PUBLIC NOTICE

A modification to an existing air pollution source is being proposed by the Tampa Electric Company near the city of Tampa, Hillsborough County, Florida. The proposed modification is the construction of a fourth coal-fired steam electric generating station with a 425 megawatt capacity. The modification will increase emissions of air pollutants by the following amounts in tons per year:

SO_2	PM	NO_x	CO	VOC
11,949	573	11,379	267	9

The maximum increment consumed by the proposed modification is as follows:

	Annual	24-Hour	3-Hour
SO_2	5%	38%	32%
PM	------------Insignificant Impact--------------		

Note that net increment consumption in the area may be less than the percentage indicated due to previous emissions reductions.

The proposed modification has been reviewed by the U.S. Environmental Protection Agency (EPA) under Federal Prevention of Significant Deterioration (PSD) Regulations (40 CFR 52.21), and EPA has made a preliminary determination that the construction can be approved provided certain conditions are met. A summary of the basis for this determination and the application for a permit submitted by Tampa Electric Company 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 to EPA regarding the proposed modification. All comments, postmarked not later than 30 days from the date of this notice, will be considered by EPA in making a final determination regarding approval for construction of this source. These comments will be made available for public review at the above location. Furthermore, a public hearing can be requested by any person. Such requests should be submitted within 15 days of the date of this notice. Letters should be addressed to:

Mr. Tommie A. Gibbs, Chief
Air Facilities Branch
U.S. Environmental Protection Agency
345 Courtland Street, NE
Atlanta, Georgia 30308

APPLICATION PSD-FL-040

PRELIMINARY DETERMINATION

I. Applicant

Tampa Electric Company (TECO)
Post Office Box 111
Tampa, Florida 33601

II. Location

The proposed modification is located 5 miles north of Ruskin, Hillsborough County, 10 miles south of the city of Tampa and 14 miles east of St. Petersburg at Big Bend between Tampa and Hillsborough Bays, Florida. The northern and southern property boundaries are Big Bend Road and U. S. Highway 41, respectively. The UTM coordinates are 3075.0 km north and 361.6 km east.

III. Project Description

The applicant proposes to modify their Big Bend power generating facility by construction of a fourth coal-fired steam electric generating station (Big Bend Unit 4) with a 425 megawatt capacity. The new unit is to utilize the existing stack servicing Big Bend Unit 3. The boiler will fire a maximum of 4330 million Btu's per hour or approximately 206.5 tons per hour of a medium sulfur bituminous coal having a maximum higher heating value of 12,628 Btu/lb. Of the coals under consideration, the maximum sulfur content coal has 4.0 percent sulfur by weight.

Coal and limestone materials handling, storage and preparation facilities also will be constructed. The scheduled starting date for commercial operation of Big Bend Unit 4 steam electric generating station is the first quarter of 1985 calendar year.

Specific emitting facilities to be constructed are as follows:

1. Steam generator (425 MW; 4330 MMBtu/hr);
2. Coal receiving facilities (barge);
3. Coal transfer facilities;
4. Coal storage pile;
5. Coal preparation (crushing and washing) facilities;
6. Limestone receiving facilities (rail);

7. Limestone storage pile;
8. Limestone transfer facilities;
9. Limestone day storage silos;
10. Flyash handling system and storage silos.

IV. Source Impact Analysis

Prevention of significant deterioration (PSD) of air quality review is required for a modification to a major stationary source which significantly increases emissions of any pollutant regulated under the Clean Air Act, consistent with the provisions of 40 CFR 52.21 promulgated August 7, 1980. The source is a fossil fuel fired steam electric plant (>250 MMBtu/hr). The three existing coal fired units clearly emit greater than 100 tons per year and therefore constitute an existing major stationary source. Table 1 shows the emissions increases from the proposed modification. It is clear that PSD review applies for emissions of particulate matter (PM), nitrogen oxides (NO_x), sulfur dioxide (SO_2), and carbon monoxide (CO).

Full PSD review involves evaluation of the following:

1. Best Available Control Technology (BACT);
2. National Ambient Air Quality Standards (NAAQS) impacts;
3. Increment impact;
4. Impacts on soils, vegetation, and visibility;
5. Growth impacts; and
6. Class I area impacts.

A. Best Available Control Technology Analysis (BACT)

A BACT analysis is required consistent with 40 CFR 52.21(j) for each pollutant with a significant emissions increase, which for the proposed modification includes SO_2, PM, NO_x and CO.

