Florida Department of
Environmental Protection

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

Lawton Chiles
Governor

Virginia B. Wetherell
Secretary

February 25, 1994

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

Dear Mr. Nelson:

Re: Polk Power Station

The enclosed letter from the Department of Interior's Fish and Wildlife Service is forwarded for your information and compliance when you apply for permits for future phases of the Polk Power Station.

Sincerely,

John C. Brown, Jr.

John C. Brown, Jr., P.E.
Administrator
Air Permitting and Standards

JB/CH/bjb

Enclosure

cc: H. Mueller, EPA
J. W. Pulliam, EPA
W. Thomas, SWD
T. Rogers, FDEP

United States Department of the Interior

FISH AND WILDLIFE SERVICE
1875 Century Boulevard
Atlanta, Georgia 30345

IN REPLY REFER TO

February 14, 1994

RECEIVED

FEB 21 1994

Bureau of
Air Regulation

Mr. Clair H. Fancy
Chief, Bureau of Air Regulation
Florida Department of
Environmental Regulation
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399

Dear Mr. Fancy:

We have reviewed the Prevention of Significant Deterioration (PSD) permit application and the Technical Evaluation and Preliminary Determination for Tampa Electric Company's (TECO) proposed 260 MW Integrated Coal Gasification Combined Cycle Unit. This is the first phase of a project at TECO's Polk Station that would eventually have a generating capacity of 1150 MW. The facility would be located in Polk County, Florida, approximately 120 km southeast of Chassahowitzka Wilderness Area (WA), a Class I air quality area, administered by the Fish and Wildlife Service (Service). The proposed project would be a significant emitter of nitrogen oxides (NO_x), sulfur dioxide (SO_2), particulate matter (PM/PM_{10}), carbon monoxide (CO), volatile organic compounds (VOC), and sulfuric acid mist (H_2SO_4). The facility is also subject to PSD regulations for lead, beryllium, and mercury.

Best Available Control Technology Analysis

The proposed acid gas removal and sulfur recovery processes are estimated to achieve an overall sulfur removal efficiency of 95.6 percent. Nitrogen oxide (NO_x) emissions from the future combined cycle and simple cycle combustion turbines will be controlled by dry low-NO_x combustion technology, resulting in NO_x concentrations of 9 and 42 parts per million (ppm) for gas and oil firing, respectively. We agree that the proposed sulfur removal systems and dry-low NO_x technology represent best available control technology to minimize sulfur dioxide and NO_x emissions from the TECO facility.

Air Quality Modeling Analysis

Although this PSD permit is for the first phase of the project, a 260 MW facility, the modeling was performed for the entire project, which will eventually have a generating capacity of 1150 MW.

The Class I increment modeling was first performed with the EPA ISCST2 and ISCLT2 dispersion models. The modeling was performed for 5 years, using surface meteorological data from Tampa, Florida, and upper air data from Ruskin, Florida. The ISC modeling was performed for both the proposed Polk Station, and for all increment consuming or expanding sources. The cumulative ISCST2 analysis did indicate that the 3-hour and 24-hour Class I increments for SO_2 would be exceeded.

Therefore, the EPA MESOPUFF II model was run to determine whether the proposed Polk Station would significantly contribute to the 3-hour and 24-hour Class I SO_2 increment exceedances. In the earlier analysis for the Environmental Impact Statement (EIS), the MESOPUFF II modeling indicated that the entire 1150 MW proposed Polk Project would not significantly contribute to a 3-hour or 24-hour increment violation. The cumulative high second-high 24-hour SO_2 concentration in that report was stated to be 5.0 $\mu g/m^3$. In the PSD modeling analysis for the Phase I application, the applicant has erroneously used the option in the MESOPUFF II model to uniformly distribute SO_2 concentrations within the puffs, instead of using the option of a gaussian distribution within the puffs. This error incorrectly produced a high second-high 24-hour SO_2 concentration of 3.8 $\mu g/m^3$. This requirement for gaussian distribution within the puffs is found in the EPA document "Interagency Workgroup on Air Quality Modeling (IWAQM) Phase 1 Report" and contains the methodology that must be used in a Class I analysis.

