AUSLEY & MCMULLEN ORIGINAL

ATTORNEYS AND COUNSELORS AT LAW

227 SOUTH CALHOUN STREET
P.O. BOX 391 (ZIP 32302)
TALLAHASSEE, FLORIDA 32301
(850) 224-9115 FAX (850) 222-7560

May 19, 1998

HAND DELIVERED

Ms. Blanca S. Bayo, Director
Division of Records and Reporting
Florida Public Service Commission
101 East Gaines Street
Tallahassee, Florida 32399-0850

Re: Environmental Cost Recovery Clause
FPSC Docket No. 980007-EI

Dear Ms. Bayo:

Enclosed for filing in the above docket are fifteen (15) copies of Tampa Electric Company's Compliance Plan for Phase II of the Clean Air Act Amendments of 1990.

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.

Sincerely,

James D. Beasley

JDB/pp
Enclosures

cc: All Parties of Record (w/enc.)

ACK
AFA 2 Wandwei
APP
CAF
CMU
CTR
EAG
LEG 1
LIN 3
OPC
RCH RECEIVED & FILED
SEC 1
WAS FPSC-BUREAU OF RECORDS
OTH

DOCUMENT NUMBER-DATE
05559 MAY 19 98
FPSC-RECORDS/REPORTING

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true copy of the foregoing Compliance Plan, filed on behalf of Tampa Electric Company, has been furnished by hand delivery (*) or U. S. Mail on this 19th day of May, 1998 to the following:

Ms. Leslie G. Paugh*
Staff Counsel
Division of Legal Services
Florida Public Service Comm'n.
2540 Shumard Oak Boulevard
Room 370, Gunter Building
Tallahassee, FL 32399-0872

Mr. John Roger Howe
Office of Public Counsel
111 West Madison Street
Suite 812
Tallahassee, FL 32399-1400

Mr. John W. McWhirter, Jr.
McWhirter, Reeves, McGlothlin,
Davidson, Rief & Bakas, P.A.
P. O. Box 3350
Tampa, FL 33601-3350

Ms. Gail Kamaras
Legal Environmental
Assistance Foudation
1115 North Gadsden Street
Tallahassee, FL 32303-6327

Mr. Joseph A. McGlothlin
McWhirter, Reeves, McGlothlin,
Davidson, Rief & Bakas, P.A.
117 South Gadsden Street
Tallahassee, FL 32301

Mr. Matthew M. Childs
Steel Hector & Davis
215 S. Monroe Street, Suite 601
Tallahassee, FL 32301

Mr. G. Edison Holland
Mr. Jeffrey A. Stone
Beggs and Lane
Post Office Box 12950
Pensacola, FL 32576

ATTORNEY

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 Phase 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 ASSUMP'.IONS

		GANNON 4, 5, & 6		BIG BEND 2	BIG BEND 1 - 2
	BASE	LIMESTONE	AMMONIA	INTEGRATION	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 IMPROVEMENTS	-----	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	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 SO_2 compliance.

TABLE 2-5

FRCC Reserves

Summer Reserves

			Firm Capacity Reserves		Firm Capacity Reserves w/ 800 MW Firm Purchase		
	Firm Reserve Margin	Reserve Capacity Above 15% Firm Reserve Margin	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 Capacity Reserves		Firm Capacity Reserves w/ 800 MW Firm Purchase		
	Firm Reserve Margin	Reserve Capacity Above 15% Firm Reserve Margin	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)	2000 - 2009 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

