For Routing To Other Than The Addressee			
To ~~Steve Smallwood~~		Location DARM	
To C2Air-Fyi		Location	
To		Location	
From		Date	

State of Florida
DEPARTMENT OF ENVIRONMENTAL REGULATION

Interoffice Memorandum

TO: Deputy Assistant Secretaries
Division Directors

FROM: John Shearer, P.E.
Assistant Secretary

DATE: August 14, 1990

RECEIVED
AUG 16 1990
DER-BAQM

SUBJECT: Professional Engineering Certification of Items of Incompleteness Regarding a Permit Application

RULE 17-4.050, F.A.C. - PROCEDURES TO OBTAIN PERMITS; APPLICATION, states that all applications for a Department permit shall be certified by a professional engineer registered in the State of Florida...

In instances where the permit application is deemed incomplete, and the Department requests additional information that is of an engineering nature, the response to these items of incompleteness also needs to be certified by a professional engineer registered in the State of Florida. Many times the missing information is what is really needed to give reasonable assurances that the source will comply with the Department's rules and regulations. The professional engineer's seal is heavily relied on for providing reasonable assurance that the state air and water quality standards are being met.

JS/pl

BEFORE THE GOVERNOR AND CABINET
OF THE STATE OF FLORIDA

IN RE: TAMPA ELECTRIC COMPANY BIG BEND STATION UNIT 4 POWER PLANT SITING CERTIFICATION APPLICATION PA 79-12 REQUEST FOR MODIFICATION	CASE NO. 80-1723

FINAL ORDER

BY THE GOVERNOR AND CABINET

The Governor and Cabinet, sitting as the Siting Board, having reviewed the Stipulation and Agreement which is attached hereto as Exhibit 1, and otherwise being fully advised herein, issue this Final Order and, therefore, it is

ORDERED:

1. The Stipulation and Agreement executed by the Florida Department of Environmental Regulation, Southwest Florida Water Management District, Department of Community Affairs, Public Service Commission and Tampa Electric Company is approved and adopted. The conditions of certification for the Tampa Electric Company Big Bend Station Unit 4 shall be and hereby are modified in the manner shown in the Stipulation and Agreement, pursuant to Section 403.516(2), Florida Statutes.

DONE AND ORDERED this 6th day of October, 1987 in Tallahassee, Florida, pursuant to the vote of the Governor and Cabinet, sitting as the Siting Board, at a duly noticed and constituted Cabinet meeting on October 6, 1987.

FOR THE GOVERNOR AND CABINET
SITTING AS THE SITING BOARD

By: ______________________
The Honorable Bob Martinez, Governor

The action of the Siting Board is based on the following vote:

	For	Against:	Absent
Honorable Bob Butterworth	X		
Honorable Betty Castor	X		
Honorable Doyle Conner			X
Honorable Bill Gunter	X		
Honorable Gerald A. Lewis	X		
Honorable Bob Martinez	X		
Honorable Jim Smith	X		

FILING AND ACKNOWLEDGEMENT
Filed on this date, pursuant to Section 120.52(10), Florida Statutes (1985), with the designated Department Clerk, receipt of which is hereby acknowledged.

C. Hutchins
Clerk

Date 10-12-87

Copies furnished to:

Lawrence N. Curtin, Esquire
Aurell, Fons, Radey & Hinkle
Post Office Drawer 11307
Tallahassee, Florida 32302

Richard Donelan, Esquire
Assistant General Counsel
State of Florida Department
of Environmental Regulation
2600 Blair Stone Road
Tallahassee, Florida 32399

C. Lawrence Keesey, Esquire
Department of Community Affairs
Howard Building
2572 Executive Center Circle,
East
Tallahassee, Florida 32399

Dan Fernandez, Esquire
Southwest Florida Water
Management District
2379 Broad Street
Brooksville, Florida 33512

Mike Twomey, Esquire
Public Service Commission
101 East Gaines Street
Tallahassee, Florida 32399

Hamilton S. Oven, Jr.
Department of Environmental
Regulation
Twin Towers Office Building
Tallahassee, Florida 32399

Honorable Betty Castor
Commissioner of Education
The Capitol
Tallahassee, Florida 32399

Honorable Bob Martinez
The Governor
The Capitol
Tallahassee, Florida 32399

Honorable Jim Smith
Secretary of State
The Capitol
Tallahassee, Florida 32399

Honorable Bob Butterworth
Attorney General
The Capitol
Tallahassee, Florida 32399

Honorable Bill Gunter
Treasurer and Insurance
Commissioner
The Capitol
Tallahassee, Florida 32399

Honorable Gerald Lewis
Comptroller
The Capitol
Tallahassee, Florida 32399

Honorable Doyle Conner
Commissioner of Agriculture
The Capitol
Tallahassee, Florida 32399

RECEIVED AUG 24 1987 LEGAL DEPARTMENT

BEFORE THE STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL REGULATION

IN THE MATTER OF:

TAMPA ELECTRIC COMPANY
POWER PLANT SITING APPLICATION
BIG BEND STATION UNIT NO. 4,
PA 79-12
_____________________________________/

CASE NO. 80-1723

AGREEMENT OF PARTIES
MODIFYING CONDITIONS OF CERTIFICATION

Pursuant to the provisions of Section 403.516(2), Florida Statutes, and Rule 17-17.211(4), Florida Administrative Code, the parties entering appearances at and appearing in the certification proceedings, by and through their undersigned representatives, hereby agree as follows:

1. The signatories to this agreement include representatives of all the parties entering appearances at and participating in the above referenced certification proceedings.

2. On August 17, 1981, the Final Order Adopting Hearing Officer's Recommendation of Certification Subject to Conditions was entered in DOAH Case No. 80-1723, reflecting action taken by the Governor and Cabinet at the duly constituted Cabinet meeting of August 4, 1981. The Final Order constitutes approval of certification for the construction and operation of Tampa Electric Company's Big Bend Unit No. 4 subject to the Conditions of Certification attached thereto.

3. Pursuant to Florida Administrative Code Rule 17-17.211(4), Tampa Electric Company seeks a modification of Conditions II.A.10., II.B.1., II.B.2.b., III.D., III.E., XXVIII. and XXX., which provide as follows:

II.A.10. Boiler and Bottom Ash Sluice System Blowdown

Blowdown from the boiler and from the bottom ash sluice system shall be treated as appropriate prior to discharge to the cooling water system. The following effluent limitations shall apply:

Effluent	Daily Maximum	Maximum 30-Day Daily Average
TSS	100 mg/l	30 mg/l
Oil and Grease	20 mg/l	15 mg/l
pH	6-9	

TECO shall provide the dimensions of the bottom ash system settling pond and provide calculations demonstrating that sufficient residence time will be provided to achieve the above limitations.

II.B.1. Chemical Monitoring

The following parameters shall be monitored during discharge as shown, discharge commencing with the start of commercial operation of Unit 4 and reported quarterly to the Department's Southwest District Office:

Parameter	Location	Sample Type	Frequency
Flow, Cooling	Intake	Pump Log	Continuous
Flow, Bottom Ash	Prior to CWS	Recorder	Continuous
Flow, Boiler Blowdown	Prior to CWS	Daily Log	Daily
Flow, FGD Bleed	Prior to CWS	Recorder	Continuous
pH	CWS and prior to CWS on FGD Bleed Boiler & Bottom Ash Blowdown	Grab	Two per Week
Temperature	CWS Outfall	Recorder	Continuous
TSS	Bottom Ash Blow-down, FGD Bleed, & Boiler Blowdown	Grab	Two per Week Two per Month
Chlorine, Total Residual	Outfall	Multiple Grab	Weekly
Oil and Grease	Boiler Blowdown Bottom Ash Blow-down and FGD bleed	Grab	Two per Month
Metals	Intake, Outfall FGD Bleed Stream Bottom Ash Blow-down & Boiler Blowdown Prior to discharge to CWS	Two-Grab composite, not less than two hours between samples	Two per Month for the first year, then monthly thereafter
Arsenic	"		"
Cadmium	"		"
Iron	"		"
Lead	"		"
Mercury	"		"
Selenium	"		"
Zinc	"		"
Copper	"		"
Chromium	"		"
Nickel	"		"

II.B.2.b. Entrainment

1. In order to evaluate the entrainment mortality at the Big Bend Station, TECO shall conduct a Fine Mesh Screen Survivability Study (similar to the 1980 Prototype FMS study) for one full spawning period (March through September). Sampling for the study will be conducted at three locations pertaining to Unit 4:

   Station 1: Front of screen after organisms are impinged and washed to the screen return system.

   Station 2: Behind the screen.

   Station 3: At the discharge point in the Organism Return Canal (ORC).

Stations 1 and 2 will be sampled simultaneously to estimate the total number of organisms entrained at the plant. Initial and latent mortality tests will be conducted on organisms collected at locations 1 and 3 only. A detailed scope of study shall be submitted by TECO at least twelve months prior to the commencement of commercial operation of Unit 4.

III.D. <u>Monitoring and Reporting</u>

Tampa Electric Company shall implement the following groundwater monitoring program:

1. The groundwater levels shall be monitored at wells as approved by DER and the Southwest Water Management District. Chemical analyses shall be made on samples from all monitored wells identified in this Condition. The location, frequency, water levels and selected chemical analyses shall be as given in Condition III.D.3.

2. The groundwater monitoring program shall be implemented at least one year prior to operation of Big Bend Unit 4. The chemical analyses shall be in accord with the latest edition of <u>Standard Methods for the Analysis of Water and Wastewater</u>. The data shall be submitted within 30 days of collection/analysis to the Southwest Florida Water Management District and to the DER Power Plant Siting Section.

3. After consultation with the DER and SWFWMD, TECO shall install a monitoring well system, as generally shown on Figure 3, to monitor groundwater quality in the top 40 feet of the surficial aquifer. One well shall be installed to a depth greater than 40 feet but less than 100 to monitor vertical dispersion or groundwater contaminants. Monitoring well locations and designs shall be submitted to the Department and SWFWMD for review. Approval or disapproval of the locations and design shall be granted within 60 days. The water samples collected from each of the monitor wells shall be collected immediately after removal by pumping of a quantity of water equal to two casing volumes. The water quality analyses shall be performed monthly during the year prior to commercial operation and for two years after operation and quarterly thereafter. Results shall be submitted to the Department and the SWFWMD by the fifteenth (15th) day of the month following the month during which such analyses were performed. Testing for the following constituents is required:

Conductance	Nickel
pH	Selenium
Chloride	Chromium
Iron	Arsenic
Cadmium	Berryllium
Zinc	Mercury
Copper	Lead
Sulfate	Gross Alpha
Silver	Barium

4. After the second year of monitoring and periodically thereafter, the Department and the permittee shall review the results of the monitoring program and determine the necessity for modifying or continuing the program.

[FIGURE 3]

III.E. <u>Leachate</u>

1. <u>Zone of Discharge</u>

Leachate from the FGD/gypsum landfill, coal storage pile, bottom ash pond, wastewater treatment ponds, <u>ash disposal cells</u>, and spray irrigation field shall <u>not</u>

contaminate waters of the State (including both surface and groundwaters) in excess of the limitations of Chapter 17-3, FAC., <u>beyond the boundary of the site</u>.

2. <u>Corrective Action</u>

When the groundwater monitoring system shows a violation of the groundwater water quality standards of Chapter 17-3, FAC., the appropriate ponds, FGD landfill, or coal pile shall be sealed, relocated or closed, or the operation of the affected facility shall be altered in such a manner as to assure the Department that no violation of the groundwater standards will occur beyond the boundary of the site.

XXVIII. <u>Fine Mesh Screens</u>

Fine mesh screens, similar to those tested and described by TECO in the 316 Demonstration, shall be installed on the intakes of Units 3 and 4 with the appropriate sprays and screen wash sluice return system to minimize entrainment. The screen wash sluice return system shall discharge to the east end of the canal north of the intake canal or to a location acceptable to the Department and EPA. <u>TECO shall submit a plan to DER to explore the possibility of re-entrainment of ORC--returned organism.</u>

XXX. <u>Variances</u>

TECO is granted variances for discharges of FGD system blowdown and bottom ash pond blowdown pursuant to Sections 403.201 and 403.511(2) F.S., for a period of two years after the start of commercial operation for the following parameters:

a. Arsenic - 17-3.061(2)(a)
b. Cadmium - 17-3.121(9)
c. Chromium - 17-3.061(2)(d)
d. Copper - 17-3.121(11)
e. Iron - 17-3.121(16)
f. Mercury - 17-3.121(18)
g. Nickel - 17-3.121(19)
h. Selenium - 17-3.121(26)

During the period that the variance is in effect, TECO shall (1) determine the concentrations of the above metals as well as lead in the two discharge streams; (2) operate the FGD blowdown treatment system so as to minimize the metal content of the discharge from the system; and (3) submit reports of the above studies and analyses after the first year and at least twenty months after the start of commercial operation of Unit 4.

Upon receipt of the aforementioned reports, the Secretary shall determine whether the variances should be renewed and may impose appropriate conditions to minimize the discharges and their impacts.

4. Tampa Electric Company seeks to modify Condition II.A.10. by deleting the references to the bottom ash sluice system from the condition. The purpose of the deletion is to reflect the fact that this sytem no longer discharges.

5. Tampa Electric Company seeks to modify Condition II.B.1. concerning chemical monitoring to (1) delete all references to monitoring requirements for discharges of blowdown from the bottom ash sluice system since that system no longer discharges;

and (2) delete monitoring requirements for heavy metals for both the circulating water system and boiler blowdown since Hillsborough Bay has been shown to be in compliance with Class III water quality standards.

6. Tampa Electric Company seeks to modify Condition II.B.2.b. by adding language that addresses the implementation of the fine mesh screens inspection and maintenance program as described by the Company to DER in its letter of July 21, 1987.

7. Tampa Electric Company seeks to modify Condition III.D. and E. by deleting all references to the Big Bend Unit 4 groundwater monitoring program and referencing the existing stationwide DER approved groundwater monitoring plan pursuant to 17-4.245, FAC.

8. Tampa Electric Company seeks to modify Condition XXVIII. by designating the time period for which the fine mesh screens shall be in operation as agreed upon by DER in their meeting with Tampa Electric Company of July 17, 1987.

9. Tampa Electric Company seeks to modify Condition XXX. by deleting the reference to a two-year limitation for the variance for discharges from the FGD system blowdown and the bottom ash pond blowdown. It is requested that the variance be extended for an additional two years. As stated above, bottom ash blowdown is no longer discharged. Big Bend Unit No. 4 has not discharged FGD blowdown since beginning commercial operation. The FGD blowdown system is still being adjusted in an effort to produce wallboard quality gypsum. Tampa Electric Company estimates that the situation will continue through June of 1988, when it is expected that the discharge of FGD blowdown will be initiated. An additional 12 months from the commencement of the discharge would then be required to characterize the volume and quality of FGD blowdown. During this period of time, it is necessary that the variance remain in effect.

10. Wherefore, the parties hereby concur, and do not object to amending and modifying Conditions II.A.10., II.B.1., II.B.2.b., III.D., III.E., XXVIII., and XXX., to read as follows:

I.A.10. Boiler ~~and Bottom Ash Sluice System~~ Blowdown

Blowdown from the boiler ~~and from the bottom ash sluice system~~ shall be treated as appropriate prior to discharge to the cooling water system. The following effluent limitations shall apply:

Effluent	Daily Maximum	Maximum 30-Day Daily Average
TSS	100 mg/l	30 mg/l
Oil and Grease	20 mg/l	15 mg/l
pH	6-9	

~~TECO shall provide the dimensions of the bottom ash system settling pond and provide calculations demonstrating that sufficient residence time will be provided to achieve the above limitations.~~

II.B.1. Chemical Monitoring

The following parameters shall be monitored during discharge as shown, discharge commencing with the start of commercial operation of Unit 4 and reported ~~quarterly~~ monthly to the Department's Southwest District Office:

Parameter	Location	Sample Type	Frequency
Flow, Cooling	Intake	Pump Log	Continuous
~~Flow, Bottom Ash~~	~~Prior to CWS~~	~~Recorder~~	~~Continuous~~
Flow, Boiler Blowdown	Prior to CWS	Daily Log	Daily
Flow, FGD Bleed	Prior to CWS	Recorder	Continuous
pH	CWS and prior to CWS on FGD Bleed & Boiler ~~& Bottom Ash~~ Blowdown	Grab	Two per Week
Temperature	CWS Outfall	Recorder	Continuous
TSS	~~Bottom Ash Blowdown,~~ FGD Bleed~~,~~ & Boiler Blowdown	Grab	Two per Week
Chlorine, Total Residual	Outfall of CWS	Multiple Grab	~~Two per Month~~ Weekly
Oil and Grease	Boiler Blowdown ~~Bottom Ash Blowdown~~ and FGD bleed	Grab	Two per Month
Metals	~~Intake, Outfall~~ FGD Bleed Stream ~~Bottom Ash Blowdown & Boiler Blowdown~~ prior to discharge to CWS	Two-Grab composite, not less than two hours between samples	~~Two~~ One per Month ~~for the first year, then monthly thereafter~~
Arsenic	"		"
Cadmium	"		"
Iron	"		"
Lead	"		"
Mercury	"		"
Selenium	"		"
Zinc	"		"
Copper	"		"
Chromium	"		"
Nickel	"		"

II.B.2.b. Entrainment

1. In order to evaluate the entrainment mortality at the Big Bend Station, TECO shall conduct a Fine Mesh Screen Survivability Study (similar to the 1980 Prototype FMS study) for one full spawning period (March through September). Sampling for the study will be conducted at three locations pertaining to Unit 4:

Station 1: Front of screen after organisms are impinged and washed to the screen return system.

Station 2: Behind the screen.

Station 3: At the discharge point in the Organism Return Canal (ORC).

Stations 1 and 2 will be sampled simultaneously to estimate the total number of organisms entrained at the plant. Initial and latent mortality tests will be conducted on organisms collected at locations 1 and 3 only. A detailed scope of study shall be submitted by TECO at least twelve months prior to the commencement of commercial operation of Unit 4.

The applicant shall implement the fine mesh screens inspection and maintenance program submitted to the Department on July 21, 1987, to assure that the screens are properly maintained and operated. The applicant shall maintain logs of inspections, maintenance, and repairs. The logs shall include the date of inspection, item(s) inspected, repairs needed, and date maintenance job request submitted.

III.D. Monitoring and Reporting

~~Tampa Electric Company shall implement the following groundwater monitoring program.~~

~~1.~~ ~~The groundwater levels shall be monitored at wells as approved by DER and the Southwest Water Management District. Chemical analyses shall be made on samples from all monitored wells identified in this Condition. The location, frequency, water levels and selected chemical analyses shall be as given in Condition III.D.3.~~

~~2.~~ ~~The groundwater monitoring program shall be implemented at least one year prior to operation of Big Bend Unit 4. The chemical analyses shall be in accord with the latest edition of Standard Methods for the Analysis of Water and Wastewater. The data shall be submitted within 30 days of collection/analysis to the Southwest Florida Water Management District and to the DER Power Plant Siting Section.~~

~~3.~~ ~~After consultation with the DER and SWFWMD, TECO shall install a monitoring well system, as generally shown on Figure 3, to monitor groundwater quality in the top 40 feet of the surficial aquifer. One well shall be installed to a depth greater than 40 feet but less than 100 to monitor vertical dispersion or groundwater contaminants. Monitoring well locations and designs shall be submitted to the Department and SWFWMD for review. Approval or disapproval of the locations and design shall be granted within 60 days. The water samples collected from each of the monitor wells shall be collected immediately after removal by pumping of a quantity of water equal to two casing volumes. The water quality analyses shall be performed monthly during the year prior to commercial operation and for two years after operation and quarterly thereafter. Results shall be submitted to the Department and the SWFWMD by the fifteenth (15th) day of the month following the month during which such analyses were performed. Testing for the following constituents is required:~~

~~Conductance~~	~~Nickel~~
~~pH~~	~~Selenium~~
~~Chloride~~	~~Chromium~~
~~Iron~~	~~Arsenic~~
~~Cadmium~~	~~Berryllium~~

~~Zinc~~ ~~Mercury~~
~~Copper~~ ~~Lead~~
~~Sulfate~~ ~~Gross Alpha~~
~~Silver~~ ~~Barium~~

~~4. After the second year of monitoring and periodically thereafter, the Department and the permittee shall review the results of the monitoring program and determine the necessity for modifying or continuing the program.~~

[FIGURE 3] (DELETE FIGURE 3)

~~III.E.~~ ~~Leachate~~

~~1.~~ ~~Zone of Discharge~~

~~Leachate from the FGD/gypsum landfill, coal storage pile, bottom ash pond, wastewater treatment ponds, ash disposal cells, and spray irrigation field shall not contaminate waters of the State (including both surface and groundwaters) in excess of the limitations of Chapter 17-3, FAC., beyond the boundary of the site.~~

~~2.~~ ~~Corrective Action~~

~~When the groundwater monitoring system shows a violation of the groundwater water quality standards of Chapter 17-3, FAC., the appropriate ponds, FGD landfill, or coal pile shall be sealed, relocated or closed, or the operation of the affected facility shall be altered in such a manner as to assure the Department that no violation of the groundwater standards will occur beyond the boundary of the site.~~

Tampa Electric Company shall monitor the groundwater at Big Bend Station in accordance with the approved groundwater monitoring plan.