We accept the results from the modeling analysis contained in the EIS that indicate the 24-hour SO_2 increment may be exceeded but not violated. However, the modeling represents the impact from the full Polk Station project of 1150 MW. While one could argue that this represents a conservative assumption, it could be construed as "increment banking," which would put future applicants in the area at risk of not having sufficient increment available for their proposed sources. It is our understanding that the State of Florida also does not accept this "increment banking" effort, and we support the State's position. For future applicants performing Class I increment analyses for Chassahowitzka WA, the emissions from the proposed TECO Polk Phase I 260 MW facility should be modeled and not the emissions from the future 1150 MW project.

The visibility analysis performed with the EPA VISCREEN model indicates that there should be no impact of a coherent visible plume at Chassahowitzka WA.

Air Quality Related Values Analysis

In our letter to EPA of July 1993 regarding the Site Certification Application for this project, we asked that TECO perform a cumulative analysis, using the revised MESOPUFF II model, to predict deposition and concentration of sulfate, nitrate, mercury, and beryllium at the Chassahowitzka WA. We asked that TECO perform an Air Quality Related Values Analysis based on the results of the deposition modeling.

EPA replied to our request in a December 1993 letter that MESOPUFF was not conducted for the requested parameters. Instead, the ISC dispersion model was used to predict deposition at Chassahowitzka WA. While we agree that TECO's contribution of sulfate and nitrate at the wilderness area is small (5.7×10^{-5} and 6.7×10^{-4} g/sq m/year, respectively), the modeling did not predict cumulative deposition. As we have stated in numerous letters to your Department, we are concerned not only with an individual source's impact to AQRVs, but with the cumulative impact of all sources in an area. EPA states that TECO's small sulfate contribution will be assimilated by the ecosystem. We are concerned that the organic soils of Chassahowitzka WA may have reached their capacity to assimilate sulfate, and that additional sulfate may oxidize the soils, resulting in their erosion.

The analysis of nitrogen deposition similarly concluded that TECO's contribution was small, and thus impacts to Chassahowitzka WA would be small. Again, we are concerned with cumulative impacts. While TECO's contribution to nitrogen deposition may only change the level of nitrogen in near shore waters by 1 percent, 20 such sources will have a much more significant impact. The analyses for mercury and beryllium deposition were not cumulative, either. We need to know: (1) the cumulative deposition of pollutants, and (2) the ecological consequences of this deposition. We ask that TECO be required to perform these analyses when they apply for permits for future phases of their Polk Power Station.

Thank you for providing us the opportunity to comment on the proposed project. If you have questions, please call Ms. Ellen Porter of our Air Quality Branch in Denver at 303/969-2071.

