillate oil. For the purposes of this study, Hookers Point Station is assumed to be retired in April of 2003, and Tampa Electric's long-term purchase power contract with Hardee Power Partners Limited remains at 297 MW summer net capability and 360 MW winter net capability for the entire study period.

TAMPA ELECTRIC COMPANY
INTEGRATED RESOURCE PLAN METHODOLOGY

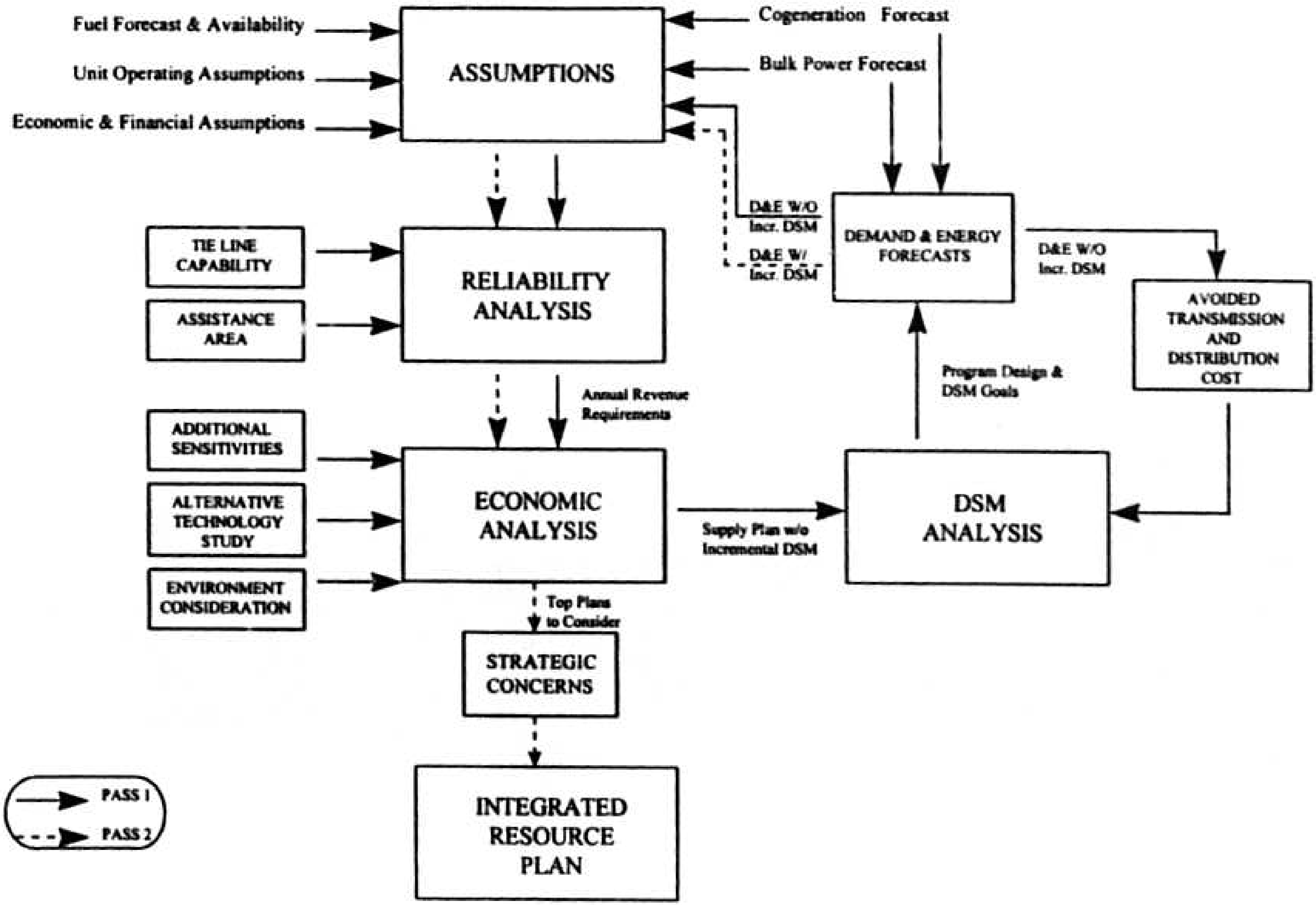


FIGURE V-1

2.30

Generation and Transmission Reliability Criteria

Generation

Tampa Electric Company uses the dual reliability criteria of 1% Expected Unserved Energy (%EUE) and a 15% minimum firm winter reserve margin for planning purposes.

