Florida Department of
Environmental Protection

Lawton Chiles
Governor

Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Virginia B. Wetherell
Secretary

December 20, 1993

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Ms. Jewell A. Harper
Air Enforcement Branch
U.S. EPA, Region IV
345 Courtland Street, NE
Atlanta, Georgia 30365

Dear Ms. Harper:

Re: Tampa Electric Company
260 MW Integrated Coal Gasification Combined Cycle Unit
Federal Number: PSD-FL-194
Site Certification Number: PA-92-32

Enclosed for your review and comment is a copy of the Technical Evaluation and Preliminary Determination for the above referenced project. Please submit any comments or questions within 30 days to Preston Lewis at the above address or call (904) 488-1344 at your earliest convenience.

Sincerely,

C. H. Fancy, P.E.
Chief
Bureau of Air Regulation

CHF/SA/bjb

Enclosure

cc: Bill Thomas, Southwest District
Chris Shaver, NPS
Greg Nelson, TECO

Technical Evaluation
and
Preliminary Determination

Tampa Electric Company
260 MW - Integrated Coal Gasification Combined Cycle Unit
Polk County, Florida

Permit No. PSD-FL-194
PA-92-32

Department of Environmental Protection
Division of Air Resources Management
Bureau of Air Regulation

December 20, 1993

State of Florida Department of Environmental Protection
Tampa Electric Company
Polk Power Station
Case No. PA92-32

I. INTRODUCTION

Pursuant to the Florida Power Plant Siting Act, Sections 403.501-519, Florida Statutes, the Tampa Electric Company (TECO) applied on July 30, 1992 for certification of 260 MW integrated coal gasification combined cycle (ICGC) unit at a site located in Southwest Polk County, Florida.

Filing of a complete application triggers an assessment process of environmental, socioeconomic, cultural and land-use impacts from construction and operation of the proposed unit. The electrical need for the unit may have already been determined at the time of site certification application filing, or the determination may be made concurrent with the impact assessment process. The Public Service Commission, pursuant to s. 403.519, F.S., is the determining body for need issues.

The Department of Environmental Protection (DEP) was made lead agency in the state impact assessment process and is responsible for preparation of the written analysis required by the Power Plant Siting Act. Both the Power Plant Siting Act and DEP's comparison rule, Chapter 17-23, F.A.C., identify the minimum criteria which must be studied in the review of the proposed electric generation facility. These include: Accessibility to transmission corridors, proximity to transportation systems, cooling systems requirements, soil and foundation conditions, impact on water supplied, impact on terrestrial and aquatic plant and animal life, impacts on air and water quality, impact on surrounding land uses, impact on public lands and submerged lands, impact on archaeological sites and historic preservation areas, construction and operational safeguards, "environmental" impacts (such as impacts from solid and hazardous waste disposal, noise, site modifications, wastewater disposal techniques, and meteorological changes) and, finally, site specific studies, which can address any feature not covered elsewhere.

While the majority of these studies are environmental in nature, some of the studies pertain to socioeconomics, archaeology, land-use planning, and other disciplines outside DEP's statutory charges. Accordingly, the Power Plant Siting Act (PPSA) also requires the participation of certain other state agencies.

The result of assessments is a set of specific conditions that must be met as a part of the certification process. The recommended Conditions of Certification for the TECO IGCC unit are part of the permit conditions.

II. SITE DESCRIPTION

A. Power Plant

The site for the proposed Polk Power Station consists of 4,348 acres, located 17.4 miles south of the City of Lakeland, 11.2 miles south of the City of Mulberry, 10.8 miles west of Fort Meade, 4.4 miles south of unincorporated Bradley Junction, and 13 miles southwest of the City of Bartow in southwest Polk County, Florida. The site is bordered by the Hillsborough County line along the western boundary; Fort Green Road on the east; County Road (CR) 630, Bethlehem, and Albritton Roads along the north; and State Road (SR) 674 and several phosphate clay settling ponds on the south. SR 37 bisects the property from the southwest to the northeast. The proposed location for the Polk Power Station is a remote area, and most of the property consists of land mined for phosphate or heavily impacted by phosphate mining activities. The majority of the site has been mined by the IMC-Agrico Company. The main power plant facilities will be located east of SR 37 on approximately 150 acres of unmined but disturbed land. The surrounding mined-out land to the east and south will be developed as a cooling reservoir with earthen berms, constructed from fill from phosphate mine cuts. The 1,511 acres to the west of SR 37 are currently being mined for phosphate matrix and will be reclaimed into wildlife habitat of uplands and wetlands. Some of the remaining land will be reclaimed pursuant to phosphate mining regulations, while other portions will be used as buffer and conservation areas. The main power plant facilities will be located in the central area of the portion of the site east of SR 37. The main power plant facilities will be located more than 2,500 feet away from offsite properties and more than 1.5 miles from residential areas to the west and 2.8 miles from residential areas to the southeast. A vegetated buffer area will be provided along public roadways surrounding the eastern portion of the site.

TECO proposes to construct and operate a nominal net 1,150 MW power plant, consisting of an IGCC facility, two additional combined cycle (CC) units, and six simple-cycle combustion turbines (CTs) fueled primarily by natural gas. The Polk Power Station will initially consist of a nominal net 190 MW combustion turbine (CT), a nominal net 70 MW HRSG, and coal gasification facilities, providing a total category of nominal net 260 MW of electric generating capacity. The coal gasification facilities will produce synthesis gas (syngas), which will be used to fuel the IGCC unit, with No. 2 fuel oil as the backup. Later facilities will consist of two nominal net 220 MW CC generating units and six stand-alone nominal net 75 MW CTs fueled primarily by natural gas, with low sulfur No. 2 fuel as a backup.

The Polk Power Station IGCC unit will consist of the following major systems: coal grinding and slurry preparation systems; an air separation unit; a gasification and syngas cooling system; slag handling and storage facilities; syngas scrubbing and cooling systems; a gasification process black water handling, grey water handling, and brine concentration system; an acid gas removal unit; a hot gas cleanup (HGCU) system; sulfuric acid by-product handling and storage facilities; and the power block.

Associated facilities will consist of the following: auxiliary boiler; access roadways and a rail spur; coal delivery, handling and storage facilities; natural gas and fuel oil delivery and storage facilities; propane unloading facilities; process, service, and potable water supply facilities; domestic and industrial wastewater treatment systems; cooling reservoir and discharge facilities; by-product slag and sulfuric acid handling temporary storage and shipping facilities; stormwater collection and management systems; a substation and associated electric transmission line facilities; and a wildlife management/corridor area.

Under an agreement with the Department of Energy (DOE), TECO will demonstrate the IGCC facility with a hot gas cleanup (HGCU) system for a two-year period to determine cost and performance of the HGCU system, as well as the overall integration of the coal gasification and combined cycle technologies. The demonstration project will be undertaken pursuant to the DOE's Clean Coal Technology Demonstration Program. The IGCC facilities will include an oxygen-blown, entrained-flow gasification system to produce syngas for the CT. The demonstration is expected to show that such facilities can achieve significant reductions of sulfur dioxide and nitrogen oxide emissions when compared to existing coal technologies. In an IGCC, coal is ground up and mixed with water, creating slurry, and then pumped into the gasifier, where it is mixed with high-purity oxygen, creating syngas. As the syngas exits the gasifier, it is cooled by syngas coolers, generating high pressure steam. The steam then flows to the combined cycle unit to generate electricity. The coal ash is water-cooled and exits from the bottom of the unit as slag, a by-product of the unit. The slag will later be sold for use in other industries. The syngas, after cooling, still contains particulates and sulfur compounds, which must first be removed in the gas cleanup system to meet environmental and CT fuel requirements. In a conventional IGCC system, the syngas is cooled prior to sulfur removal and then reheated prior to firing in the CT, a process known as cold gas cleanup (CGCU). As part of the demonstration project with the DOE, TECO will utilize a HGCU system, which cleans the syngas without first cooling it. HGCU systems are more efficient than CGCU systems. The Polk Power Station will utilize both HGCU and CGCU systems. The sulfuric acid resulting from sulfur removal will also be sold for use in other industries. IGCC facilities are among the cleanest and most efficient of the emerging clean coal technologies.

Roadway access to the main power facilities will be provided by two entrances on SR 37 and an entrance from Fort Green Road. All entrance roads will include appropriate improvements as necessary at the intersections with existing roadways. All entrance roads will have security gates to control access. A railroad spur will be constructed for the existing CSX Railroad line, which runs along the east side of Fort Green Road to the main power plant area for the delivery of construction materials, coal, large equipment, and other materials.

At the Polk Power Station, TECO will provide its own electricity, potable water, domestic and industrial wastewater treatment services, and brine storage services. Solid waste disposal services will be provided by licensed waste carriers/contractors serving the region.

TECO will be responsible for project management at the Polk Power Station and plans to incorporate security measures at the site, such as fencing, security gates at the entrances, and staffing. TECO expects a full-time staff for plant operations of approximately 130 workers for the initial IGCC unit and 210 workers at full buildout, to be drawn from the surrounding counties. The employees will undergo in-depth power plant training and safety programs sponsored by TECO.

B. <u>Description of Electrical Transmission Line Corridors</u>

Four 230-kV electric transmission circuits will be needed to connect the Polk Power Station with the TECO and Florida transmission grid. Two of the circuits will run northeast from the onsite Polk Power Station Substation to interconnect with TECO's existing Hardee Power Station-Pebbledale 230 kV transmission line, adjacent to the Polk Power Station site along Fort Green Road. The corridor for these two circuits will be located within the site boundaries. The other two circuits will run west from the onsite substation to SR 37, then north along SR 37 approximately 5 miles to interconnect with TECO's existing Mines-Pebbledale 230-kV transmission line at a point to the west of the community of Bradley Junction. These two circuits will be located within a new 5.2-mile corridor adjacent to SR 37, ranging in width from 0.5 to 1.0 mile. To the extent feasible, TECO will avoid guyed transmission line structures in any residential areas and will locate the linear facilities within existing utility rights-of-way and away from residences, schools, and places of employment.

III. AMBIENT AIR QUALITY ANALYSIS FOR TECO POLK POWER STATION

A. Introduction

The proposed Tampa Electric Company Polk Power Station site is located approximately 17 miles south of the City of Lakeland, approximately 11 miles south of the City of Mulberry, and approximately 13 miles southwest of the City of Bartow in southwest Polk County, Florida.

The applicant's proposed maximum annual emissions, along with the prevention of significant deterioration (PSD) significant emission rates, are presented in Table 1. As presented in Table 1, PSD review was required for the pollutants carbon monoxide (CO), nitrogen oxides (NO_x), sulfur dioxide (SO_2), particulate matter (PM_{10}), total suspended particulates (TSP), volatile organic compounds (VOC), beryllium (Be), sulfuric acid mist (H_2SO_4), lead (Pb) and mercury (Hg). In addition to the PSD pollutants, the project will also emit several air contaminants considered to be air toxics by the Department, which are also presented in Table 1.

As part of the PSD review process, the Department reviewed analyses on existing air quality, PSD increment consumption (Class I and II areas), ambient air quality standards (AAQS), soils, vegetation and wildlife impacts, visibility, growth-related air quality impacts, and proposed stack heights. In addition, an air toxics analysis was conducted in accordance with the Department's draft "Air Toxics Guidelines".

B. Modeling Methodology

In support of the PSD permit application, the applicant was required to demonstrate to the Department that the proposed project would not cause or contribute to an exceedance of any federal or state AAQS, PSD increment, visibility limit of Florida Ambient Reference Concentration (Department's draft "Air Toxics Guidelines"). These demonstrations were conducted by dispersion modeling techniques approved by the Department.

For emissions from combustion turbines (CT's) and combined cycle units, operating load and ambient temperature can affect plume dispersion, and therefore, ground-level impacts. For each fuel (oil, syngas with 100% cold gas cleanup, and syngas with 50% hot gas cleanup and 50% cold gas cleanup), two or three operating load cases (100%, 75%, and 50%) at three ambient temperatures (20 F, 59 F, and 90 F) were analyzed at the screening level. The model used was SCREEN, an EPA-approved model. The load/temperature case shown in the screening analysis to cause the highest impacts for each source were used in the refined modeling analysis (See application Volume 4, Tables 7-1 through 7-7).

For estimating ambient impacts on air quality from the proposed project, the applicant used the refined Industrial Source Complex (ISC2) dispersion models and the MESOPUFF-II long-range transport model. ISCLT2 was used for annual and quarterly computations, while ISCST2 was used for short-term concentrations. The applicant's choice of models for compliance demonstration purposes was acceptable to the Department. In conducting the ISC modeling, the applicant applied the model's building downwash option, the rural dispersion option, and chose the regulatory default option, which are all acceptable to the Department.

The applicant modeled the proposed project's ambient impacts at the nearest PSD Class I area (Chassahowitzka National Wilderness Area), located approximately 120 km to the Northwest as well as the area surrounding the Polk County Site. The MESOPUFF-II model was used in conjunction with the ISCST2 model, to address impacts in the PSD Class I area. The methodology used to run the MESOPUFF-II model is discussed in detail in Section 9.0 of the original application.