Sincerely yours,

James W. Pulliam, Jr.
Regional Director

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

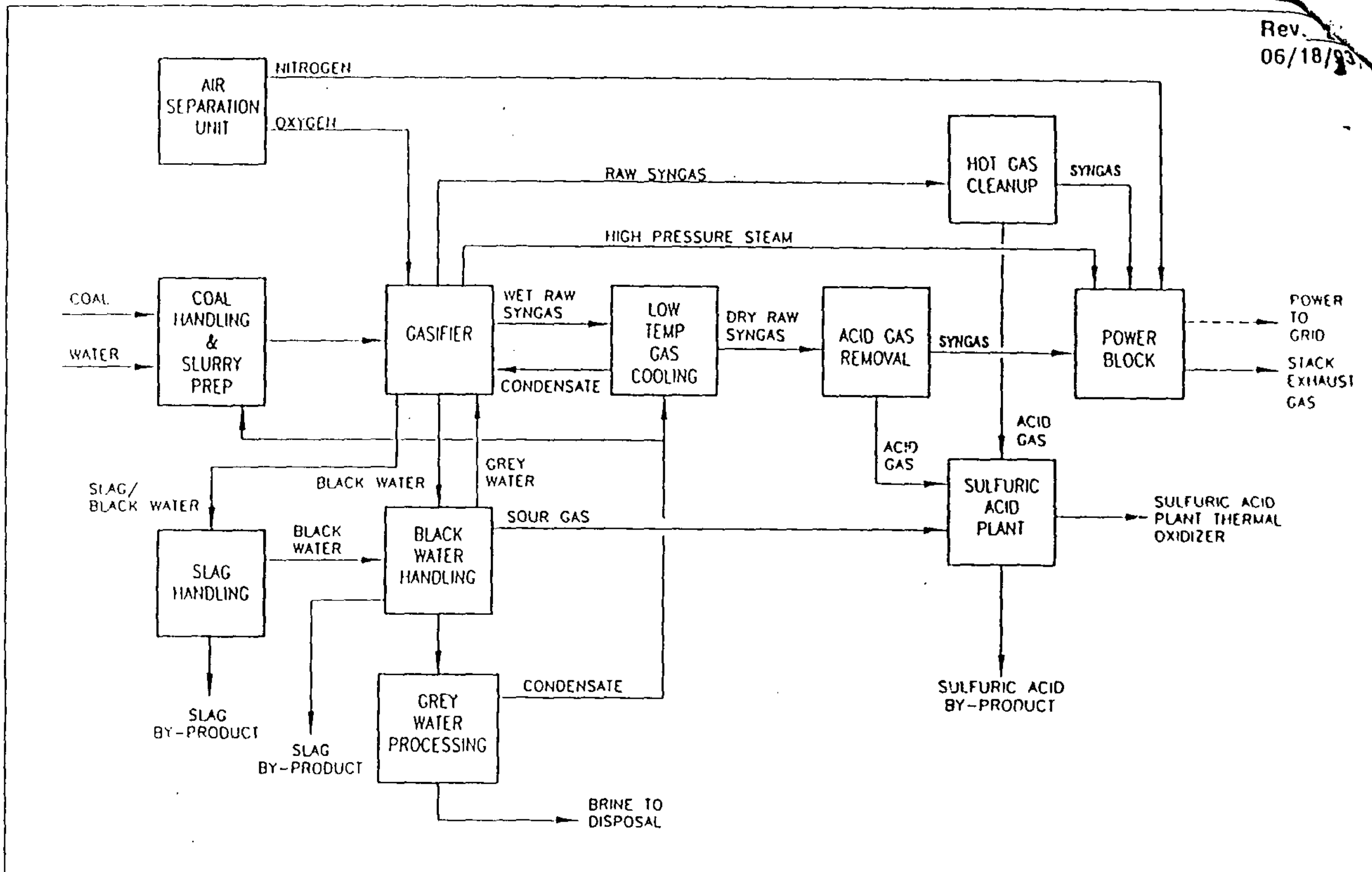

FIGURE 2-2.

GENERALIZED FLOW DIAGRAM OF IGCC SYSTEMS AND PROCESS

Source: ECT, 1993.