1. Sulfur Dioxide Emissions Control

BACT for SO_2 is required on the steam generator (boiler) which is the only SO_2 emitting facility affected by the modification. The applicant proposes to use a nonregenerable limestone scrubber system with removal efficiencies of greater than or equal to 86 percent. The coal will be pretreated by washing to yield about a 25 percent potential SO_2 emissions reduction. An additional 5 percent is expected to remain in the recovered flyash. The applicant proposes an overall sulfur removal efficiency of 90 percent for this system.

The New Source Performance Standard (NSPS) for electric utility steam generation was promulgated June 11, 1979. This limits SO_2 emissions to 10 percent of potential SO_2 emissions and a maximum of 1.2 lb/MMBtu heat input except when the emissions are less than 0.6 lb/MMBtu. At these rates a minimum of 70 percent reduction (30 percent of potential emitted) in potential SO_2 emissions is required. For SO_2 emissions rate below 0.2 lb/MMBtu, no percent reduction is required. The percentage reduction in potential SO_2 emissions depends on the sulfur content of the coal.

The BACT analysis considered three alternative coals with properties as follows:

	Coal F-1A	Coal F-2A	Coal F-2B
Heating Value (Btu/lb Dry Basis)	12,275	12,626	12,628
Sulfur Content (Dry Basis; Percent By Weight)	3.42	3.91	4.00

Coals F-2A and F-2B were the specific coals considered in developing design specifications for the flue gas desulfurization (FGD) system. Firing of these coals in the boiler controlled with the proposed control system (25% sulfur removal from washing, 5% sulfur removal in flyash and 86% sulfur removal in the FGD; totaling 90% sulfur removal), yields SO_2 emission rates as follows for the 4330 MMBtu/hr boiler.

Emissions Rate	Coal F-1A	Coal F-2A	Coal F-2B
lb/MMBtu	0.56	0.62	0.63
lb/hour	2413	2682	2743

The applicant proposed an allowable SO_2 emissions limit range of 0.77 to 0.82 lbs/MMBtu to be determined on a 30-day rolling average. The coal analyses considered by the applicant in estimating these values have slightly higher sulfur contents (3.88% and 4.02%) and significantly lower heating values (10,111 Btu/lb and 9,936 Btu/lb) from those considered in the FGD system BACT analysis. For this reason, EPA rejects the proposed emissions limits, and on the basis of the BACT analysis presented in the application, requires an SO_2 emissions limit of 0.63 lb/MMBtu (2728 lb/hour) on a 30-day rolling average.

The emissions limit was set on the worst case of those cases considered in the BACT analysis to provide maximum flexibility for the applicant in the choice of coals and operation of the system. The sulfur dioxide content of the flue gas will be continuously monitored and recorded to determine compliance with the allowable emissions limit. In addition, NSPS percent reduction requirements will be met through coal sulfur content monitoring and other procedures established in 40 CFR 60 Subpart Da.

2. Particulate Matter (PM)

BACT is required for all PM emitting facilities including the boiler and coal, limestone and flyash handling and storage facilities. The applicant proposes to install an electrostatic precipitator (ESP) with a removal efficiency greater than 99 percent to control emissions of TSP from the boiler.

The New Source Performance Standard for electric generating stations promulgated June 11, 1979, stipulates particulate emissions be no greater than 0.03 lb/MMBtu. The applicant proposes that PM allowable emissions rates be 0.03 lb/MMBtu (130 lb/hr) and 20 percent opacity to comply with the New Source Performance Standard (NSPS) and to meet BACT. EPA agrees that this limit meets BACT for PM for this boiler. The collection efficiency will be required to be greater than 99 percent. Two performance tests will be required; one test will be initiated 90 days after commercial operation and the second will be within 12 months of the first successful performance test, consistent with NSPS requirements. In addition, opacity will be continuously monitored.

Fugitive emissions from coal handling will be controlled by 1) proper maintenance of the coal piles, 2) enclosure of all conveyors and transfer points and 3) water spraying. In addition, mean precipitation, 49.4 inches per year and more than 0.1 inches on 107 days per year, act to minimize dust generation from erosion and mechanical disturbance. During dry periods and high winds, water spraying of the coal pile and all drop points is required. Moreover, the coal pile will be oriented and shaped to minimize wind erosion. Due to the moisture content maintained by rainfall and water spraying, the use of chemical stabilizers and dust suppressants are not warranted, and EPA agrees that the proposed practices and equipment represent BACT for PM from coal handling equipment.