Initial modeling used the SCREEN model. For this model the receptor grid started at 1000 meters, since this distance approximates the distance between the proposed sources and the nearest property line. For the refined modeling, discrete receptors were places at the property boundary. Receptor rings were placed at distances beginning at 2000 meters; note that for the 2000 meter ring receptors at 40, 100, 110, 120, 140, 190, 200, 210, 220, 230, 240, and 250 degree radials fell within the property boundary. Receptor rings were placed at distances of 2000, 2500, 3000, 3500, 4000, 5000, 6000, 7000, 8000, 9000, 10,000, 12,500, 15,000, 17,500, 20,000, 22,500, 25,000, 27,500, 30,000, 32,500, 35,000, 40,000, 45,000, and 50,000 from the grid center.

For the ISCST2 model, meteorological data used by the applicant was supplied by the Department in the form of hourly preprocessed National Weather Service (NWS) data from Tampa, Florida and twice-daily upper air soundings from Ruskin, Florida, for the five years 1982 through 1986. For the ISCLT2 model, the applicant used Tampa STAR (STability ARray) data for the same period.

The applicant's proposed maximum annual emissions are summarized in Table 1. All sources of SO_2, NO_x and TSP associated with the Polk County Site are considered "increment consuming" in relation to the PSD Class I and II areas.

C. Analysis of Existing Air Quality

The proposed project will be located in a PSD Class II area currently classified as attainment for all criteria pollutants, except PM_{10}, by both the U.S. Environmental Protection Agency (EPA) and the Department. The entire state is unclassified for PM_{10}.

For each pollutant identified in Table 1 as having a significant emission rate (with the exception of volatile organic compounds and sulfuric acid mist), the applicant determined the highest annual or quarterly predicted impact or the highest and second-highest predicted ambient impacts for shorter time periods, using the ISCST dispersion models. The results of the applicant's modeling exercise, as well as the Department's significant impact levels and de minimis levels are presented in Table 2. Volatile organic compounds, an ozone precursor, can not be adequately modeled at present and are addressed in the BACT determination. Sulfuric acid mist was modeled. The results of this modeling are presented in Section VI. Air Toxics Analysis.

The applicant's modeling revealed SO_2, NO_2 and PM_{10} as the only pollutants for which a predicted off-site impact was greater than the significant impact level.

The applicant was required to establish an ambient air monitoring program for SO_2, PM_{10} and ozone (O_3) based on a comparison with the de minimis levels established by the Department.

D. PSD Increment Analyses (NO_2, TSP and SO_2)

i. Class I Area

The Polk Power Station is approximately 120 km from the nearest PSD Class I area (Chassahowizka National Wilderness Area). Prior to receiving a PSD permit the applicant must demonstrate to the Department that the proposed project will not "cause or contribute" to an violation of a PSD Class I increment. The ISCST2 and MESOPUFF-II models were used to estimate the impacts on the Class I area. The applicant's predicted ambient impacts of the proposed project on the PSD Class I area revealed NO_2, PM_{10} and SO_2 as having significant impacts (significant as defined by the values suggested by the National Park Service and the U.S. Fish and Wildlife Service). This analysis, including other increment-consuming sources, revealed that no allowable PSD Class I increment was exceeded (Table 3).

ii. Class II Area

The applicant's significant impact area analysis (Table 2) identified SO_2, NO_2 and PM_{10} as the only pollutants having an off-site significant impact. The modeling analysis performed by the applicant revealed predicted ambient impacts from all PSD sources including the Polk Power Station to be within the allowable PSD Class II increments for these pollutants. The results of analysis are presented in Table 4.

E. AAQS Analysis

Background air quality concentrations were based on information contained in the Department's 1992 air quality data base and information collected from an on-site air monitoring station. The applicant provided on-site monitoring for SO_2, PM_{10} and ozone during the period 3/91 through 3/92. The background concentrations are presented in Table 5.

The applicant's maximum predicted SO_2, NO_2 and PM_{10} concentrations in the vicinity of the Polk Power Station are presented in Table 5. The maximum concentrations represent the sum of the applicant's proposed project impacts, the modeled impacts of other nearby sources and the monitored background concentrations. The sum of these concentrations is below both the federal and state AAQS. Since the project's impacts for lead and CO were not significant, it was not required that other sources of these pollutants be modeled. However, the project's impacts plus a background concentration is provided in Table 5 for informational purposes.

Ozone cannot be explicitly modeled. However, the Department has addressed ozone via BACT for volatile organic compounds and nitrogen oxides. The maximum hourly concentration of ozone measured by the applicant's required pre-construction monitor near the proposed construction site was below the ambient air quality standard of .120 ppm for ozone.

F. Air Toxics Analysis

The applicant's predicted ambient air quality impact of various trace metals are contained in Table 6. A comparison of the predicted impacts versus the Department's draft "Air Toxics Guidelines" reveals that the project's maximum impacts are less than the Florida Ambient Reference Concentrations.

G. Additional Impact Analysis

Potential impacts of the proposed project on the vegetation, soils, and wildlife of the PSD Class I area were examined by the applicant. The applicant compared maximum concentrations with values described in the literature as having adverse impacts on the various vegetation, soils, and/or wildlife near the proposed facility. Based on this analysis, predicted impacts from the proposed facility are not expected to result in any harm or damage to the vegetation, soils, and/or wildlife of the PSD Class I area.

In addition to the analysis on impacts to vegetation, soils, and wildlife, the applicant also examined the impact of the proposed project on the visibility of the PSD Class I area. In this analysis, the applicant used the VISCREEN computer model which reported impact values inside the Class I area that were well below the screening thresholds. Therefore, emissions from this facility are not expected to cause impairment of visibility in the Class I area.

Growth-related air quality impacts associated with the project were examined by the applicant. The analysis addressed impacts resulting from industrial, commercial and residential growth in the vicinity of the Polk County Site potentially associated with the project. The analysis addressed only growth which would be considered permanent. In the analysis, the applicant projected a population increase of approximately 310 people, by 2010, into the area. This projected increase represents much less than 1 percent of the population of Polk County as reported in 1990. The applicant anticipates no air quality impacts due to associated industrial/commercial growth since existing infrastructure should be more than adequate to provide the necessary services.

The applicant also performed an analysis of impacts on soils and vegetation, and visibility impairment potential for the region immediately surrounding the proposed facility. The results of these analyses suggest that the proposed facility will not have a significant adverse impact on soils and vegetation, or significantly contribute to any visibility degradation.

The applicant addressed the Department's stack height policy (Rule 17-2.270, F.A.C.) by use of the Bowman GEP computer modeling program for downwash analysis. As designed, the applicant's proposed stack heights are within the requirements of the stack height policy.

IV. Conclusion

Based on the information presented by the applicant in the above analysis, the Department has been provided reasonable assurances that the proposed project as described in the applicant and subject to the conditions of approval proposed herein will not cause or contribute to any violation of any PSD increment or ambient air quality standard.

Note: Subsequent to the initial analysis, described in this report, the applicant made some revisions in plant design. The effects of these changes on air quality were reviewed by the Department. In general, air quality impacts decreased, with the single exception of PM_{10} for the 24-hour averaging period. The modeled increase in PM_{10} was minor (approximately 3 ug/m^3) and not considered significant in light of the conservative assumptions used in determining PM_{10} impacts.

Therefore, the Department has reasonable assurance that the revised project will not cause or significantly contribute to any violation of any PSD increment or air quality standard.

12/16/93

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Therefore, the Department has reasonable assurance that the revised project will not cause or significantly contribute to any violation of any PSD increment or air quality standard.

D. [illegible] 12/16/93

TABLE 1

TECO POLK POWER STATION
MAXIMUM POTENTIAL ANNUAL EMISSIONS
AND PSD SIGNIFICANCE VALUES

Pollutant	Proposed Maximum Emissions (TPY)(1)	PSD Significant Emission Rate (TPY)	PSD Review Required (Yes/No)
Carbon Monoxide	2526	100	Yes
Nitrogen Oxides	5250	40	Yes
Sulfur Dioxide	3917	40	Yes
Particulate Matter (PM_{10})	917	15	Yes
Total Suspended Particulates (TSP)	917	25	Yes
Volatile Organic Compounds	394	40	Yes
Lead	0.6	0.6	Yes
Asbestos	0.0	10	No
Beryllium	.03	0.0004	Yes
Mercury	0.5	0.1	Yes
Vinyl Chloride	0.0	1	No
Total Fluorides	1.2	3	No
Sulfuric Acid Mist	393	7	Yes
Hydrogen Sulfide	7.1	10	No
Total Reduced Sulfur	7.1	10	No
Arsenic	.52	NA	NA
Cadmium	.18	NA	NA
Chromium	1.5	NA	NA

(1) Emissions include the highest annual emission estimates from the 7F CT, plus other related combustion emissions (e.g., thermal oxidizer), plus other associated process and fugitive emissions, plus four stand-alone CT's in CC mode, plus six stand-alone CT's in simple-cycle mode.

TPY = Tons per year.
NA = Not Applicable.

TABLE 2

TECO POLK POWER STATION
MAXIMUM AIR QUALITY IMPACTS FOR COMPARISON TO THE SIGNIFICANT IMPACT AND DE MINIMUS AMBIENT LEVELS

Pollutant	Averaging Time	Highest Predicted Impact ($\mu g/m^3$)	Highest, Second-Highest Predicted Impact ($\mu g/m^3$)	Sign. Impact Level ($\mu g/m^3$)	De Minimus Level ($\mu g/m^3$)
Carbon Monoxide	1-hour 8-hour	169.2 67.1	168.1 63.3	2000 500	NA 575
Nitrogen Dioxide	Annual	1.8	NA	1.0	14
Sulfur Dioxide	3-hour 24-hour Annual	68.6 19.0 1.6	51.7 18.1 NA	25 5 1	NA 13 NA
PM_{10} or TSP	24-hour Annual	29.4 1.5	24.6 NA	5 1	10 NA
Lead	Quarterly	.0018	NA	NA	.1
VOC's	Annual	394 TPY	NA	NA	100 TPY
Beryllium	24-hour	.00075	.00069	NA	.001
Mercury	24-hour	.005	.004	NA	.25

TABLE 3

TECO POLK POWER STATION
PSD CLASS I AREA INCREMENT ANALYSIS

Pollutant	Averaging Time	Maximum Predicted Impact ($\mu g/m^3$)	PSD Class I Increment ($\mu g/m^3$)
Sulfur Dioxide	3-hour 24-hour Annual	12.9 3.8 0.4	25 5 2
Nitrogen Dioxide	Annual	0.8	2.5
TSP	24-hour Annual	5.7 1.1	10 5

Note: Maximum short-term values less than annual concentrations are highest, second-highest values.

TABLE 4

TECO POLK POWER STATION
PSD CLASS II AREA INCREMENT ANALYSIS

Pollutant	Averaging Time	Maximum Predicted Impact ($\mu g/m^3$)	PSD Class II Increment ($\mu g/m^3$)
Sulfur Dioxide	3-hour 24-hour Annual	104.0 27.0 0.0	512 91 20
Nitrogen Dioxide	Annual	3.3	25
TSP	24-hour Annual	31.8 5.4	37 19

Notes: Maximum short-term values less than annual concentrations are highest, second-highest values.

Increment consumption for the annual average of sulfur dioxide was negative over the entire receptor grid.

TABLE 5

TECO POLK POWER STATION
AMBIENT AIR QUALITY STANDARDS (AAQS) ANALYSIS

Pollutant	Averaging Time	Modeled Impact ($\mu g/m^3$)	Backgrnd. Conc. ($\mu g/m^3$)	Total Impact ($\mu g/m^3$)	Florida AAQS ($\mu g/m^3$)
Sulfur Dioxide	3-hour 24-hour Annual	616.1 213.7 40.4	26 13 5	642.1 226.7 45.4	1300 260 60
Nitrogen Dioxide	Annual	5.9	19	24.9	100
PM_{10}	24-hour Annual	101.5 15.4	45.4 18.4	146.9 33.8	150 50
Lead	Quarterly	.0018	0.0	.0018	1.5
Carbon Monoxide	1-hour 8-hour	168.1 63.3	8015 4580	8183.1 4643.3	40,000 10,000

Notes: Maximum short-term values less than annual concentrations are highest, second-highest values.

Sulfur dioxide and PM_{10} background concentrations obtained from TECO AQ1 monitoring station (3/91 - 3/92).

Nitrogen dioxide background value obtained from FDER site 4360-065 located in Hillsborough County (1992).

Carbon monoxide background values obtained from FDER site 4360-060 located in Hillsborough County (1992).