XXVIII. Fine Mesh Screens

Fine mesh screens, similar to those tested and described by TECO in the 316 Demonstration, shall be installed on the intakes of Units 3 and 4 with the appropriate sprays and screen wash sluice return system to minimize entrainment. The screen wash sluice return system shall discharge to the east end of the canal north of the intake canal or to a location acceptable to the Department and EPA. ~~TECO shall submit a plan to DER to explore the possibility of re-entrainment of ORC--returned organism.~~ The applicant shall operate the fine mesh screens for Units 3 and 4 intake structures and the organism return mechanism from March 15 through October 15 of each year.

XXX. Variances

TECO is granted variances for discharges of FGD system blowdown ~~and bottom ash pond blowdown~~ pursuant to Sections 403.201 and 403.511(2) F.S., for a period of two years from the date of the final order granting this modification ~~after the start of commercial operation~~ for the following parameters:

a. Arsenic - 17-3.061(2)(a)
b. Cadmium - 17-3.121(9)
c. Chromium - 17-3.061(2)(d)
d. Copper - 17-3.121(11)
e. Iron - 17-3.121(16)
f. Mercury - 17-3.121(18)
g. Nickel - 17-3.121(19)
h. Selenium - 17-3.121(26)

During the period that the variance is in effect, TECO shall (1) determine the concentrations of the above metals as well as lead in the ~~two~~ discharge stream~~s~~; (2) operate the FGD blowdown treatment system so as to minimize the metal content of the discharge from the system; and (3) submit a report~~s~~ of the above studies and analys~~is~~es ~~after the first year and at least twenty months after the start of commercial operation of Unit 4.~~ no later than 15 months after the start of normal operational discharge.

Upon receipt of the aforementioned reports, the Secretary shall determine whether the variances should be renewed and may impose appropriate conditions to minimize the discharges and their impacts.

R T Donelan, Jr.

Florida Department of
Environmental Regulation
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399

John T. Mitchell

Southwest Florida Water
Management District
5060 U.S. Highway 41 South
Brooksville, Florida 33512

Katie Nichols

Florida Public Service Commission
101 East Gaines Street
Tallahassee, Florida 32304

C. Laurence Keesey

Florida Department of
Community Affairs
2571 Executive Center Circle East
Tallahassee, Florida 32301

Lawrence N. Curtin

Lawrence N. Curtin
Aurell, Fons, Radey & Hinkle
Post Office Drawer 11307
Tallahassee, Florida 32302

STATE OF FLORIDA

DEPARTMENT OF ENVIRONMENTAL REGULATION

TWIN TOWERS OFFICE BUILDING
2600 BLAIR STONE ROAD
TALLAHASSEE, FLORIDA 32301-8241

BOB GRAHAM
GOVERNOR

VICTORIA J. TSCHINKEL
SECRETARY

May 6, 1985

Mr. James T. Wilburn, Chief
Air Management Branch
USEPA-Region IV
345 Courtland Street, N.E.
Atlanta, Georgia 30365

Re: Modification to PSD-FL-040
TECO Big Bend Unit 4

Dear Mr. Wilburn:

This is to acknowledge the receipt of your March 12, 1985 letter requesting a public notice to be published prior to a modification of the above referenced permit.

Tampa Electric Company (TECO) requested that the carbon monoxide (CO) emission limits contained in this permit be changed to correct an error when an incorrect emission factor was used in their application. The correction of this error will result in a theoretical significant increase in the CO emission limits. At your request, we have enclosed a copy of the proof of publication so you can proceed to revise the PSD permit to reflect the emission change for CO.

Should you require any further information, please feel free to contact me.

Sincerely,

C. H. Fancy, P.E.
Deputy Chief
Bureau of Air Quality
Management

CHF/ES/s

cc: Richard Garrity
Iwan Choronenko
Jerry Williams

attachment

TAMPA ELECTRIC
A TECO ENERGY COMPANY

DER
MAY 8 1985
BAQM

May 1, 1985

Mr. C.H. Fancy, P.E.
State of Florida
Department of Environmental
Regulation
Bureau of Air Quality
Management
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, FL 32301

Re: Proof of Public Notice
Modification to PSD-FL-040
Big Bend Unit #4

Dear Mr. Fancy:

Please find attached a copy of the "Public Notice" for the above referenced source as published in the Tampa Tribune on Saturday, April 20, 1985.

If you have any questions, please call.

Sincerely,

A. Spencer Autry
Manager
Environmental Planning

ASA/jst/024/3

attached

cc: Richard Garrity
Iwan Choronenko

RECEIVED

MAY 01 1985

ENVIRONMENTAL PLANNING

THE TAMPA TRIBUNE

Published Daily
Tampa, Hillsborough County, Florida

State of Florida
County of Hillsborough } ss.

Before the undersigned authority personally appeared G. T. Gleason, who on oath says that he is Controller of The Tampa Tribune, a daily newspaper published at Tampa in Hillsborough County, Florida; that the attached copy of advertisement being a LEGAL NOTICE

in the matter of PUBLIC NOTICE BY THE TAMPA ELECTRIC COMPANY REQUESTED THAT THEIR PREVENTION OF SIGNIFICANT DETERIORATION PERMIT (PSD-FL-040)

was published in said newspaper in the issues of APRIL 20th, 1985

Affiant further says that the said The Tampa Tribune is a newspaper published at Tampa, in said Hillsborough County, Florida, and that the said newspaper has heretofore been continuously published in said Hillsborough County, Florida, each day and has been entered as second class mail matter at the post office in Tampa, in said Hillsborough County, Florida, for a period of one year next preceding the first publication of the attached copy of advertisement; and affiant further says that he has neither paid nor promised any person, firm, or corporation any discount, rebate, commission or refund for the purpose of securing this advertisement for publication in the said newspaper.

G. P. Gleason

Sworn to and subscribed before me, this 22nd *day of* APRIL *A.D. 19*85

Notary Public, State of Florida
My Commission Expires Jan. 6, 1989
Bonded Thru Troy Fain - Insurance, Inc.

(SEAL)

PUBLIC NOTICE

On January 30, 1985, the Tampa Electric Company requested that their Prevention of Significant Deterioration permit (PSD-FL-040) for the coal-fired boiler, Unit 4, at the Big Bend facility near Ruskin, Florida, be revised. The requested revision will result in a projected increase of 271 tons per year of carbon monoxide.

EPA has reviewed the proposal to increase emissions. The increase is due to an error in emissions calculations for this source and no process or structural modifications are involved. The projected increase in emissions from 272 tons per year to 443 tons per year of carbon monoxide will increase the ambient concentration (8-hour average) to approximately 146 ug/m3. The significant level for carbon monoxide is 575 ug/m3 and therefore, no adverse impacts are expected due to the increase. The best available control technology has been determined to be proper combustion controls and is not changed in this proposed revision.

Any person may submit written comments regarding this proposed permit revision. All comments must be received not later than 30 days from the date of this notice in order to be considered. A public hearing may be held if sufficient justification is provided, as determined by the Administrator. Letters should be addressed to:

Mr. Clair Fancy, P.E.
State of Florida
Department of
Environmental Regulation
Bureau of Air
Quality Management
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32301

2111 4/20/85

STATE OF FLORIDA

DEPARTMENT OF ENVIRONMENTAL REGULATION

TWIN TOWERS OFFICE BUILDING
2600 BLAIR STONE ROAD
TALLAHASSEE, FLORIDA 32301-8241

BOB GRAHAM
GOVERNOR

VICTORIA J. TSCHINKEL
SECRETARY

March 27, 1985

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. Jerry L. Williams, Environmental Director
Tampa Electric Company
P.O. BOx 111
Tampa, Florida 33601

RE: Request for permit modification to PSD-FL-040,
Big Bend Unit 4

Dear Mr. Williams:

On February 4, 1985, the Bureau of Air Quality Management received your request to modify the carbon monoxide limits for permit PSD-FL-040. Because this change concerns a federal PSD permit, your request was forwarded to the EPA in Atlanta for their review and comments.

Because this change will result in a theoretical significant increase in carbon monoxide emissions, a public notice will need to be published regarding this change. Please use the sample public notice attached to this letter and provide us with a proof of publication so that we can finish processing the requested change.

If you have any questions, please write to me at the above address, or call Edward Svec, Review Engineer, at (904)488-1344.

Sincerely,

C. H. Fancy, P.E.
Deputy Chief
Bureau of Air Quality
Management

CHF/ES/rw

Attachment
cc: Richard Garrity
Iwan Choronenko

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

REGION IV

345 COURTLAND STREET
ATLANTA, GEORGIA 30365

MAR 12 1985

REF: APT-AM

Mr. Clair H. Fancy, Deputy Chief
Bureau of Air Quality Management
Florida Department of Environmental
Regulation
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32301

RE: PSD-FL-040 TECO Big Bend Unit 4

Dear Mr. Fancy:

This is to acknowledge receipt of your February 8, 1985, letter requesting the modification of the federal Prevention of Significant Deterioration (PSD) permit (PSD-FL-040) issued for the construction of the coal-fired boiler, Unit 4, at the Tampa Electric Company's (TECO) Big Bend facility near Ruskin, Florida. The permit issued on October 15, 1981, contained carbon monoxide (CO) emission limits for the unit based on estimates provided by the company in which an incorrect emission factor was used.

The PSD preliminary and final determinations for Unit 4 at the TECO Big Bend facility reflected CO emission estimates which appeared in the TECO application. The company used the wrong emission factor from the EPA document "Compilation of Air Pollutant Emission Factors" (AP-42). As a result, there was an underestimation of CO emissions in the original review. The requested modification would theoretically increase CO emissions from 272 tons per year to 543 tons per year and will increase the ambient concentration (8-hour average) to approximately 16 ug/m^3. The significant level for CO is 575 ug/m^3, 8-hour average and therefore, no adverse impacts are expected due to the increase. The best available control technology has been determined to be proper combustion controls and has not been changed in this proposed revision. As the correction of this error will result in a theoretical significant increase in CO emissions (271 tons per year), a public notice will need to be published regarding this change. For your convenience, enclosed is a sample public notice which may be used. Please provide us a copy of the proof of publication so that we may proceed to revise the PSD permit to reflect the emission change for CO.

If you have any questions regarding this letter, you may contact me or Wayne J. Aronson, New Source Review Team Leader, at 404/881-4552.

Sincerely yours,

James T. Wilburn, Chief
Air Management Branch
Air, Pesticides, and Toxics
Management Division

Enclosure

PUBLIC NOTICE

On January 30, 1985, the Tampa Electric Company requested that their Prevention of Significant Deterioration permit (PSD-FL-040) for the coal-fired boiler, Unit 4, at the Big Bend facility near Ruskin, Florida, be revised. The requested revision will result in a projected increase of 271 tons per year of carbon monoxide.

EPA has reviewed the proposal to increase emissions. The increase is due to an error in emissions calculations for this source and no process or structural modifications are involved. The projected increase in emissions from 272 tons per year to 543 tons per year of carbon monoxide will increase the ambinet concentration (8-hour average) to approximately 16 ug/m^3. The significant level for carbon monoxide is 575 ug/m^3 and therefore, no adverse impacts are expected due to the increase. The best available control technology has been determined to be proper combustion controls and is not changed in this proposed revision.

Any person may submit written comments regarding this proposed permit revision. All comments must be received not later than 30 days from the date of this notice in order to be considered. A public hearing may be held if sufficient justification is provided, as determined by the Administrator. Letters should be addressed to:

Mr. Clair Fancy, P.E.
State of Florida Department of
Environmental Regulation
Bureau of Air Quality Management
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32301

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

REGION IV

345 COURTLAND STREET
ATLANTA, GEORGIA 30365

MAR 12 1985

REF: APT-AM

DER
BAQM

Mr. Clair H. Fancy, Deputy Chief
Bureau of Air Quality Management
Florida Department of Environmental
Regulation
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32301

RE: PSD-FL-040 TECO Big Bend Unit 4

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Sincerely yours,

James T. Wilburn, Chief
Air Management Branch
Air, Pesticides, and Toxics
Management Division

Enclosure

DEPARTMENT OF ENVIRONMENTAL REGULATION

ROUTING AND TRANSMITTAL SLIP

ACTION NO

ACTION DUE DATE

TO: (NAME, OFFICE, LOCATION)	
1. Bill T.	Initial Date
2.	Initial Date
3.	Initial Date
4.	Initial Date

REMARKS:

Please handle: send letter to TECO to tell them to publish attached notice for 30 days & send us proof of publication. Check with Larry on this.

Ed

Have you been into this at all?

JF

INFORMATION
Review & Return
Review & File
Initial & Forward

DISPOSITION
Review & Respond
Prepare Response
For My Signature
For Your Signature
Let's Discuss
Set Up Meeting
Investigate & Report
Initial & Forward
Distribute
Concurrence
For Processing
Initial & Return

FROM: Clair

DATE 3/19

PHONE

PUBLIC NOTICE

On January 30, 1985, the Tampa Electric Company requested that their Prevention of Significant Deterioration permit (PSD-FL-040) for the coal-fired boiler, Unit 4, at the Big Bend facility near Ruskin, Florida, be revised. The requested revision will result in a projected increase of 271 tons per year of carbon monoxide.

EPA has reviewed the proposal to increase emissions. The increase is due to an error in emissions calculations for this source and no process or structural modifications are involved. The projected increase in emissions from 272 tons per year to 543 tons per year of carbon monoxide will increase the ambinet concentration (8-hour average) to approximately 16 ug/m^3. The significant level for carbon monoxide is 575 ug/m^3 and therefore, no adverse impacts are expected due to the increase. The best available control technology has been determined to be proper combustion controls and is not changed in this proposed revision.

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Mr. Clair Fancy, P.E.
State of Florida Department of
Environmental Regulation
Bureau of Air Quality Management
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32301

STATE OF FLORIDA

DEPARTMENT OF ENVIRONMENTAL REGULATION

TWIN TOWERS OFFICE BUILDING
2600 BLAIR STONE ROAD
TALLAHASSEE, FLORIDA 32301-8241

BOB GRAHAM
GOVERNOR

VICTORIA J. TSCHINKEL
SECRETARY

February 8, 1985

Mr. James T. Wilburn, Chief
Air Management Branch
USEPA - Region IV
345 Courtland Street, N.E.
Atlanta, Georgia 30365

Re: Request from Tampa Electric Company
to Modify PSD-FL-040

Dear Mr. Wilburn:

The Bureau of Air Quality Management received a request from Tampa Electric Company on February 4, 1984, to modify their federal permit, PSD-FL-040, for their Big Bend Station Unit 4 in Ruskin, Florida. In their permit application, Tampa Electric used an incorrect emission estimate from AP-42 which underestimated the emissions of CO by a factor of two.

After reviewing this request, the bureau recommends that Table 1 of permit PSD-FL-040 be modified to reflect the proper AP-42 emission factor CO as follows:

From:

Facility	Pollutants CO lb/MMBtu	Pollutants CO lb/hr
1. Unit 4 Boiler (4330 MMBtu/hr) Continuous Limit	0.014	61

To:

Facility	Pollutants CO lb/MMBtu	Pollutants CO lb/hr
1. Unit 4 Boiler (4330 MMBtu/hr) Continuous Limit	0.029	124

Should you require any further information, please feel free to contact me.

Sincerely,

C. H. Fancy, P.E.
Deputy Chief
Bureau of Air Quality
Management

CHF/ES/s

cc: Richard Garrity
Iwan Choronenko
Jerry Williams

attachment

TAMPA ELECTRIC
A TECO ENERGY COMPANY

January 30, 1985

Mr. Steve Smallwood
Florida Department of Environmental
Regulation
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32301

RE: Request for Permit Modification
Big Bend Station Unit 4
Tampa Electric Company
PSD-FL-040

Dear Mr. Smallwood:

As you are probably aware, Tampa Electric Company is in the final stages of constructing a 417 MW (net) coal fired electric generating unit at the Big Bend Station in Ruskin, Florida. The commercial operation date for this new unit, Big Bend Unit 4, is expected to be in March of 1985.

In anticipation of our upcoming commercial operation of Unit 4, Tampa Electric Company has been reviewing all permitting associated with the new unit. On reviewing the above referenced Prevention of Significant Deterioration (PSD) permit and associated application documents, a calculation error was identified in the PSD application emissions estimate for carbon monoxide (CO). In the application, an incorrect emission factor from the EPA document Compilation of Air Pollutant Emission Factors, AP-42, was inadvertently used to estimate the CO emissions. The use of the incorrect emission factor lead to an underestimation of the CO emissions by a factor of two. Attachment I contains the calculations for the corrected estimate.

As seen in Attachment I, the CO emission rate is expected to be approximately 124 lb/hr and 0.029 lb/MMbtu.

DER
FEB 4 1985
BAQM

TAMPA ELECTRIC COMPANY
P.O. Box 111 Tampa, Florida 33601 (813) 228-4111

Tampa Electric Company requests a modification of the CO limits listed in Table 1 of permit number PSD-FL-040 to reflect the corrected estimate. Attachment II contains the corrected pages to our PSD application.

If you should have any questions please feel free to call me.

Sincerely,

Jerry L. Williams

Jerry L. Williams
Director
Environmental

JLW/jbj/047/1

Attachment

cc: Dr. Richard Garrity (DER)

Attachment I

CARBON MONOXIDE (CO) EMISSIONS ESTIMATE
BIG BEND STATION UNIT 4
PSD-FL-040

Fuel input rate at 100% load = 413,000 $\frac{\text{lbs coal}}{\text{hour}}$

Heat input rate at 100% load = 4330 $\frac{\text{MMbtu}}{\text{hour}}$

CO emission factor = 0.6 $\frac{\text{lbs CO*}}{\text{ton coal}}$

(a) $413{,}000 \ \frac{\text{lbs coal}}{\text{hour}} \times \frac{1}{2000} \ \frac{\text{tons coal}}{\text{lbs coal}} \times 0.6 \ \frac{\text{lbs CO}}{\text{ton coal}}$ **

$= 123.9 \ \frac{\text{lbs CO}}{\text{hour}}$

(b) $123.9 \ \frac{\text{lbs CO}}{\text{hour}} \times \frac{1}{4330} \ \frac{\text{hour}}{\text{MMBtu}} = 0.0286 \ \frac{\text{lbs CO}}{\text{MMBtu}}$

---

* Compilation of Air Pollutant Emission Factors, AP-42. See Table 1.1-1. attached.

** In the previously submitted and approved PSD application an emission factor of 0.3 $\frac{\text{KgCO}}{\text{Mg Coal}}$ was mistakenly used as 0.3 $\frac{\text{lb CO}}{\text{Ton Coal}}$. See Table 1.1-1. attached.

TABLE 1.1-1. EMISSION FACTORS FOR EXTERNAL BITUMINOUS AND SUBBITUMINOUS COAL COMBUSTION[a]

Firing Configuration	Particulate[b] kg/Mg	Particulate[b] lb/ton	Sulfur Oxides[c] kg/Mg	Sulfur Oxides[c] lb/ton	Nitrogen Oxides[d] kg/Mg	Nitrogen Oxides[d] lb/ton	Carbon Monoxide[e] kg/Mg	Carbon Monoxide[e] lb/ton	Nonmethane VOC[e,f] kg/Mg	Nonmethane VOC[e,f] lb/ton	Methane[e] kg/Mg	Methane[e] lb/ton
Pulverized coal fired												
Dry bottom	5A	10A	19.5S(17.5S)	39S(35S)	10.5(7.5)[g]	21(15)[g]	0.3	0.6	0.04	0.07	0.015	0.03
Wet bottom	3.5A[h]	7A[h]	19.5S(17.5S)	39S(35S)	17	34	0.3	0.6	0.04	0.07	0.015	0.03
Cyclone furnace	1A[h]	2A[h]	19.5S(17.5S)	39S(35S)	18.5	37	0.3	0.6	0.04	0.07	0.015	0.03
Spreader stoker												
Uncontrolled	30[i]	60[i]	19.5S(17.5S)	39S(35S)	7	14	2.5	5	0.04	0.07	0.015	0.03
After multiple cyclone												
With flyash reinjection from multiple cyclone	8.5	17	19.5S(17.5S)	39S(35S)	7	14	2.5	5	0.04	0.07	0.015	0.03
No flyash reinjection from multiple cyclone	6	12	19.5S(17.5S)	39S(35S)	7	14	2.5	5	0.04	0.07	0.015	0.03
Overfeed stoker[j]												
Uncontrolled	8[k]	16[k]	19.5S(17.5S)	39S(35S)	3.25	7.5	3	6	0.04	0.07	0.015	0.03
After multiple cyclone	4.5	9	19.5S(17.5S)	39S(35S)	3.25	7.5	3	6	0.04	0.07	0.015	0.03
Underfeed stoker												
Uncontrolled	7.5[l]	15[l]	15.5S	31S	4.75	9.5	5.5	11	0.65	1.3	0.4	0.8
After multiple cyclone	5.5	11	15.5S	31S	4.75	9.5	5.5	11	0.65	1.3	0.4	0.8
Handfired units	7.5	15	15.5S	31S	1.5	3	45	90	5	10	4	8

[a]Factors represent uncontrolled emissions unless otherwise specified and should be applied to coal consumption as fired.