TAMPA ELECTRIC
A TECO ENERGY COMPANY

POLK POWER STATION

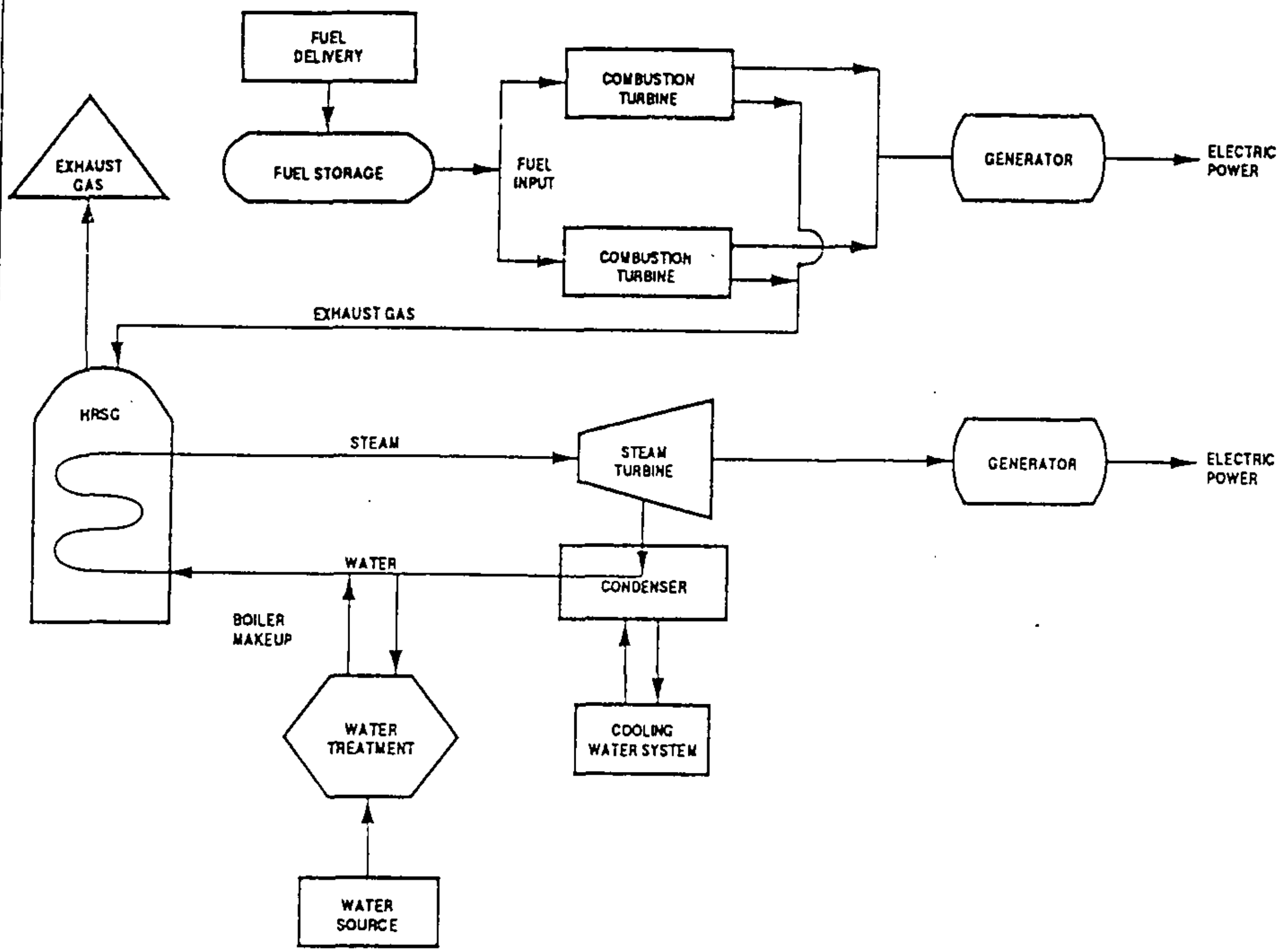

FIGURE 1.5.2-1.

SIMPLIFIED FLOW DIAGRAM OF COMBINED CYCLE POWER SYSTEM

Source: ECT, 1992.