Fugitive emissions from limestone handling will be controlled in a similar fashion through enclosure and water spraying. Transfer points and conveyors will be enclosed. Moreover, the receiving hopper, transfer conveyors and day silos will be maintained at a negative pressure with an exhaust system venting to a bag filter or wet scrubber. The two separate systems, silos and hopper/transfer conveyors will emit a maximum of 0.05 and 0.65 lb/hr, respectively.

The flyash handling system including transfer and storage silo will exhaust through a bag filter. The emission rate will not exceed 0.2 lb/hr. The technologies and emission rates proposed by the applicant are accepted as BACT for PM for the limestone and flyash handling systems.

3. <u>Nitrogen Oxides (NO_x) and Carbon Monoxide (CO)</u>

The applicant proposes to use combustion controls to guarantee a maximum NO_x emission rate of 0.6 lb/MMBtu (2598 lb/hr) and CO of 0.014 lb/MMBtu (61 lb/hr). This is equivalent to the NO_x limit required in the NSPS for steam generating stations firing bituminous coal and the CO emission rate proposed by the applicant. The CO emission limit is considerably less than that predicted by the appropriate AP-42 factor of about 200 lb/hr (see Table 1.1-2). An attachment to this preliminary determination summary specifies combustion control requirements to balance the tradeoffs between NO_x and CO emissions through the use of a flue gas oxygen monitor. BACT for NO_x is low excess air firing and the use of staged combustion to maintain minimum NO_x emissions with a maximum as stated above. BACT for CO is proper combustion controls with a maximum emission rate as discussed above. The CO technology is maintained by the oxygen monitor. In addition, emissions of NO_x will be continuously monitored and recorded. EPA accepted the proposed emissions limits and technologies discussed as BACT for CO and NO_x for the proposed boiler.

B. Air Quality Analysis

The applicant has evaluated the modification's air quality impacts and their effects on NAAQS and maximum allowable increment. The maximum air quality impacts (highest, second highest concentrations) were estimated using EPA UNIMAP models and 5 years of meteorological data from Tampa International Airport. Annual average concentrations were estimated with AQDM-Briggs. Short-term modeling (24-and 3-hour averages) were estimated by first screening 5 years of meteorological data to identify the 24-hour (TSP and SO_2) and 3-hour periods (SO_2) which caused maximum impacts from the proposed modification. Second, CRSTER was used to locate general areas of maximum impacts (1.0 kilometer grid). Finally, maximum short-term concentrations were refined to 0.1 kilometer grid spacing using the PTMTPW model.

Review of the maximum predicted impacts from Unit 4 (see Table 2) shows the modification to have insignificant impacts for PM, NO_x and CO. Further, the maximum impacts of PM and SO_2 on nearby non-attainment areas (SO_2 - Pinellas County at about 55 km and PM - Tampa area at 5.3 km) are below the significance values defined in the Preamble to 40 CFR 52.21. Because non-attainment air quality is not significantly impacted, the modification is not subject to LAER or offset requirements. In addition, detailed analysis of PM, NO_x and CO is not required on the basis that impacts do not pose a threat to the NAAQS or available increment and no Class I area is impacted, as discussed below. Only emissions of SO_2 must be analyzed in detail to evaluate NAAQS and increment impacts.

It should be noted that the modeling did not consider PM emissions from the coal and limestone storage and handling facilities or other fugitive emissions sources, consistent with EPA Region IV policy. EPA Region IV does not require modeling of fugitive sources of this type for applications determined to be complete prior to August 7, 1980. Also, the applicant demonstrated that the stack height does not exceed good engineering practice or require consideration of downwash effects in the air quality analysis.

1. Increment Analysis

The applicant evaluated the impact on available SO_2 increment consistent with the requirements of 40 CFR 52.21 (k). The analysis considered all increment consuming sources located within a 50 km radius of the proposed construction site. Minor sources (<100 T/Y) within a 15 km radius and major sources within 50 km were modeled in determining maximum impacts.

In identifying sources for use in the increment and NAAQS analysis (discussed later) the applicant utilized the NEDS emissions data storage system and FDER air permit file system. Increment consuming sources were identified according to the definition of baseline in 40 CFR 52.21(b). Non-baseline emissions consume increment. An update to the original source list to account for sources permitted between the original search date and the PSD application complete date (about 1 year) identified several additional sources, none of which, however, affected the conclusions of the analysis.