[b]Based on EPA Method 5 (front half catch) as described in Reference 12. Where particulate is expressed in terms of the coal ash content (A), the factor is determined by multiplying the weight % ash content of the coal (as fired) by the numerical value preceding the "A". For example, if a coal having 8% ash is fired in a dry bottom unit, the particulate emission factor would be 5 x 8 or 40 kg/Mg (80 lb/ton). On average, the "condensible" material collected in the back half catch of EPA Method 5 is less than 5% of the front half, or "filterable", catch for pulverized coal and cyclone furnaces; about 10% for spreader stokers; about 15% for other stokers; and about 50% for handfired units (References 6, 19, and 49).

[c]Expressed as SO_2, including SO_2, SO_3 and gaseous sulfates. The factors in parentheses should be used to estimate gaseous sulfur oxide emissions for subbituminous coal. In all cases, "S" is the weight % sulfur content of the coal as fired. See Footnote b for an example calculation. On average for bituminous coal, 97% of the fuel sulfur is emitted as SO_2, whereas only about 0.7% of the fuel sulfur is emitted as SO_3 and gaseous sulfate. An equally small percent of the fuel sulfur is emitted as particulate sulfate (References 9, 13). Small quantities of sulfur are also retained in the bottom ash. With subbituminous coal, generally about 10% more fuel sulfur is retained in the bottom ash and particulate, because of the more alkaline nature of the coal ash. Conversion to gaseous sulfate appears to be about the same as for bituminous coal.

[d]Expressed as NO_2. Generally, 95 - 99 volume % of the nitrogen oxides present in combustion exhaust will be in the form of NO, the rest being NO_2 (Reference 11). To express these factors as NO, multiply by a factor of 0.66. All factors represent emissions at baseline operation (i.e., 60 - 110% load and no NO_x control measures, as discussed in the text).

[e]Nominal values achieveable under normal operating conditions. Values one or two orders of magnitude higher can occur when combustion is not complete.

[f]Nonmethane volatile organic compounds (VOC), expressed as C_2 to C_{16} n-alkane equivalents (Reference 58). Because limited data on NMVOC were available to distinguish the effects of firing configuration, all data were averaged collectively to develop a single average for pulverized coal units, cyclones, spreader and overfeed stokers.

[g]Parenthetic value is for tangentially fired boilers.

[h]Uncontrolled particulate emissions, when no flyash reinjection is employed. When a control device is installed, and collected flyash is reinjected to the boiler, particulate from the boiler reaching the control equipment can increase by up to a factor of two.

[i]Accounts for flyash settling in an economizer, air heater or breeching upstream of a control device or stack. (Particulate directly at the boiler outlet typically will be twice this level.) This factor should be applied even when flyash is reinjected to the boiler from boiler, air heater or economizer dust hoppers.

[j]Includes traveling grate, vibrating grate and chain grate stokers.

[k]Accounts for flyash settling in the breeching or stack base. Particulate loadings directly at the boiler outlet typically can be 50% higher.

[l]Accounts for flyash settling in the breeching downstream of the boiler outlet.

Attachment II

Revised pages to:

VOLUME I

Prevention of Significant Deterioration (PSD) Application - Tampa Electric Company

(PSD-FL-040)

system for measuring SO_2 emissions will be installed, calibrated, maintained, and operated at a point downstream of the FGD system.

4.3 Oxides of Nitrogen

The emission of NO_x from the combustion system will be minimized by the design of the burners and boiler to be provided by CE. The tangentially-fired boiler has been demonstrated to be capable of limiting NO_x formation to 0.6 lb/MMBtu, the NSPS, when firing bituminous coal. The EPA cites several CE boilers in operation that are able to meet the NSPS, although these boilers are neither designed nor guaranteed to have an NO_x emission at these levels.

The formation of thermally produced NO_x is inhibited in the CE boiler by the off-stoichiometric combustion, that is, operating the burners at a fuel-rich mixture. Off-stoichiometric combustion can be accomplished by two techniques: biased-firing and two-staged combustion. The former technique consists of operating selected burners at fuel-rich mixtures and others at lean mixtures. Initial combustion then occurs in a reducing atmosphere, followed by complete combustion after substantial heat loss. The resultant lower flame temperatures inhibit the formation of thermal NO_x. The latter technique, two-staged combustion, is accomplished by diverting a portion of the combustion air to over-fire air ports located above the burners. The same fuel-rich combustion occurs with the attendant heat loss, followed by complete mixing and combustion above the primary combustion zone. Although CE has incorported over-fire air ports in the boiler design to maintain NO_x concentrations at the NSPS, operation of these ports has been found to be unnecessary below 90% MCR. Two-stage combustion will thus be used should monitoring indicate that the NO_x emissions may exceed standards. The NO_x emission limitation is equivalent to an emission rate of 2,598 lb/hr.

The EPA sponsored a test program, performed by CE, at the Alabama Power Company's Barry Station #2. This program assessed the effects of modifications in boiler operation and design on the emission of

NO_x. Included in the modifications were variations in excess air, biased-firing, over-fire air, burner tilt, and water-wall slagging. The results of this program that are applicable to Unit 4 boiler operation are summarized in Table 4-7. Note that all tests demonstrated boiler compliance with the NSPS for NO_x, with the exception of that test with no modifications and water-wall slagging.

Compliance with the NSPS for NO_x will be demonstrated in accordance with Section 60.48a, Subpart Da, and by procedures prescribed in Method 19, Appendix A, 40 CFR 60. A continuous monitoring system for measuring NO_x emissions will be installed, calibrated, maintained, and operated at a point downstream of the economizer outlet.

4.4 Carbon Monoxide

The only significant source of CO is the Unit 4 steam generator. CE does not include monitoring of combustibles in the design of their boilers because CO emissions are expected to be negligible. The recording of combustibles, however, may be included in the specification of the combustion air control system. Using the emission factor from the EPA document Compilation of Air Pollution Emission Factors, AP-42, the CO emission rate will be approximately ~~62~~ 124 lb/hr based on Coal F-1A and boiler performance data. This factor represents a consensus mean emission from both boilers of older and more recent design. The EPA test on the Alabama Power Company's Barry Station #2 demonstrates that CO emissions typically range from 0.016 to 0.022 lb/MMBtu, which is equivalent to 70 to 95 lb/hr (see Table 4-7). These data then generally support the AP-42 emission factor, which is used to estimate the CO emission rate.

4.5 Summary

The emission of pollutants from the proposed Unit 4 steam generator is summarized in Table 4-8. The applicable NSPS for electric utility facilities are also presented for direct comparison.

TABLE 4-7

EPA TEST PROGRAM FOR NO_x REDUCTION

Test No.	Test Condition*	Excess Air	Emission (lb/MMBtu) NO_x**	CO
1	No modification	22.7	0.58	0.022
2	No modification; WW slagging	26.0	0.68	0.024
3	BF	24.2	0.33	0.019
4	OFA	25.4	0.55	0.016
5	OFA; WW slagging	25.9	0.50	0.016
6	OFA; -5° burner tilt	25.9	0.39	0.016
7	OFA; $+19^{\circ}$ burner tilt	25.1	0.43	0.023
8	Optimum conditions	27.4	0.39	0.018

*WW = water-wall; BF = biased-firing; OFA = over-fire air.

**As NO_2.

Source: EPA 1975.

TABLE 4-8

POLLUTANT EMISSIONS SUMMARY

BIG BEND STATION UNIT 4

Pollutant	Pollutant Emission: lb/hr	Pollutant Emission: lb/MMBtu	Pollutant Emission: % Reduction	Applicable NSPS/SIP Requirement
PM	129.9	0.03	99.7	0.03 lb/MMBtu
NO_x	2,598.	0.60	65.0	0.60 lb/MMBtu
SO_2*	2,592.-5,184.	0.60-1.2	90.0	90% reduction
CO	124 ~~62.~~	0.029 ~~0.014~~	NA	NA

*SO_2 emission represents range of sulfur content of raw coals of 3.0 and 6.0 lb/MMBtu.

BIG BEND UNIT 4

CORRECTIVE ACTION PLAN FOR

POLLUTION CONTROL EQUIPMENT

TAMPA ELECTRIC COMPANY

DECEMBER 1984

CONTENTS

CONTENTS (Contd)

I. Introduction

Tampa Electric Company (TEC) Big Bend Unit 4 is a 417 MW (net) coal-fired electric generating unit at the existing Big Bend power plant site (See Figure 1). It has been designed to meet all applicable air quality control laws, and regulations.

This report satisfies the State of Florida Department of Environmental Regulations (FDER) permit number PA 79-12, Conditions of Certification, Section I, B.6. which states:

> Prior to operation of the source, the permittee shall submit to the Department a standardized plan or procedure that will allow the permittee to monitor emission control equipment efficiency and enable the permittee to return malfunctioning equipment to proper operation as expeditiously as possible.

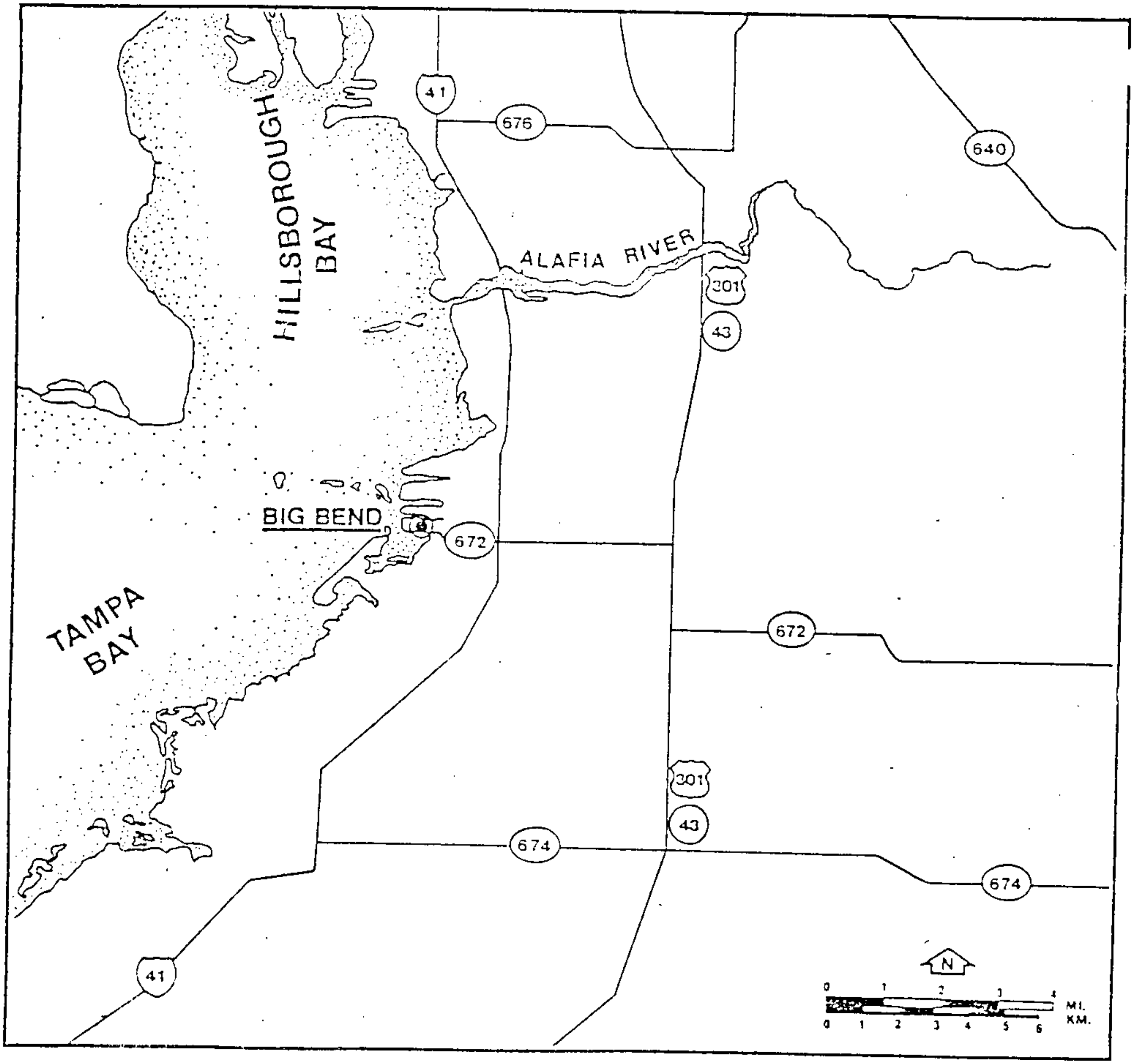


FIGURE 1 Location of Tampa Electric Company Big Bend Generating Units

II. Air Pollution Controls

As stated in Tampa Electric Company's PSD application, the principle air pollution control techniques and systems incorporated in the design of the facility are:

- Particulate Matter emissions from the boiler will be controlled by an electrostatic precipitator (ESP) installed at the exit of the air preheater (in compliance with the New Source Performance Standards (NSPS)).

- SO_2 emissions will be minimized by a combination of coal washing and boiler exhaust gas cleaning using a flue gas desulfurization (FGD) system (in compliance with the NSPS).

- NO_x formation during combustion will be inhibited by the proper operation and design of the boiler and combustion air control system (in compliance with NSPS).

- CO emissions will be minimized by optimum excess-air operation and design of the combustion air control system.

- Fugitive dust emissions resulting from the receiving, handling, and storage of coal and limestone will be minimized by the surface moisture content of coal in storage piles; particle size of received limestone; containment and control of transfer points, conveyors, and crushing equipment; and proper maintenance of coal and limestone handling facilities.

A flow diagram of the combustion system and associated air pollution control techniques and equipment is presented in Figure 2.

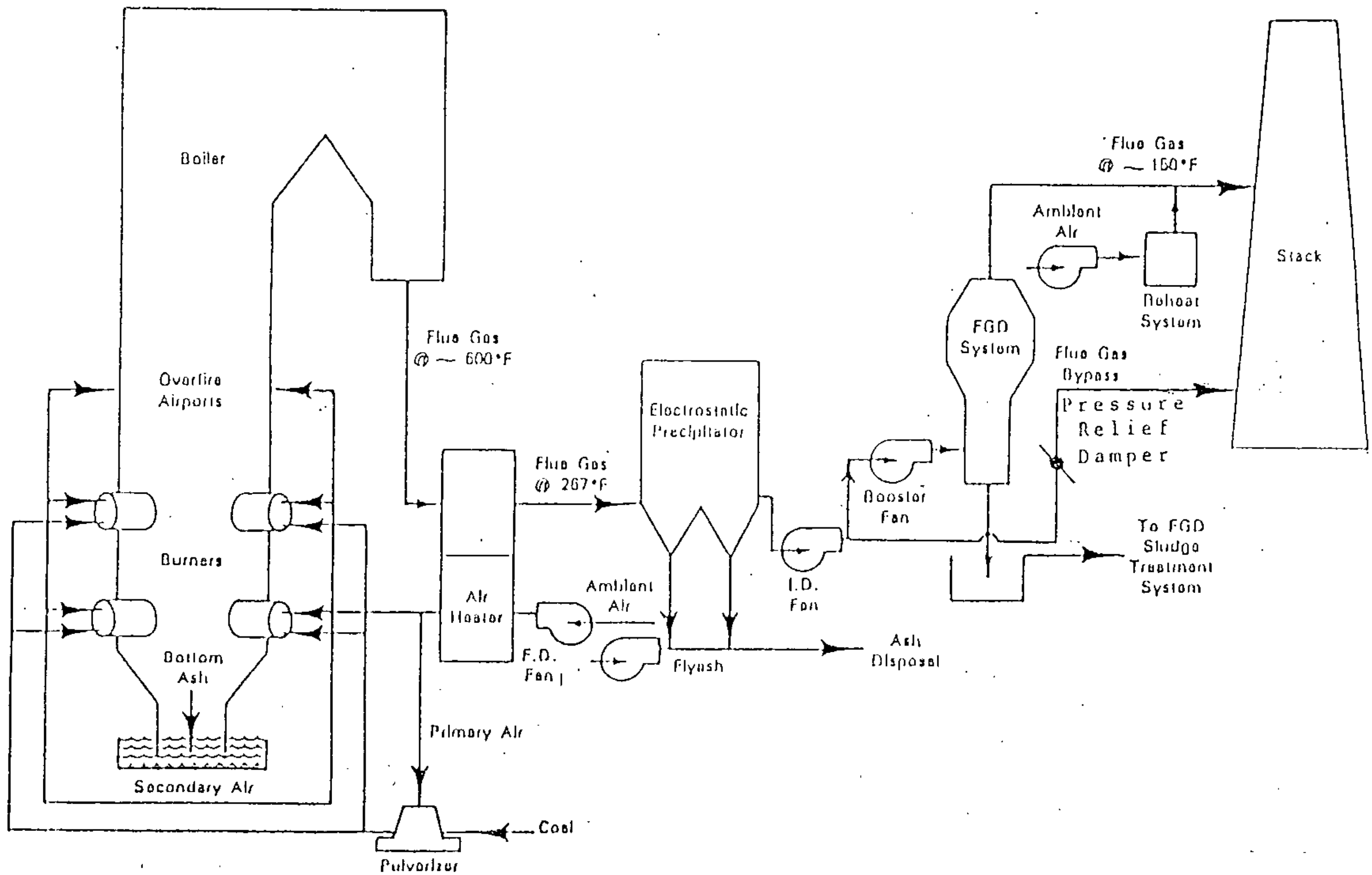


Figure 2 Air Pollution Control Systems for Big Bend Station Unit 4

III. Particulate Control System

1. General Description

Big Bend Unit 4 is equipped with two identical Belco rigid frame electro-static precipitators (upper and lower) for the control of particulate contained in the boiler exhaust gases. The precipitator is located downstream of the air preheater and upstream of the FGD system. The precipitator has been designed for a removal efficiency of 99.74%. Based on the design coals for Big Bend Unit 4, this removal efficiency ensures an emission limit of 0.03 pounds of particulate per million BTU. Compliance will be demonstrated annually by an in-stack emission compliance test. Figure 2 shows the Big Bend Unit 4 combustion system and associated pollution control equipment.

2. Principle of Operation

Boiler exhaust gases containing particulate pass between high voltage electrodes and grounded collecting plates. The electric fields established between the electrodes and the grounded plates polarizes the particulate which causes it to become attached to the grounded collecting plates. Periodic mechanical rapping of the collecting plates dislodges the attached particles from the plates and collect it in the flyash hoppers. The collected particulate will be conveyed from the hoppers and transported to the Big Bend Unit 4 flyash silo.

3. Operation

3.1 Operator Monitoring

Performance of the electrostatic precipitator is monitored by plant operators. Collective responsibilities of these operators include:

A. Maintaining proper opacity.

B. Reviewing the following precipitator parameters:

   1. Power availability to the annunciator panel
   2. Status of the alarms
   3. Primary voltage
   4. Primary current
   5. Proper functioning of the mechanical rapping system
   6. Spark rate

C. Reviewing the following flyash handling system parameters:

   1. Power availability to the annunciator panels
   2. Status of the alarms
   3. Proper functioning of the flyash feeder valves
   4. Proper sequencing of each flyash feeder
   5. Adequacy of flow of flyash from hoppers through flyash feeders.

D. Initiating a Maintenance Job Request (MJR) for any needed repairs. (An MJR is the means by which all maintenance work is initiated and documented by Tampa Electric Company.)

3.2 Annunciator System

Any monitored variable that deviates from the specified control limits will be alarmed in the main plant control room as well as the precipitator control room. The alarm in the main plant control room will indicate PRECIPITATOR TROUBLE and the alarm in the precipitator control room will indicate the cause of the PRECIPITATOR TROUBLE alarm. Figures 3 and 4 show the main plant control room and the lower precipitator control room annunciator panels, respectively. The annunciator panel shown in Figure 4 is duplicated for the upper precipitator. Both the upper and lower annunciator precipitator panels are located in the precipitator control room.