TABLE 6

TECO POLK POWER STATION
AIR TOXICS IMPACT ANALYSIS

Pollutant	Averaging Time	Maximum Impact ($\mu g/m^3$)	Florida Ambient Reference Concentration ($\mu g/m^3$)
Sulfuric Acid	8-hour 24-hour	3.76 1.64	10 2.4
Fluorides	1-hour	0.06	25
Mercury	8-hour 24-hour	0.011 0.0048	0.1 0.024
Beryllium	Annual	0.00006	0.0004
Arsenic	Annual	0.00019	0.0002
Cadmium	Annual	0.000126	0.00056
Chromium	Annual	0.000062	0.000083

Florida Department of
Environmental Protection

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Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Virginia B. Wetherell
Secretary

PERMITTEE:
Tampa Electric Company
702 North Franklin Street
Tampa, Florida 33602

Permit Number: PA-92-32
PSD-FL-194
Expiration Date: June 1, 1996
County: Polk
Latitude/Longitude: 27°43'43"N
81°59'23"W
Project: 260 MW Integrated Coal Gasification Combined Cycle Combustion Turbine

This permit is issued under the provisions of Chapter 403, Florida Statutes, and Florida Administrative Code Chapters 17-212 and 17-4. The above named permittee is hereby authorized to perform the work or operate the facility shown on the application and approved drawings, plans, and other documents attached hereto or on file with the Department and specifically described as follows:

For one 260 MW integrated coal gasification combined cycle (IGCC) combustion turbine (GE 7F CT or equivalent) with maximum heat input at 59°F of 1,755 MMBtu/hr (syngas) and 1765 MMBtu/hr (oil) to be located at the Polk County site near Bowling Green, Florida. The coal gasification facility will consist of coal receiving, storage and process facilities, air separation unit, gasifier, product gas cleaning facilities, acid gas removal unit, and auxiliary equipment. The first phase will also include a 49.5 MMBtu/hr auxiliary boiler and a 71,450 barrel fuel oil storage tank.

The source shall be constructed in accordance with the permit application, plans, documents, amendments and drawings, except as otherwise noted in the General and Specific Conditions.

Attachments are listed below:

1. Tampa Electric Company (TECO) application received July 30, 1992.
2. Department's letter dated September 22, 1992.
3. TECO's letter dated April 12, 1993.

GENERAL CONDITIONS:

1. The terms, conditions, requirements, limitations, and restrictions set forth in this permit are "Permit Conditions" and are binding and enforceable pursuant to Sections 403.161, 403.727, or 403.859 through 403.861, Florida Statutes. The permittee is placed on notice that the Department will review this permit periodically and may initiate enforcement action for any violation of these conditions.

2. This permit is valid only for the specific processes and operations applied for and indicated in the approved drawings or exhibits. Any unauthorized deviation from the approved drawings, exhibits, specifications, or conditions of this permit may constitute grounds for revocation and enforcement action by the Department.

3. As provided in Subsections 403.087(6) and 403.722(5), Florida Statutes, the issuance of this permit does not convey any vested rights or any exclusive privileges. Neither does it authorize any injury to public or private property or any invasion of personal rights, nor any infringement of federal, state or local laws or regulations. This permit is not a waiver of or approval of any other Department permit that may be required for other aspects of the total project which are not addressed in the permit.

4. This permit conveys no title to land or water, does not constitute State recognition or acknowledgement of title, and does not constitute authority for the use of submerged lands unless herein provided and the necessary title or leasehold interests have been obtained from the State. Only the Trustees of the Internal Improvement Trust Fund may express State opinion as to title.

5. This permit does not relieve the permittee from liability for harm or injury to human health or welfare, animal, or plant life, or property caused by the construction or operation of this permitted source, or from penalties therefore; nor does it allow the permittee to cause pollution in contravention of Florida Statutes and Department rules, unless specifically authorized by an order from the Department.

6. The permittee shall properly operate and maintain the facility and systems of treatment and control (and related appurtenances) that are installed or used by the permittee to achieve compliance with the conditions of this permit, as required by Department rules. This provision includes the operation of backup or auxiliary facilities or similar systems when necessary to achieve compliance with the conditions of the permit and when required by Department rules.

GENERAL CONDITIONS:

7. The permittee, by accepting this permit, specifically agrees to allow authorized Department personnel, upon presentation of credentials or other documents as may be required by law and at a reasonable time, access to the premises, where the permitted activity is located or conducted to:

   a. Have access to and copy any records that must be kept under the conditions of the permit;

   b. Inspect the facility, equipment, practices, or operations regulated or required under this permit; and

   c. Sample or monitor any substances or parameters at any location reasonably necessary to assure compliance with this permit or Department rules.

Reasonable time may depend on the nature of the concern being investigated.

8. If, for any reason, the permittee does not comply with or will be unable to comply with any condition or limitation specified in this permit, the permittee shall immediately provide the Department with the following information:

   a. A description of and cause of non-compliance; and

   b. The period of noncompliance, including dates and times; or, if not corrected, the anticipated time the non-compliance is expected to continue, and steps being taken to reduce, eliminate, and prevent recurrence of the non-compliance.

The permittee shall be responsible for any and all damages which may result and may be subject to enforcement action by the Department for penalties or for revocation of this permit.

9. In accepting this permit, the permittee understands and agrees that all records, notes, monitoring data and other information relating to the construction or operation of this permitted source which are submitted to the Department may be used by the Department as evidence in any enforcement case involving the permitted source arising under the Florida Statutes or Department rules, except where such use is prescribed by Sections 403.73 and 403.111, Florida Statutes. Such evidence shall only be used to the extent it is consistent with the Florida Rules of Civil Procedure and appropriate evidentiary rules.

GENERAL CONDITIONS:

10. The permittee agrees to comply with changes in Department rules and Florida Statutes after a reasonable time for compliance, provided, however, the permittee does not waive any other rights granted by Florida Statutes or Department rules.

11. This permit is transferable only upon Department approval in accordance with Florida Administrative Code Rules 17-4.120 and 17-730.300, F.A.C., as applicable. The permittee shall be liable for any non-compliance of the permitted activity until the transfer is approved by the Department.

12. This permit or a copy thereof shall be kept at the work site of the permitted activity.

13. This permit also constitutes:

(X) Determination of Best Available Control Technology (BACT)
(X) Determination of Prevention of Significant Deterioration (PSD)
(X) Compliance with New Source Performance Standards (NSPS)

14. The permittee shall comply with the following:

a. Upon request, the permittee shall furnish all records and plans required under Department rules. During enforcement actions, the retention period for all records will be extended automatically unless otherwise stipulated by the Department.

b. The permittee shall hold at the facility or other location designated by this permit records of all monitoring information (including all calibration and maintenance records and all original strip chart recordings for continuous monitoring instrumentation) required by the permit, copies of all reports required by this permit, and records of all data used to complete the application for this permit. These materials shall be retained at least three years from the date of the sample, measurement, report, or application unless otherwise specified by Department rule.

GENERAL CONDITIONS:

c. Records of monitoring information shall include:

- the date, exact place, and time of sampling or measurements;
- the person responsible for performing the sampling or measurements;
- the dates analyses were performed;
- the person responsible for performing the analyses;
- the analytical techniques or methods used; and
- the results of such analyses.

15. When requested by the Department, the permittee shall within a reasonable time furnish any information required by law which is needed to determine compliance with the permit. If the permittee becomes aware that relevant facts were not submitted or were incorrect in the permit application or in any report to the Department, such facts or information shall be corrected promptly.

SPECIFIC CONDITIONS:

A. Operation and Construction

The construction and operation of Polk Power Station (Project) shall be in accordance with all applicable provisions of Chapter 17, F.A.C. The following emission limitations reflect final BACT determinations for Phase I (integrated gasification, combined cycle (IGCC) combustion turbine and auxiliary equipment) of the project fired with syngas or fuel oil. BACT determinations for the remaining phases will be made upon review of supplemental applications. In addition to the foregoing, the Project shall comply with the following conditions of certification as indicated.

B. Heat Input

The maximum heat input to the IGCC combustion turbine (CT) shall neither exceed 1,755 MMBtu/hr while firing syngas, nor 1765 MMBtu/hr while firing No. 2 fuel oil at an ambient temperature of 59° F. Heat input may vary depending on ambient conditions and the CT characteristics. Manufacturer's curves for the heat input correction to other temperatures shall be provided to DEP for review 120 days after the siting board approval of the site certification. Subject to approval by the Department, the manufacturer's curve may be used to establish heat input rates over a range of temperature for the purpose of compliance determination.

SPECIFIC CONDITIONS:

C. Hours of Operation

The IGCC unit in Phase I may operate continuously, i.e., 8,760 hrs/year.

D. Fuel

Only syngas and low sulfur fuel oil shall be fired in the IGCC combustion turbine. Only low sulfur fuel oil shall be fired in the auxiliary boiler. The maximum sulfur content of the low sulfur fuel oil shall not exceed 0.05 percent, by weight.

E. Auxiliary Boiler

The maximum heat input to the auxiliary boiler shall not exceed 49.5 MMBtu/hr when firing No. 2 fuel oil with 0.05 percent maximum sulfur content (by weight). All fuel consumption must be continuously measured and recorded for the auxiliary boiler.

F. Fuel Consumption

The maximum coal input to the coal gasification plant shall not exceed 2,325 tons per day, on a dry basis.

G. Fugitive Dust

Fugitive dust emissions during the construction period shall be minimized by covering or watering dust generation areas. Particulate emissions from the coal handling shall be controlled by enclosing all conveyors and conveyor transfer points (except those directly associated with the coal stacker/reclaimer for which an enclosure is operationally infeasible). Fugitive emissions shall be tested as specified in Specific Condition No. J. Inactive coal storage piles shall be shaped, compacted, and oriented to minimize wind erosion. Water sprays or chemical wetting agents and stabilizers shall be applied to uncovered storage piles, roads, handling equipment, etc. during dry periods and, as necessary, to all facilities to maintain an opacity of less than or equal to five percent. When adding, moving or removing coal from the coal pile, an opacity of 20 percent is allowed.

SPECIFIC CONDITIONS:

H. Emission Limits

1. The maximum allowable emissions from the IGCC combustion turbine, when firing syngas and low sulfur fuel oil, in accordance with the BACT determination, shall not exceed the following:

POLLUTANT	FUEL	BASIS[a]	EMISSIONS LIMITATIONS - 7F CT Post Demonstration Period LB/HR*	TPY[b]
NOx	Oil	42 ppmvd**	311	N/A
	Syngas	25 ppmvd	222.5	1,044
VOC[c]	Oil	0.028 lb/MMBtu	32	N/A
	Syngas	0.0017 lb/MMBtu	3	38.5
CO	Oil	40 ppmvd	99	N/A
	Syngas	25 ppmvd	98	430.1
PM/PM_{10}[d]	Oil	0.009 lb/MMBtu	17	N/A
	Syngas	0.013 lb/MMBtu	17	74.5
Pb	Oil	5.30E-5 lb/MMBtu	0.101	N/A
	Syngas	2.41E-6 lb/MMBtu	0.0035	0.067
SO_2	Oil	0.048 lb/MMBtu	92.2	N/A
	Syngas	0.17 lb/MMBtu	357	1563.7
Visible Emissions	Syngas	10 percent opacity		
	Oil	20 percent opacity		

(*) Emission limitations in lbs/hr are 30-day rolling averages. "Pollutant emission rates may vary depending on ambient conditions and the CT characteristics. Manufacturer's curves for the emission rate correction to other temperatures at different loads shall be provided to DEP for review 120 days after the siting board approval of the site certification. Subject to approval by the Department, the manufacturer's curve may be used to establish pollutant emission rates over a range of temperature for the purpose of compliance determination."

(**) The emission limit for NO_x is adjusted as follows for higher fuel bound nitrogen contents up to a maximum of 0.030 percent by weight:

SPECIFIC CONDITIONS:

FUEL BOUND NITROGEN (% by weight)	NO_x EMISSION LEVELS (ppmvd @ 15% O_2)
0.015 or less	42
0.020	44
0.025	46
0.030	48

using the formula STD = 0.0042 + F where:

STD = allowable NO_x emissions (% by volume at 15% O_2 and on a dry basis).

F = NO_x emission allowance for FBN defined by the following table:

FUEL BOUND NITROGEN (% by weight)	F (NO_x % BY VOLUME)
0 < N < 0.015	0
0.015 < N < 0.03	0.04 (N-0.015)

N = nitrogen content of the fuel (% by weight).

NO_x emissions are preliminary for the fuel oil specified in Specific Condition XIII.C of Conditions of Certification. The permittee shall submit fuel bound nitrogen content data for the low sulfur fuel oil prior to commercial operation to the Bureau of Air Regulation in Tallahassee, and on each occasion that fuel oil is transferred to the storage tanks from any other source to the Southwest District office in Tampa. The % FBN (Z) following each delivery of fuel shall be determined by the following equation:

x(Y) + m(n) = (x+m) (Z)
where x = amount fuel in storage tank
y = % FBN in storage tank
m = amount fuel added
n = % FBN of fuel added
Z = % FBN of composite

(a) Syngas lb/MMBtu values based on heat input (HHV) to coal gasifier and includes emissions from H_2SO_4 plant thermal oxidizer. Pollutant concentrations in ppmvd are corrected to 15% oxygen.