It should be noted that previous emissions reductions at TECO Big Bend (units 1 - 3), at Gardinier, and at a number of other Tampa area sources has occurred which has expanded available increment. Most notable of these are the TECO Big Bend SO_2 reductions made to comply with revised SIP limits. The allowable emissions history of units 1 - 3 are as follows:

	Allowable Emissions Cap for Units 1-3 Collectively (Tons per Hour)		Total Cumulative Increment Expanding Emissions Reduction (Tons per Hour)
	3-Hour Average	24-Hour Average	
Original Limits	39.5	39.5	-
April 7, 1977	35	32	-
October 1, 1977	35	25	7
September 7, 1980	31.5	25	7

The reduction in 24-hour average emissions on October 1, 1977 constitutes a post January 6, 1975 emissions reduction due to construction at a major stationary source which expands increment. Baseline emission rates for Big Bend units 1-4 used as input to the increment analysis were based on actual operating data. Short-term emission rates (3-hour and 24-hour) were consistent with the allowable rates at full load. Annual emissions, however, were based on about two-thirds capacity operation which was experienced by units 1-3 in 1977. In addition, short-term impacts, under 50 and 75 percent load conditions, were evaluated to ensure identification of maximum impacts, which for power plants can occur at reduced loads due to bouyancy and momentum effects on plume rise.

The analysis involved two model runs for each averaging time and wind direction/meteorological data scenario investigated. In one run all new and modified sources were modeled at allowable emission rates. The source list included all new major sources commencing construction after January 6, 1975 and all new or modified minor sources (<100 T/Yr) commencing construction after August 7, 1977. The second run predicted impacts from all modified sources at their estimated premodification actual emission rates. The results of subtracting the impacts from the runs on a receptor by receptor basis were assumed by the applicant to approximate increment consumption.

The modeling results for the SO_2 annual averaging period show no positive values. The premodification concentration exceeded the projected impact from all new and modified sources at all receptors. Moreover, the projected maximum annual SO_2 impact from new and modified sources alone, without subtracting the premodification model run results, does not exceed the annual SO_2 increment (9.0 ug/m^3 impact vs 19 ug/m^3 increment). The analysis clearly demonstrates that the annual SO_2 increment will not be violated.

Results for the short term (3-hour and 24-hour) increment analysis were developed in a similar fashion. However, the premodification emission rates for Big Bend Units 1-3 were modeled at allowable emission rates (full capacity) which was indicative of worst case, short-term operation. The 24-hour results obtained from subtracting model runs again showed no positive values. The 3-hour results however show a net positive SO_2 impact of 67.7 ug/m^3.

The meteorological periods (3-hour and 24-hour) which caused maximum impact for TECO, as identified by the CRSTER model, had wind directions such that no significant interaction with other sources occurred (winds from the west and east). For this reason, several meteorological periods for which source interaction could occur were modeled. This modeling showed very little contribution to ground level concentrations in the vicinity of Big Bend relative to the contribution from Big Bend from interacting sources. The results of this modeling were incorporated into the overall estimated net impacts on 3-hour and 24-hour SO_2 increment, discussed previously.

The results of the increment analysis are listed in Table 3. The analysis is accepted by EPA as adequate demonstration that the available SO_2 increment will not be violated by the proposed modification.

2. NAAQS Impact

In evaluating maximum SO_2 ambient air quality impacts the applicant modeled all existing sources in conjunction with the proposed Unit 4. As indicated in the increment analysis, maximum short-term impacts due to interactions with other existing sources were evaluated but found to be less than maximum impact from TECO Big Bend sources alone. The NAAQS modeling results are listed in Table 4. Assuming a background value of 20 ug/m^3 to account for natural sulfur dioxide sources (swamps, etc.) and long range SO_2 transport, the maximum predicted impacts in conjunction with background remain below the NAAQS levels (See Table 4). Since this application was determined to be complete prior to August 7, 1980, therefore subjecting the modification to the 1978 monitoring requirements (40 CFR 52.21(m); June 19, 1978) and the location is rural with only a small number of large sources, the approach described above is acceptable.

On the basis of the results of the air quality analysis the applicant proposes and EPA agrees that adequate demonstration has been made that NAAQS levels will not be violated. However, to verify these results the applicant will be required to perform continuous SO_2 ambient air quality monitoring for a period of at least 1 year following start-up of Unit 4.