4. **Malfunction Response**

An opacity monitor continuously monitors precipitator exit gases. The opacity monitor will indicate any exceedance of the applicable opacity limits, including exceedances that may be due to precipitator malfunctions.

In the event that stack opacity reaches an alert alarm point based on the applicable opacity limits, an annunciator will alarm in the main plant control room, SMOKE DENSITY HIGH (Figure 3). The main plant control room operator will alert the responsible operator within the plant. This operator will review both the precipitator and flyash system to identify and correct the cause of the SMOKE DENSITY HIGH alarm. If necessary, the operator will reduce generation in order to ensure environmental compliance.

Any problem identified by plant operators will be corrected by the operators. Those problems that cannot be corrected by the operator will be referred to the appropriate craft personnel by generating an MJR. Craft personnel will address the problem under an emergency status. When repairs can be effected immediately, craft personnel will do so. Otherwise, repairs will be deferred until the next unit outage.

Another type of alarm that an operator will respond to is PRECIPITATOR TROUBLE which will be alarmed in the plant main control room and called out on the plant public address (PA) system so that a plant operator can respond to the condition.

Upon hearing the PRECIPITATOR TROUBLE alarm called out on the plant PA system, the plant operator will go to the precipitator control room where an annuciator panel will identify the specific cause of the PRECIPITATOR TROUBLE alarm. Afterwards, the operator will go to the affected equipment and correct the problem immediately. Those problems which cannot be corrected by the operator will be referred to appropriate craft personnel by the operator generating an MJR.

5. **Repair Procedures**

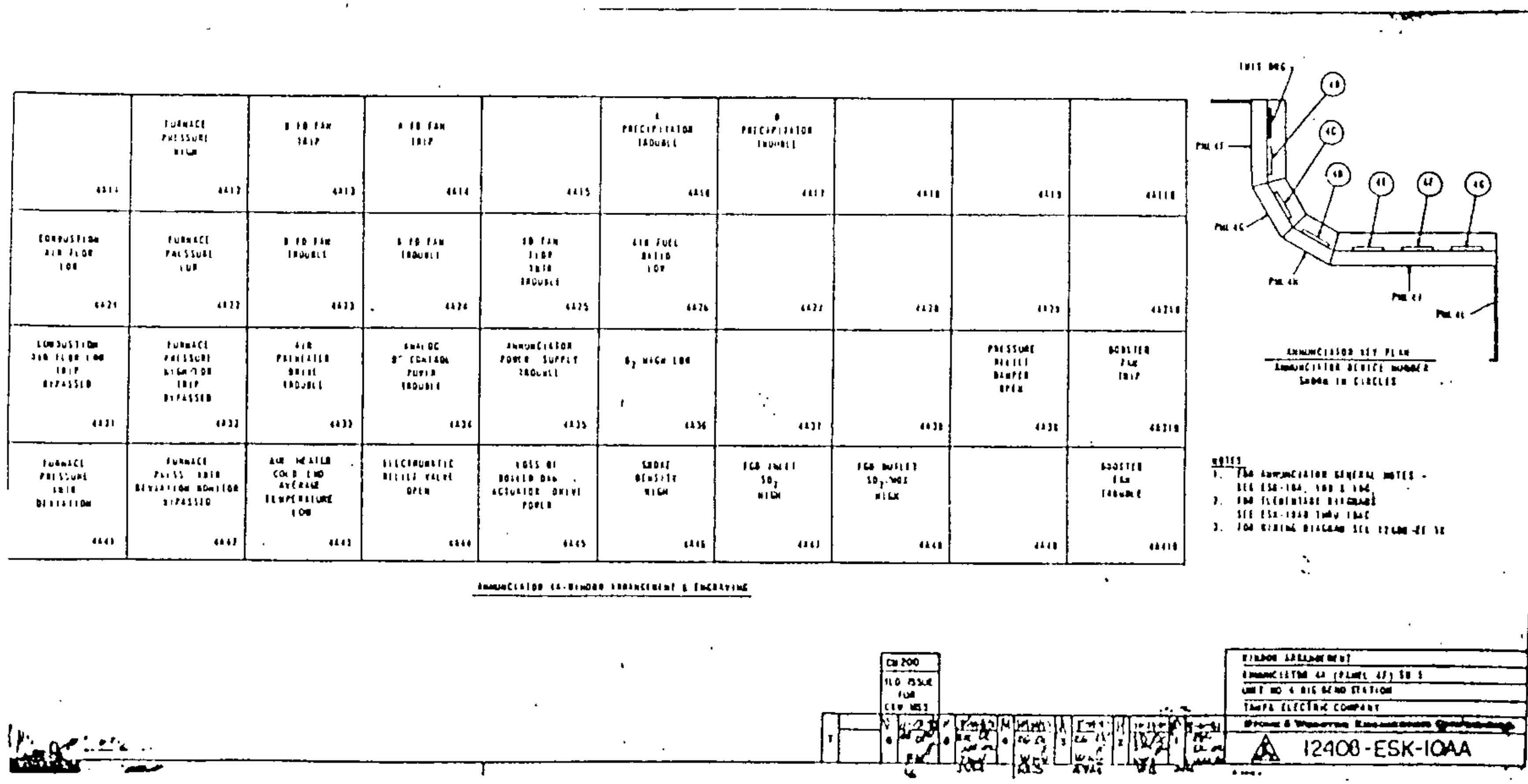
All maintenance work is initiated by an MJR. All operating, maintenance, and engineering personnel share the responsibility of originating MJRs.

In the event of an emergency (a situation which constitutes a hazard to equipment or personnel, loss of production, or noncompliance), immediate attention and repairs will be initiated. Work will continue until the problem has been corrected. An MJR is not needed to start emergency type work, but must be provided as soon as practical.

Copies of emergency MJRs are forwarded to plant management for their review and analysis.

Main Plant Control Room Annunciator Panel

Figure 3



A PRECIPITATOR VOLTAGE HIGH 4LJ11	A PRECIPITATOR ANNUNCIATOR GROUND 4LJ12	OUTLET DISTRIBUTION PLATE RAPPER TROUBLE 4LJ13	RAPPER DRIVE MOTOR TROUBLE 4LJ14
INSULATOR COMPARTMENT FAN TROUBLE 4LJ21	INSULATOR COMPARTMENT FILTER CLOGGED 4LJ22	INSULATOR COMPARTMENT PRESSURE LOW 4LJ23	INSULATOR COMPARTMENT TEMP LOW 4LJ24
4LJ31	4LJ32	4LJ33	4LJ34
HOPPER 11A ASH LEVEL HIGH 4LJ41	HOPPER 12A ASH LEVEL HIGH 4LJ42	HOPPER 13A ASH LEVEL HIGH 4LJ43	HOPPER 14A ASH LEVEL HIGH 4LJ44
HOPPER 21A ASH LEVEL HIGH 4LJ51	HOPPER 22A ASH LEVEL HIGH 4LJ52	HOPPER 23A ASH LEVEL HIGH 4LJ53	HOPPER 24A ASH LEVEL HIGH 4LJ54
HOPPER 31A ASH LEVEL HIGH 4LJ61	HOPPER 32A ASH LEVEL HIGH 4LJ62	HOPPER 33A ASH LEVEL HIGH 4LJ63	HOPPER 34A ASH LEVEL HIGH 4LJ64
HOPPER 41A ASH LEVEL HIGH 4LJ71	HOPPER 42A ASH LEVEL HIGH 4LJ72	HOPPER 43A ASH LEVEL HIGH 4LJ73	HOPPER 44A ASH LEVEL HIGH 4LJ74
HOPPER 51A ASH LEVEL HIGH 4LJ81	HOPPER 52A ASH LEVEL HIGH 4LJ82	HOPPER 53A ASH LEVEL HIGH 4LJ83	HOPPER 54A ASH LEVEL HIGH 4LJ84
4LJ91	4LJ92	4LJ93	4LJ94

A PRECIPITATOR LOCAL ANN 4LJ WINDOW ARRANGEMENT & ENGRAVING
PRECIP - ELEVATION [illegible]05'

Figure 4

Precip[illegible] [illegible]trol Room Ann[illegible]ciator Panel

IV. Sulfur Dioxide Removal System

1. General Description

Big Bend Unit 4 is equipped with a Research-Cottrell Double Loop (TM) FGD system for the control of sulfur dioxide (SO_2) emissions. At least 90% of the potential SO_2 emissions will be reduced utilizing washed coal and the above FGD system as required by the PSD permit.

The Big Bend Unit 4 FGD system has been designed to provide for reliable FGD system operation. Tampa Electric Company's specification required the vendors to provide the best available equipment for the application, to provide 100% equipment redundancy on rotating equipment and major systems, and to provide the proper organization for initial operation.

2. Principle of Operation

The FGD system receives flue gas from the boiler I.D. fans discharge and either removes the required amount of SO_2 utilizing limestone (calcium carbonate, $CaCO_3$), and reheats the gas for discharge to the stack or directs the flue gas through the pressure relief damper (PRD) under emergency conditions. (See Figure 2).

Limestone ($CaCO_3$) slurry contacts the SO_2 in the flue gas in the absorber towers. In the towers, the conditions necessary for the SO_2 and $CaCO_3$ chemical reactions are maintained. The Unit 4 FGD system consists of four absorber towers each capable of treating one third of the total gas flow.

The flue gas is directed tangentially into the quencher section of each absorber tower by the tower booster fan. The cyclonic motion of the gas in the quencher reduces gas velocity. The gas is cooled to saturation by spraying it with a solids-slurry mix, of which 3-5% of the solids is unreacted limestone and the remainder reaction products. This liquid to gas contact removes a small amount of the incoming SO_2.

The gas then passes around the slurry bowl to the absorber loop. The gas is brought into contact with a solids slurry mix, of which 20-40% of the solids is unreacted limestone and the remainder reaction products. It is in the absorber section that the $SO_2/CaCO_3$ reaction is maximized and the required SO_2 removal is completed. Water entrained in the scrubbed gas stream is then removed by the mist eliminators in the absorber tower. The gas enters a common duct where it mixes with the gas exiting the other towers in service. The combined gases are reheated through direct contact with hot ambient air before entering the stack.

The number of towers in service and the amount of limestone reagent needed in the towers is dependent on the amount of flue gas being scrubbed and the SO_2 mass flow entering the towers.

3. Operation

Plant personnel will monitor FGD system performance by operator surveillance, the plant computer, laboratory analysis, and control room instrumentation. This instrumentation, includes but is not limited to, the process continuous monitoring equipment and process stream instrumentation on the control panels.

3.1 Analytical Work

Fuel, limestone, make-up water, return water, and process slurry streams will be sampled and analyzed for verification of continuous monitoring equipment, for monitoring mechanical equipment performance, and for monitoring process performance. Additionally, laboratory analyses will assure by-product gypsum quality and an efficient and cost effective operation.

3.2 FGD System Monitoring

The FGD system is equipped with instrumentation that continuously monitor the various operational parameters associated with the "scrubbing" process. The instrumentation indication includes, but is not limited to: flowrate, temperature, pressure, SO_2 concentrations, pH and density. Plant operators rely on all instrumentation and controls to monitor and operate the FGD system.

In addition to the above, continuous emission monitors (CEM) located in the FGD inlet duct and in the FGD outlet duct, are used to document the FGD system emissions and the FGD system percent $S0_2$ removal. The output from the CEMS is tied into a Honeywell software package in the main computer. The computer processes the data into a format which documents the following:

1. The SO_2 emission rate from the FGD system (lb/MM BTU).
2. The inlet SO_2 concentration.
3. The hourly, daily, and 30-day rolling averages of the inlet SO_2 and outlet SO_2 emissions.
4. The percent reduction in SO_2.
5. The 2-hour averages of outlet SO_2.

The software package also identifies an instrument malfunction or the following:

1. 2-hour averages of SO_2 emissions in excess of permit limitations.
2. 30-day rolling averages of SO_2 emissions in excess of permit limitations.
3. Reduction of SO_2 levels for the 30 day rolling averages less than the 90 percent reduction required by permit conditions.

4. Malfunction Response

4.1 General FGD

Plant operators will respond to problems identified through routine operator surveillance. When an exceedance of an emission limit is imminent, immediate operator action will be taken to identify and correct the problem in order to stay in compliance or to minimize stack emissions. If the problem cannot be corrected by operator action, an MJR will be generated.

4.2 Pressure Relief Damper (PRD)

Flue gas leaving the induced draft fans can enter the stack in two ways, through the absorber towers or through the PRD. The PRD is open during boiler start-up on warm-up oil. When the boiler is burning coal, the PRD is closed, and all flue gas is directed through the absorber towers. The flue gas is routed through an absorber tower by the tower booster fan.

The PRD has two important functions:

1. To protect the boiler from back pressure due to loss of gas path.
2. To protect the FGD system from a boiler upset.

Because these functions are critical, redundant inlet temperature and inlet pressure signals are provided to a programmable controller. Redundant output signals are also provided from the programmable controller to de-energize the solenoids and operate the dampers in a "fast-open" mode. The PRD will fail "safe" in the open position in the event of a mechanical or control malfunction. This further reinforces the importance of its proper operation.

The following are conditions that will "fast open" the PRD indicating a unit upset or malfunction:

a. Master Fuel Trip

b. High FGD System Inlet Pressure

c. Booster Fan Trip

d. High FGD System Inlet Temperature

e. Loss of Quencher Flow (in a tower that is in service)

f. Loss of PC (programmable controller)

g. Loss of instrument air

h. Loss of 120V AC power to the solenoids

The alarm PRESSURE RELIEF DUCT DAMPER OPEN will be annunciated whenever the PRD is opened. This alarm will annunciate in both the FGD control room and the main plant control room. The cause for it opening (e.g., quencher low flow, high inlet temperature, and high inlet pressure), will annunciate in the FGD control room. The master fuel trip, as well as the cause for the master fuel trip, will alarm in the main plant control room.

a. MASTER FUEL TRIP

A master fuel trip will be initiated when an emergency condition requiring an immediate unit trip occurs. All fuel supplies to the boiler will be immediately shut off when the trip occurs.

b. HIGH FGD SYSTEM INLET PRESSURE

Increasing pressure in the ductwork between the induced draft fan discharge and the booster fan inlet (FGD inlet duct) will cause the booster fan inlet vanes to open in an attempt to maintain setpoint pressure. If the inlet vanes reach 100% rating and the pressure continues to increase, the control logic will open the PRD. The absorber towers will remain in service and the PRD will remain opened to relieve the excess pressure. Because the opening of the PRD will cause the inlet duct pressure to drop, the booster fan inlet vanes controls will respond in attempt to maintain inlet duct setpoint pressure.

Both the high FGD system inlet pressure and the PRD opening will be alarmed in both the FGD control room and the main plant control room. When the PRD is open, unit generation will be curtailed at a rate consistent with responsible operating practices to minimize SO_2 emissions. When the fault is cleared, the PRD will be closed and generation will be restored.

In the event that the high inlet pressure is caused by a large boiler upset, the main plant control center operator will use his best judgement in stablizing the boiler to protect plant equipment and personnel. This may or may not involve immediate generation curtailment. If it does not, generation will be reduced as soon as the control center operator is able to do so. When the upset is cleared the PRD will be closed directing 100% of the flue gas through the FGD system.

c. BOOSTER FAN TRIP

In the event of a booster fan trip, an automatic unit load "runback" is initiated by the boiler controls. The unit load runback is to one of two(2) predetermined load set points based on the gas flow condition at the time of the trip. One setpoint is for a two (2) tower operation, when three (3) fans are operating (3 tower operation) and one fan trips; the second setpoint is a lower load setpoint for a one (1) tower operation, when two (2) fans are operating (2 towers in operation) and one fan trips. The automatic runback of unit load is an attempt to lower the gas flow to prevent the PRD from opening on high inlet duct pressure.

If the PRD does open on a booster fan trip while the runback is active, the runback stops and holds that load value even though the setpoint has not been achieved. The main plant control center operator will release the hold and manually lower unit load until the operating tower(s) can accomodate the gas flow; the PRD will then be closed.

d. HIGH FGD INLET GAS TEMPERATURE

In the event that the FGD inlet duct temperature reaches 450 degrees F , the PRD will open, the booster fan inlet vanes will close, and the deluge water valve for each tower in service will open. This control action is for tower thermal protection. When the PRD is verified open, the control logic will close the absorber tower inlet and outlet isolation dampers and trip the booster fans;

when the isolation dampers are verified fully closed, the deluge valve will close. Alarms will annunciate in both the main plant and FGD control rooms indicating that the FGD system inlet gas temperature is high and that the PRD is open. This is an emergency condition requiring an immediate reduction in generation or an initiation of a unit trip by the main plant control center operator.

e. LOSS OF QUENCHER FLOW IN A TOWER IN SERVICE

One quencher pump with adequate flow is required for a tower in service to quench the gas for SO_2 absorption and thermal protection of tower internals. In the event that low flow is indicated by low pump motor wattage, the standby pump will receive a start command. If adequate flow is not restored within 3 minutes, the PRD will open. Alarms will indicate the PRD opening in both the main plant and FGD control rooms. In addition, a quencher low flow alarm on the effected tower will annunciate in the FGD control room. Once the PRD is verified open, the control logic will isolate the tower with the low flow condition by closing the tower inlet and outlet isolation dampers and tripping the tower booster fan. The remaining tower(s) in service will stay in service. Because the opening of the PRD will cause the inlet duct pressure to drop, the booster fan inlet vanes controls will respond in attempt to maintain inlet duct set point pressure.

Generation will be reduced until the remaining towers in service can accomodate the gas flow at which time the PRD will be closed. When the fault is cleared or another tower is readied for service, generation will be restored.

f. LOSS OF PROGRAMMABLE CONTROLLER (PC)

Loss of the PC will cause all FGD mechanical components to fail "safe". The PRD will open and all towers inlet and outlet isolation dampers will close causing all boiler flue gas to bypass the FGD system. The main plant control center operator will reduce generation in order to minimize SO_2 emissions. When the back-up programmable controller has been made operational and the correct logic has been established, the FGD system will be returned to service, and the PRD closed. Generation will then be restored.

g. LOSS OF INSTRUMENT AIR

A loss of main plant instrument air will trip the unit and cause the PRD to fail "safe" in the open position.

A loss of instrument air to the PRD solenoids will also cause the PRD to fail "safe" in the open position. In the latter case, the FGD tower(s) are still operational. Because the opening of the PRD will cause the inlet duct pressure to drop, the booster fan inlet vanes controls will respond in attempt to maintain inlet duct set point pressure. The main plant control center operator will reduce generation in order to minimize SO_2 emissions. When instrument air to the PRD solenoids is reestablished the PRD will be closed and generation will be restored.

h. LOSS OF 120V AC POWER

Loss of power to the solenoids will cause the PRD to fail "safe" in the open position. In this case, the FGD tower(s) are still operational. Because the opening of the PRD will cause the inlet duct pressure to drop, the booster fan inlet vanes controls will respond in attempt to maintain inlet duct set point pressure. The main plant control center operator will reduce generation in order to minimize SO_2 emissions. This will continue until power is restored to the PRD. When power is restored, the PRD will be closed and load will be restored.

4.3 PRD Testing

Because of the importance of the PRD responding under emergency conditions, it will be fully stroked once per day. Test control switches have been provided solely for this purpose. The FGD system will remain in service during this activity, which should require approximately forty seconds.

4.4 Emergency Communications

In the event of an emergency condition the person in charge (Supervisor of Plant Operations) will contact the plant general manager or his designated assistant.

Information containing the time of upset, the cause of upset, the corrective action taken, and the actions taken to minimize air emissions will be documented by plant operations. The log will be reviewed by the FGD engineer who will notify Tampa Electric Company's Environmental Planning Department. The Environmental Planning Department will implement notifications to the Environmental agencies, as necessary.

5. **Repair Procedures**

FGD Repair Procedures are similar to that for the Electrostatic Precipitator. See Section III.5.

V. Continuous Emission Monitors (CEM)

1. Equipment Application

Big Bend Unit 4 is equipped with continuous emission monitors to analyze flue gas for SO_2, NO_x, O_2, and opacity. These monitors supply data that is necessary to ensure environmental compliance when the unit is in operation. Each of these process variables is discussed below.

1.1 SO_2

SO_2 concentration is measured at both the inlet and outlet ducts of the FGD system. The two measurements are used jointly to determine overall percent SO_2 removal by the FGD system. The outlet duct concentration is used to determine SO_2 emissions.