(b) Annual emission limits (TPY) based on 10 percent annual capacity factor firing fuel oil.

$\frac{\text{Load (\%)}}{100}$ x hours of operation $\leq$ 876 for fuel oil.

SPECIFIC CONDITIONS:

(c) Exclusive of background concentrations.

(d) Excluding sulfuric acid mist.

2. The maximum allowable emissions from the IGCC combustion turbine, when firing syngas and No. 2 fuel oil **during the two year demonstration period**, shall not exceed the following:

		EMISSIONS LIMITATIONS 7FCT	
POLLUTANT	**FUEL**	**LB/HR***	**TPY[a]**
NO_x	Oil	311	N/A
	Syngas	664.2	2,908.3
VOC[b]	Oil	32	N/A
	Syngas	3	38.5
CO	Oil	99	N/A
	Syngas	99	430.1
PM/PM_{10}[c]	Oil	17	N/A
	Syngas	17	74.5
Pb	Oil	0.101	N/A
	Syngas	0.023	0.13
SO_2	Oil	92.2	N/A
	Syngas	518	2,269
Visible Emissions		Syngas 10 percent opacity	
		Oil 20 percent opacity	

(*) Emission limitations in lbs/hr are 30-day rolling averages.

(a) Annual emission limits (TPY) based on 10-percent annual capacity factor firing No. 2 fuel oil.

$$\frac{\text{Load (\%)}}{100} \times \text{hours of operation} \leq 876 \text{ for oil.}$$

(b) Exclusive of background concentrations.

(c) Excluding sulfuric acid mist.

SPECIFIC CONDITIONS:

3. The following allowable turbine emissions, were determined by BACT, and are also tabulated for PSD and inventory purposes:

ALLOWABLE EMISSIONS

		IGCC POST DEMONSTRATION		IGCC 2-YEAR DEMONSTRATION	
POLLUTANT	FUEL	LB/HR	TPY[a]	LB/HR	TPY[b]
Sulfuric Acid[c]	Syngas	55	241	55	241
Inorganic Arsenic	Syngas	0.0006	0.019	0.08	0.35
Beryllium	Syngas	0.0001	0.0029	0.0001	0.0029
Mercury	Syngas	0.0034	0.017	0.025	0.11

(a) Based on baseload operations firing syngas, with emission rates equivalent to 100 percent CGCU operations; up to 10 percent annual capacity factor firing fuel oil.

(b) Based on baseload operations firing syngas, with a maximum of 8760 hrs/yr of HGCU operations; up to 10 percent annual capacity factor firing fuel oil.

(c) Sulfuric acid mist emissions assume a maximum of 0.05 percent sulfur in the fuel oil.

4. Excess emissions from the turbine resulting from startup, shutdown, malfunction, or load change shall be acceptable providing (1) best operational practices to minimize emissions are adhered to and (2) the duration of excess emissions shall be minimized but in no case exceed two hours in any 24-hour period unless specifically authorized by the Department for a longer duration. Best operating practices shall be documented in writing and a copy submitted to the Department along with the initial compliance test data. The document may be updated as needed with all updates submitted to the Department within thirty (30) days of implementation and shall include time limitations on excess emissions caused by turbine startup.

5. After the demonstration period, permittee shall operate the combustion turbine to achieve the lowest possible NO_x emission limit but shall not exceed 25 ppmvd corrected to 15% oxygen and ISO conditions.

SPECIFIC CONDITIONS:

6. The combustion turbine will be operated for 12-18 months after the demonstration period (estimated to be from Mid 1998 until December 31, 1999). During that period NO_X emission testing will be performed on the turbine at a regular interval of every 2 months. The Department shall be provided with a test protocol including a time schedule 15 days prior to the initial test. The permittee will provide the Department the emission test results 30 days after the test is performed. These results are not for compliance purposes. The Department shall be notified and the reasons provided if a scheduled test is delayed or canceled.

7. One month after the test period ends (estimated to be by February 2000), the permittee will submit to the Department a NO_X recommended BACT Determination as if it were a new source using the data gathered on this facility, other similar facilities and the manufacturer's research. The Department will make a determination on the BACT for NO_X only and adjust the NO_X emission limits accordingly.

I. Auxiliary Boiler Operation

Operation of the auxiliary boiler shall be limited to a maximum of 1,000 hours per year and only during periods of startup and shutdown of the IGCC unit, or when steam from the IGCC unit's heat recovery steam generator is unavailable. The following emission limitations shall apply:

1. NO_X emissions shall not exceed 0.16 lbs/MMBtu for oil firing.

2. Sulfur dioxide emissions shall be limited by firing low sulfur fuel oil with a maximum sulfur content of 0.05 percent by weight.

3. Visible emissions shall not exceed 20 percent opacity (except for one six-minute period per hour during which opacity shall not exceed 27 percent), while burning low sulfur fuel oil.

J. Performance Testing

Initial (I) compliance tests shall be performed on the turbine using both fuels and on the auxiliary boiler using fuel oil. The stack test for the turbine and the auxiliary boiler shall be performed with the sources operating at capacity (maximum heat rate input for the tested operating temperature). Capacity is defined as 90 - 100 percent of rated capacity. If it is impracticable to test at capacity, then sources may be tested at less than capacity; in this case subsequent source operation is limited to 110 percent of the test load until a new test is conducted. Once the unit is so limited, then operation at higher capacities is allowed for no

SPECIFIC CONDITIONS:

more than fifteen days for purposes of additional compliance testing to regain the rated capacity in the permit, with prior notification to the Department. Annual (A) compliance tests shall be performed on the turbine and the auxiliary boiler with the fuel(s) used for more than 400 hours in the preceding 12-month period. Tests for the applicable emission limitations shall be conducted using EPA reference methods in accordance with 40 CFR 60, Appendix A, as adopted by reference in Rule 17-297, F.A.C., and the requirements of 40 CFR 75:

1. Combustion Turbine

   a. Reference Method 5B for PM (I, A, for oil only).

   b. Reference Method 8 for sulfuric acid mist (I, for oil only).

   c. Reference Method 9 for VE (I, A).

   d. Reference Method 10 for CO (I, A).

   e. Reference Method 20 for NO_x (I, A).

   f. Reference Method 18 for VOC (I, A).

   g. Trace elements of Lead (Pb), Beryllium (Be) and Arsenic (As) shall be tested (I, for oil only) using Emission Measurement Technical Information Center (EMTIC) Interim Test Methods. As an alternative, Method 104 for Beryllium (Be) may be used; or Be and Pb may be determined from fuel analysis using either Method 7090 or 7091, and sample extraction using Method 3040 as described in the EPA solid waste regulations SW 846.

   h. ASTM D 2880-71 (or equivalent) for sulfur content of distillate oil (I,A).

   i. ASTM D 1072-80, D 3031-81, D 4084-82, or D 3246-81 for sulfur content of natural gas (I, and A if deemed necessary by DEP).

   j. Reference Method 22 for fugitive emissions (I,A).

2. Auxiliary Boiler

   a. Reference Method 9 of VE (I,A).

   b. ASTM D 2880-71 (or equivalent) for sulfur content of distillate oil (I,A).

SPECIFIC CONDITIONS:

c. Reference Methods 7, 7A, 7C, 7D, or 7E for NO_x (I,A).

Other DEP approved methods may be used for compliance testing after prior departmental approval.

K. Sulfur Content of Fuel

The maximum sulfur content of the low sulfur fuel oil shall not exceed 0.05 percent by weight. Compliance shall be demonstrated in accordance with the requirements of 40 CFR 60.334 by testing for sulfur content of the fuel oil in the storage tanks once per day when firing oil. Testing for fuel oil heating value, shall also be conducted on the same schedule.

L. Monitoring Requirements

A continuous emission monitoring system (CEMS) shall be installed, operated, and maintained in accordance with 40 CFR 60, Appendix F, for the combined cycle unit to monitor nitrogen oxides and a diluent gas (CO_2 or O_2). The applicant shall request that this condition of certification be amended to reflect the Federal Acid Rain Program requirements of 40 CFR 75 when those requirements become effective within the state.

1. Each CEMS shall meet performance specifications of 40 CFR 60, Appendix B.

2. CEMS data shall be recorded and reported in accordance with Chapter 17-297.500, F.A.C., 40 CFR 60 and 40 CFR 75. The record shall include periods of startup, shutdown, and malfunction.

3. A malfunction means any sudden and unavoidable failure of air pollution control equipment or process equipment to operate in a normal or usual manner. Failures that are caused entirely or in part by poor maintenance, careless operation or any other preventable upset condition or preventable equipment breakdown shall not be considered malfunctions.

4. The procedures under 40 CFR 60.13 shall be followed for installation, evaluation, and operation of all CEMS.

5. For purposes of the reports required under this permit, excess emissions are defined as any calculated average emission concentration, as determined pursuant to Specific Condition No. H.4. herein, which exceeds the applicable emission limits in Condition No. 1.

SPECIFIC CONDITIONS:

M. Notification, Reporting and Recordkeeping

To determine compliance with the syngas and fuel oil firing heat input limitation, the permittee shall maintain daily records of syngas and fuel oil consumption for the turbine and the heating value for each fuel. All records shall be maintained for a minimum of two years after the date of each record and shall be made available to representatives of the Department upon request.

N. Applicable Requirements

The project shall comply with all the applicable requirements of Chapters 17-209 through 17-297, F.A.C., and 40 CFR 60 Subparts A and GG. The requirements shall include:

1. 40 CFR 60.7(a)(1) - By postmarking or delivering notification of the start of construction no more than 30 days after such date.

2. 40 CFR 60.7(a)(2) - By postmarking or delivering notification of the anticipated date of the initial startup of each turbine and the auxiliary boiler not more than 60 days nor less than 30 days prior to such date.

3. 40 CFR 60.7(a)(3) - By postmarking or delivering notification of the actual startup of each turbine and the auxiliary boiler within 15 days of such date.

4. 40 CFR 60.7(a)(5) - By postmarking or delivering notification of the date for demonstrating the CEMSs performance, no less than 30 days prior to such date.

5. 40 CFR 60.7(a)(6) - By postmarking or delivering notification of the anticipated date for conducting the opacity observations no less than 30 days prior to such date.

6. 40 CFR 60.7(b) - By initiating a recordkeeping system to record the occurrence and duration of any startup, shutdown or malfunction of a turbine and the auxiliary boiler, of the air pollution control equipment, and when the CEMS is inoperable.

7. 40 CFR 60.7(c) - By postmarking or delivering a quarterly excess emissions and monitoring system performance report within 30 days of the end of each calendar quarter. This report shall contain the information specified in 40 CFR 60.7(c) and (d).

8. 40 CFR 60.8(a) - By conducting all performance tests within 60 days after achieving the maximum turbine and boiler firing rates, but not more than 180 days after the initial startup of each turbine and the auxiliary boiler.

SPECIFIC CONDITIONS:

9. 40 CFR 60.8(d) - By postmarking or delivering notification of the date of each performance test required by this permit at least 30 days prior to the test date; and,

10. 17-297.345 - By providing stack sampling facilities for the combustion turbine and the auxiliary boiler.

All notifications and reports required by this specific condition shall be submitted to the Department's Air Program, within the Southwest District office. Performance test results shall be submitted within 45 days of completion of such test.

O. Submission of Reports

The following information shall be submitted to the Department's Bureau of Air Regulation within 12 months of issuance of this permit:

1. Description of the final selection of the turbine and the auxiliary boiler to be installed at the facility. Descriptions shall include the specific make and model numbers, any changes in the proposed method of operation, fuels, emissions or equipment.

2. Description of the CEMS selected. Description shall include the type of sensors, the manufacturer and model number of the equipment.

3. If construction has not commenced within 18 months of issuance of this permit, then the permittee shall obtain from DEP a review and, if necessary, a modification of the BACT determination and allowable emissions for the unit(s) on which construction has not commenced [40 CFR 52.21(r)(2)]. Units to be constructed or modified in later phases of the project will be reviewed and limitations revisited under the supplementary review process of the Power Plant Siting Act.

P. Protocols

The following protocols shall be submitted to the Department's Air Program, within the Southwest District office, for approval:

1. CEMS Protocol - Within 60 days of selection of the CEMS, but prior to the initial startup, a CEMS protocol describing the system, its installation, operating and maintenance characteristics and requirements. The Department shall approve the protocol provided that the system and the protocol meet the requirements of 40 CFR 60.13, 60.334, Appendix B and Appendix F. This condition of certification shall be amended to reflect the Federal Acid Rain Program requirements of 40 CFR 75 when those requirements become effective within the State.

SPECIFIC CONDITIONS:

2. Performance Test Protocol - At least 90 days prior to conducting the initial performance tests required by this permit, the permittee shall submit to the Department's Air Program, within the Southwest District office, a protocol outlining the procedures to be followed, the test methods and any differences between the reference methods and the test methods proposed to be used to verify compliance with the conditions of this permit. The Department shall approve the testing protocol provided that it meets the requirements of this permit.