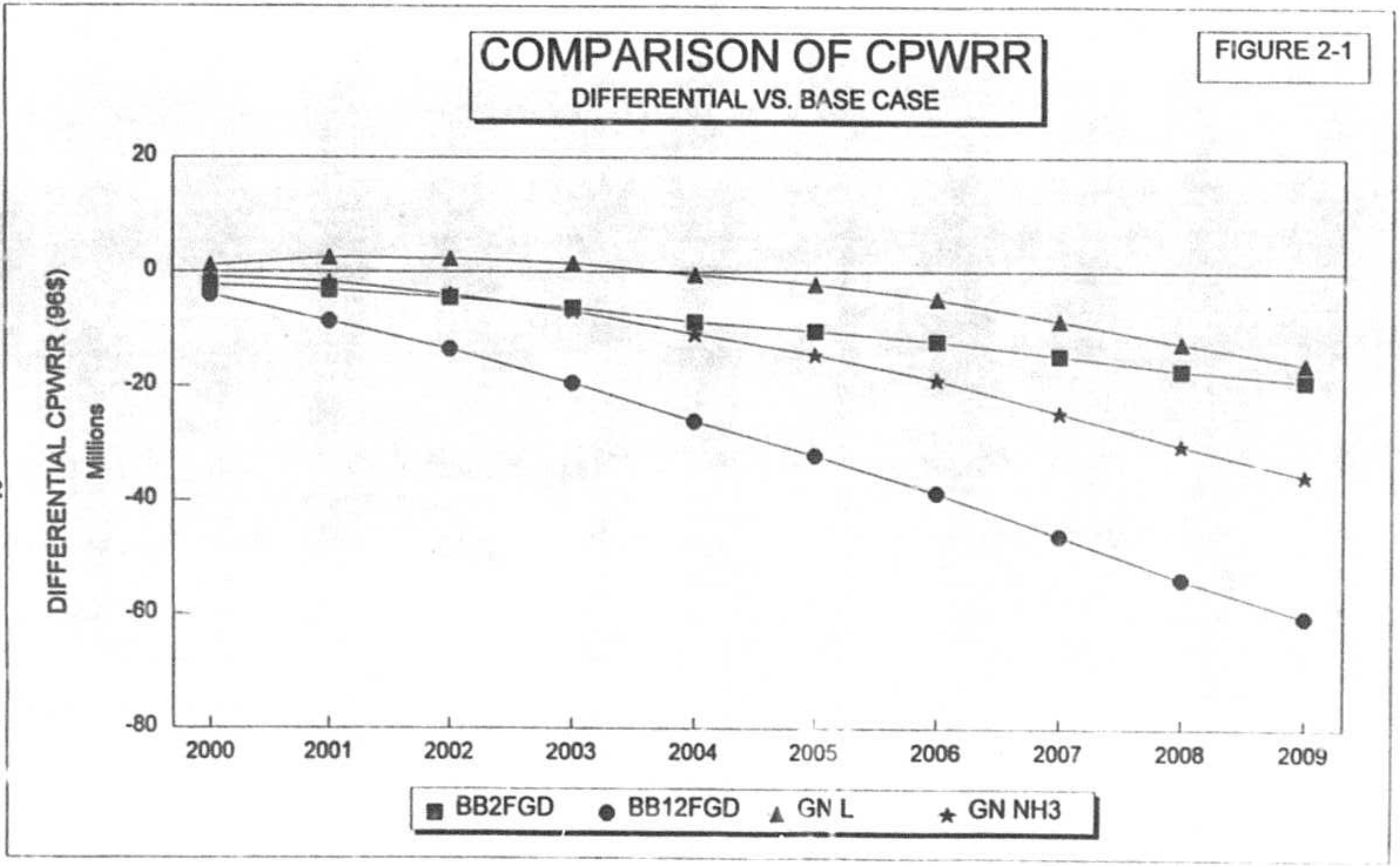

COMPARISON OF CPWRR
DIFFERENTIAL VS. BASE CASE
FIGURE 2-1
DIFFERENTIAL CPWRR (96$)
Millions
20
0
-20
-40
-60
-80
2000
2001
2002
2003
2004
2005
2006
2007
2008
2009
BB2FGD
BB12FGD
GN L
GN NH3

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.