Tampa Electric Company's approach to calculating percent reserves is consistent with the industry accepted method of using total available generating and firm purchased power capacity (capacity less planned maintenance and contracted unit sales) and subtracting the annual firm peak load, then dividing by the firm peak load, and multiplying by 100%. Since the reserve margin calculation assumes no forced outages, Tampa Electric includes the Hardee Power Station in its available capacity. Contractually, Hardee Power Station is planned to be available to Tampa Electric at the time of system peak. Also, the capacity dedicated to any firm unit or station power sales at the time of system peak is subtracted from Tampa Electric's available capacity.

Tampa Electric's percent Expected Unserved Energy (%EUE) criteria addresses annual reliability. Similar to calculating percent reserves, all firm unit and station power sales are accounted for in determining Tampa Electric's available capacity resources. The 1% EUE target was developed as an equivanlent to the loss of Tampa Electric's largest unit (Big Bend Unit 4, 447 MW) for an entire year and maintaining firm reserves of approximately 15%. In calculating the EUE, the Hardee Power Station is considered to be available as a Tampa Electric capacity resource only after its availability is reduced for planned outages, forced outages, and projected Seminole Electric Cooperative (SEC) usage. SEC provides Tampa Electric with its projected usage of the Hardee Power Station capacity. Percent EUE is calculated by dividing Tampa Electric's projected annual non-firm purchases (excluding economy) by its Net Energy for Load and multiplying by 100%. Under these conditions, Tampa Electric will have adequate reserves or available emergency and/or contracted short-term firm capacity to mitigate expected unserved energy.

Transmission

The following criteria are used as guidelines by Tampa Electric Company Transmission Planners during planning studies. However, they are not absolute rules for system expansion; the criteria are used to alert planners of potential transmission system capacity limitations. Engineering analysis is used in all stages of the planning process to weigh the impact of system deficiencies, the likelihood of the triggering contingency, and the viability of any operating options. Only by carefully researching each planning criteria violation can a final evaluation of available transmission capacity be made.

Generation Dispatch Modeled

The generation dispatched in the planning models is dictated on an economic basis and is calculated by the Economic Dispatch (ECDI) function of the PSS/E loadflow software. The ECDI function schedules the unit dispatch so that the total generation cost required to meet the projected load is minimized. This is the generation scenario contained in the power flow cases submitted to fulfill the requirements of FERC Form 715 and the Florida Reliability Coordinating Council (FRCC).

Since unplanned and planned unit outages can result in a system dispatch that varies significantly from a base plan, bulk transmission planners also investigate several scenarios that may stress Tampa Electric's transmission system. These additional generation sensitivities are analyzed to ensure the integrity of the bulk transmission system under maximized bulk power flows.

Transmission System Planning Criteria

Tampa Electric follows the FRCC planning criteria as contained in Section V of the FRCC System Planning Committee Handbook.

In addition to FRCC criteria, Tampa Electric utilizes company-specific planning criteria. Listed below are the guidelines which are used prior to contingency analysis to identify any inherent system flaws:

Transmission System Loading Limits	
Transmission System Conditions	**Acceptable Loading Limit for Transformers and Transmission Lines**
All facilities in service	100% or less

Transmission System Voltage Limits			
	Industrial Substation Buses at point-of-service	**69 kV Buses**	**138 kV and 230 kV Buses**
All facilities in service	0.950 - 1.050 pu	0.950 - 1.050 pu	0.950 - 1.050 pu

Single Contingency Planning Criteria

The following two tables summarize the thresholds which alert planners to problematic transmission line and transformer single contingency scenarios.

Transmission System Loading Limits	
Transmission System Conditions	**Acceptable Loading Limit for Transmission Lines and Transformers**
Single Contingency, pre-switching	115% or less
Single Contingency, after all switching	100% or less
Bus Outages, pre-switching	115% or less
Bus Outages, after all switching	100% or less

Transmission System Voltage Limits			
Transmission System Conditions	**Industrial Substation Buses at point-of- service**	**69 kV Buses**	**138 kV and 230 kV Buses**
Single Contingency, pre-switching	0.925 - 1.050 pu	0.950 - 1.050 pu	0.950 - 1.050 pu
Single Contingency, after all switching	0.950 - 1.050 pu	0.950 - 1.050 pu	0.950 - 1.050 pu
Bus Outages	0.925 - 1.050 pu	0.950 - 1.050 pu	0.950 - 1.050 pu

Available Transmission Transfer Capability (ATC) Criteria

Tampa Electric adheres to the FRCC ATC calculation methodology as well as the principles contained in the NERC ATC Definitions and Determinations document.