Q. Modifications

The permittee shall give written notification to the Department when there is any modification to this facility. This notice shall be submitted sufficiently in advance of any critical date involved to allow sufficient time for review, discussion, and revision of plans, if necessary. Such notice shall include, but not be limited to, information describing the precise nature of the change; modifications to any emission control system; production capacity of the facility before and after the change; and the anticipated completion date of the change.

Issued this ______ day
of ______________, 1993

STATE OF FLORIDA DEPARTMENT OF ENVIRONMENTAL PROTECTION

Virginia B. Wetherell, Secretary
Department of Environmental Protection

Best Available Control Technology (BACT) Determination
Tampa Electric Company
Polk County
PSD-FL-194
PA-92-32

The applicant is proposing to construct, in phases, a 1,150 MW power plant in Polk County. The proposed facilities will be known as the Tampa Electric Company Polk Power Station. The first phase will consist of an Integrated Coal Gasification Combined Cycle (IGCC) unit with heat recovery steam generator (HRSG) and steam turbine (ST) for a nominal net 260 MW IGCC unit. The coal-fueled advanced CT will be capable of baseload operations (i.e., 100 percent capacity factor) on syngas, while retaining the option to fire fuel oil as backup (maximum 10 percent capacity factor). Units proposed to be added at Polk Power Station include two combined cycle (CC) units totaling 440 MW (nominal) and six simple cycle (SC) CTs totaling 450 MW (nominal). All of these units will be fired with natural gas as the primary fuel and No. 2 fuel oil as backup. The phased schedule for construction and operation of the proposed generating units at the Polk Power Station is presented in Table 1.

Table 1

Proposed Schedule for Construction and Operation of Generating Units for ultimate capacity at the Polk Power Station Site

Activity/Unit	Start Construction	Completion/ In-Service
Advanced CT, CG & HRSG/ST for 260-MW IGCC unit[a]	First Half 1994	July 1995
75-MW CT	April 1998	January 1999
75-MW CT	April 1999	January 2000
HRSG/ST for conversion of two 75-MW CTs for 220-MW CC unit	April 2000	January 2001
75-MW CT	April 2001	January 2002
220-MW CC	April 2001	January 2003
75-MW CT	April 2005	January 2006
75-MW CT	April 2006	January 2007
75-MW CT	April 2007	January 2008
75-MW CT	April 2008	January 2009
75-MW CT	April 2009	January 2010

a - 220 MW when fired on fuel oil and operated in CC mode.

The IGCC unit will be supported in part through funding from the U.S. Department of Energy (DOE) under the Clean Coal Technology Demonstration Program. Under the program, the IGCC unit will be used to demonstrate the integration of coal gasification (CG) and CC technologies and to demonstrate a more efficient method for removal of sulfur from syngas. The new cleanup technology is called hot gas clean up (HGCU). Conventional methods for sulfur removal for IGCC units require that the gas be cooled prior to cleaning, called cold gas cleanup (CGCU), and then reheated. By comparison, the HGCU technology efficiently cleans the gas at high temperatures, thereby increasing the overall plant efficiency. Under the agreement with DOE, Tampa Electric Company will demonstrate the HGCU system for a 2-year period.

The projected maximum tonnage of regulated air pollutants emitted from the proposed facility based on a 100 percent capacity factor and 8,760 hours per year are shown in Table 2. A simplified flow chart for the operation of the IGCC systems at the site is attached (Figures 1 - 3).

Table 2

Projected Maximum Annual Emissions (tpy)
for ultimate site capacity

Pollutant	IGCC[a] +	CC[b] +	SC[c] =	Total	Significance Rate (tpy)
PM (TSP)	399	260	246	905	25
PM (PM_{10})	399	260	246	905	15
SO_2	2469	720	654	3843	40
NO_x	2923	1308	1014	5245	40
CO	453	1092	978	2523	100
VOC	45	180	168	393	40
Pb	0.15	0.28	0.17	0.6	0.6
H_2SO_4	241	80	72	393	7
Fluorides	0.92	0.17	0.10	1.2	3
Hg	0.12	0.21	0.19	0.5	0.1
Be	0.007	0.013	0.008	0.03	0.0004
Total reduced sulfur (including H_2S)	6.2	0	0	6.2	10

FIGURE 1

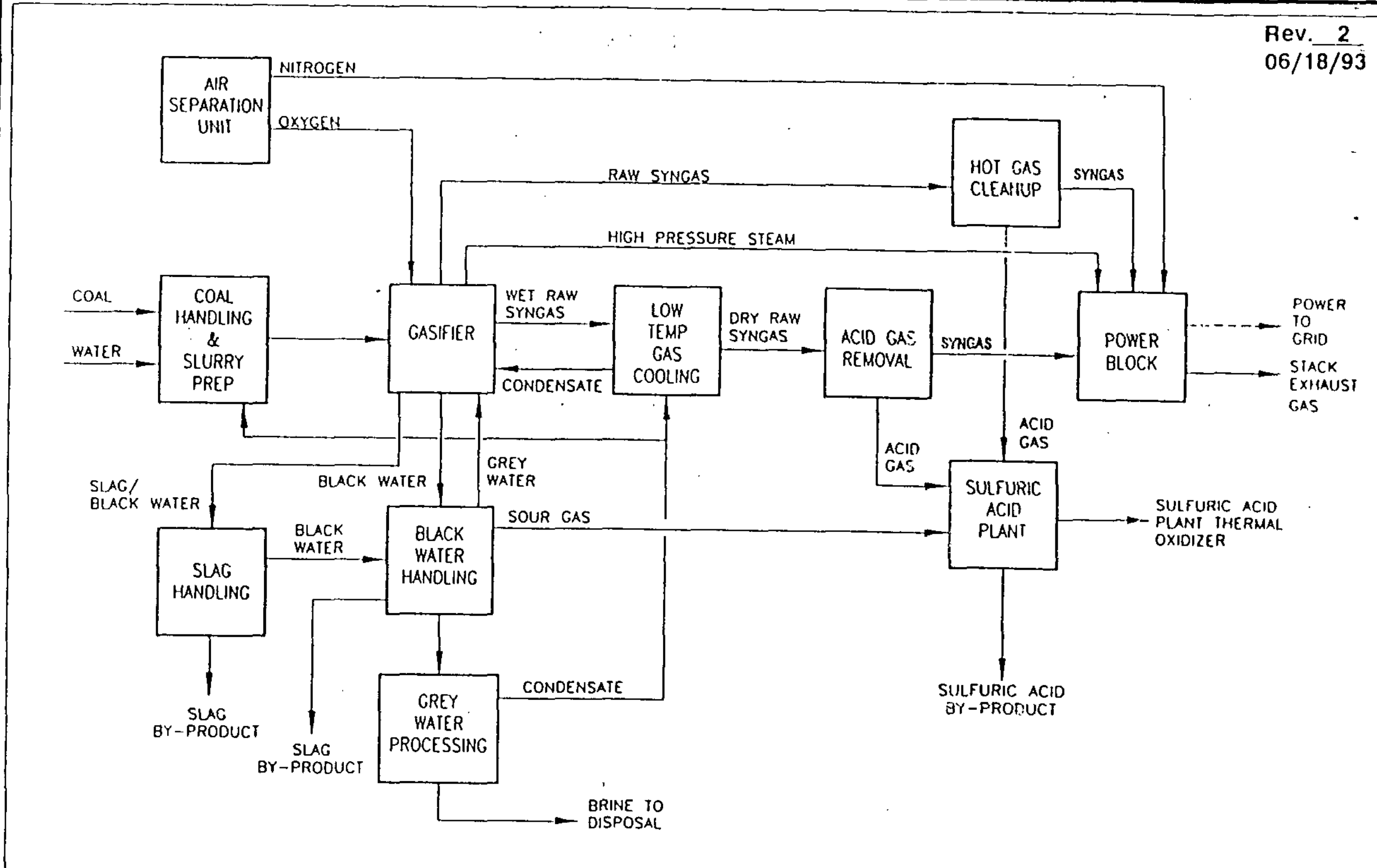

FIGURE 2-2.

GENERALIZED FLOW DIAGRAM OF IGCC SYSTEMS AND PROCESS

Source: ECT, 1993.

TAMPA ELECTRIC
A TECO ENERGY COMPANY

POLK POWER STATION

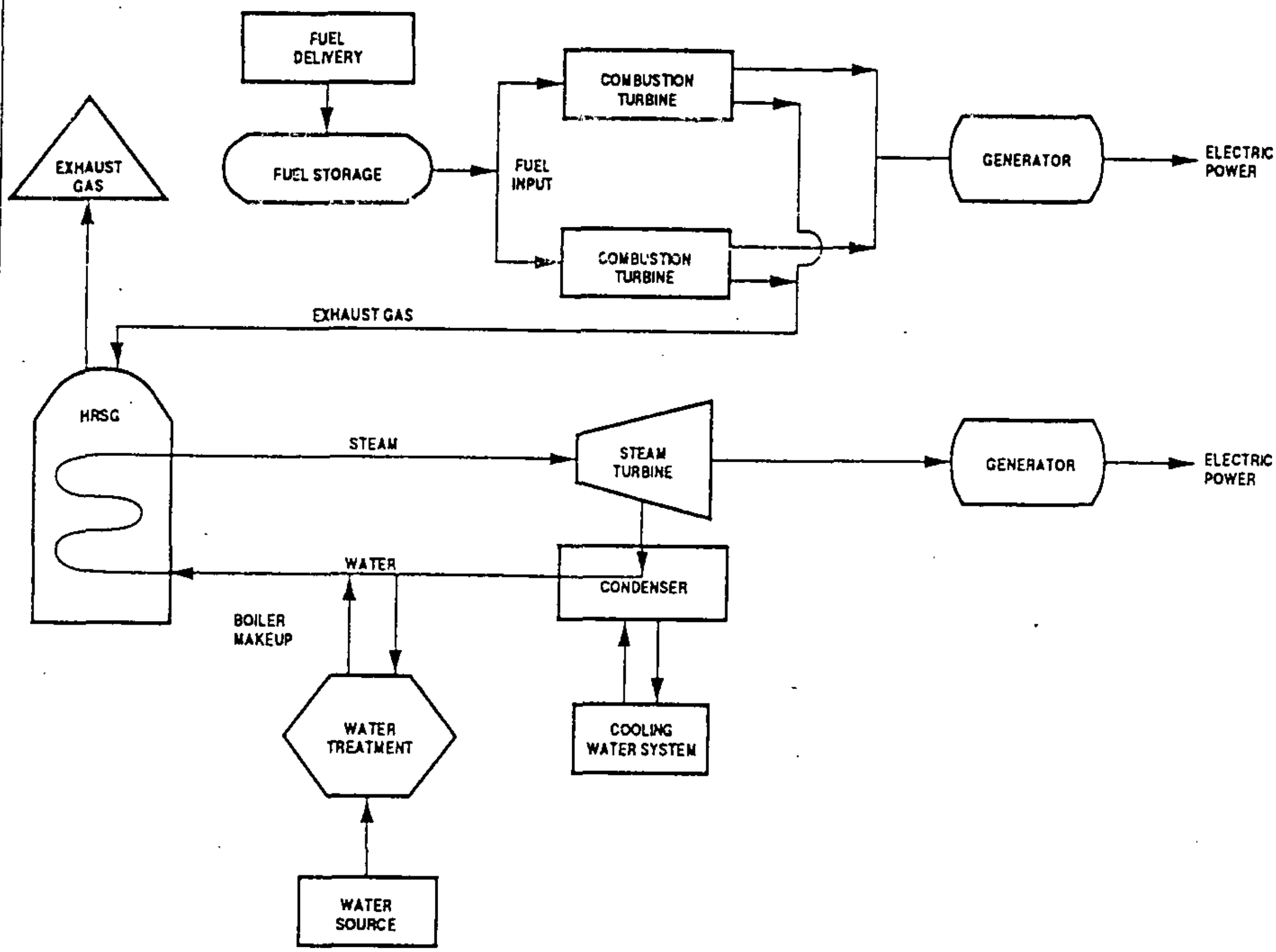

FIGURE 1.5.2-1.

SIMPLIFIED FLOW DIAGRAM OF COMBINED CYCLE POWER SYSTEM

Source: ECT, 1992.