<u>Capital Cost</u>

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

<u>Incremental O&M Costs</u>

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

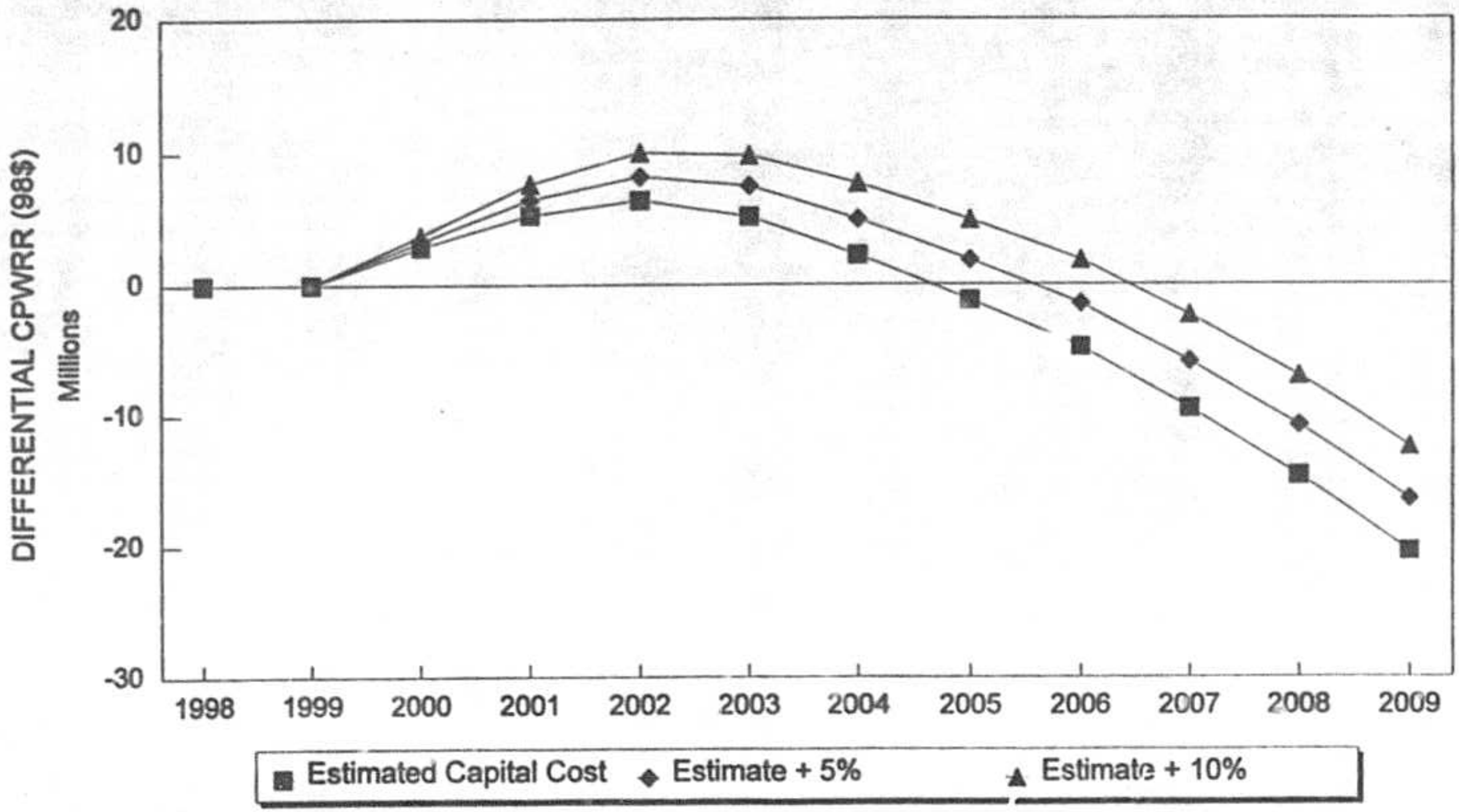
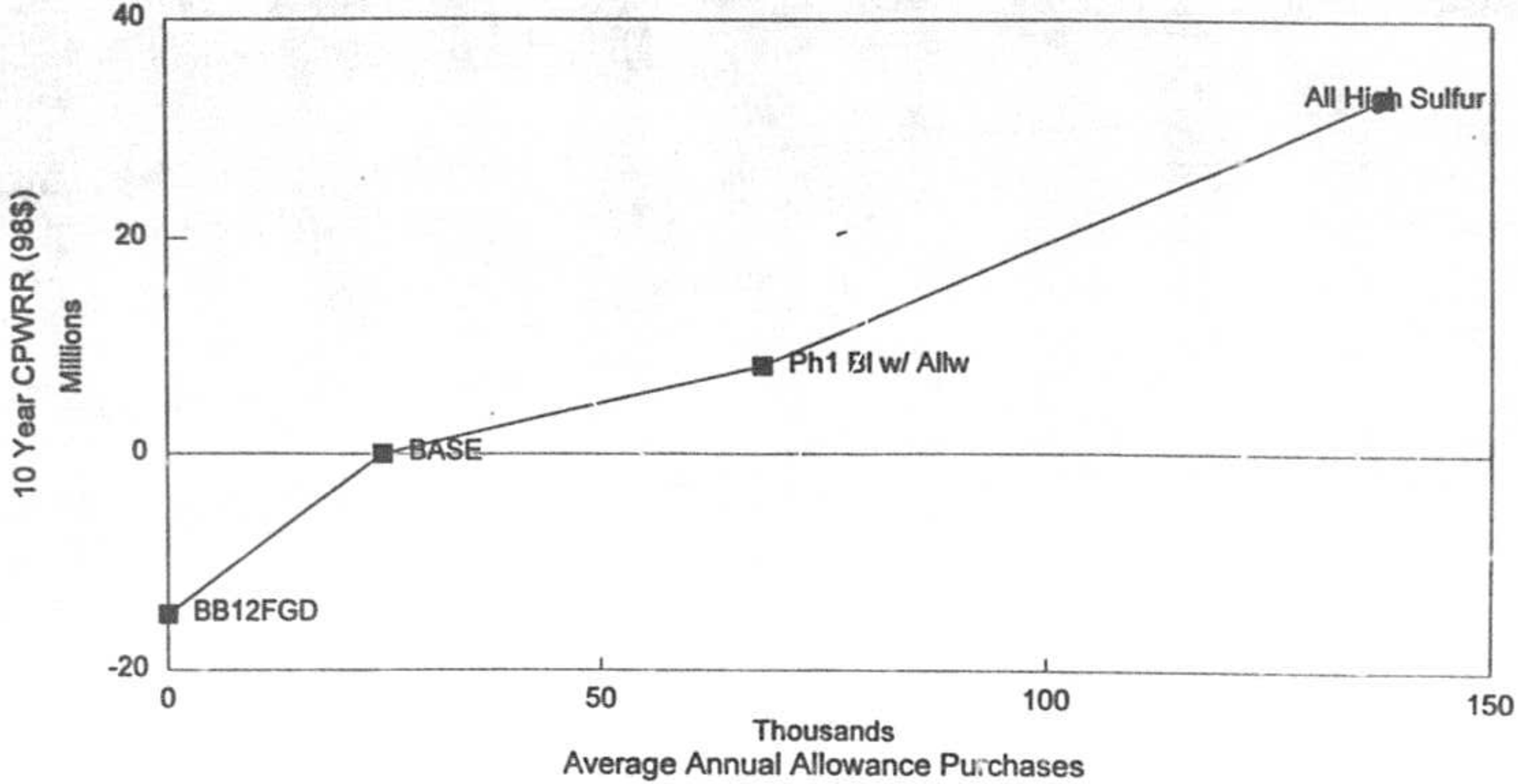