SO_2 concentration at the outlet duct is measured by a Lear Siegler Model SM 810 in-situ SO_2/NO_x dual gas analyzer. SO_2 concentration at the inlet duct is measured by a Lear Siegler Model SM 810 in-situ SO_2 single gas analyzer. Both analyzers provide analog signals representing SO_2 concentration and flue gas temperature to the plant process computer and to a strip chart recorder located in the plant main control room. The plant process computer will convert the analog signal to pounds SO_2 per MM BTU and the strip chart recorder will indicate SO_2 concentration in ppm. In the event that SO_2 concentration exceeds a predetermined setpoint, an annunciator panel alarm in the plant main control room will alert operators to higher than normal SO_2 level.

Each analyzer also provides a digital signal to the plant process computer anytime it is in a malfunction condition or in a zero/span calibration mode. Additionally, the computer will also log any occurrence of the analyzer exceeding calibration span.

1.2 NO_x

NO_x concentration is measured at both the inlet and outlet ducts of the FGD system. Either the inlet or outlet duct signals can be used to determine NO_x emissions.

NO_x concentration in the outlet duct is measured by a Lear Siegler Model SM 810 in-situ SO_2/NO_x dual gas analyzer. This is the same analyzer used to measure SO_2 concentration in the outlet duct of the FGD system. NO_x concentration in the inlet duct is measured by a Dupont Model 461 extractive NO_x analyzer.

Either monitor can be used to provide an analog signal representing NO_x concentration to the plant process computer and to a strip chart recorder located in the plant main control room. The plant process computer will convert the analog signal to pounds NO_x per MM BTU and the strip chart recorder will indicate NO_x concentration in ppm. In the event that NO_x concentration exceeds a predetermined setpoint, an annunciator panel in the main plant control room will alert operators to higher than normal NO_x level.

Each analyzer also provides a digital signal to the plant process computer anytime it is in a malfunction condition or in zero/span calibration mode. Additionally, the computer will also alarm any occurrence of the analyzer exceeding calibration span.

1.3 O_2

O_2 concentration is measured at both the inlet and outlet ducts of the FGD system. These values are used by the plant process computer to calculate SO_2 and NO_x emissions using a dry basis F factor (Fd).

O_2 concentration in both the inlet and outlet ducts is measured by a Lear Siegler Model CM 50 in-situ dilutant O_2 analyzer.

Both analyzers provide analog signals representing dilutant O_2 concentration to the plant process computer and to a strip chart recorder located in the plant main control room.

Each analyzer also provides a digital signal to the plant process computer anytime the analyzer is in a malfunction condition or in a zero/span calibration mode.

1.4 Opacity

Opacity is measured at the inlet duct of the FGD system by a Contraves Goerz Model 400 Opacity monitor coupled with a Model 500 Remote display unit.

This analyzer provides an analog signal representing opacity to the plant process computer and to a strip chart recorder located in the plant main control room. In the event that opacity exceeds a predetermined setpoint, an alarm in the plant main control room will alert operators to a higher than normal opacity level.

This analyzer also provides a digital signal to the plant process computer anytime the analyzer is in a malfunction condition or zero/span calibration mode.

2. Monitor Maintenance

In order to ensure continuous, accurate and reliable monitor performance, the following preventative maintenance checks will be initiated:

2.1 Lear Siegler, Inc; SM810

Daily

- Check security of mounting bolts, especially at the probe/flange interface
- Check fault monitors
- Check effluent temperature
- Check reference light intensity
- Review data file since last visit

Weekly

- Manually zero/span

- Inspect/clean optics system
- Check air purge system

Quarterly

- Grease probe
- Performed dynamic calibration
- Check heat blanket temperature

Semi-annual

- Inspect, clean and align optics plate assemblies
- Inspect and lubricate moving parts
- Inspect probe tubing and measurement cavity
- Clean window
- Align probe and transceiver
- Inspect J-Box, check operation
- Check calibration drifts
- Calibrate total system

Annual

- Replace probe filter

2.2 Dupont Co. Model 461

Daily

- Check sensing line heaters
- Check oven temperature
- Check sample flow
- Check oxygen pressure gauge
- Check sample vacuum indication
- Verify computer and recorder indication
- Verify 24 hour span check

Weekly

- Compare Meter Function Switch indicated values to calibration data.

Quarterly

- Check for loose or corroded terminations and fittings
- Perform amplifier Balance Test

Semi-annual

- Perform linearity Test
- Perform lamp Voltage Test
- Perform leak Test
- Perform analog Signal Processor Calibration

2.3 Lear Siegler Inc.; CM50

Daily

- Check fault monitors
- Review data file since last visit

Weekly

- Insure all fault indicators are in working order
- Check for agreement between recording mediums
- Check flow values
- Check air pressure
- Check probe temperature
- Perform an operational calibration

Quarterly

- Grease probe

Semi-annual

- Inspect/clean probe
- Calibrate probe heater circuit
- Calibrate cold junction correction circuitry
- Perform leak test
- Test output loops
- Clean, and inspect all switches, relays and solenoids
- Check TV and RMI/EMI circuits
- Check drift rate

Annually

- Replace ceramic probe filter

2.4 Contraves Goerz Corp.; Model 400/500

Daily

- Check fault monitors
- Review automatic zero and span values for excessive drift rate trends

Weekly

- Check function of all fault monitors
- Manually calibrate

Quarterly

- Clean optics
- Clean chopper
- Replace air filters
- Replace optical head dessicant
- Replace retroreflector dessicant

Semi-annual

- Clean and inspect optics/electronics
- Perform 24-hour calibration drift test
- Perform calibration error test
- Clean and inspect air flow system assemblies

3. **Malfunction Response**

When a problem is identified with any of the continuous emission monitors that causes a loss of data, the immediate operator action will be taken to correct the problem in order to resume data collection. If the problem cannot be corrected by operator action, an MJR will be generated to correct the problem.

In the event the malfunctioning CEM cannot be repaired to obtain the minimum data capture required by the environmental regulations, alternative monitoring system will be available to the plant to provide back-up data capture.

4. **Repair Procedures**

All maintenance work is initiated by a Maintenance Job Request (MJR). All operating, maintenance and engineering personnel share the responsibility of originating MJR's.

In the event of a CEM malfunction, an emergency MJR will be initiated and immediate action will be taken to identify the malfunction and correct the problem. An MJR is not needed to start emergency type work.

TAMPA ELECTRIC
A TECO ENERGY COMPANY

April 30, 1982

DER
MAY 03 1982
BAQM

8/81 was certified for conditions

Mr. Steve Smallwood
Florida Department of
Environmental Regulation
2600 Blair Stone Road
Tallahassee, Florida 32301

Re: Tampa Electric Company
Big Bend Unit No. 4

Dear Mr. Smallwood:

As per Section I.D.2 of the Conditions of Certification for Big Bend Unit 4, quarterly reporting of ambient air monitoring data to the Bureau of Air Quality Management is required. Enclosed is a corrected copy of the twenty-four hour sulfur dioxide data for the fourth quarter of 1981.

The data collected from November 15, 1981 to December 30, 1981 at one of the air monitoring stations is considered invalid.

If you have any questions concerning this data, please contact me.

Sincerely,

Jerry L. Williams

Jerry L. Williams, P.E.
Director
Environmental Planning

JLW:dh
Enclosure

TAMPA ELECTRIC COMPANY
P.O. Box 111 Tampa, Florida 33601 (813) 228-4111

CENTRAL TESTING LABORATORY
STATISTICAL ANALYSIS
TAMPA BAY AREA, FLORIDA
OCTOBER 1981-DECEMBER 1981
24 HOUR SO2 DATA SUMMARY
MICROGRAMS PER CUBIC METER

STATION NUMBER	NUMBER OF OBSERVATIONS	MINIMUM OBSERVATION	MAXIMUM OBSERVATION	2ND MAXIMUM OBSERVATION	ARITHMETIC MEAN	STANDARD DEVIATION
2	24	0.0	42.31	38.30	12.79	11.89
3	19	0.0	32.56	25.56	12.01	9.78
5	19	0.0	81.98	40.90	14.90	20.17
9	27	0.0	28.86	25.16	10.14	9.16
10	13	0.0	40.90	30.91	11.77	13.63
17	25	0.0	28.37	19.01	5.54	7.44

CENTRAL TESTING LABORATORY
TAMPA BAY AREA
24 HOUR SO2 DATA SUMMARY

DATE SAMPLED	START TIME	AMBIENT TEMPERATURE	STATION NUMBER	UG/M3	P.P.B.
10/01/81	0001	93	2	38.30	14.63
10/01/81	0001	95	3	25.56	9.76
10/01/81	0001	90	5	25.42	9.71
10/01/81	0001	90	9	25.16	9.61
10/01/81	0001	90	10	40.90	15.63
10/01/81	0001	78	17	28.37	10.84
10/04/81	0001	93	2	0.0	0.0
10/04/81	0001	92	3	0.57	0.22
10/04/81	0001	91	5	0.57	0.22
10/04/81	0001	92	9	0.0	0.0
10/04/81	0001	91	10	0.0	0.0
10/04/81	0001	78	17	0.0	0.0
10/07/81	0001	87	2	8.95	3.42
10/07/81	0001	90	3	17.14	6.55
10/07/81	0001	86	5	20.40	7.79
10/07/81	0001	90	9	19.57	7.47
10/07/81	0001	88	10	7.90	3.02
10/07/81	0001	80	17	0.0	0.0
10/10/81	0001	88	2	20.79	7.94
10/10/81	0001	94	3	21.26	8.12
10/10/81	0001	89	5	81.98	31.32
10/10/81	0001	91	9	3.57	1.36
10/10/81	0001	85	10	22.51	8.60
10/10/81	0001	75	17	17.52	6.69

DATE SAMPLED	START TIME	AMBIENT TEMPERATURE	STATION NUMBER	UG/M3	P.P.B.
10/13/81	0001	**	2	**.**	**.**
10/13/81	0001	**	3	**.**	**.**
10/13/81	0001	**	5	**.**	**.**
10/13/81	0001	**	9	**.**	**.**
10/13/81	0001	**	10	**.**	**.**
10/13/81	0001	**	17	**.**	**.**
10/16/81	0001	**	2	**.**	**.**
10/16/81	0001	**	3	**.**	**.**
10/16/81	0001	83	5	2.29	0.87
10/16/81	0001	89	9	9.07	3.47
10/16/81	0001	81	10	5.14	1.96
10/16/81	0001	**	17	**.**	**.**
10/19/81	0001	**	2	**.**	**.**
10/19/81	0001	**	3	**.**	**.**
10/19/81	0001	**	5	**.**	**.**
10/19/81	0001	89	9	4.00	1.53
10/19/81	0001	**	10	**.**	**.**
10/19/81	0001	**	17	**.**	**.**
10/22/81	0001	87	2	24.54	9.37
10/22/81	0001	90	3	19.59	7.48
10/22/81	0001	86	5	24.09	9.20
10/22/81	0001	88	9	18.94	7.24
10/22/81	0001	85	10	27.02	10.32
10/22/81	0001	**	17	**.**	**.**

DATE SAMPLED	START TIME	AMBIENT TEMPERATURE	STATION NUMBER	UG/M3	P.P.B.
10/25/81	0001	95	2	42.31	16.16
10/25/81	0001	**	3	**.**	**.**
10/25/81	0001	**	5	**.**	**.**
10/25/81	0001	89	9	3.13	1.20
10/25/81	0001	92	10	4.80	1.83
10/25/81	0001	81	17	3.74	1.43
10/28/81	0001	81	2	4.55	1.74
10/28/81	0001	83	3	14.87	5.68
10/28/81	0001	80	5	8.26	3.15
10/28/81	0001	77	9	28.86	11.02
10/28/81	0001	79	10	30.91	11.81
10/28/81	0001	80	17	0.0	0.0
10/31/81	0001	81	2	1.96	0.75
10/31/81	0001	85	3	0.62	0.24
10/31/81	0001	83	5	0.0	0.0
10/31/81	0001	88	9	0.0	0.0
10/31/81	0001	81	10	4.80	1.83
10/31/81	0001	74	17	0.0	0.0
11/03/81	0001	89	2	7.95	3.04
11/03/81	0001	85	3	0.64	0.24
11/03/81	0001	83	5	0.0	0.0
11/03/81	0001	85	9	0.64	0.24
11/03/81	0001	84	10	4.84	1.85
11/03/81	0001	76	17	0.0	0.0

DATE SAMPLED	START TIME	AMBIENT TEMPERATURE	STATION NUMBER	UG/M3	P.P.B.
11/06/81	0001	81	2	6.59	2.52
11/06/81	0001	83	3	4.16	1.59
11/06/81	0001	**	5	**.**	**.**
11/06/81	0001	83	9	19.11	7.30
11/06/81	0001	80	10	1.80	0.69
11/06/81	0001	70	17	1.86	0.71
11/09/81	0001	83	2	24.49	9.36
11/09/81	0001	81	3	2.35	0.90
11/09/81	0001	**	5	**.**	**.**
11/09/81	0001	80	9	3.03	1.16
11/09/81	0001	83	10	1.81	0.69
11/09/81	0001	81	17	1.88	0.72
11/12/81	0001	84	2	4.15	1.58
11/12/81	0001	74	3	9.16	3.50
11/12/81	0001	**	5	**.**	**.**
11/12/81	0001	79	9	8.85	3.38
11/12/81	0001	87	10	0.60	0.23
11/12/81	0001	84	17	5.45	2.08
11/15/81	0001	77	2	7.71	2.94
11/15/81	0001	76	3	10.81	4.13
11/15/81	0001	80	5	1.75	0.67
11/15/81	0001	78	9	1.17	0.45
11/15/81	0001	**	10	**.**	**.**
11/15/81	0001	77	17	0.0	0.0

DATE SAMPLED	START TIME	AMBIENT TEMPERATURE	STATION NUMBER	UG/M3	P.P.B.
11/18/81	0001	75	2	19.50	7.45
11/18/81	0001	72	3	19.32	7.38
11/18/81	0001	72	5	24.29	9.28
11/18/81	0001	72	9	24.30	9.28
11/18/81	0001	**	10	**.**	**.**
11/18/81	0001	73	17	15.75	6.02
11/21/81	0001	84	2	20.97	8.01
11/21/81	0001	76	3	12.56	4.80
11/21/81	0001	79	5	25.55	9.76
11/21/81	0001	75	9	21.39	8.17
11/21/81	0001	**	10	**.**	**.**
11/21/81	0001	81	17	19.01	7.26
11/24/81	0001	72	2	0.0	0.0
11/24/81	0001	**	3	**.**	**.**
11/24/81	0001	**	5	**.**	**.**
11/24/81	0001	70	9	9.72	3.71
11/24/81	0001	**	10	**.**	**.**
11/24/81	0001	**	17	**.**	**.**
11/27/81	0001	**	2	**.**	**.**
11/27/81	0001	**	3	**.**	**.**
11/27/81	0001	70	5	4.22	1.61
11/27/81	0001	**	9	**.**	**.**
11/27/81	0001	**	10	**.**	**.**
11/27/81	0001	75	17	5.17	1.98

DATE SAMPLED	START TIME	AMBIENT TEMPERATURE	STATION NUMBER	UG/M3	P.P.B.
11/30/81	0001	**	2	**.**	**.**
11/30/81	0001	**	3	**.**	**.**
11/30/81	0001	**	5	**.**	**.**
11/30/81	0001	82	9	3.52	1.34
11/30/81	0001	**	10	**.**	**.**
11/30/81	0001	79	17	3.63	1.38
12/03/81	0001	78	2	18.69	7.14
12/03/81	0001	**	3	**.**	**.**
12/03/81	0001	**	5	**.**	**.**
12/03/81	0001	80	9	10.63	4.06
12/03/81	0001	**	10	**.**	**.**
12/03/81	0001	81	17	9.10	3.47
12/06/81	0001	75	2	16.46	6.29
12/06/81	0001	81	3	11.80	4.51
12/06/81	0001	80	5	5.97	2.28
12/06/81	0001	74	9	5.89	2.25
12/06/81	0001	**	10	**.**	**.**
12/06/81	0001	77	17	5.88	2.25
12/09/81	0001	**	2	**.**	**.**
12/09/81	0001	77	3	2.93	1.12
12/09/81	0001	80	5	2.44	0.93
12/09/81	0001	80	9	17.28	6.60
12/09/81	0001	**	10	**.**	**.**
12/09/81	0001	78	17	10.56	4.03

DATE SAMPLED	START TIME	AMBIENT TEMPERATURE	STATION NUMBER	UG/M3	P.P.B.
12/12/81	0001	61	2	3.15	1.20
12/12/81	0001	62	3	22.24	8.50
12/12/81	0001	71	5	40.90	15.62
12/12/81	0001	69	9	20.97	8.01
12/12/81	0001	**	10	**.**	**.**
12/12/81	0001	71	17	5.23	2.00
12/15/81	0001	78	2	4.29	1.64
12/15/81	0001	80	3	32.56	12.44
12/15/81	0001	**	5	**.**	**.**
12/15/81	0001	**	9	**.**	**.**
12/15/81	0001	**	10	**.**	**.**
12/15/81	0001	76	17	0.0	0.0
12/18/81	0001	0	2	0.0	0.0
12/18/81	0001	**	3	**.**	**.**
12/18/81	0001	55	5	10.14	3.87
12/18/81	0001	58	9	10.79	4.12
12/18/81	0001	**	10	**.**	**.**
12/18/81	0001	80	17	0.0	0.0
12/21/81	0001	54	2	0.0	0.0
12/21/81	0001	**	3	**.**	**.**
12/21/81	0001	**	5	**.**	**.**
12/21/81	0001	60	9	0.0	0.0
12/21/81	0001	**	10	**.**	**.**
12/21/81	0001	62	17	0.0	0.0

DATE SAMPLED	START TIME	AMBIENT TEMPERATURE	STATION NUMBER	UG/M3	P.P.B.
12/24/81	0001	78	2	12.06	4.61
12/24/81	0001	80	3	0.0	0.0
12/24/81	0001	76	5	0.0	0.0
12/24/81	0001	85	9	0.0	0.0
12/24/81	0001	**	10	**.**	**.**
12/24/81	0001	70	17	0.0	0.0
12/27/81	0001	**	2	**.**	**.**
12/27/81	0001	**	3	**.**	**.**
12/27/81	0001	**	5	**.**	**.**
12/27/81	0001	**	9	**.**	**.**
12/27/81	0001	**	10	**.**	**.**
12/27/81	0001	**	17	**.**	**.**
12/30/81	0001	85	2	19.55	7.47
12/30/81	0001	**	3	**.**	**.**
12/30/81	0001	84	5	4.83	1.84
12/30/81	0001	83	9	4.11	1.57
12/30/81	0001	**	10	**.**	**.**
12/30/81	0001	79	17	5.26	2.01

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

REGION IV

345 COURTLAND STREET
ATLANTA, GEORGIA 30365

DER

APR 5 1982

BAQM

MAR 31 1982

REF: 4AW-AF

Mr. Heywood A. Turner
Senior Vice President Production
Tampa Electric Company
P.O. Box 111
Tampa, Florida 33601

Re: PSD-FL-040

Dear Mr. Turner:

On February 16, 1982, Tampa Electric Company applied for a minor modification to their application to construct a fourth unit at their existing Big Bend facility. TECO received a PSD permit to construct this coal-fired boiler on November 14, 1981. The proposed modification to unit #4 would consist of the construction of a new stack to accommodate the exhaust gas stream from the #4 boiler.

A public notice delineating this proposed change in the application appeared in the Tampa Tribune on February 22, 1982. This announced public comment period closed fifteen (15) days later and no comments were received.

EPA concludes, that since this proposed construction modification does not contribute to any significant emissions increases or additional increment consumption, the modification is hereby accepted. This letter granting authority for the construction modification described in TECO's February 16, 1982 submittal should be attached to and become a part of your November 14, 1981 permit. In addition, TECO's February 16, 1982 submittal will become an amendment to the original application.

Any questions concerning this approval may be directed to Mr. Kent Williams, Chief, New Source Review Section, at (404) 881-4552.

Sincerely yours,

for John A. Little, Deputy

Charles R. Jeter
Regional Administrator

Best Available Control Technology (BACT) Determination

Tampa Electric Company

Hillsborough County

Tampa Electric Company proposes to increase electric generating capacity by the addition of a 425 megawatt coal-fired steam generating unit to the existing Big Bend facility located near Tampa, Florida. The unit will use approximately 207 tons per hour of bituminous coal with a maximum sulfur content of 4.0 percent by weight. In addition, coal and limestone materials handling, storage and preparation systems will be constructed. The unit is scheduled to start up during the first quarter of 1985.

BACT Determination Requested by the Applicant:

Pollutant	Emission Limit lb/million BTU	Percent Reduction
Particulate	0.03	99.7
NO_x	0.60	65.0
SO_2	90% reduction	90.0

Particulates will be controlled by an electrostatic precipitator (ESP); SO_2 emissions will be minimized by a combination of coal washing and use of a flue gas desulfurization (FGD) system; NO_x will be minimized by proper design and operation of the boiler and combustion air control system.