TAMPA ELECTRIC
A TECO ENERGY COMPANY

POLK POWER STATION

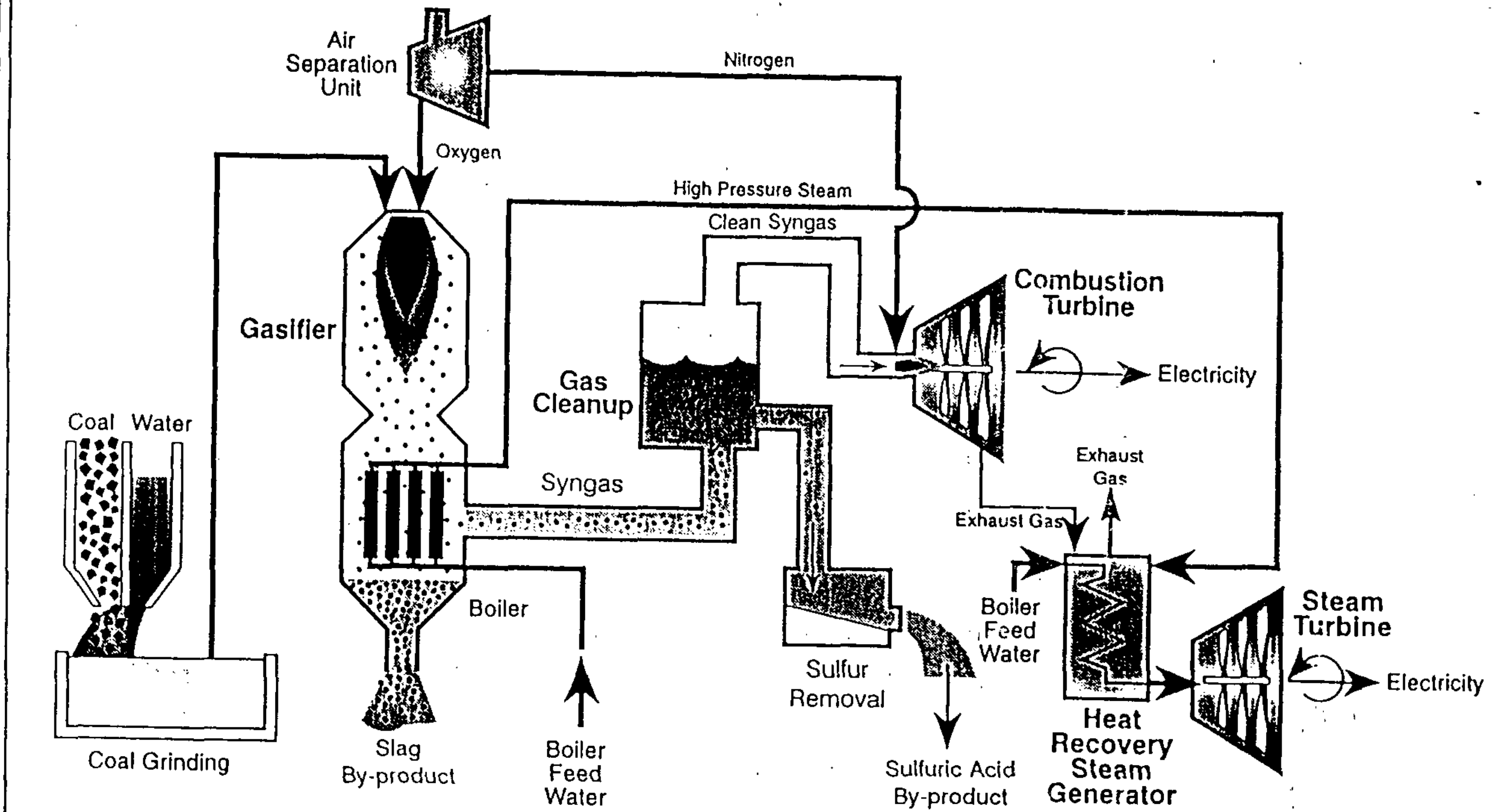

FIGURE 1.5.3-1.

SIMPLIFIED FLOW DIAGRAM OF INTEGRATED COAL GASIFICATION COMBINED CYCLE UNIT

Source: Texaco, 1992. Tampa Electric Company, 1992.

TAMPA ELECTRIC
A TECO ENERGY COMPANY

POLK POWER STATION

a - IGCC emissions include the highest annual emissions estimates from the 7F CT (based on the larger of 100 percent CGCU or 50/50 CGCU/HGCU), plus related combustion emissions (e.g., thermal oxidizer), plus other associated process and fugitive emissions (PM, CO, VOC, and H_2S).

b - CC emissions represent the totals for four stand-alone CTs in CC mode.

c - SC emission represent the totals for six stand-alone CTs in simple cycle mode.

The proposed facility will also include one 49.5 MMBtu/hr auxiliary boiler fired with low sulfur (0.05% or less by weight) distillate fuel oil. The auxiliary boiler will operate only during startup and shutdown of the IGCC unit, or when steam from the IGCC unit's HRSG is unavailable. The auxiliary boiler will operate a maximum of 1,000 hours per year.

The coal gasification facility will serve as a source of medium Btu, low sulfur (0.07% or less, by weight, sulfur bearing compounds) coal-derived gas. The coal used in the gasification facility will have a maximum sulfur content of 3.05% and have a minimum heating value of approximately 11,035 Btu/lb. The coal gasification plant will consist of coal receiving, storage and process facilities, air separation unit, gasifier, product gas cleaning facilities, acid gas removal unit, and auxiliary equipment. The coal gasification unit will have two stacks, one flare stack used during startup, shutdown and emergency conditions and one thermal oxidation unit stack which will be used continuously.

The applicant has indicated the maximum tonnage of regulated air pollutants emitted from the IGCC unit CT during the initial phase, demonstration and post demonstration periods to be as shown in Table 3.

Table 3

Maximum Annual Emissions from IGCC Unit CT for Various Operating Configurations

Pollutant	Demonstration Period (tpy)[a]	Post-Demonstration Period (tpy)[b]
PM[c]	74.5	74.5
SO_2	2,269	1,564
NO_x	2,908	1,044
CO	430	430
VOC	38.5	38.5

H_2SO_4	241	241
Pb	0.13	0.067
Fluorides	0.92	0.92
Hg	0.11	0.017
Be	0.0029	0.0029

a - Based on baseload operations firing syngas, with a maximum of 8,760 hr/yr utilization of HGCU and up to 10 percent annual capacity factor firing fuel oil.

b - Based on baseload operations firing syngas, with emission rates equivalent to 100 percent CGCU operations; up to 10 percent annual capacity factor firing fuel oil.

c - Excluding sulfuric acid mist.

Florida Administrative Code Rule 17-212.400 requires a BACT review for all regulated pollutants emitted in an amount equal to or greater than the significant emission rates listed in Table 1.

Date of Receipt of A BACT Application

September 21, 1992

BACT Determination Requested by the Applicant

	Combined Cycle Units
Pollutant	Determination
NO_x	9 ppmvd (NG) 25 ppmvd (Syngas firing) 42 ppmvd (No. 2 fuel oil firing)
SO_2	Firing of NG or Syngas Fuel oil with a maximum sulfur content of 0.05 % by weight, 0.048 lb/MMBtu
CO	Combustion control 25 ppmvd (NG) 40 ppmvd (No. 2 fuel oil firing) 25 ppmvd (Syngas firing)
VOC	Combustion control 7 ppmvd (NG) 7 ppmvd (No. 2 fuel oil firing) 1 ppmvd (Syngas firing)

Particulates	Good combustion, and type of fuels fired
Pb	Good combustion, and type of fuels fired
H_2SO_4	Firing of NG, Syngas and No. 2 fuel oil
Be	Firing of NG, Syngas and No. 2 fuel oil
AS	Firing of NG, Syngas and No. 2 fuel oil

Coal Gasification Plant

Raw Product Gas

Pollutant	Control Technology
Sulfur	Acid Gas Removal (95.6%)
Particulates	Water scrubbing

The raw product gas is fired in the combined cycle combustion turbine units and emissions of product gas are included in the BACT determination for those units.

CG Emission (Thermal Oxidizer)

Pollutant	Control Technology
SO_2	Fuel oil firing with a sulfur content not to exceed 0.05% by weight. (45.3 lb/hr)
NO_x	Combustion controls
CO	Combustion controls
Pb	Efficient Operation
H_2SO_4	Efficient Operation
Mercury	Efficient Operation
Beryllium	Efficient Operation
Inorganic Arsenic	Efficient Operation

	Materials Handling and Storage
Fugitive Dust Source	Control Technology
Coal Unloading	Enclosed - including a Collection System
Conveyers and Transfer Points (Coal, Slag)	Transfer points enclosed with Collection System. Conveyers enclosed
Coal Storage and Reclaiming	Crusting Agent Application Wet Suppression Systems or Crusting Agents Surfactant Application[1]
Fuel Oil Storage	Bottom Loaded/Submerged Filling
	Auxiliary Boiler
NO_x	Low NOx Burners and Combustion Controls, limited operation[2] (0.159 lb/MMBtu)
SO_2	Fuel oil firing with a sulfur content not to exceed 0.05 % by weight, and limited operation (0.053 lb/MMBtu)
CO	Combustion Controls (0.087 lb/MMBtu)
VOC	Combustion Controls (0.0485 lb/MMBtu)
Particulates	Combustion Controls (0.061 lb/MMBtu)
Pb	Combustion Controls
Mercury	Combustion Controls
Beryllium	Combustion Controls
Inorganic Arsenic	Combustion Controls

1 - Total Coal Handling Sources PM Emissions are 11.2 tpy
2 - Maximum of 1000 hours of operation per year

Annual pollutant emissions are shown in Table 1 for all sources. Pollutant emission rates are listed in the section entitled "BACT Determination by DEP".

Flare Stacks

This source did not propose a BACT since its operation is expected to be infrequent (startup and shutdown, and emergencies).

BACT Determination Procedure

In accordance with Florida Administrative Code Chapter 17-296, Stationary Sources - Emission Standards, this BACT determination is based on the maximum degree of reduction of each pollutant emitted which the Department, on a case-by-case basis, taking into account energy, environmental and economic impacts, and other costs, determines is achievable through application of production processes and available methods, systems, and techniques. In addition, the regulations state that in making the BACT determination the Department shall give consideration to:

(a) Any Environmental Protection Agency determination of Best Available Control Technology pursuant to Section 169, and any emission limitation contained in 40 CFR Part 60 (Standards of Performance for New Stationary Sources) or 40 CFR Part 61 (National Emission Standards for Hazardous Air Pollutants).

(b) All scientific, engineering, and technical material and other information available to the Department.

(c) The emission limiting standards or BACT determinations of any other state.

(d) The social and economic impact of the application of such technology.

The EPA currently stresses that BACT should be determined using the "top-down" approach. The first step in this approach is to determine for the emission source in question the most stringent control available for a similar or identical source or source category. If it is shown that this level of control is technically or economically infeasible for the source in question, then the next most stringent level of control is determined and similarly evaluated. This process continues until the BACT level under consideration cannot be eliminated by any substantial or unique technical, environmental, or economic objections.

The air pollutant emissions from combined cycle power plants and coal fired power plants can be grouped into categories based upon what control equipment and techniques are available to control emissions from these facilities. Using this approach, the emissions can be classified as follows:

- o Combustion Products (Particulates and Heavy Metals). Controlled generally by good combustion of clean fuels and/or fabric filters.
- o Products of Incomplete Combustion (CO, VOC, Toxic Organic Compounds). Control is largely achieved by proper combustion techniques.
- o Acid Gases (SOx, NOx, HCL, Fl). Controlled generally by gaseous control devices.

Grouping the pollutants in this manner facilitates the BACT analysis because it enables the equipment available to control the type or group of pollutants emitted and the corresponding energy, economic, and environmental impacts to be examined on a common basis. Although all of the pollutants addressed in the BACT analysis may be subject to a specific emission limiting standard as a result of PSD review, the control of "nonregulated" air pollutants is considered in imposing a more stringent BACT limit on a "regulated" pollutant (i.e., particulates, sulfur dioxide, fluorides, sulfuric acid mist, etc.), if a reduction in "nonregulated" air pollutants can be directly attributed to the control device selected as BACT for the abatement of the "regulated" pollutants.

<u>Combustion Products</u>

The IGCC facility's projected emissions for combustion products (Particulate Matter (PM) and trace heavy metals) exceed the significant emission rates given in Florida Administrative Code Rule 17-212.410, Table 212.400-2. A review of the BACT/LAER Clearinghouse indicates that the proposed PM/PM_{10} emission level of 0.013 lbs/MMBtu (excluding H_2SO_4) for syngas for the IGCC unit is consistent with the particulate limit for recent determinations of coal fired boilers. The applicant proposed PM/PM_{10} emission level of 0.009 lbs/MMBtu for No. 2 oil firing for the IGCC unit is consistent with previous BACT determinations in Florida.

In general, the BACT/LAER Clearinghouse does not contain specific emission limits for beryllium, mercury and arsenic from turbines. BACT for heavy metals is typically represented by the level of particulate control. The emission factors for PM/PM_{10} when firing the IGCC with syngas and No. 2 fuel oil are judged to represent BACT for beryllium, arsenic and mercury.

PM/PM_{10} emissions are controlled for the auxiliary boiler by firing with No. 2 fuel oil with a sulfur concentration not to exceed 0.05%, by weight. This fuel sulfur level is consistent with recent BACT determinations for similar facilities.