FIGURE 3-2

OPTIMIZATION OF ALLOWANCE PURCHASES

BB1&2 FGD ANALYSIS



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.

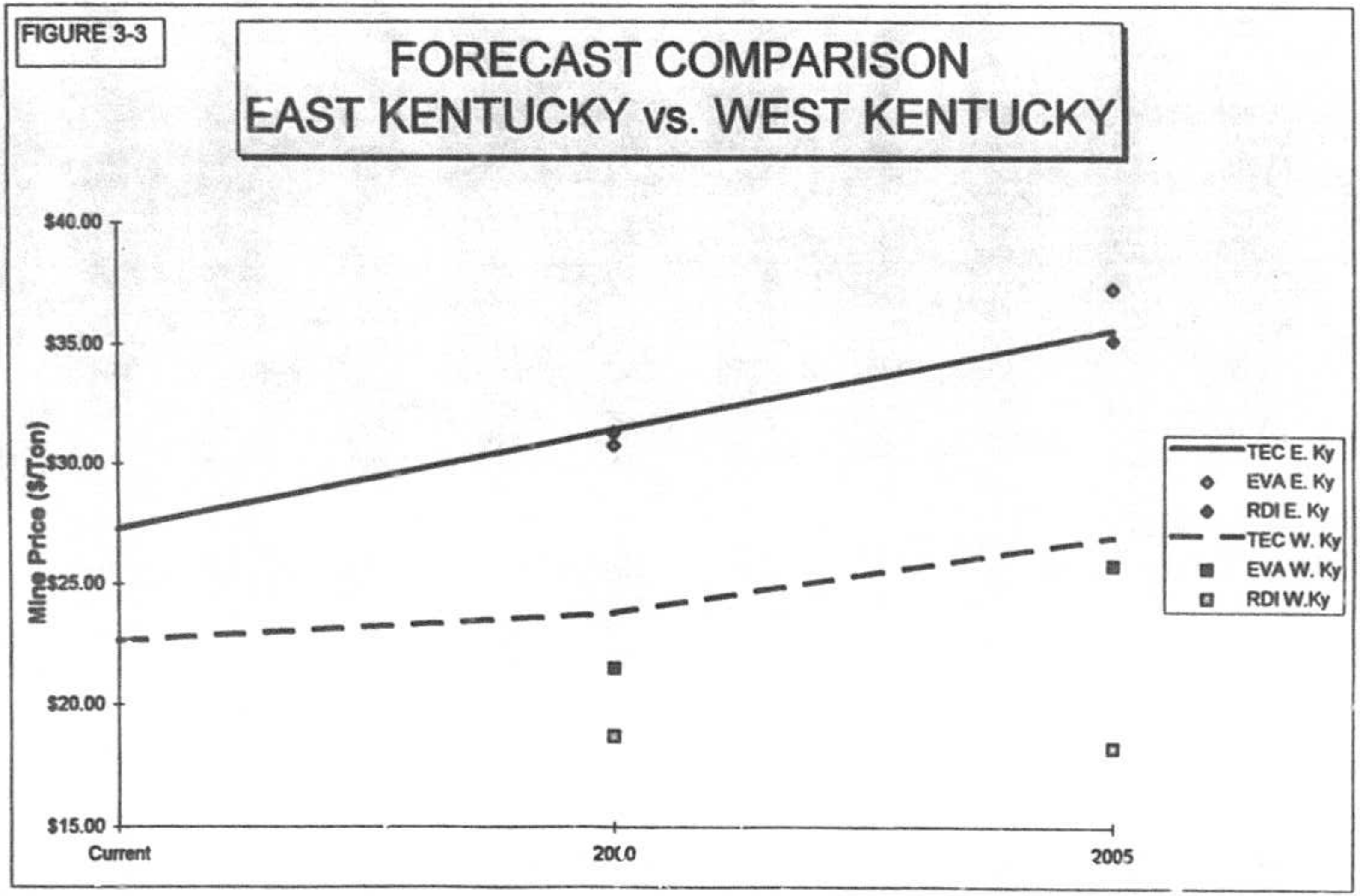


FIGURE 3-3
FORECAST COMPARISON
EAST KENTUCKY vs. WEST KENTUCKY
Mine Price ($/Ton)
$40.00
$35.00
$30.00
$25.00
$20.00
$15.00
Current
2000
2005
TEC E. Ky
EVA E. Ky
RDI E. Ky
TEC W. Ky
EVA W. Ky
RDI W.Ky