C. Class I Area Impacts

The proposed construction site for Unit 4 is about 90 km from the Chassahowitzka National Wildlife Refuge. Impacts on this Class I area have been evaluated to ensure that the proposed modification does not degrade the Class I area air quality beyond allowable increments. As discussed previously, allowable emissions reductions since August 7, 1977 at Big Bend Units 1-3 more than offset the increased emissions from the proposed Unit 4 for short-term averages (3-hour and 24-hour). Moreover, a number of sources in the vicinity of Big Bend have similarly reduced emissions of SO_2. For this reason, the proposed construction is not expected to endanger the available SO_2 Class I increment.

Emissions of PM have been modeled and shown not to cause impacts in excess of the significance levels (Preamble 40 CFR 52.21). Although these significance levels do not apply to Class I areas, the additional dilution incurred over the 90 km distnace between Big Bend and the Class I area, considered in conjunction with the small impacts predicted to occur in the vicinity of the plant (<1 ug/m^3 annual average), show the proposed modification to be no threat to available Class I increment. Similarly, emissions of

NO_x and CO do not pose a threat to Class I air quality. The results of this analysis will be transmitted to the Federal Land Manager responsible for this Class I area for comments on the significance of the impacts.

D. Growth Impacts

It is anticipated that an average of 510 construction workers (craft and nonmanual) will be required per year during the 3-year Unit 4 construction period. A peak of approximately 1,100 personnel is expected during a 4-month period in 1984, the third year of construction. Based on TECO observations and labor availability surveys from construction of the previous three Big Bend units, approximately 90 percent of the construction work force will be hired from labor organizations in the Tampa area. It is, therefore, reasonable to assume that no special provisions for housing, education, or community facilities will be necessary.

Unit 4 will provide electricity for general private, commercial and industrial consumption in central Florida. In this way, it will facilitate commercial and industrial growth. However, no acute air pollution effects are expected from this growth due to the gradual widespread nature of the anticipated development.

E. Additional Impacts on Soils, Vegetation and Visibility

The applicant has evaluated effects on soils, vegetation and visibility consistent with the provisions of 40 CFR 52.21(o). Tomatoes are the primary commercial crop in the vicinity of Big Bend. No unusually valuable or sensitive ecosystems have been identified. Supported by the analysis showing that ambient air quality will not exceed NAAQS levels which are set with a margin of safety to ensure protection of public health and welfare, no significant adverse effects to soils, vegetation and visibility are expected. In addition, the State of Florida has adopted ambient air quality standards (which the proposed modification is not expected to violate) which provide an additional margin of safety over the Federal standards. Moreover, opacity from Unit 4 will be limited to 20 percent). On this basis, the applicant feels that the proposed modification poses no threat to the area's soils, vegetation or visibility. These same factors coupled with a 90 km distance apply to the Chassahowitzka Class I area which is not expected to be adversely affected.

V. Conclusion

EPA proposes a preliminary determination of approval with conditions for construction of the proposed steam electric generating station, PSD-FL-040, based upon the application dated September 21, 1979 and the additional information dated November 8, 1979, January 18, 1980, February 29, 1980 and July 8, 1980. The preliminary determination of approval is contingent upon the following conditions:

1. The proposed steam generating station shall be constructed and operated in accordance with the capacities and specifications of the application including the 425 megawatt generating capacity and the 4330 MMBtu/hr heat input rate.

2. Emissions shall not exceed the allowable emission limits listed in Table 5 for SO_2, NO_x, PM, and CO.

3. Compliance with the boiler allowable emission limits required in Condition 2 will be demonstrated with performance tests conducted in accordance with the provisions of 40 CFR 60.46a, 48a and 49a, including applicable test methods, sampling procedures, sample volumes, sampling periods, etc. Compliance with opacity limits on the limestone and flyash handling system baghouse, the limestone day silos and the flyash silos will be determined with EPA reference method 9 (Appendix A, 40 CFR 60). These facilities are exempted from mass emission rate compliance tests unless opacity limits are exceeded or the Administrator (or his representative) otherwise determines that such performance testing is required. All facilities will operate within 10 percent of maximum operating opacity during performance tests.

4. The applicant will install and maintain continuous monitoring and recording opacity meter, sulfur dioxide and nitrogen oxide analyzers and oxygen analyzer in accordance with the provisions of 40 CFR 60.47a.

5. To maintain compliance with the boiler CO allowable emissions limits required in Condition 2. The applicant will comply with the provisions of the attached condition "Use of Flue Gas Oxygen Meter as BACT for Combustion Controls."