Review Group Members:

There was no formal review group. Comments and recommendations were obtained from the BAQM New Source Review Section and Air Modeling Section, the Power Plant Siting Committee, the Hillsborough County Environmental Protection Commission and the DER Southwest District office.

BACT Determination by DER:

Pollutant	Emission Limit lb/million BTU	Minimum Reduction
Particulate	0.03	99%
SO_2	1.2	90%
NO_x	0.6	65%
VE	20% (6-minute average), except one 6-minute period per hour of not more than 27% opacity	

Justification of DER Determination:

The facility is located in the area of influence of the Hillsborough county nonattainment area for particulate matter (17-2.13(1)(2)F.A.C.). The major modification does not significantly impact the nonattainment area and is therefore exempt from the nonattainment requirements (17-2.17(2)(b)F.A.C.). It must, however, comply with the provisions of 17-2.04 F.A.C. (Prevention of Significant Deterioration).

No increase in pollutant concentration over the baseline is allowed unless BACT is employed to control emissions. BACT in this case is determined to be equivalent to the New Source Performance Standard (NSPS) Subpart Da, Section 60.40a, promulgated June 11, 1979. Federal Register (44 FR 33580).

Details of the Analysis May be Obtained by Contacting:

Edward Palagyi, BACT Coordinator
Department of Environmental Regulation
Bureau of Air Quality Management
2600 Blair Stone Road
Tallahassee, Florida 32301

Recommended By:

Lawrence A. George / for
Steve Smallwood, Chief, BAQM

Date: April 9, 1981

Approved:

Victoria Tschinkel
Victoria Tschinkel, Secretary

Date: April 10, 1981

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

REGION IV

345 COURTLAND STREET
ATLANTA, GEORGIA 30365

FEB 19 1982

DER

FEB 22 1982

BAQM

REF: 4AW-AF

Mr. Steve Smallwood
Florida Department of Environmental Regulation
2600 Blair Stone Road
Tallahassee, Florida 32301

Dear Mr. Smallwood:

Enclosed please find a public notice plus documentation for a permit modification requested from TECO. This request to modify is for PSD-FL-040, Big Bend Unit 4. If you have any questions or comments regarding this request, please contact Dr. Kent Williams of my staff at 404/881-4552.

Sincerely yours,

Tommie A. Gibbs

Tommie A. Gibbs
Chief
Air Facilities Branch

Enclosure

DEPARTMENT OF ENVIRONMENTAL REGULATION

ROUTING AND TRANSMITTAL SLIP

ACTION NO

ACTION DUE DATE

KAHEL		FANCY		STARNES	
BLOMMEL		~~THOMAS~~		MARTY HALL	
BARKER		GEORGE		MARSHALL MOTT-SMITH	
J. ROGERS		PALAGYI			

INFORMATION
- REVIEW & RETURN
- REVIEW & FILE
- INITIAL & FORWARD

DISPOSITION
- REVIEW & RESPOND
- PREPARE RESPONSE
- FOR MY SIGNATURE
- FOR YOUR SIGNATURE
- LET'S DISCUSS
- SET UP MEETING
- INVESTIGATE & REPT
- INITIAL & FORWARD
- DISTRIBUTE
- CONCURRENCE
- FOR PROCESSING
- INITIAL & RETURN

REMARKS

EPA PSD Permit

TECO Big Bend

Copy Buck Oven (sent 2/24 PA)

To: ~~Larry~~ ~~Bill~~ for comments

No comment, we sent Buck a memo on this saying no changes needed in conditions of certification.

File: PSD-FL-040

FROM: STEVE SMALLWOOD SS

DATE 2-24

Phone

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION IV
345 COURTLAND STREET
ATLANTA GEORGIA 30365

FEB 1 9 1982

REF: 4AW-AF

Mr. Jerry L. Williams, Director
Environmental Planning
Tampa Electric Company
P. O. Box 111
Tampa, Florida 33601

Dear Mr. Williams:

Enclosed is a public notice for the modification of the PSD permit for TECO's Big Bend Unit No. 4. Please place this in the Tampa Tribune and send the affidavit to our office.

In addition, I have enclosed the materials to be put on display in Roger Stewart's office at the Hillsborough County Environmental Protection Commission. I am requesting that you deliver them for public viewing so that the publication of the notice can be coordinated with the public availability of these materials.

Thank you for your assistance.

Sincerely yours,

Kent C. Williams
Chief
New Source Review Section

Enclosure(s)

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

REGION IV

345 COURTLAND STREET
ATLANTA GEORGIA 30365

FEB 19 1982

REF: 4AW-AF

Mr. Roger P. Stewart, Director
Hillsborough County Environmental
Protection Commission
1900 9th Avenue
Tampa, Florida 33605

Dear Mr. Stewart:

The Tampa Electric Company has requested a minor permit modification to a previously issued federal PSD permit, PSD-FL-040. The modification request, along with a public notice to be published in the Tampa Tribune, accompanys this letter. Please maintain these materials in the Commission's offices for public review until the comment period closes. The comment period is for 15 days and begins on the date the notice is published in the newspaper. We will notify you as to the close of the comment period based upon the date the notice first appears.

Thank you for your assistance. If you have any questions, please contact Dr. Kent Williams of my staff at 404/881-4552.

Sincerely yours,

Tommie A. Gibbs
Chief
Air Facilities Branch

Enclosure

cc: FL DER

PUBLIC NOTICE

On October 15, 1981, the Tampa Electric Company (TECO) received a federal Prevention of Significant Deterioration permit, PSD-FL-040, to modify an existing air pollution source near the City of Tampa in Hillsborough County, Florida. The modification consisted of the construction of a coal-fired steam electric generating station with a 425 megawatt capacity.

TECO has requested a minor permit modification from the U.S. Environmental Protection Agency. The modification will result in no new emissions above those previously permitted nor will there be any increase in ambient air quality impacts from the new unit. No increase in increment consumption will result. TECO's request, along with supporting documentation, are available for public review in the office of Mr. Roger P. Stewart, Hillsborough County Environmental Protection Commission, 1900 9th Avenue, Tampa, Florida 33605.

Any person may submit written comments regarding this proposed permit modification. All comments received not later than 15 days from the date of this notice will be considered in the permit modification request. Letters should be addressed to:

Mr. Tommie A. Gibbs
Chief, Air Facilities Branch
U. S. Environmental Protection Agency
345 Courtland Street
Atlanta, Georgia 30365

TAMPA ELECTRIC
A TECO ENERGY COMPANY

February 16, 1982

Mr. Kent Williams
Chief, New Source Review Section
U.S. Environmental Protection Agency
345 Courtland Street
Atlanta, Georgia 30365

Dear Mr. Williams:

In accordance with discussions at your recent meeting with Heywood Turner, enclosed is a summary of the effects of the new stack for Big Bend Unit No. 4. This information demonstrates that only very minor changes in impacts will occur as a result of the new stack. In addition, there will be no changes in emissions from Unit No. 4. Based upon our review, we believe that further review of Unit No. 4, under 40 C.F.R., Section 52.21, is not required.

Should you have any questions concerning the foregoing, please contact us.

Sincerely,

Jerry L. Williams

Jerry L. Williams, P.E.
Director
Environmental Planning

JLW:dh
Enclosure
cc: Howard D. Zeller
Heywood A. Turner

INTRODUCTION

Big Bend Unit 4 was originally designed to share an existing common stack with Unit 3. Information which has recently become available indicates that significant technical and subsequent operational problems will occur if this arrangement is used.

Although there are numerous problems associated with the use of a common stack for both units, the basic problem is the corrosive nature of the flue gas when it cools and condenses sulfuric acid, or when it has been "scrubbed" and therefore saturated and acidic. The only condition which is worse is when cold, scrubbed flue gas is mixed with hot, unscrubbed flue gas and the temperature of the sulfuric acid which condenses is raised resulting in more severe corrosion. During the past year, this problem has become apparent at two flue gas desulfurization installations where extreme corrosion has resulted from the conditions.

To avoid exposing the outlet ducts of Unit 3 to scrubbed flue gas from Unit 4 when Unit 3 is down, it would be necessary to install two (2) isolation dampers in the outlet ductwork of Unit 3. Because of the corrosive nature of the flue gas, these dampers would have to be constructed of an alloy such as Inconel 625 which is very expensive. To avoid exposing the outlet ductwork of Unit 4 to Unit 3 flue gas which would condense acid in stagnant areas, it would be necessary to install isolation dampers in the Unit 4 outlet ductwork. In addition, the four (4) breechings, the metal ductwork between the concrete shell of the stack and the brick liner, would be exposed to all of the various flue gas conditions: scrubbed, unscrubbed and mixed flue gas. This would require replacement of the existing carbon steel breechings with an alloy such as Inconel 625 or a lining over the carbon steel.

Even with the use of alloys and/or linings, high maintenance of the dampers and breechings is expected as a result of the corrosive nature of the flue gas. Dampers, in general, are very unreliable and when exposed to these conditions, reliability can be expected to decrease. In regard to the breechings, the architect/engineer recommended that regardless of what material is used, inspections should be performed at least every six (6) months and repairs should be done annually to prevent catastrophic failure. To perform the required maintenance on the isolation dampers and breechings, simultaneous outages for Unit 3 and Unit 4 would be required because of the location of this equipment. This would be the major impact on the reliability and availability of these two (2) units in regard to this problem. In addition, to remove and replace the existing Unit 3 carbon steel breechings with alloy breechings and to install the Unit 3 isolation dampers, would require significant downtime for Unit 3.

In summary, because of the capital and operating cost of the required isolation dampers and new breechings and the impact on availability of both units that a common stack would have, the economic and technical aspects of constructing a new stack at Big Bend Station have been evaluated and compared to the cost associated with the current arrangement of the shared stack. The conclusion of the evaluation is that the construction of a new stack for Unit 4 is the most feasible solution.

NEW STACK CONFIGURATION

The new stack for Unit 4 will be constructed on the west side of the flue gas desulfurization system and directly south of the existing eastern most stack. The location is illustrated on the attached plot plan. The engineering and construction effort associated with locating the new stack in this area will not delay the Unit 4 commercial operation date.

The new stack height will be 490 feet with a maximum inside diameter of 24 feet. These dimensions are equivalent to those of the two existing stacks. These physical dimensions of the new stack coupled with the fact that there will be no change in Unit 4 air emissions or flue gas flow parameters as a result of the addition, make the Unit 4 air quality impacts of the new stack scenario equivalent to the air quality impacts originally predicted for a shared common stack with Unit 3 off-line, a case detailed in the Unit 4 PSD application.

IMPACT ON AMBIENT AIR QUALITY

SULFUR DIOXIDE

Environmental Science and Engineering, Inc. performed a computer modeling evaluation of the Big Bend generating facility with Unit 4 exhaust gases exiting through a new, separate stack. The flue gas parameters and heat input rate for the boilers were the same as those in the original Unit 4 PSD analysis. The parameters for the new stack were identical to those for the existing stack serving Unit 3 (i.e. 490 feet tall, 24 feet I.D.). Unit 4 was modeled at the maximum NSPS limit of 1.2 lbs. sulfur dioxide/MM BTU heat input rate, thus the modeling is conservative. The methodology used and the results of the analysis are discussed below.

The United States Environmental Protection Agency (EPA) / Florida Department of Environmental Regulation (FDER) approved single source (CRSTER) model, along with a 5-year meterological data base (1970-1974) from Tampa International Airport, were used to determine worst case meterological periods for two scenarios. Receptor ranges extended from 0.5 kilometers to 5.0 kilometers with a 0.5 kilometer spacing. Several emission cases were evaluated for each scenario.

Scenario I included all four units on-line with Units 1 and 2 exiting through one stack, and Unit 3 and Unit 4 each exiting through separate stacks. Plant load conditions evaluated consisted of 100%, 75% and 50%.

Scenario II included Unit 1 on-line and Unit 2 off-line with Unit 3 and Unit 4 each exiting through separate stacks. Plant load conditions evaluated consisted of 100% and 75% only, since Scenario I and past Big Bend modeling showed that 50% load is not critical in determining maximum impact concentrations.

Results of the CRSTER modeling were refined using the EPA/FDER approved Industrial Source Complex model (ISC). Receptors were located at 0.1 km intervals. Interaction with other sources were included in the refinement runs, as was performed in the Big Bend 4 PSD application evaluation.

The highest, second-highest 3-hour concentration of 1188 ug/m^3 occurred at 100% load for Scenario I. No significant contribution from other sources occurred for these conditions. This scenario also resulted in the highest, second-highest 24-hour concentration, due to all sources of 208 ug/m^3. TECO's contribution was 85% of the total concentration (177 ug/m^3). The results of the computer modeling predicts there will be no violation of Florida Ambient Air Quality Standards.

The table below compares the results of this analysis (Case IV) to the worst case sulfur dioxide ambient air quality impacts originally predicted. The originally predicted impacts of Unit 4 operating alone do not change with the additional stack.

WORST CASE SO_2 IMPACTS (ug/m^3)

	Case	Annual	24-Hour	3-Hour
I	Unit 4 only (as originally proposed)[a.]	1.0	34.2	163
II	Unit 4 only (with new stack)[b.]	1.0	34.2	163
III	All sources (as originally proposed)[a.]	18.5	185	1087
IV	All sources (with new stack)	N.A.	208	1188
	Florida AAQS	60	260	1300
	Federal AAQS	80	365	1300

Notes:

a. EPA-PSD preliminary determination, Table 4

b. Same as Case I

PARTICULATE MATTER, NITROGEN OXIDES, CARBON MONOXIDE

In the original PSD analysis, the maximum predicted impacts for particulate matter (PM) nitrogen oxides (NOx) and Carbon Monoxide (CO) were shown to be insignificant (PSD determination p.6.). This information is summarized in the following table.

MAXIMUM AIR QUALTIY IMPACTS DUE TO UNIT 4 BOILER (ug/m^3)

Annual PM	Annual SO_2	Annual NO_X	24-Hour PM	24-Hour SO_2	8-Hour CO	3-Hour SO_2	1-Hour CO
1	1.0	0.5	0.9	34.2	8	163	2000
Significance Levels							
1	1	1	5	5	500	25	2000

Source: EPA, PSD preliminary determination, Table 2

Because the new stack will be of the same height and inside diameter as the stack originally intended to be common to Units 3 and 4 and the fact that the above impacts were determined for Unit 4 operating alone, there is no change in these predictions for the case of a new stack.

IMPACT ON NONATTAINMENT AREAS

Because the Case of Big Bend 4 operating with a new stack is equivalent to the case of Unit 4 operating alone as examined in the original PSD analysis, the predicted impacts on nonattainment areas will not change. These impacts were found to be below significant levels as shown in the table below.

	Annual PM	Annual SO_2	24-Hour PM	24-Hour SO_2	3-Hour SO_2
Maximum impact on nonattainment areas (ug/m^3)	1	1	0.4	4.0	17.0
Significance levels(ug/m^3)	1	1	5	5	25

Source: EPA-Preliminary Determination Table 2

PSD INCREMENT IMPACT

SULFUR DIOXIDE

The worst case sulfur dioxide increment impacts from the original PSD analysis occurred for the case of Unit 4 operating alone. This case is equivalent to Unit 4 operation with the new stack, thus maximum increment consumption is not affected by the addition of the new stack. This information is summarized in the tabe below.

WORST CASE SO_2 INCREMENT IMPACTS (ug/m^3)

Case	Annual	24-Hour	3-Hour
Unit 4 only (as originally proposed)[a.]	1.0	34.2	163
Unit 4 only (with new stack)	1.0	34.2	163

a. Source: EPA-PSD preliminary determination - Table 3

PARTICULATE MATTER

EPA determined from the original PSD analysis that Unit 4 had an insignificant TSP impact, and therefore, a TSP increment analysis was not required. This was based on the impacts due to the operation of Unit 4 alone which is equivalent to the impacts with the new stack. Thus the particulate matter impacts remain insignificant.

VISIBLE EMISSIONS

Because Big Bend Unit 4 is subject to new source performance standards, opacity will be limited to 20% on a 6 minute average with the exception of one 6 minute period per hour when opacity is limited to 27%. The opacity limitations apply to either the case of a shared stack or a new separate stack. Thus there will be no change in the allowable opacity as a result of the new stack.

With individual stacks, two distinct plumes will be generated which may cause a greater portion of the sky to appear discolored. However, actual plume opacity may decrease for both units as compared to a single stack, since the plume will be initially dispersed into a greater volume of air. As a result, no significant increase in visible emissions is expected as a result of the new stack.

The NSPS emission limits insure that impacts on and impairments to visibility will be minimal. The nearest Class I area is located 92 km from Big Bend, and therefore no significant visibility impacts on such areas are expected due to the new stack.

SOILS AND VEGETATION

Since the AAQS and the allowable Class I and Class II PSD increments are not predicted to be exceeded with the new stack, the impacts of operation upon soils and vegetation are not expected to be significant. Federal Primary AAQS were promulgated in order to protect the public health, and Secondary AAQS were promulgated in order to protect the public welfare (i.e. damage to vegetation, animals, soils, visibility, structures, etc.), both with an adequate margin of safety. As part of the Florida Sulfur Oxides Study (Environmental Research and Technology, Inc., 1978), a study was conducted in Florida of the environmental effects of ambient sulfur dioxide. The study concluded that "There is not reasonable basis in the established body of scientific information for assuming that existing federal ambient air quality legislation is not sufficiently stringent to protect Florida's environment from significant stress caused by sulfur oxides." It is noted that while the U.S. EPA has rescinded it's 24-hour and annual Secondary AAQS, the State of Florida has retained these standards, providing additional margin of safety beyond that already inherent in the federal standards.

CONCLUSIONS

In summary, the following conclusions can be made with regard to the installation of the new stack for Big Bend Unit No. 4:

- Construction of the new stack for Unit No. 4 at the proposed location is the most economical and feasible solution to the common stack problem which will still allow for meeting the commercial operation date of the unit.

- There will be no increase in emissions.

- Ambient air quality impacts for sulfur dioxide will be well below the Florida Ambient Air Quality Standards.

- Ambient air quality impact predictions for particulate matter, nitrogen oxides and carbon monoxide will not change from the original predictions which were below the significance levels.

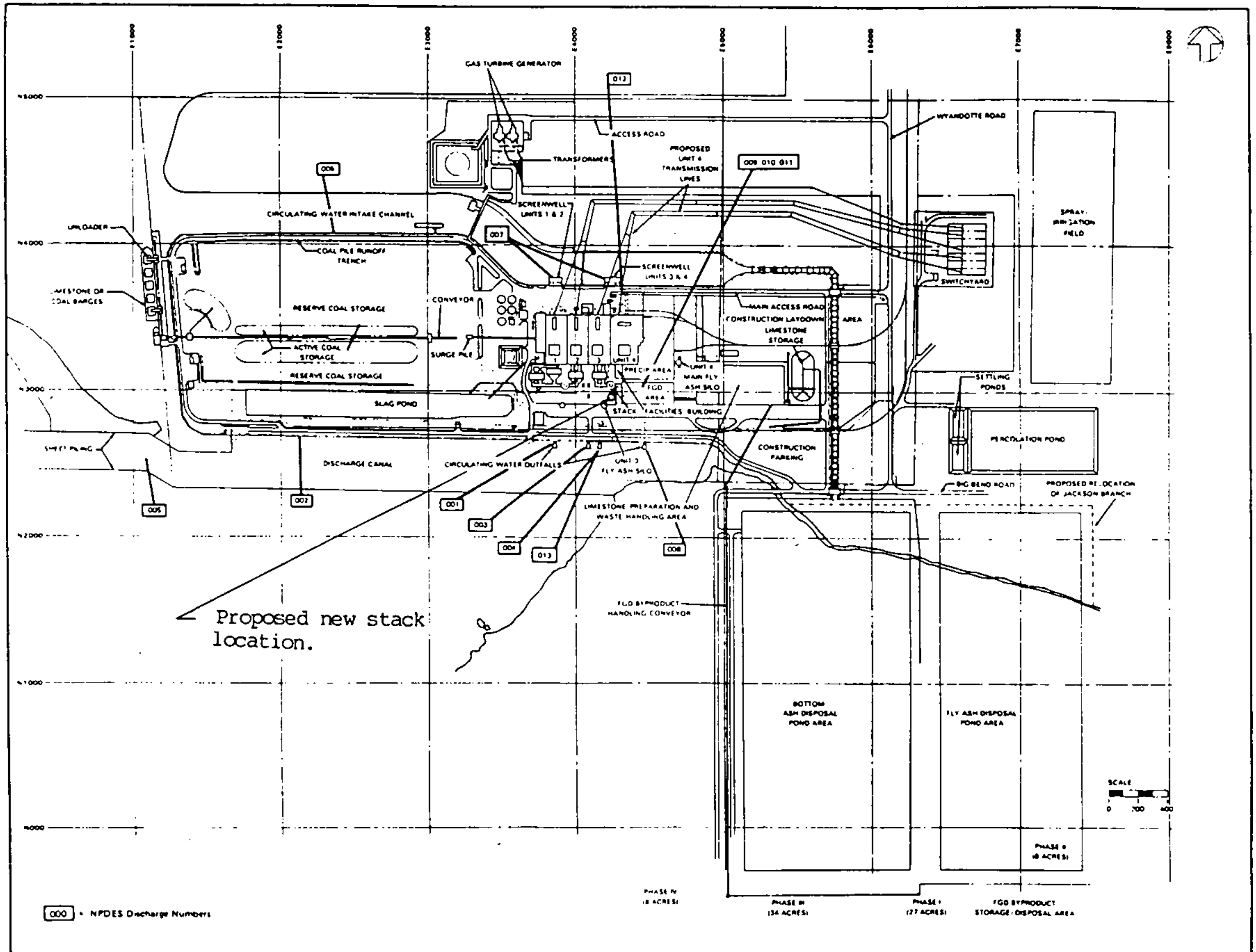
- Impact on nonattainment areas will not change from the original predictions which were below significance levels.