Transmission Planning Assessment Practices

Base Case Operating Conditions

Transmission planners ensure that Tampa Electric's transmission system can first and foremost support peak and off-peak system load with no facility overload, voltage violation, or imprudent operating modes. Therefore, the first step in assessing the health of the transmission system is to guarantee that all equipment is within specified continuous loading and voltage guidelines. Consult the previous section for more specific system parameters.

Single Contingency Planning Criteria

The objective of transmission planning is to design a system that can sustain the loss of any single circuit element without loading any transmission line or transformer beyond its rating or resulting in voltage levels that deviate outside of the bandwidths set forth in the Transmission System Planning Criteria section. In the course of single contingency analysis, single contingency fault events which result in the removal of multiple transmission system elements from service due to protection system response are modeled in the manner that the system would respond to the fault. Any verified criteria violation which cannot be mitigated with an appropriate operating measure is flagged as a limitation on transmission system capacity. Consult the Transmission System Planning Criteria section of this document for more specific system parameters.

Tampa Electric plans on any given piece of transmission system equipment being unavailable for service at some point in time. In addition to Tampa Electric equipment being out of service, Tampa Electric transmission planners plan the system to tolerate the loss of service of equipment outside of Tampa Electric's control area. This mainly consists of bulk transmission system equipment and generation units throughout the state.

Multiple Contingency Planning Criteria

Criteria for multiple contingency conditions are the same as single contingency criteria but are simulated at off-peak load levels. Appropriate double contingencies are investigated at 100% load level when warranted by area load factors. Multiple contingency conditions are also used to gauge the urgency of system deficiencies which are identified during single contingency analysis as cause for concern.

First Contingency Total Transfer Capability Considerations

Bulk transmission planners also use multiple generator/transmission equipment contingency criteria to ensure that Tampa Electric's transmission system import corridors are loaded within approved limits in the event of a Tampa Electric generation shortfall. To accomplish this, statewide dispatches are investigated which load each of Tampa Electric's tie lines to their First Contingency Total Transfer Capability.

Base case and contingency conditions are then imposed to locate any transmission or sub-transmission weaknesses which would require reinforcement under such a scenario. When necessary, bulk planners identify situations where FCTTC and/or internal system capacities should be increased to raise the capability of a transmission corridor.

FCTTC's which must be observed for Tampa Electric's multi-line corridors are listed below:

Tie line	FCTTC
Lake Tarpon-Sheldon 230 kV	1100 MVA
Big Bend-Florida Power & Light 230 kV	1500 MVA

DSM Energy Savings Durability

Tampa Electric Company identifies and verifies the durability of energy savings from our conservation and DSM programs by several methods. First, Tampa Electric Company has established a monitoring and evaluation (M&E) process where historical analysis identifies the energy savings. These include:

(1) end-use metering of a load survey sample to identify the savings achieved on air conditioning, heating, and water heating;

(2) bill analysis of program participants compared to control groups to minimize the impact of weather abnormalities; and

(3) in commercial programs such as Standby Generator and C/I Load Management, the reductions are verified through submetering of those loads under control to determine participant incentives relative to demand and energy savings.

Secondly, the programs are designed to promote the use of high-efficiency equipment having permanent installation characteristics. Where programs promote the installation of energy efficient measures or equipment (heat pumps, hard-wired lighting fixtures, ceiling insulation, air distribution system repairs), program standards require they be of a permanent nature. For example, our Commercial Indoor Lighting Program requires full-fixture replacement or hard-wiring of fixture replacements.

Supply Side Resources Procurement Process

Tampa Electric Company will manage the procurement process in accordance with established policies and procedures. Prospective suppliers of supply side resources as well as suppliers of equipment and services will be identified using various data base resources and competitive bid evaluations, and will be used in developing award recommendations to management.

This process will allow for future supply side resources to be supplied from self-build, purchase power, or competitively bid third parties. Consistent with company practice, bidders will be encouraged to propose incentive arrangements that promote development and implementation of cost savings and process improvement recommendations. The procurement process will also demonstrate continued positive efforts by Tampa Electric to include minority, small, and women-owned businesses. Goals will be established and tracked to measure opportunities and awards realized by these firms.

Transmission Construction and Upgrade Plans

In 2005, Tampa Electric plans to add an 11-mile 230 kV transmission line for the purpose of maintaining reliability in its Eastern Service Area. The new transmission line will be sourced from the proposed Lithia 230 kV Switching Station and will terminate at the existing Wheeler Road 69 kV Substation. This new transmission line will be used to source a new 230/69 kV transformer at the Wheeler Road Substation. This transformer will be required to alleviate potential voltage criteria violations and sub-transmission circuit overloads which are projected to occur in 2005.