TAMPA ELECTRIC
A TECO ENERGY COMPANY

POLK POWER STATION

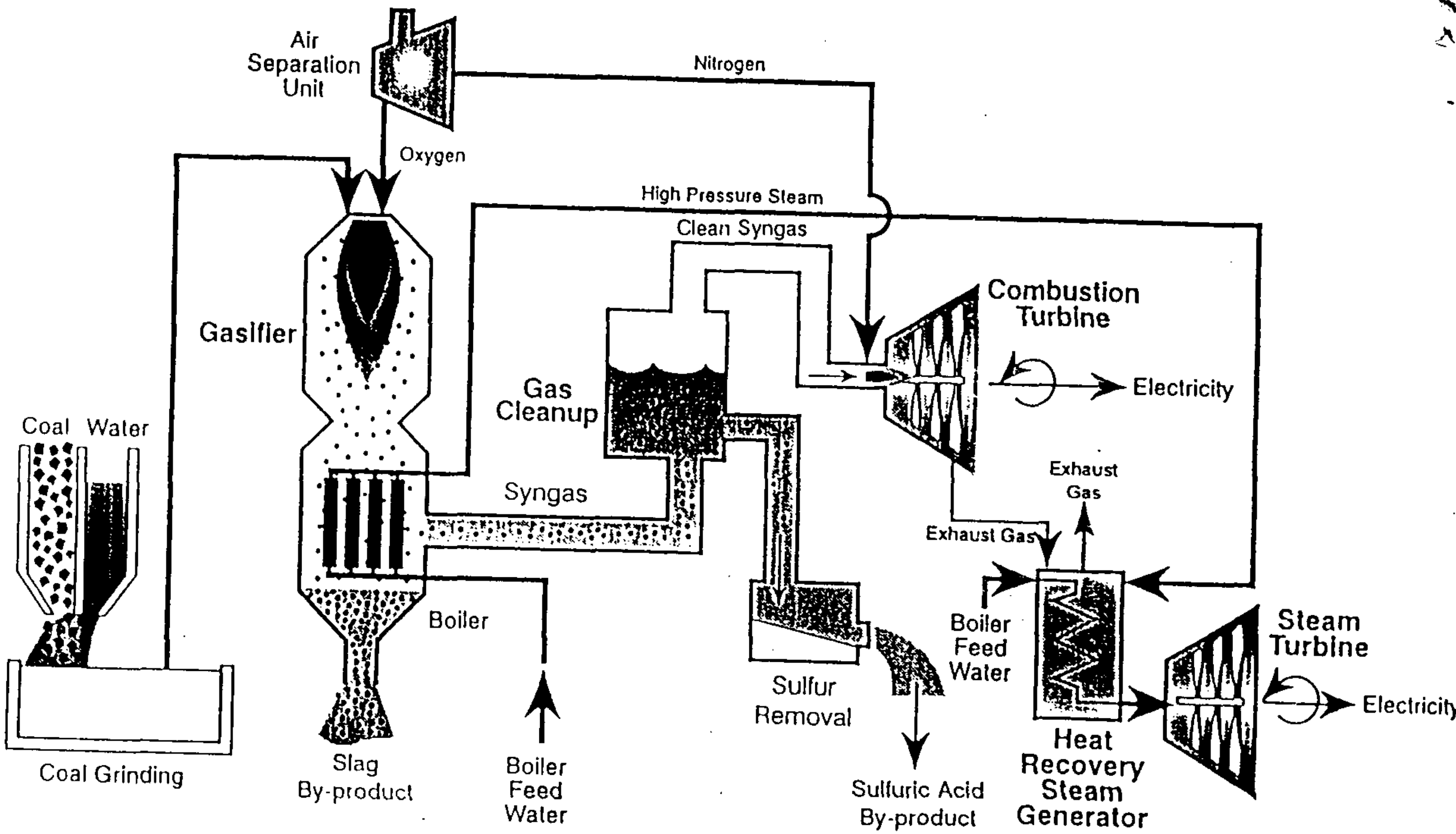

FIGURE 1.5.3-1.

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 2 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.

<u>Acid Gases - Sulfur Dioxide</u>

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.

<u>H_2SO_4 Plant Thermal Oxidizer</u>

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.

<u>Fugitive Sources</u>

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.

<u>Acid Gases - Nitrogen Oxides</u>

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:

Emission Limitations - 7F CT

Pollutant	IGCC Post Demonstration				IGCC 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.

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

Recommended by:

CH Fancy

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

February 18 1994
Date

Approved by:

Virginia B. Wetherell

Virginia B. Wetherell, Secretary
Dept. of Environmental Protection

February 24 1994
Date

ECT

Environmental Consulting & Technology, Inc.

February 18, 1994
ECT No. 90263-0502-1300

SENT BY FAX ON 02/18/94

RECEIVED

FEB 2 2 1994

Bureau of
Air Regulation

Mr. Syed Arif
Florida Department of
Environmental Protection
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, FL 32399-2400

Re: Tampa Electric Company
Polk Power Station
Fish & Wildlife Service Comments

Dear Mr. Arif:

A review has been conducted of the Fish & Wildlife Service (F&WS) comments on the draft Polk Power Station PSD permit. As discussed during our recent telephone conversation, the comments from the F&WS indicate approval of the 260 MW IGCC phase of the PPS project with respect to Class I area issues and therefore a response to the F&WS is not necessary. Specific observations on the F&WS comments are provided as follows:

Issue: Best Available Control Technology (BACT)

The F&WS concurs with FDEP that the controls and processes planned for the Polk Power Station (PPS) constitute BACT.