6. The following requirements will be met to minimize fugitive emissions of particulate from the coal storage and handling facilities, the limestone storage and handling facilities, haul roads and general plant operations:

   a. All conveyors and conveyor transfer points will be enclosed to preclude PM emissions excepting the coal handling stacker reclaimer, the tail end conveyor feeding the tripper and the barge unloading belt which are exempted for feasibility considerations;

   b. Coal storage piles will be shaped, compacted and oriented to minimize wind erosion;

   c. Water sprays for storage piles, handling equipment etc., including the handling equipment exempted from the conveyor enclosure requirement, will be applied during dry periods and as necessary to all facilities to maintain opacity (determined with reference Method 9) below 20 percent;

   d. The limestone handling receiving hopper, transfer conveyors and day silos will be maintained at negative pressures with the exhaust vented to a control system; and

   e. The flyash handling system (including transfer and silo storage) will be maintained at negative pressures and vented to the control system.

7. Within 90 days of commencement of operations, the applicant will determine and submit to EPA the pH level in the scrubber effluent that will ensure 86% removal of the SO_2 in the flue gas. Moreover, the applicant is required to operate a continuous pH meter equipped with an upset alarm, to ensure that the pH level of the scrubber

effluent does not fall below this level. The minimum value pH may be revised at a later date provided notification to EPA is made demonstrating the minimum percent removal will be achieved on a continuous basis. Further, if compliance data show that higher FGD performance is necessary to maintain an overall system reduction of greater than or equal to 90% considering sulfur removal from coal washing and in flyash, a higher minimum pH value will be determined and maintained consistent with the required more stringent removal efficiency.

8. The applicant will perform post-construction continuous ambient monitoring of sulfur dioxide emissions in accordance with EPA Region IV policies and procedures and the guidance offered in "Ambient Monitoring Guidelines for Prevention of Significant Deterioration (PSD), EPA-450/2-78-019, May 1978 and the quality assurance procedures of 40 CFR 58 Appendix B. Such monitoring will be continued for a period of at least 1 year and until determined by the Administrator (or his representative) that the effects of the modification on ambient air quality have been quantified.

9. The applicant will comply with all requirements and provisions of the New Source Performance Standard for electric utility steam generating units (40 CFR 60 Part Da). In addition, the applicant must comply with the provisions and the requirements of the attached General Conditions.

10. While Tampa Electric Company has complied with the regulations entitling them to this PSD permit (40 CFR 52.21), this does not constitute an environmental endorsement of this permit nor does it in any way prejudge or predetermine the ongoing EIS review.

11. If it is determined through the NPDES permitting process or related EIS review, that cooling towers would be required for the construction and operation of the facility at this location, this permit would be revoked and a complete new application would be required addressing all new emissions and subsequent requirements for this new plant configuration.

12. The applicant must submit to EPA Region IV's Air Facility Branch within five (5) working days after it becomes available, copies of all technical data pertaining to the selected control devices, including formal bids from vendors, guaranteed efficiencies or emission rates. Although the type of control equipment described in the application has been determined by EPA to be adequate, EPA may, upon review of the data, disapprove the application if EPA determines the selected devices to be inadequate to meet the emission limits specified in this conditional approval.

GENERAL CONDITIONS

1. The permittee shall notify the permitting authority in writing of the beginning of construction of the permitted source within 30 days of such action and the estimated date of start-up of operation.

2. The permittee shall notify the permitting authority in writing of the actual start-up of the permitted source within 30 days of such action and the estimated date of demonstration of compliance as required in the specific conditions.

3. Each emission point for which an emission test method is established in this permit shall be tested in order to determine compliance with the emission limitations contained herein within sixty (60) days of achieving the maximum production rate, but in no event later than 180 days after initial start-up of the permitted source. The permittee shall notify the permitting authority of the scheduled date of compliance testing at least thirty (30) days in advance of such test. Compliance test results shall be submitted to the permitting authority within forty-five (45) days after the complete testing. The permittee shall provide (1) sampling ports adequate for test methods applicable to such facility, (2) safe sampling platforms, (3) safe access to sampling platforms, and (4) utilities for sampling and testing equipment.

4. The permittee shall retain records of all information resulting from monitoring activities and information indicating operating parameters as specified in the specific conditions of this permit for a minimum of two (2) years from the date of recording.