Products of Incomplete Combustion

The emissions of carbon monoxide, volatile organic compounds and other organics from combustion turbines are largely dependent upon the completeness of combustion and the type of fuel used. The applicant has indicated that the carbon monoxide emissions from the proposed turbines are based on exhaust concentrations of 25 ppmvd for syngas and 30 ppmvd for No. 2 fuel oil. Volatile organic compound emissions have been based on exhaust concentrations of 7 and 1 ppmvd for fuel oil firing and syngas, respectively.

A review of the BACT/LAER clearinghouse indicates that several of the largest combustion turbines (those with heat inputs greater that 1,000 MMBtu/hour) have been permitted with CO limitations which are similar to those proposed by the applicant. For VOC, the clearinghouse also indicates that the proposed emissions are consistent with that established for other turbines of similar size, thereby suggesting that the proposed emission levels for both CO and VOC are reasonable. Although the majority of BACT emissions limitations have been based on combustion controls for carbon monoxide and volatile organic compounds minimization, additional control is achievable through the use of catalytic oxidation.

Catalytic oxidation is a post-combustion control that has been employed in CO nonattainment areas where regulations have required CO emission levels to be less than those associated with wet injection for NO_x control. These installations have been required to utilize LAER technology, and typically have CO limits in the 10 ppm range (corrected to dry conditions).

In an oxidation catalyst control system, CO emissions are reduced by allowing unburned CO to react with oxygen at the surface of a precious metal catalyst such as platinum. Combustion of CO starts at about 300°F, with efficiencies above 90 percent occurring at temperatures above 600°F. Catalytic oxidation occurs at temperatures 50 percent lower than that of thermal oxidation, thereby reducing the amount of thermal energy required compared to thermal oxidation. For CC combustion turbines, the oxidation catalyst can be located directly after the CT or in the HRSG. Catalyst size depends upon the exhaust flow, temperature and desired efficiency. Most gas turbine applications have been limited to smaller cogeneration facilities burning natural gas in nonattainment areas.

The application of oxidation catalyst is not being required as BACT for the IGCC unit due to high content of sulfur in the fuel. Syngas fuel which will be utilized at 100 percent capacity factor contains up to 0.07% by weight sulfur content. These sulfur compounds are oxidized to SO_2 in the combustion process and will be further oxidized by the catalyst to sulfur trioxide (SO_3). SO_3 will, in turn, combine with moisture in the gas stream to form H_2SO_4 mist. Therefore, the use of an oxidation catalyst system for the IGCC unit is not BACT due to corrosion problems.

Acid Gases - Sulfur Dioxide

The emissions of sulfur dioxide, nitrogen oxides, fluorides, and sulfuric acid mist, as well as other acid gases which are not "regulated" under the PSD Rule, represent a significant proportion of the total emissions and need to be controlled if deemed appropriate. Sulfur dioxide emissions from combustion turbines are directly related to the sulfur content of the fuel being combusted.

The IGCC facility's projected emissions for SO_2 exceed the significant emission rates given in Florida Administrative Code Rule 17-212.410, Table 212.400-2. A review of the BACT/LAER Clearinghouse indicates that the proposed post-demonstration SO_2 emission level of 0.17 lbs/MMBtu for syngas is consistent with the SO_2 limit for recent determinations of coal fired boilers.

For the IGCC combustion turbine, the applicant has proposed the use of Syngas, No. 2 fuel oil with a maximum sulfur content of 0.05%, by weight, and coal gasification to control sulfur dioxide emissions. In accordance with the "top down" BACT review approach, only two alternatives exist that would result in more stringent SO_2 emissions. These include the use of a lower sulfur content syngas and fuel oil or the use of wet lime or limestone-based scrubbers, otherwise known as flue gas desulfurization (FGD).

In developing the NSPS for stationary gas turbines, EPA recognized that FGD technology was inappropriate to apply to these combustion units. EPA acknowledged in the preamble of the proposed NSPS that "Due to the high volumes of exhaust gases, the cost of flue gas desulfurization (FGD) to control SO_2 emissions from stationary gas turbines is considered unreasonable." EPA reinforced this point when, later on in the preamble, they stated that "FGD... would cost about two to three times as much as the gas turbine." The economic impact of applying FGD today would be no different.

Furthermore, the application of FGD would have negative environmental and energy impacts. Sludge would be generated that would have to be disposed of properly, and there would be increased utility (electricity and water) costs associated with the operation of a FGD system. Finally, there is no information in the literature to indicate that FGD has ever been applied to stationary gas turbines burning distillate oil.

Coal gasification sulfur content is controlled through fuel-production process controls. Sulfur removal stages in the coal gasification process include acid gas removal, and sulfuric acid plant thermal oxidizer. Acid gas removal systems remove hydrogen sulfide, carbonyl sulfide and carbon dioxide from the fuel gas using an acid gas absorbent solution. The acid gases are stripped from the adsorbent solution and sent to the sulfuric acid plant for introduction into a thermal oxidizer, where the remaining sulfur compounds are converted to SO_2, and finally converted to commercial grade liquid H_2SO_4. The overall sulfur removal efficiency is 95.6%. The sulfur bearing compounds content of the syngas is reduced to 0.07% by weight, or less.

The elimination of flue gas control as a BACT option then leaves the use of NG, CG with the sulfur removal process or low sulfur coal as the options to be investigated. The applicant has proposed the use of syngas, CG with sulfur removal or No. 2 fuel oil (maximum of 876 hours per year per IGCC combustion turbine) with a maximum sulfur content of 0.05%, by weight, as BACT for this project.

Although the applicant's proposed coal gasification acid gas cleanup process is an existing technology, development is continuing on coal gasification systems. The data base to determine whether the proposed post-demonstration sulfur bearing compounds level of 0.07% by weight is reasonable for a coal gasification facility with resulting proposed emissions of 0.17 lbs/MMBtu is limited. A commercial scale demonstration of an IGCC 100 MW power plant has been conducted adjacent to Southern California Edison's Cool Water generating station. During the Cool Water demonstration project, high sulfur coals, Illinois #6 and Pittsburgh #8, with a sulfur content of about 3.1 percent were tested. The SO_2 emission rate was 0.11 lbs/MMBtu for the Pittsburgh #8 coal and was even lower for the Illinois #6 coal (Technical Brief, Cool Water Coal Gasification Program: Commercial Scale Demonstration of IGCC Technology Completed, Electric Power Research Institute). The Polk Power Station IGCC unit has been designed for a larger capacity and is expected to be capable of using coals from various sources not included in the Cool Water demonstration project tests. Although, emission rates from the Cool Water tests are representative of the SO_2 emission range that can be achieved using IGCC units, the study was conducted as a demonstration project and the unit was later converted to another fuel source.

The Polk Power Station IGCC coal gasification system includes an option for both cold gas and hot gas cleanup and emissions from the Cool Water demonstration project are not directly comparable to the hot gas cleanup system. However, an objective of the hot gas cleanup system test is to demonstrate the efficiency in decreasing sulfur emissions compared to cold gas cleanup system.

Acid Gases - Nitrogen Oxides

The applicant has stated that BACT for nitrogen oxides for the IGCC unit will be met by using nitrogen diluent injection to limit emissions to 25 ppmvd at 15% oxygen when burning syngas, and water injection to achieve 42 ppmvd at 15% oxygen when burning No. 2 fuel oil. The emission limit of 25 ppmvd when burning syngas is higher compared to 9 ppmvd when burning NG in a combustion turbine due to the difference in composition and heat content between the two fuels. In contrast to natural gas which is predominately methane, syngas is composed of a variety of constituents including CO, hydrogen, CO_2, nitrogen, and water. The combustible components of syngas are primarily CO and hydrogen instead of methane. CO and hydrogen burn at a higher adiabatic flame temperature than methane and therefore can produce approximately three times as much NO_x as natural gas.

A review of EPA's BACT/LAER Clearinghouse indicates that the lowest NO_x emission limit established to date for a combustion turbine is 4.5 ppmvd at 15 percent oxygen. This level of control was accomplished through the use of water injection and a selective catalytic reduction (SCR) system. The two 25 MW combustion turbines are located in Kern County, California and the degree of control at this facility exceeds BACT requirements.

Selective catalytic reduction is a post-combustion method for control of NO_x emissions. The SCR process combines vaporized ammonia with NO_x in the presence of a catalyst to form nitrogen and water. The vaporized ammonia is injected into the exhaust gases prior to passage through the catalyst bed.

The applicant has indicated that the cost effectiveness for the application of SCR technology to the Polk Power Station IGCC project was determined to be $4,935 per ton of NO_x removed for a 50% reduction of NO_x concentration from 25 ppmvd to 12.5 ppmvd. The cost impact analysis was conducted using the OAQPS factors and project-specific economic factors. An assessment of economics impacts was performed by comparing control costs between a baseline case of advanced combustion and nitrogen injection and baseline technology with the addition of SCR controls. Baseline technology is expected to achieve NO_x exhaust concentrations of 25 and 42 ppmvd at 15% oxygen for syngas and oil-firing, respectively. Based on Japanese experience, SCR technology was premised to achieve NO_X concentration of 12.5 and 21 ppmvd at 15% oxygen for syngas and oil-firing, respectively, representing a 50% NO_X removal efficiency.

Since SCR has been determined to be BACT for several combined cycle facilities firing natural gas, the EPA has clearly stated that there must be unique circumstances to consider the rejection of such control on the basis of economics. In a recent letter from EPA Region IV to the Department regarding the permitting of a combined cycle facility (Tropicana Products Inc.), the following statement is made:

"In order to reject a control option on the basis of economic considerations, the applicant must show why the costs associated with the control are significantly higher for this specific project than for other similar projects that have installed this control system or in general for controlling the pollutant."

The auxiliary boiler is expected to operate 1,000 hours per year or less. The applicant is proposing to control SO_2 and acid gas emissions by firing with No. 2 fuel oil with a sulfur content of 0.05% or less, by weight, and by using combustion controls. Therefore, limited operation and low sulfur distillate oil represents BACT for the auxiliary boiler.

H_2SO_4 Plant Thermal Oxidizer

The predominant emission from the thermal oxidizer is sulfur dioxide. The sulfur dioxide emissions proposed for the facility are based on the highest removal efficiency that is now being maintained at other coal gasification facilities. This is accomplished by using an acid gas removal system followed by a sulfuric plant thermal oxidizer. This process is capable of providing an overall sulfur removal rate of 95.6 percent.

Fugitive Sources

The applicant has indicated that fugitive particulate emissions may result from the storage and handling of coal, slag, and sulfur. BACT for controlling these activities is good engineering design and practices. Control measures shall include the following:

- Minimize number of material transfer points
- Apply crusting agent application to inactive storage areas
- Enclose conveyers and transfer points
- Provide induced collection systems for dust

- Provide wet suppression systems (surfactant)
- Cover by-product storage areas (upon completion of cell)
- Handle and store sulfur in a molten or continuous crystalline state

A review of the control strategy indicates that the applicant has proposed taking all reasonable measures to minimize fugitive particulate emissions.

Environmental Impact Analysis

The predominant environmental impacts associated with this proposal are related to the use of SCR for NO_X control. The use of SCR results in emissions of ammonia, which may increase with increasing levels of NO_X control. In addition, some catalysts may contain substances which are listed as hazardous waste, thereby creating an additional environmental burden. Although the use of SCR does have some environmental impacts, the disadvantages do not outweigh the benefit which would be provided by reducing nitrogen oxide emissions by 50 percent. The benefits of NO_X control by using SCR is substantiated by the fact that a number of BACT determinations have established SCR as the control measure for nitrogen oxides over the last five years for combustion turbines.

In addition to the criteria pollutants, the impacts of toxic pollutants associated with the combustion of syngas and No. 2 fuel oil have been evaluated. Beryllium and Mercury exceeds the PSD significant level. Other toxics are expected to be emitted in minimal amounts, with the total emissions combined to be less than one ton per year.

Although the emissions of the toxic pollutants could be controlled by particulate control devices such as a baghouse or scrubber, the amount of emission reductions would not warrant the added expense for firing with natural gas or fuel oil. Therefore, the Department does not believe that the BACT determination would be affected by the emissions of the toxic pollutants associated with the firing of syngas or No. 2 fuel oil.

Potentially Sensitive Concerns

With regard to controlling NOx emissions from SCR the applicant has expressed concerns regarding SCR catalyst deactivation due to poisoning, oxidation of SO2 to SO3, formation of H2SO4, formation of ammonium bisulfate and ammonium sulfate, risk due to potential leaks from storage of NH3 and disposal of spent catalyst which may be considered hazardous.

A review of permitting activities for combined cycle proposals across the nation indicates that SCR has been required or proposed for installations with a variety of operating conditions including firing with fuel oil. SCR also has been accepted as BACT for boilers fired with pulverized coal. Although the concerns expressed by the applicant were valid at one time, the most recent experiences indicate that these problems have been resolved through advances in catalysts and experiences gained in operation.

BACT Determination by DEP

1. Combustion Products - PM/PM_{10} (excluding H_2SO_4)

During the two year demonstration period for the IGCC unit at the Polk Power Station, the applicant's proposed PM/PM10 emission limit of 0.013 lb/MMBtu is accepted for IGCC hot cleanup testing conducted under the Cooperative agreement with the US DOE.