Response: No response required.

Issue: Air Quality Modeling Analysis

The F&WS comments indicate that the MESOPUFF-II model was run using an incorrect model option in the PSD permit application submittal. Specifically, a uniform, instead of Gaussian, vertical distribution was employed. The F&WS cites an EPA report, "Interagency Workgroup on Air Quality Modeling (IWAQM) Phase 1 Report", for guidance on MESOPUFF-II model options. The F&WS comments

P.O. Box 8188
Gainesville, FL
32605-8188

3701 Northwest
98TH Street
Gainesville, FL
32606

(904)
332-0444

FAX (904)
332-6722

also state that the original Class I area analysis which indicated that the 24-hour SO_2 increment may be exceeded but not violated is acceptable and that increment consumption for the full 1,1150 MW facility cannot be used for "increment banking".

Response: Because the F&WS has accepted the original Class I increment analysis, no response is required. The following comments are provided for informational purposes:

- The IWAQM guidance document cited by the F&WS is dated April, 1993 and therefore was not available at the time the revised MESOPUFF-II modeling was performed in November, 1992;
- As noted on Page 9-24 of the PSD permit application, the Class I increment analysis was performed using allowable emission rates. Because actual emission rates can be used for PSD increment analyses and because actual emission rates are typically lower than permitted, allowable rates, the Class I increment analysis prepared for the Chassahowitzka NWA is considered to be conservative; i.e., over-estimate actual impacts; and
- The PSD permit that will be issued by FDEP will authorize construction and operation of a 260 MW IGCC facility. Future emission sources planned for the PPS that trigger PSD review will need to obtain a PSD permit. As with all PSD applications, a demonstration of compliance with NAAQS and PSD increments will need to be made as part of the application submittal.

Issue: Air Quality Related Values Analysis (AQRV)

The F&WS comments acknowledge that impacts from PPS emission sources will be small but also state that the agency is concerned with cumulative impacts of sulfate, nitrate, mercury, and beryllium at the Chassahowitzka NWA. The F&WS requests that Tampa Electric Company (TEC) be required to perform cumulative analyses for these parameters for future phases of the PPS project.

Response: Because the F&WS has accepted the submitted AQRV analysis for the 260 MW IGCC phase of the PPS project, no response is required. The following comments are provided for informational purposes:

- Performing a cumulative analysis of sulfate, nitrate, mercury, and beryllium on the Chassahowitzka NWA would be a substantial undertaking; particularly for mercury and beryllium. Emission inventories would need to be assembled for these parameters and modeling conducted using MESOPUFF-II; and

- In previous discussions with FDEP staff (Tom Rogers), it was indicated that a cumulative impact study would probably best be performed by a consortium of affected industries due to the scope of the study.

Please call me at (904) 332-0444 if there are any questions concerning these comments.

Sincerely,

ENVIRONMENTAL CONSULTING & TECHNOLOGY, INC.

Thomas W. Davis

Thomas W. Davis, P.E.
Senior Engineer

TWD/tw

Memorandum

Florida Department of
Environmental Protection

TO: Virginia B. Wetherell

FROM: Howard L. Rhodes

DATE: February 17, 1994

SUBJECT: Approval of a PSD Permit (PSD-FL-194)
Tampa Electric Company, Polk Power Station

Attached for your approval and signature is the Final Determination for a PSD permit and a Best Available Control Technology for a 260 megawatt (MW) integrated coal gasification combined cycle (IGCC) facility at an electrical power plant site near Bartow, Polk County, Florida.

On January 25, 1994, the Governor and Cabinet, sitting as Siting Board, approved certification for the location, construction and operation of 260 MW of intergrated coal gasification combined cycle generating capacity at the Tampa Electric Company, Polk Power Station Site as proposed in the Site Certification Application.

This permit represents approval for the initial 260 MW of power generation at the Polk Power Station. The total project consists of the construction of multiple generating units and directly associated facilities at the Polk County site in multiple phases with an ultimate capacity of 1,150 MW.

The public did not express any objections to the issuance of this PSD permit.

I recommend your approval and signature.

HLR/SA/bjb

Attachment