5. If, for any reason, the permittee does not comply with or will not be able to comply with the emission limitations specified in this permit, the permittee shall provide the permitting authority with the following information in writing within five (5) days of such conditions:

   (a) description of noncomplying emission(s),

   (b) cause of noncompliance,

   (c) anticipated time the noncompliance is expected to continue or, if corrected, the duration of the period of noncompliance,

   (d) steps taken by the permittee to reduce and eliminate the noncomplying emission,

   and

   (e) steps taken by the permittee to prevent recurrence of the noncomplying emission.

   Failure to provide the above information when appropriate shall constitute a violation of the terms and conditions of this permit. Submittal of this report does not constitute a waiver of the emission limitations contained within this permit.

6. Any change in the information submitted in the application regarding facility emissions or changes in the quantity or quality of materials processed that will result in new or increased emissions must be reported to the permitting authority. If appropriate, modifications to the permit may then be made by the permitting authority to reflect any necessary changes in the permit conditions. In no case are any new or increased emissions allowed that will cause violation of the emission limitations specified herein.

7. In the event of any change in control or ownership of the source described in the permit, the permittee shall notify the succeeding owner of the existence of this permit by letter and forward a copy of such letter to the permitting authority.

8. The permittee shall allow representatives of the State environmental control agency and/or representatives of the Environmental Protection Agency, upon the the presentation of credentials:

   (a) to enter upon the permittee's premises, or other premises under the control of the permittee, where an air pollutant source is located or in which any records are required to be kept under the terms and conditions of the permit;

   (b) to have access to and copy at reasonable times any records required to be kept under the terms and conditions of this permit, or the Act;

   (c) to inspect at reasonable times any monitoring equipment or monitoring method required in this permit;

   (d) to sample at reasonable times any emission of pollutants;

   and

   (e) to perform at reasonable times an operation and maintenance inspection of the permitted source.

9. All correspondence required to be submitted by this permit to the permitting agency shall be mailed to the:

   Chief, Air Facilities Branch
   Air and Hazardous Materials Division
   U.S. Environmental Protection Agency
   Region IV
   345 Courtland Street
   Atlanta, Georgia 30308

10. The conditions of this permit are severable, and if any provision of this permit, or the application of any provision of this permit to any circumstance, is held invalid, the application of such provision to other circumstances, and the remainder of this permit, shall not be affected thereby.

The emission of any pollutant more frequently or at a level in excess of that authorized by this permit shall constitute a violation of the terms and conditions of this permit.

USE OF FLUE GAS OXYGEN METER AS BACT FOR

COMBUSTION CONTROLS

Within the time limits specified in General Condition 3 of this permit, the permittee shall determine the emissions of nitrogen oxides and carbon monoxide from the permitted combustion device in accordance with test methods and procedures set out in 40 CFR Part 60, Appendix A, Methods 7 and 10 respectively. These emission determinations shall be made at:

1) Maximum design capacity; and

2) Normal operational load.

The permittee shall install a continuous oxygen monitor in the flue of the permitted combustion device which meets the requirements of 40 CFR Part 60, Appendix B, Performance Specification 3. Results of emission determinations shall be correlated to the flue gas oxygen content to define:

1) The point at which Nitrogen Oxides (NO_x) emissions (lb/MMBtu) equal the allowable NO_x emission rate contained in the permit or the appropriate emission factor found in the latest edition of AP-42, "Compilation of Air Pollution Emission Factors", whichever is lower; and

2) The point at which carbon monoxide (CO) emissions exceed either the allowable CO emission rate contained in the permit or the applicable CO emission factor found in AP-42 "Compilation of Air Pollution Emission Factors", whichever is lower.

The flue gas oxygen content shall be maintained between these points and alarms shall be set to sound when flue gas oxygen levels exceed either side of this range. Any operation outside of this range will constitute noncompliance with this specific condition, shall be recorded in accordance with General Condition 4 of this permit, and will be reported quarterly along with excess emissions in accordance with 40 CFR 60.7 (c).

Should any combustion equipment modifications be made, such as different type burners, combustion air relocation, fuel conversion, tube removal or addition, etc., emission determinations as described above shall be conducted within 90 days of attaining full operation after such modification. Results of all emission determinations shall be sent to the permitting authority within 90 days after completion of the tests.

(JRA:JLS:JBT 7/28/80)

TABLE 1

Emissions Summary

Pollutant	Significant Emissions Rate (tons/yr)	Potential Emissions[a] (tons/yr)
SO_2	40	11,949
PM	25	573[b]
NO_x	40	11,379
CO	100	6,267
VOC	40	9
Lead	0.6	c
Asbestos	0.007	c
Beryllium	0.0004	c
Mercury	0.1	c
Fluorides	3.0	c
Other	-	c

[a] Based on continuous maximum capacity operations and equal to the allowable emission rates specified in the conclusions section.