CHAPTER VI

ENVIRONMENTAL AND LAND USE INFORMATION

The future generating capacity additions identified in Chapter IV will occur at the existing Polk Power Plant facility. The Polk Power Plant site is located in southwest Polk County close to the Hillsborough and Hardee County lines (See Figure VI-1). This facility is an existing power plant site that has been permitted under the Florida Power Plant Siting Act. There are no new potential sites being considered for the 10-year horizon.

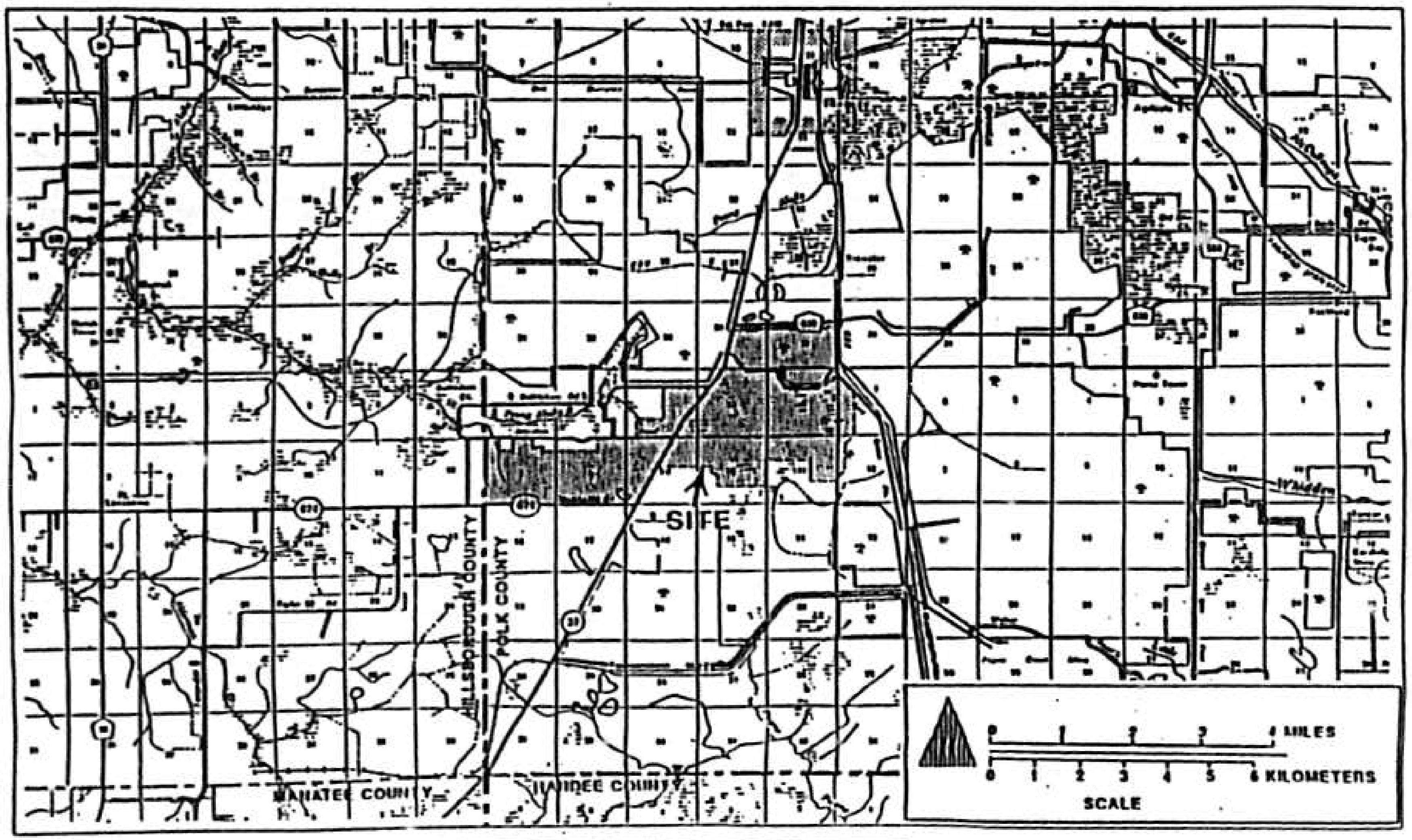


FIGURE VI-1

SITE LOCATION OF POLK POWER STATION

TAMPA ELECTRIC COMPANY
Ten-Year Site Plan
For Electrical Generating Facilities
And Associated Transmission Lines

SOURCES: FDOT MAP, FLA. ECT.