- Worst case PSD increment consumption will not change.

- There will be no impact on visible emissions.

- There will be no impact on soils and vegetation.

Based upon these items it is further concluded that the new stack will not be a significant change to the project and does not constitute a modification. Thus, further review under 40 C.F.R. Section 52.51, is not required.



Plot plan, Big Bend Station.

State of Florida Department of Environmental Regulation
Tampa Electric Company
Big Bend Unit 4
PA 79-12

TECO

CONDITIONS OF CERTIFICATION (Revised 6-2-81)

I. Air

The construction and operation of Big Bend Unit 4 at the Tampa steam electric power plant site shall be in accordance with all applicable provisions of Chapters 17-2, 17-4, 17-5 and 17-7, Florida Administrative Code. In addition to the foregoing, the permittee shall comply with the following conditions of certification:

A. Emission Limitations

1. Based on a maximum heat input of 4,330 million BTU per hour, stack emissions from Big Bend Unit 4 shall not exceed the following when burning coal:

   a. SO_2 - 1.2 lb. per million BTU heat input, maximum two hour average, 0.84 lb/MMBtu on a 30-day rolling average.

   b. NO_x - 0.60 lb. per million BTU heat input.

   c. Particulates - 0.03 lb. per million BTU heat input.

   d. Visible emissions - 20% (6-minute average), except one 6-minute period per hour of not more than 27% opacity.

2. The height of the boiler exhaust stack for Unit 4 shall not be less than 490 ft. above grade.

3. Particulate emissions from the coal handling facilities:

   a. The permittee shall not cause to be discharged into the atmosphere from any coal processing or conveying equipment, coal storage system or coal transfer and loading system processing coal, visible emissions which exceed 20 percent opacity. Particulate emissions shall be controlled by use of control devices.

   b. The permittee must submit to the Department within ten (10) working days after it becomes available, copies of technical data pertaining to the selected particulate emissions control for the coal handling facility. These data should include, but not be limited to, guaranteed efficiency and emission rates, and major design parameters such as air/cloth ratio and flow rate. The Department may, upon review of these data, disapprove the use of such device if the Department determines the selected control device to be inadequate to meet the emission limits specified in 3(a) above. Such disapproval shall be issued within 30 days of receipt of the technical data.

4. Particulate emissions from limestone and flyash handling shall not exceed the following:

   a. Limestone silos - 0.05 lb/hr.

   b. Limestone hopper/transfer conveyors - 0.65 lb/hr.

   c. Flyash handling system - 0.2 lb/hr.

5. Visible emissions from the following facilities shall be limited to 5% opacity: (a) limestone and flyash handling system, (b) limestone day silos and (c) flyash silos.

6. Compliance with opacity limits of the facilities listed in Condition 5 will be determined by EPA reference method 9 (Appendix A, 40 CFR 60).

7. Construction shall reasonably conform to the plans and schedule given in the application.

8. The permittee shall report any delays in construction and completion of the project to the Department's Southwest District Office.

9. Reasonable precautions to prevent fugitive particulate emissions during construction, such as coating of roads and construction sites used by contractors, will be taken by the permittee.

10. Coal should not be burned in the unit unless both electrostatic precipitator and limestone scrubber are operating properly.

11. Coal burned in the unit should be washed before it is transported to the plant site.

B. Air Monitoring Program

1. The permittee shall install and operate continuously monitoring devices for the Unit 4 boiler exhausts for sulfur dioxide, nitrogen dioxide, oxygen and opacity. The monitoring devices shall meet the applicable requirements of Section 17-2.08, FAC, and 40 CFR 60.47a. The opacity monitor may be placed in the duct work between the electrostatic precipitator and the FGD scrubber.

2. The permittee or Hillsborough county shall operate the two ambient monitoring devices for sulfur dioxide in accordance with EPA reference methods in 40 CFR, Part 53, and two ambient monitoring devices for suspended particulates. The monitoring devices shall be specifically located at a location approved by the Department. The frequency of operation shall be every six days commencing as specified by the Department.

3. The permittee shall maintain a daily log of the amounts and types of fuels used and copies of fuel analyses containing information on sulfur content, ash content and heating values.

4. The permittee shall provide sampling ports into the stack and shall provide access to the sampling ports, in accordance with DER publication, Standard Sampling Techniques and Methods of Analysis for the Determination of Air Pollutants from Point Source, July, 1975.

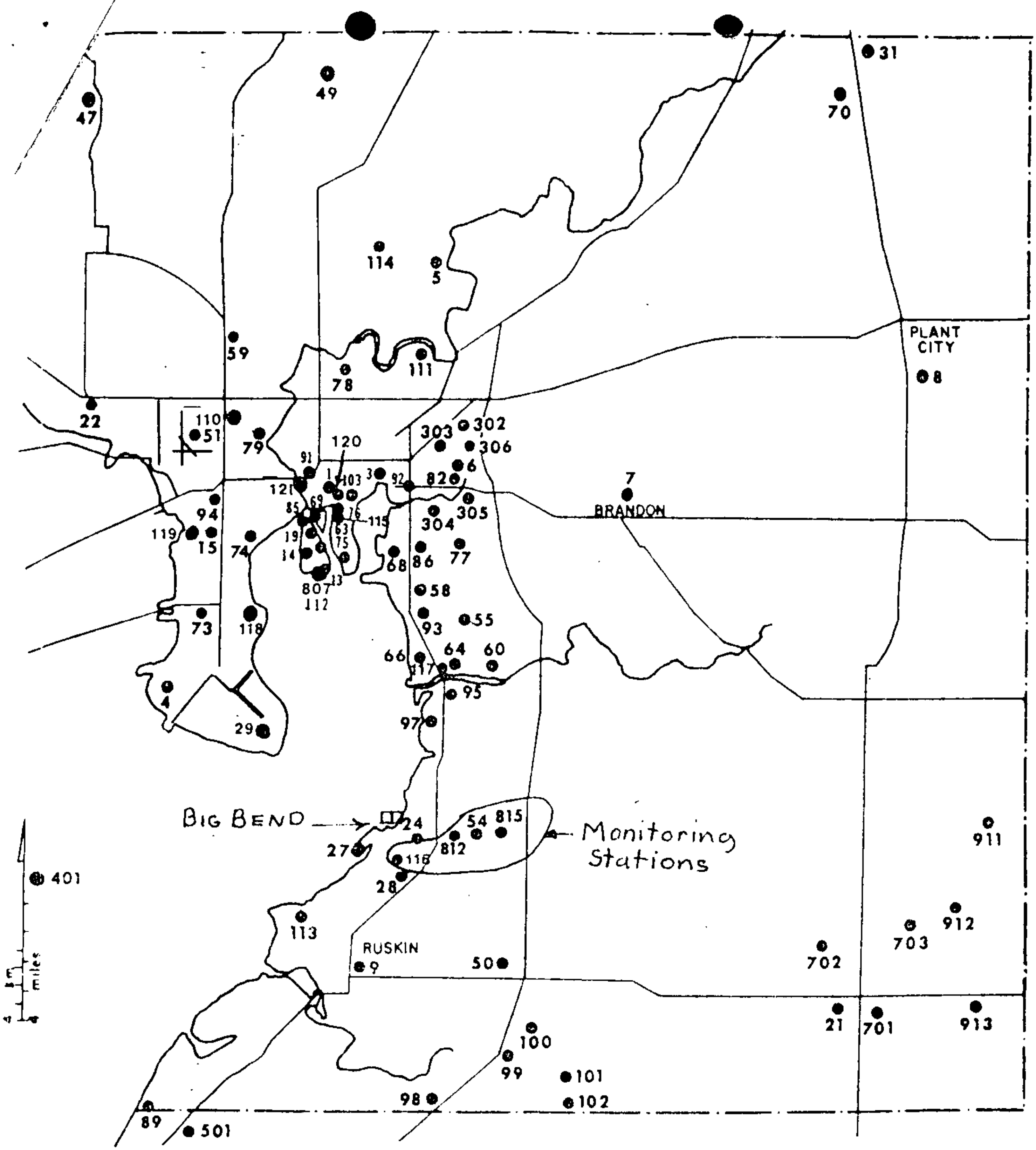
5. The ambient monitoring program may be reviewed by the Department and the permittee annually beginning two years after start-up of Unit 4.

6. Prior to operation of the source, the permittee shall submit to the Department a standardized plan or procedure that will allow the permittee to monitor emission control equipment efficiency and enable the permittee to return malfunctioning equipment to proper operation as expeditiously as possible.

C. Stack Testing:

1. Within 60 calendar days after achieving the maximum capacity at which each unit will be operated, but no later than 180 operating days after initial start-up, the permittee shall conduct performance tests for particulates SO_2, NO_x and visible emissions during normal operations near 4,330 MMBtu/hr heat input and furnish the Department a written report of the results of such performance tests within 30 days. The performance tests will be conducted in accordance with the provisions of 40 CFR 60.46a, 48a, and 49a.

2. Performance tests shall be conducted and data reduced in accordance with methods and procedures in accordance with DER's Standard Sampling Techniques and Methods of Analysis for Determination on Air Pollutants from Point Sources, July, 1975.



AIR SAMPLING STATIONS
HILLSBOROUGH COUNTY, FLORIDA
1979

Figure 1

3. Performance tests shall be conducted under such conditions as the Department shall specify based on representative performance of the facility. The permittee shall make available to the Department such records as may be necessary to determine the conditions of the performance tests.

4. The permittee shall provide 30 days prior notice of the performance tests to afford the Department the opportunity to have an observer present.

5. Stack tests for particulates and SO_2 shall be performed annually in accordance with conditions C. 2, 3, and 4 above.

D. Reporting

1. For Unit 4, stack monitoring, fuel usage and fuel analysis data shall be reported to the Department's Southwest District Office on a quarterly basis commencing with the start of commercial operation in accordance with 40 CFR, Part 60, Section 60.7., and in accordance with Section 17-2.08, FAC.

2. Utilizing the SAROAD or other format approved in writing by the Department, ambient air monitoring data shall be reported to the Bureau of Air Quality Management of the Department quarterly. Commencing on the date of certification, such reports shall be due by the last day of the month following the quarterly reporting period.

3. Beginning one month after certification, the permittee shall submit to the Department a quarterly status report briefly outlining progress made on engineering design and purchase of major pieces of equipment (including control equipment). All reports and information required to be submitted under this condition shall be submitted to the Administrator of Power Plant Siting, Department of Environmental Regulation, 2600 Blair Stone Road, Tallahassee, Florida, 32301.

II. Water Discharges

Any discharges into any waters of the State during construction and operation of Big Bend Unit 4 shall be in accordance with all applicable provisions of Chapter 17-3, Florida Administrative Code, and 40 CFR, 423, Effluent Guidelines and Standards for Steam Electric Power Generating Point Source Category, except as provided herein. Also, the permittee shall comply with the following conditions of certification:

A. Plant Effluents and Receiving Body of Water

For discharges made from the power plant the following conditions shall apply:

State of Florida Department of Environmental Regulation
Tampa Electric Company
Big Bend Unit 4
PA 79-12

CONDITIONS OF CERTIFICATION (Revised 6-2-81)

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10. Coal <u>should</u> not be burned in the unit unless both electrostatic precipitator and limestone scrubber are operating properly.

11. Coal burned in the unit <u>should</u> be washed before it is transported to the plant site.

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6. Prior to operation of the source, the permittee shall submit to the Department a standardized plan or procedure that will allow the permittee to monitor emission control equipment efficiency and enable the permittee to return malfunctioning equipment to proper operation as expeditiously as possible.

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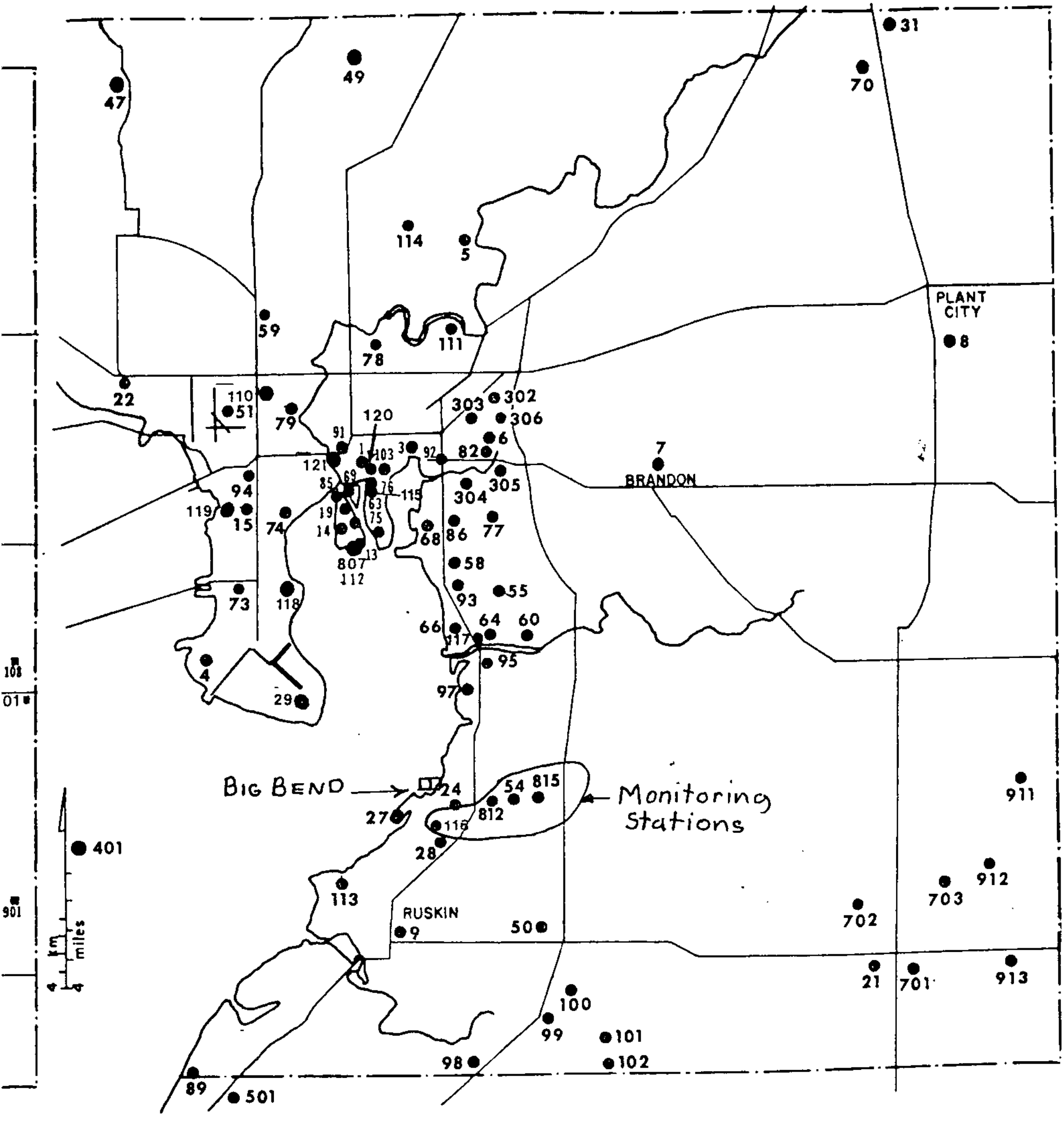

AIR SAMPLING STATIONS
HILLSBOROUGH COUNTY, FLORIDA
1979

Figure I

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A. Plant Effluents and Receiving Body of Water

For discharges made from the power plant the following conditions shall apply:

TECO
TAMPA ELECTRIC COMPANY

POST OFFICE BOX 111 TAMPA, FLORIDA 33601 TELEPHONE (813) 879-4111

May 15, 1981

Mr. Hamilton S. Oven
Florida Department of
  Environmental Regulation
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 322301

RE: Big Bend Unit 4
Site Certification Application
Amendment 6

Dear Mr. Oven:

Based on the State of Florida Department of Environmental Regulation Site Certification Review in regard to the Big Bend Station 316 Demonstrations, Tampa Electric Company will install fine mesh screens at the cooling water intake structures of Units 3 and 4 to meet state and federal requirements.

The attached document describes the conceptual design and operation of the fine mesh screen facility, including the organism return system. The document amends the Units 3 and 4 NPDES Permit Applications and the once-through cooling alternative in the Unit 4 Site Certification Application.

Sincerely,

Heywood A. Turner

Heywood A. Turner
Sr. Vice President-Production

Attachment

cc: Mr. Mickey Bryant

Preliminary Design and Operation Description
Fine-Mesh Dual-Flow Screens
Big Bend Station Units 3 and 4
Tampa Electric Company
May, 1981

The intake would consist of a fine-mesh screen structure surrounding the Units 3 and 4 screenwells. The structure would be supported on piles and extend approximately 30 feet into the channel beyond the existing Unit 3 screenwell. The bottom would be at el.-24.5 ft and the deck would be at el. +9 ft. Flow would enter the structure after passing through chain link fence. There would be six (three for each unit) fine-mesh dual-flow traveling water screens fitted in a 60 ft-by-180 ft sheetpile wall enclosure. Flow passing through these screens would then enter coarse-mesh screens at the circulating water pumps of Units 3 and 4.

The new dual-flow screens will be designed for travel speeds from 7 to 28 fpm and the 10-ft-long screen panels would be equipped with fine mesh (approximately 0.5mm). The distance between the ascending and descending screens faces would be nine feet, and the design approach velocity would be approximately 0.5 fps at full flow.

High and low pressure spray systems would be provided on each screen. The low pressure system would wash organisms off the screen mesh and lifting trays into an organism trough located on the ascending side of each screen. The high pressure system would wash debris from the descending side into another trough. All troughs would manifold into a common sluiceway and the combined flow would pass through a debris trap and 4-inch mesh screen. The flow would than carry organisms to the "Organism Return Canal" (ORC) via an 18-inch diameter gravity-flow pipeline. Alternative pipeline routes are being evaluated.

Construction would be performed in the wet and would consist of excavation, driving necessary piles and sheeting, fabricating the operating deck, and then installing the equipment. Any maintenance required on the screens below the operating deck would require lifting of the screens with a bridge crane. Screenwash pumps would require about 250 hp. and the dual-flow screens require a total of 60 hp.

In the event of excessive screen clogging, a control room alarm would activate on a 10-inch head differential and relief gates would be provided through the cutoff wall which open on a 1.5-ft head differential to supply the station flow. The coarse mesh (3/8-in. opening) screen wells would be maintained and function as a back-up in the event the new screens clogged and the relief gates opened. When fine-mesh screens are removed for maintenance, the sheetpile opening would be blocked.

DEPARTMENT OF ENVIRONMENTAL REGULATION

ROUTING AND TRANSMITTAL SLIP

BAQM - Central Air Permitting

ACTION NO.

ACTION DUE DATE

TO: (NAME, OFFICE, LOCATION)				
1 AMODIO	BOCK	GEORGE	HANKS	INITIAL / DATE
2 HERON	HODGES	HOLLADAY	KING	INITIAL / DATE
3 PALAGYI	POWELL	ROGERS	SVEC	INITIAL / DATE
4 THOMAS	VEGA	FILE	ALL	INITIAL / DATE

REMARKS:

Please review ASAP.
To discuss Monday the 16th at 1:30 p.m.

1. rule [illegible] capability
2.