[b] Includes emissions from the boiler, the flyash system, and the coal and limestone handling systems.

[c] Emissions of lead and non-criteria regulated pollutants do not exceed 50 tons per year and are not subject to regulations under the State Implementation Plan or 40 CFR Part 60 and 61 for this source. For this reason, no PSD review requirements apply to these pollutants and detailed emissions estimates were not required.

Table 2

MAXIMUM AIR QUALITY IMPACTS (ug/m3)

	Averaging Time							
	Annual			24-Hour		8-Hour	3-Hour	1-Hour
	PM	SO_2	NO_x	PM	SO_2	CO	SO_2	CO
Boiler (Big Bend Unit 4)	<<1	1.0	0.5	0.9	34.2	<8[a]	163	<2000[a]
A. Limestone and Flyash Handling Systems (max. at distance of 0.3 km)[b]	0.33			4.11				
B. Boiler Maximum Impact at 0.5 km	negl.			0.001				
Combined maximum (A & B)	0.33			4.111				
Maximum Impact on Nonattainment Areas[c]	<<1	<<1		0.4	4.0		17.0	
Significance Levels	1	1	1	5	5	500	25	2000

[a] A 3-hour CO concentration of 8 ug/m^3 was estimated based on SO_2 short-term modeling results and a ratio of emission rates (CO/SO_2). Although the 1-hour concentration will exceed 8 ug/m^3, it will not exceed the significance level of 2000 ug/m^3.

[b] The limestone and flyash systems emissions were not modeled together with the boiler; however, maximum boiler contributions at 0.5 km (the shortest distance modeled) are combined as a conservative estimate to demonstrate that the modification as a whole is insignificant for PM. At 5km the handling system impact falls to below 0.13 (annual) and 0.9 (24-hour), thus insuring no significant interaction with the boiler.

[c] SO_2 non-attainment area - Pinellas County; PM non-attainment area - Hillsborough County (Tampa). This concentration was estimated based on a 1.2 lb/MMBtu emission rate for Unit 4.

Table 3

SO_2 INCREMENT IMPACTS [a]

	Averaging Time		
	Annual	24-Hour	8-Hour
Proposed Unit 4 (ug/m^3)	1.0	34.2	163
Proposed Unit 4 with Existing Units 1-3[b] (ug/m^3)	zero[b]	zero[b]	67.7
Unit 4 with All Interacting Sources (ug/m^3)	zero[b]	zero[b]	67.7
Allowable Increment (ug/m^3)	20	91	512

[a] Note that the proposed modification had an insignificant TSP impact, and therefore, a TSP increment analysis was not required.

[b] A reduction in actual emissions from Units 1-3 and other sources in the area occurred in 1977, thus expanding available increment.

TABLE 4

SULFUR DIOXIDE NAAQS IMPACTS[a]

	Annual (ug/m^3)	24-Hour (ug/m^3)	3-Hour (ug/m^3)
Proposed Unit 4	1.0	34.2	163
All Interacting Sources (Including Unit 4)	18.5	185[b]	1,087[b]
Background	20	20	20
Total	38.5	205	1,107
NAAQS Ceiling	80	365	1,300

[a] Unit 4 impacts of PM, NO_x and CO are insignificant and no detailed NAAQS analysis is required.

[b] Maximum impact occurs due to Units 1-4 only with a west to east wind. No other sources interact under these conditions.

TABLE 5

ALLOWABLE EMISSION LIMITS

Facility	SO_2 lb/MMBtu	SO_2 lb/hour	NO_x lb/MMBtu	NO_x lb/hr	PM lb/MMBtu	PM lb/hr	CO lb/MMBtu	CO lb/hr	Opacity
1. Unit 4 Boiler (4330 MMBtu/hr) Continuous Limit					0.03	130	0.014	61	20%[a]
30 Day Rolling Average	0.63	2728	0.6	2598					
2. Limestone and Flyash Handling System Baghouse						0.65[b]			5%
3. Limestone Day Silo						0.05[b]			5%
4. Flyash Silos						0.2[b]			5%

[a] Not to be exceeded for more than one six minute period per hour and never to exceed 27 percent opacity.

[b] Exempt from compliance testing provided opacity limit is maintained.