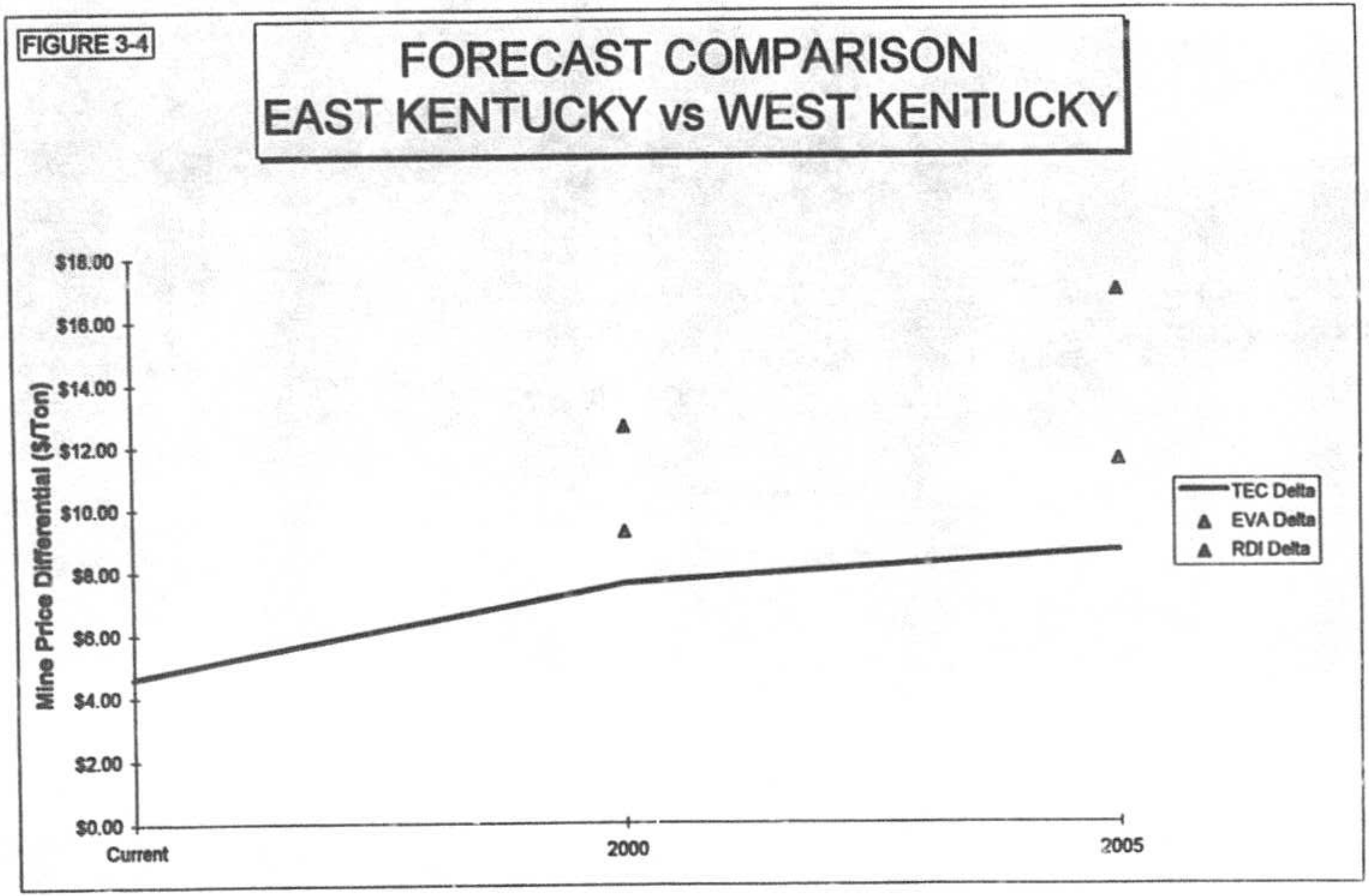


FIGURE 3-4
FORECAST COMPARISON
EAST KENTUCKY vs WEST KENTUCKY
Mine Price Differential ($/Ton)
$18.00
$16.00
$14.00
$12.00
$10.00
$8.00
$6.00
$4.00
$2.00
$0.00
Current
2000
2005
TEC Delta
EVA Delta
RDI Delta