INFORMATION
- REVIEW & RETURN
- REVIEW & FILE
- INITIAL & FORWARD

DISPOSITION
- REVIEW & RESPOND
- PREPARE RESPONSE
- FOR MY SIGNATURE
- FOR YOUR SIGNATURE
- LET'S DISCUSS
- SET UP MEETING
- INVESTIGATE & REPT
- INITIAL & FORWARD
- DISTRIBUTE
- CONCURRENCE
- FOR PROCESSING
- INITIAL & RETURN

FROM: Larry

DATE

PHONE

VI. Facility Specific Concerns

A. Air Quality

1. Selected Fuel

Tampa Electric Company plans to utilize bituminous coal in Unit 4. Approximately 950,000 tons of coal per year will be burned in the Unit. Normally coal is delivered to the Big Bend Station by covered barges. ~~If it~~ Should it become necessary, the existing rail access could be utilized to allow coal delivery by rail. However, TECo would have to install rail unloading facilities and a conveyor system from the rails to the existing coal handling system.

It appears that the coals under consideration have a heat content of approximately 11,000 Btu/per pound, an ash content of 9-28% and a sulfur content of approximately 3%. TECo ~~is planning on having~~ plans to have the coal washed in order to ~~The washing will~~ remove some ash and sulfur which ~~in turns~~ will subsequently reduce air pollutant emission levels.

2. Air Quality Impacts

The air quality in the area of the Big Bend site is currently affected by emissions from Big Bend Units 1-3, the Agrico phosphate terminal and the Gardinier complex. The air quality in the area ~~will also~~ would additionally be impacted by the construction and operation of the Big Bend Unit #4.

a. Construction Emissions

During construction, ambient air quality in the area ~~will~~ would be slightly degraded due to fugitive dust generated by the movement of trucks and construction vehicles. These impacts ~~will~~ would be temporary.

TECo has agreed to employ dust suppression measures during construction. The general industrial/agricultural nature of the surrounding areas minimizes the number of people who might be affected. The distance between the site and residences will also help to mitigate any nuisance caused by smoke or dust.

b. Operational Emissions

The emission of air pollutants from the Big Bend site are ~~limited~~ regulated by Chapter 17-2, FAC, and by the New Source Performance Standards as imposed by the U.S. Environmental Protection Agency. In order to comply with these regulations, TECo plans to utilize washed coal with electrostatic precipitators to control emission of fly ash and a wet limestone scrubber to control emission of sulfur oxides. Nitrogen oxides emissions will be controlled by proper operation and design of the boiler.

coal	206.5 ton/hr
SO_2	3100 lb/hr
PM	130 lb/hr
NO_x	2600 lb/hr

When Unit 4 is operating at capacity, the unit will consume 206.5 tons per hour of coal and will emit 3100 pounds per hour of SO_2, 130 pounds per hour of particulates, and 2600 pounds per hour of nitrogen oxides.

c. Operational Impacts on Ambient Air Quality

The 490 foot stack height ~~of 490 feet~~ will assist the emission control equipment in reducing ambient air quality impacts. Only during rare meteorological conditions will stack emissions reach the ground in the vicinity of ~~close to~~ the plant. The stack height insures dispersion and dilution of air pollutants, before the pollutants reach ground level at some distance from the site.

Unit 4 will share a stack with Unit 3. Consequently, the combined heat of both units will increase the buoyancy of the exhaust plume. This increases the altitude ~~height~~ to which the plume will rise, thereby enhancing dispersion of the air pollutants.

Air quality impacts are shown on Table 5. The computerized dispersion models used by TECo to predict ambient air quality impacts indicate no violations of ambient air quality standards and no significant interaction with the non-attainment area in Tampa.

TABLE ___

Ambient Air Quality Impacts

($\mu g/m^3$)

Prevention of Significant Deterioration Increments

Pollutant & Source		Annual Avg.*	24 Hour Avg.**	3 Hour Avg.*
SO_2:	Unit 4 Only	1.1 [redacted]	34.2 [redacted]	163 [redacted]
	Plant + Existing Sources	18.5 [redacted]	185 [redacted]	992 [redacted]
	(Ambient Standard)	60	260	1300
	(PSD Increment)	20	91	512
Particulates:	Unit 4 Only	4.1 [redacted]	0.9 [redacted]	N/A
	Plant + Existing Sources	69.2*** [redacted]	128.1**** [redacted]	N/A
	(Ambient Standards)	60	150	N/A
	(PSD Increment)	19	37	N/A
NO_x:	Unit 4 Only	0.8		N/A
	Plant + Existing Sources	20.5		
	(ambient Standards)	100		N/A

* Annual Includes Sources within 50 Kilometers
** Includes Sources within 15 Kilometers
[redacted]
*** Based on modeling with Agrico at max allowable emissions
**** Based on actual emissions value would be 2 $\mu g/m^3$

3. Prevention of Significant Deterioration

Pursuant to Section 17-2, FAC, and 40 CFR 52,21, the Big Bend Unit 4 is subject to a review for the Prevention of Significant Deterioration (PSD), of air quality. The Clean Air Act Amendments of 1977 prescribe incremental limitations on the air quality impacts of a new source. As seen in Table 5 on Ambient Air Quality Impacts, Unit 4 should not violate ambient air quality standards nor should it cause a violation of the PSD increments.

The U.S. Environmental Protection Agency The EPA Preliminary PSD Determination for TECo Big Bend Station Unit 4 was received by the Department. ~~The EPA~~ regulations on PSD require the following air quality impacts to be addressed:

1. National Ambient Air Quality Standards
2. PSD increments
3. Visibility, soils and vegetation
4. Impacts due to growth caused by the proposed source.

The EPA found that air quality modelling showed no violations of the National Ambient Air Quality Standards. Likewise EPA found the PSD increments in the area would not be violated with Unit 4 in operation. The percent consumption of the applicable Class II PSD increments caused by the Big Bend Station are presented in the following table:

Table

Increment	Pollutant	
	Particulate	SO_2
Annual	0	----
24 hour	----	----
3 hour	N/A	. . .

EPA judged that the projected impacts on visibility, soils and vegetation and on air quality due to growth would be minimal.

4. **Best Available Control Technology**

Section 17-2.03 Florida Administrative Code (FAC) and Section 169, 424SC 7401 require evaluation of proposed air pollutant emission control equipment and a determination as to whether or not an applicant will utilize the Best Available Control Technology (BACT) for each pollutant. In the preliminary PSD Determination for TECo ~~Seminole~~, EPA concluded that the systems proposed by the applicant represent BACT for controlling particulates, ~~SO_2 and~~ and oxides of nitrogen ~~oxides~~. and sulfur.

The installation of high efficiency electrostatic precipitators to control particulate emission from the boilers, bag filters to control particulate emissions from fly ash handling, and liquid spray and bag filter systems to control particulate emissions from coal handling and lime and limestone hanlding all represent BACT.

The use of washed coal and the installation of limestone scrubber ~~which~~ will achieve a 90% ~~an overall~~ reduction of ~~90% of~~ the potential sulfur oxide emissions and would comply with EPA's requirements Under 40 CFR Part 60, Federal New Source Performance Standards. EPA considers this control technology BACT.

The use of boiler design controls which limit flame temperature and oxygen availability in order to control the formation of nitrogen oxides in the boiler to 0.6 pounds per million BTU is considered by EPA to be BACT.

The Department of Environmental Regulation having considered (a) EPA's BACT determination; (b) all available scientific, engineering and technical material; (c) existing ~~the~~ emission ~~limiting~~ control standards of other states; and (d) the social and economic impact of the application of such technology, also finds that the emission control technology to be used by Tampa Electric Company, to be the Best Available Control Technology as shown in the following:

Best Available Control Technology
Analysis for the Proposed
Tampa Electric Company Big Bend Station Unit 4

The Best Available Control Technology section of the Site Certification Application and Environmental Analysis for the Tampa Electric Company have been reviewed by the Bureau of Air Quality Management. The application was generally complete~~, and well prepared.~~ The Best Available Control Technology emission rates requested by the applicant were a maximum sulfur dioxide (SO_2) emission rate of 1.2 lbs/MMBTU with 90% removal of SO_2; a maximum particulate emission rate of 0.03 lbs/MMBTU with 99% reduction in particulate; and a maximum emission rate of 0.6 lbs/MMBTU for nitrogen oxides (NO_x) with a 65% reduction.

The emission rates proposed by TECO are all equal to the New Source Performance Standards~~, which were adopted by the U. S. EPA on~~ . The emission rates adopted by the U.S. EPA are based on extensive recent evaluations of technology employed by the electric power industry in the United States. The emission rates requested by the ~~Seminole~~ Electric ~~Cooperative~~ are more restrictive than Florida's emission limiting standards for new coal fired fossil fuel steam generators with a heat imput greater than 250 MMBTU/hour.

A determination of Best Available Control Technology for visible emissions from the unit was not requested by the applicant. Specific emission rates were not requested for the limestone and coal handling systems.

The applicant's requested emission rate of 1.2 lbs/MMBTU with 90% removal of SO_2 constitutes Best Available Control Technology for this pollutant. ~~The applicant analyzed three alternatives which~~ included a double alkali process, a lime process and the Wellman-Lord regenerable process. The double alkali system was found to be economically unattractive for several reasons. First, the the two alkalies increases the reagent operating costs to a level six to seven times greater than that of the limestone system. The waste sludge is not marketable and cannot be land filled without treatment. Consequently ~~which increases~~ the comparative costs over the limestone system will be greater. For the same reason, the lime process was found economically unattractive. The Wellman-Lord system is highly capital intensive with high operating and maintenance costs. It is also highly energy intensive. TECo has found little available market demand for any sulfuric acid product. For these reasons TECo found the Wellman-Lord process unattractive.

~~In~~ Provision of ~~increased~~ SO_2 removal efficiency of greater than 90% would not markedly improve the ambient air quality in the area, therefore the increased cost of additional removal efficiency would neither ~~not~~ be cost effective nor ~~or~~ warranted.

The additional "waste of large quantities of fuel energy and the use of greater land areas" required to meet SO_2 removal ~~the more stringent~~ rates (more than 90%) are not justified by the degree of Air Quality improvement projected.

To acheive the 90% reduction, TECo analyzed four control processes, the limestone system selected, and three alternatives. The alternatives

The applicant's requested emission rate of 0.03 lbs/MMBTU for particulate is 70% lower than the emission currently allowed by Florida's emission limiting standards for new coal fired fossil fuel steam generators. The applicant reviewed ~~undertook an~~ assessments of the particulate control alternatives which ~~and~~ concluded that baghouses and precipitators would be roughly equivalent in terms of the degree control achieved. In comparing the practicality of the two methods, ~~addition,~~ the electrostatic precipitator constitutes proven technology on units of the size proposed by Tampa Electric Company. However, while the U.S. EPA has published studies on two facilities of 39 MW and 175 MW capacity which are utilizing baghouses ~~, however;~~ the application of this technology to a 417 MW unit with flue gas desulfurization could produce scale up difficulties. Further, an analysis conducted by the Seminole Electric Cooperative on 640 MW units indicated the cost of baghouses to be an additional $5 million in capital and $2 million/year in maintenance. Therefore, although the U.S. EPA finds that the ~~'s proposed~~ New Source Performance Standard of 0.03 lbs/MMBTU is achievable with either baghouse or electrostatic precipitator as ~~will constitute~~ Best Available Control Technology for particulates, TECo chose to use electrostatic precipitators.

The applicant requested that an emission rate of 0.60 lbs/MMBUT be declared Best Available Control TEchnology for nitrogen oxides (NO_x). This is consistent with the proposed federal New Source Performance Standards. Reductions in nitrogen oxide emissions would be ~~are~~ accomplished through boiler design.

Equipment designer's have guaranteed that NO_x emissions from units will not exceed 0.6 lbs/MMBTU at loads ranging from 20% to 100%. Since loads of less than 20% are only due to start-up or operation as spinning
guarantees for unit range are
reserve, this is recognized as acceptable practice, particularly on base load units. Based on presently available information, an emission rate of 0.6 lbs/MMBTU constitutes Best Available Control Technology for nitrogen oxides from TECo's proposed boilers.

The applicant did not request a visible emission limit for the proposed facility. The U.S. EPA's ~~proposed~~ New Source Performance Standards specify a visible emission limit of 20% opacity with an allowable opacity of not more than 27% for six minutes in any hour. The Florida Standards for new coal fired fossil fuel steam generators limits the visible emissions to 20% opacity except that 40% opacity may not be exceeded more than two minutes in any hour. Because ~~Since~~ the proposed federal standards have been based on a review of the best control technology available, the Best Available Control TEchnology constitutes 20% opacity except that an opacity of 27% may not be exceeded more than six minutes in any hour.

The coal and limestone handling facilities are discussed in the application; however, a specific emission rate is not requested as Best Available Control Technology. Therefore, the Bureau recommends an emission rate based on the determination for Crystal River Units #1 and #2 fly ash handling facilities. Best Available Control TEchnology for coal and limestone handling facilities shall constitute the use of covered conveyors and sprays to control fugitive dust in areas where baghouses are not utilized.

Baghouses with a particulate removal efficiency of 99.9%+ constitutes Best Available Control Technology. This is the collection efficiency for which a baghouse is normally considered capable.

Upon reviewing the preceeding information, the Department also finds that the Big Bend Station Unit 4 will not contribute to significant deterioration of air quality.

5. Acid Rain

6. Radiation from Coal-Fired Power Plants

ate of Florida
EPARTMENT OF ENVIRONMENTAL REGULATION

NTEROFFICE MEMORANDUM

For Routing To District Offices And/Or To Other Than The Addressee		
To:	Loctn.:	
To:	Loctn.:	
To:	Loctn.:	
From:	Date:	
Reply Optional [ ]	Reply Required [ ]	Info. Only [ ]
Date Due:	Date Due:	

TO: Buck Oven, Power Plant Siting Section

THRU: Bill Thomas, Bureau of Air Quality Management

THRU: Willard Hanks

FROM: Bob King

DATE: March 26, 1981

SUBJ: Site Certification - TECO's Big Bend Unit #4

The Bureau believes that the following specific conditions are required as part of the site certification for Big Bend Unit #4.

1. Maximum heat input to the Unit will be 4,330 million Btu per hour.

2. Coal will not be burned in the Unit unless both electrostatic precipitator and limestone scrubber are operating properly.

3. Coal burned in the Unit must be washed before it is transported to the plant site.

4. The Unit is subject to all the provisions of 40 CFR 60, subpart Da, under section 17-2.21, F.A.C., which includes:

Proposed/effective 9/19/78

A. Maximum emissions from the boiler shall not exceed the following allowable emission limits:

10/03/79 Application Received

Pollutant	Maximum Emission Rate (lb/MMBtu)	Minimum Reduction
Particulate	0.03	99%
SO_2	1.2	90%
NO_x	0.6	65%
Visible Emission	20% (6-minute average), except one 6-minute period per hour of not more than 27% opacity.	

B. After construction is completed, the Unit will be tested for particulate matter, sulfur dioxide, nitrogen oxides and visible emissions during normal operations near 4,330 MMBtu/hr heat input. The performance tests will be conducted in accordance with the provisions of 40 CFR 60.46a, 48a and 49a.

C. The applicant will install and maintain continuous monitoring instruments to measure and to record emissions for opacity, sulfur dioxide, nitrogen oxides and oxygen in accordance with the provisions of 40 CFR 60.47a.

5. Visible emissions from the following facilities shall be limited to 5% opacity: (a) limestone and flyash handling system, (b) limestone day silos and (c) flyash silos.

6. Compliance with opacity limits of the facilities listed in Condition 5 will be determined by EPA reference method 9 (Appendix A, 40 CFR 60).

7. Construction shall reasonably conform to the plans and schedule given in the application.

8. The applicant shall report any delays in construction and completion of the project to the Department's Southwest District Office.

9. Reasonable precautions to prevent fugitive particulate emissions during construction, such as coating of roads and construction sites used by contractors, will be taken by the applicant.

BK:BT:WH:dav

State of Florida
DEPARTMENT OF ENVIRONMENTAL REGULATION

INTEROFFICE MEMORANDUM

For Routing To District Offices And/Or To Other Than The Addressee	
To:	Loctn.:
To:	Loctn.:
To:	Loctn.:
From:	Date:

TO: Power Plant Siting Review Committee

FROM: Hamilton S. Oven, Jr. HSO

DATE: January 28, 1981

SUBJECT: TECO Big Bend #4

By law DER must complete its report on TECO Big Bend #4 by April 19, 1981. In order to allow time for review by Steve Fox and Secretary Varn, a final draft should be complete by the end of March. Please submit any comments, analyses, opinions, recommendations or suggested conditions of certification as soon as practical but no later than March 1, 1981. If you need additional information, please contact me ASAP. NOTE: Water quality variances may be requested.

We are also expecting an application from JEA on February 18, 1981.

HSOjr:my

cc: Suzanne Walker
Lou Hubener
Bill Brown
Bill Kutash
Steve Palmer
Larry Olsen
Bob King
Bill Hinkley
Al Bishop
Bob McVety
Don Kell
Rodney Dehan
Mickey Bryant
Jay Thabaraj

H6 - Rev 7/76

DEPARTMENT OF ENVIRONMENTAL REGULATION

ROUTING AND TRANSMITTAL SLIP

ACTION NO.

ACTION DUE DATE

1. TO: (NAME, OFFICE, LOCATION) Bob King, Suite 600	INITIAL	DATE 1/28/81
2.	INITIAL	DATE
3.	INITIAL	DATE
4.	INITIAL	DATE

REMARKS:

Comments on

(1) Permit condition 0.03 lb/MMBTU

(2) Drift impact from cooling tower operation

RECEIVED JAN 1981 BUREAU AQM

INFORMATION
- REVIEW & RETURN
- REVIEW & FILE
- INITIAL & FORWARD

DISPOSITION
- REVIEW & RESPOND
- PREPARE RESPONSE
- FOR MY SIGNATURE
- FOR YOUR SIGNATURE
- LET'S DISCUSS
- SET UP MEETING
- INVESTIGATE & REPT
- INITIAL & FORWARD
- DISTRIBUTE
- CONCURRENCE
- FOR PROCESSING
- INITIAL & RETURN

FROM: Buck Oven, Jr.

DATE 1/28/81

PHONE

Jl DER

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

REGION IV

345 COURTLAND STREET
ATLANTA, GEORGIA 30308

OCT 17 1980

REF: 4AH-AF

Dr. William Johnson, Manager
Environmental Planning
Post Office Box 111
Tampa, Florida 33601

RECEIVED OCT 1980 BUREAU A Q M

RE: Big Bend Unit #4, PSD-FL-040

Dear Dr. Johnson:

Review of the referenced application in accordance with Federal Prevention of Significant Deterioration (PSD) Regulations (40 CFR 52.21) continues. The August 7, 1980 amendments to the PSD Regulations has necessitated submittal of certain additional information.

Please submit information to answer the questions outlined on the attached page.

The information on allowable emissions in Question #1 is necessary due to the 1980 PSD Regulations' emphasis on regulated pollutants including criteria and non-criteria pollutants. Because your application was determined complete as of March 11, 1980 which precedes the promulgation date, additional BACT analysis and monitoring are not required. However, an analysis of emissions and allowable emissions rates must be included in your application.

Questions 2 and 3 are necessary to determine if the October 1, 1977 sulfur dioxide reduction affects increment consumption. The baseline date for sulfur dioxide for the Big Bend area is November 25, 1977. Since the reduction occurred prior to baseline date, it affects increment consumption only if it results from construction at a major stationary source. If in complying with the Florida imposed lower emissions limit the source did not undergo a physical change or a change in the method of operation, the reduction does not affect increment consumption.

Moreover, if the change is determined not to expand increment, additional analysis also will be required to demonstrate that emissions from the proposed modification do not threaten the allowable increment. A determination on whether or not increment was expanded by the 1977 reduction will be made on the basis of the information you submit.

Given this determintation's potential impact on growth in the Big Bend area, your response should be thorough. In addition, we encourage that your response be prompt. A preliminary determination concerning approval cannot be made without review of the requested information.

Should you have questions regarding this letter please contact Kent Williams, Chief, New Source Review, at 404/881-4552.

Sincerely,

Tommie A. Gibbs

Tommie A. Gibbs, Chief
Air Facilities Branch

TAG:JLS:cg

Attachment

ATTACHMENT

1. Provide emissions estimates from Unit #4 and proposed allowable emission rates for the following pollutants regulated under the Clean Air Act. Previously submitted information on this subject is summarized in the table.

Pollutant	Maximum Quantity Entering Boiler[a] (T/yr)	Significance Level[b] (T/yr)
Lead	c	0.6
Asbestos	c	0.007
Beryllium	3.1	0.0004
Mercury	0.21	0.1
Fluorides	117.0	3.0
Any other regulated pollutants	c	--

a. Maximum amount (T/yr) in coal fired in the boiler estimated from data in the application, amendment 4.

b. Extracted from 40 CFR 52.21 (b)(23); 45FR52737.

c. No data provided in the application.

2. Was the October 1, 1977 reduction in sulfur dioxide emissions from Units #1-3 the result of construction at the source? If so, describe the physical change or the change in the method of operation which occurred.

3. When will construction commence on the proposed modification?