For IGCC operation following the 2-year demonstration period particulate emissions control for the IGCC unit will be limited to 0.013 lb/MMBtu.

2. Products of Incomplete Combustion - CO and VOC

The use of an oxidation catalyst system for the IGCC system is not found to be BACT due to the high sulfur content in the syngas and resulting corrosion problems. Emissions are to be controlled by good combustion practices during demonstration and post demonstration periods.

3. Acid Gases - Sulfur Dioxides

During the 2-year demonstration period for the IGCC unit at the Polk Power Station, the applicant's proposed SO_2 emissions limit of 0.247 lbs/MMBtu is accepted for IGCC demonstration testing conducted under the Cooperative Agreement with the US DOE. The proposed emissions limit will allow for testing of coals with a broad range of sulfur content and for evaluation of the IGCC unit design.

For IGCC operations following the demonstration period, SO_2 emissions shall not exceed the 0.17 lbs/MMBtu limit established in a recent BACT determination for the Indiantown Cogeneration facility.

The SO_2 emissions shall be limited to 0.17 lbs/MMBtu for the IGCC unit by the use of low sulfur coal and the integral IGCC sulfur removal and recovery processes.

Acid Gases - Nitrogen Oxides

The annualized cost per ton for NO_X removal of $4,935 for the IGCC SCR estimated by the applicant exceeds recent estimates for other applications. Recent published estimates for a pulverized coal plant (Selective Catalytic Reduction for a 460 MW coal fueled unit: Overview of a NO_X Reduction System Selection, EPRI, 1993) with a NO_X reduction of 47 percent was $3,265 per ton in 1997 dollars. Costs per ton in this range indicate SCR is a reasonable alternative. However, there are significant differences between a pulverized coal-fired power plant and an IGCC unit in the design and operation of SCR NO_X control systems.

Due to the uncertainty in actual system performance and high cost of a SCR control system, NO_X BACT for the IGCC CT will be determined following a data collection period. After the demonstration phase, NO_X emission testing will be conducted on the CT every two months over a 12 to 18 month period. Test results will be provided to the Department within thirty (30) days after each test is performed. During the test period, the CT shall be operated to achieve the lowest possible NO_X emission rate and shall not exceed 25 ppmvd NO_X corrected to 15 percent oxygen and ISO conditions. This concentration limitation, equivalent to an emission rate of 0.099 lb NO_X/MMBtu, is 42 percent lower than rates recently established as BACT for other pulverized coal-fired power plant applications. One month after the test period ends, the applicant will submit a recommended BACT determination for NO_X using the test results, data obtained from other similar facilities, and research conducted by the CT manufacturer. The Department will then make a BACT determination for NO_X only and adjust the NO_X emission limits as appropriate.

The emission limits for the IGCC unit for firing with syngas and No. 2 fuel oil for the Polk Power Station are thereby established as follows:

Pollutant	Emission Limitations - 7F CT							
	IGCC				IGCC			
	Post Demonstration				2-year Demonstration			
	Fuel	Basis	lb/hr	tpy[a]	Fuel	Basis	lb/hr	tpy[b]
NO_x	Oil	42 ppmvd[f]	311	N/A	Oil	42 ppmvd	311	N/A
	Syngas	25 ppmvd[f]	222.5	1,044	Syngas	81 ppmvd	664.2	2,908.3
VOC[c]	Oil	0.028 lb/MMBtu	32	N/A	Oil	0.028 lb/MMBtu	32	N/A
	Syngas	0.0017 lb/MMBtu	3	38.5	Syngas	0.0017 lb/MMBtu	3	38.5
CO	Oil	40 ppmvd	99	N/A	Oil	40 ppmvd	99	N/A
	Syngas	25 ppmvd	98	430.1	Syngas	25 ppmvd	99	430.1
PM/PM_{10}[d]	Oil	0.009 lb/MMBtu	17	N/A	Oil	0.009 lb/MMBtu	17	N/A
	Syngas	0.013 lb/MMBtu	17	74.5	Syngas	0.013 lb/MMBtu	17	74.5
Pb	Oil	5.30E-5 lb/MMBtu	0.101	N/A	Oil	5.30E-5 lb/MMBtu	0.101	N/A
	Syngas	2.41E-6 lb/MMBtu	0.0035	0.067	Syngas	1.10E-5 lb/MMBtu	0.023	0.13
SO_2	Oil[e]	0.048 lb/MMBtu	92.2	N/A	Oil	0.048 lb/MMBtu	92.2	N/A
	Syngas	0.17 lb/MMBtu	357	1563.7	Syngas	0.247 lb/MMBtu	518	2,269

NOTES: a - Based on baseload operations firing syngas, with emission rates equivalent to 100 percent CGCU operations; up to 10 percent annual capacity factor firing fuel oil.

b - Based on baseload operations firing syngas, with a maximum of 8760 hrs/yr utilization of HGCU operations; up to 10 percent annual capacity factor firing fuel oil.

c - Exclusive of background concentrations.

d - Excluding sulfuric acid mist.

e - Sulfur dioxide emissions based on a maximum of 0.05 percent sulfur, by weight.

f - ppmvd at 15% O_2 and ISO conditions.

Auxiliary Boiler

For the auxiliary boiler, BACT will be represented by a limitation on hours of operation and the use of clean fuel (maximum 1,000 hours per year firing No. 2 fuel oil with 0.05% sulfur, by weight).

H_2SO_4 Plant Thermal Oxidizer

A review of the proposed emission rates for the thermal oxidizer indicates that equipment in and of itself represents BACT for these sources.

Fugitive Sources

A review of the control strategy indicates that the applicant has proposed taking all reasonable measures to minimize fugitive particulate emissions and is representative of BACT.

<u>Details of the Analysis May be Obtained by Contacting</u>:
Doug Outlaw, P.E., BACT Coordinator
Department of Environmental Protection
Bureau of Air Regulation
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Recommended by:

C. H. Fancy, P.E., Chief
Bureau of Air Regulation

_______________ 1993
Date

Approved by:

Virginia B. Wetherell, Secretary
Dept. of Environmental Protection

_______________ 1993
Date

Florida Department of
Environmental Protection

Lawton Chiles
Governor

Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Virginia B. Wetherell
Secretary

December 17, 1993

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. Greg Nelson
Tampa Electric Company
Post Office Box 111
Tampa, Florida 33601-0111

Re: Polk Power Station
PSD Public Notice

Dear Mr. Nelson:

This letter is in reference to a requirement of 17-210.350 PSD permit public notice that was not fulfilled in the notice published for the certification hearing of the Polk Power Station.

The public notice requirements for sources subject to PSD or nonattainment area new source review is outlined in 17-210.350 and the portions of the item left out in the certification hearing public notice is the following:

> "Specifying whether BACT or LAER has been determined and the degree of PSD increment consumption expected"

Attached is a revised public notice that should be published in the same newspaper as the certification hearing notice. A 30 day public comment period shall be provided by the notice. Simultaneously, we will be submitting the Technical Evaluation and Preliminary Determination to EPA for their 30 days comment period, along with a copy of this letter to provide assurance to EPA that proper public notice procedures were followed for a PSD permit.

If there are any questions or comments on the above, please call Syed Arif at (904) 488-1344.

Sincerely,

for John C. Brown
C. H. Fancy, P.E.
Chief
Bureau of Air Regulation

cc: Richard Donelan
Buck Oven
Larry Curtin, Holland & Knight
Tom Davis, ECT
Jewell Harper, EPA

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
NOTICE OF INTENT TO ISSUE PERMIT

The Department of Environmental Protection gives notice of its intent to issue a PSD permit (PSD-FL-194) to Tampa Electric Company, located 13 miles south of Bartow, Polk County, Florida, to construct a 260 MW integrated coal gasification combined cycle facility. A determination of Best Available Control Technology (BACT) was required. The PSD increments consumed by this facility in the Class I and II areas are:

Class I					% of Increment
SO_2	-	3-hour	12.9	25	52%
		24-hour	3.8	5	76%
		Annual	0.4	2	20%
NO_2	-	Annual	0.8	2.5	32%
PM	-	24-hour	5.7	10	57%
		Annual	1.1	5	22%

Class II					% of Increment
SO_2	-	3-hour	104	512	20%
		24-hour	27	91	30%
		Annual	0	20	0%
NO_2	-	Annual	3.3	25	13%
PM	-	24-hour	31.8	37	86%
		Annual	5.4	19	28%

The Department is issuing this Intent to Issue for the reasons stated in the Technical Evaluation and Preliminary Determination.

A person whose substantial interests are affected by the Department's proposed permitting decision may petition for an administrative proceeding (hearing) in accordance with Section 120.57, Florida Statutes. The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department at 2600 Blair Stone Road, Tallahassee, Florida 32399-2400, within 14 days of publication of this notice. Petitioner shall mail a copy of the petition to the applicant at the address indicated above at the time of filing. Failure to file a petition within this time period shall constitute a waiver of any right such person may have to request an administrative determination (hearing) under Section 120.57, Florida Statutes.

The Petition shall contain the following information; (a) The name, address, and telephone number of each petitioner, the applicant's name and address, the Department Permit File Number and the county in which the project is proposed; (b) A statement of how and when each petitioner received notice of the Department's action or proposed action; (c) A statement of how each petitioner's substantial interests are affected by the Department's action or proposed action; (d) A statement of the material facts disputed by Petitioner, if any; (e) A statement of facts which petitioner contends warrant reversal or modification of the Department's action or proposed action; (f) A statement of which rules or statutes petitioner contends require reversal or modification of the Department's action or proposed action; and (g) A statement of the relief sought by petitioner, stating precisely the action petitioner wants the Department to take with respect to the Department's action or proposed action.

If a petition is filed, the administrative hearing process is designed to formulate agency action. Accordingly, the Department's final action may be different from the position taken by it in this Notice. Persons whose substantial interests will be affected by any decision of the Department with regard to the application have the right to petition to become a party to the proceeding. The petition must conform to the requirements specified above and be filed (received) within 14 days of publication of this notice in the Office of General Counsel at the above address of the Department. Failure to petition within the allowed time frame constitutes a waiver of any right such person has to request a hearing under Section 120.57, F.S., and to participate as a party to this proceeding. Any subsequent intervention will only be at the approval of the presiding officer upon motion filed pursuant to Rule 28-5.207, F.A.C.

The application is available for public inspection during normal business hours, 8:00 a.m. to 5:00 p.m., Monday through Friday, except legal holidays, at:

Department of Environmental Protection
Bureau of Air Regulation
111 S. Magnolia Park Courtyard
Tallahassee, Florida 32301

Department of Environmental Protection
Southwest District
3804 Coconut Palm Drive
Tampa, Florida 33619-8218

Any person may send written comments on the proposed action to Mr. Preston Lewis at the Department's Tallahassee address. All comments received within 30 days of the publication of this notice will be considered in the Department's final determination.

Further, a public hearing can be requested by any person(s). Such requests must be submitted within 30 days of this notice.

Is your RETURN ADDRESS completed on the reverse side?

SENDER:
- Complete items 1 and/or 2 for additional services.
- Complete items 3, and 4a & b.
- Print your name and address on the reverse of this form so that we can return this card to you.
- Attach this form to the front of the mailpiece, or on the back if space does not permit.
- Write "Return Receipt Requested" on the mailpiece below the article number.
- The Return Receipt will show to whom the article was delivered and the date delivered.

I also wish to receive the following services (for an extra fee):

1. ☐ Addressee's Address
2. ☐ Restricted Delivery

Consult postmaster for fee.

3. Article Addressed to:
Mr. Greg Nelson
Tampa Electric Company
Post Office Box 111
Tampa, Florida 33601-0111

4a. Article Number
P 872 562 512

4b. Service Type
☐ Registered ☐ Insured
☒ Certified ☐ COD
☐ Express Mail ☐ Return Receipt for Merchandise

7. Date of Delivery
DEC 27 1993

5. Signature (Addressee)

6. Signature (Agent)

8. Addressee's Address (Only if requested and fee is paid)

PS Form 3811, December 1991 ☆U.S. GPO: 1992—323-402 DOMESTIC RETURN RECEIPT

Thank you for using Return Receipt Service.

P 872 562 512

Receipt for Certified Mail
No Insurance Coverage Provided
Do not use for International Mail
(See Reverse)

UNITED STATES POSTAL SERVICE

Sent to	Mr. Greg Nelson
Street and No.	Post Office Box 111
P.O., State and ZIP Code	Tampa, Florida 33601-0111
Postage	$
Certified Fee	
Special Delivery Fee	
Restricted Delivery Fee	
Return Receipt Showing to Whom & Date Delivered	
Return Receipt Showing to Whom, Date, and Addressee's Address	
TOTAL Postage & Fees	$

Postmark or Date
Mailed: 12/20/93
Polk Power Station
PSD Public Notice

PS Form 3800, JUNE 1991