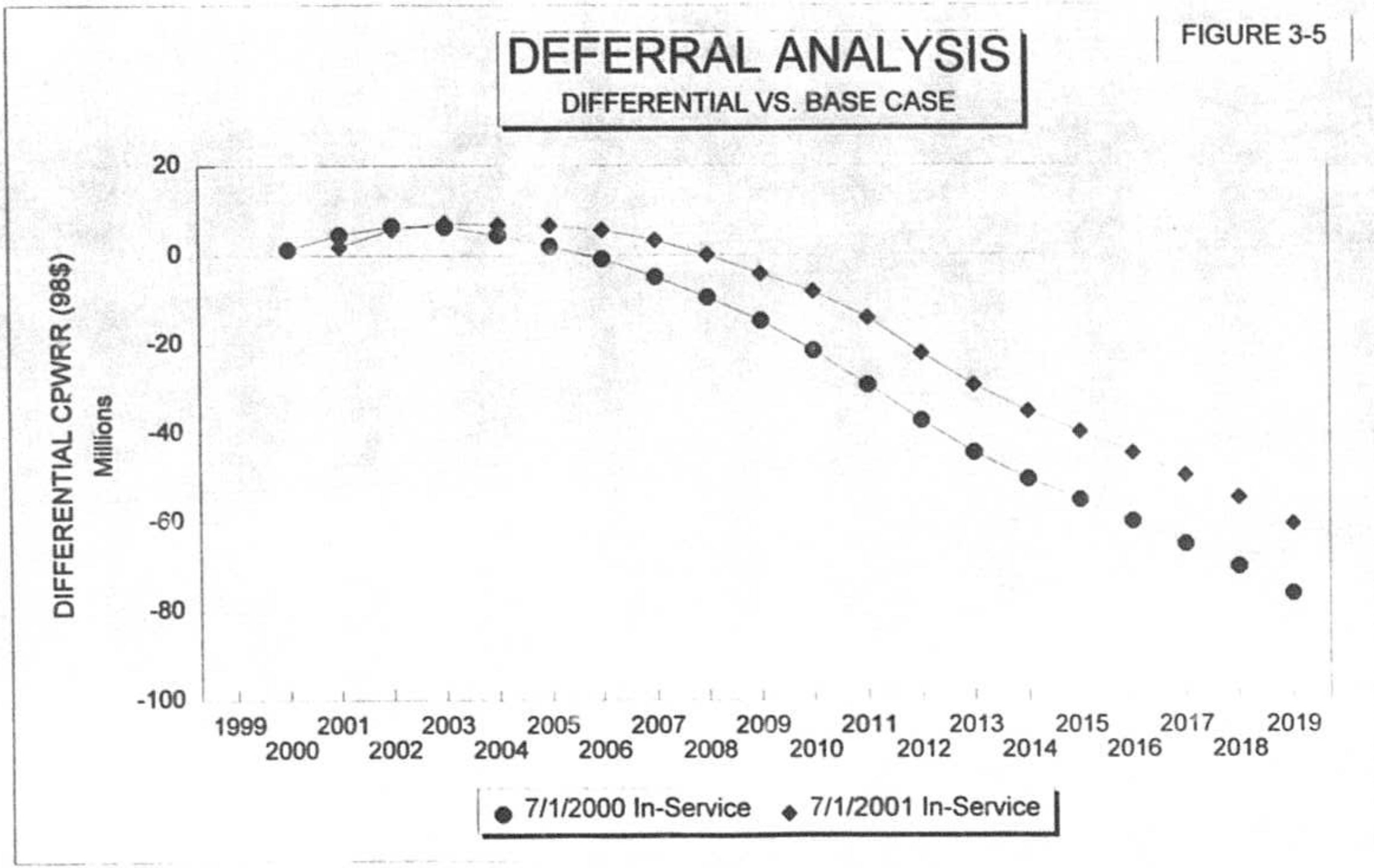


FIGURE 3-5
DEFERRAL ANALYSIS
DIFFERENTIAL VS. BASE CASE
DIFFERENTIAL CPWRR (98$)
Millions
20
0
-20
-40
-60
-80
-100
1999
2000
2001
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
7/1/2000 In-Service
7/1/2001 In-Service

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 constructio costs low is aided by the fact that man 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.

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