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Environmental Consulting & Technology, Inc.

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3701 Northwest 98th Street
Gainesville, Florida 32606
904/332-0444

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Division of Air
Resources Management

TELECOPY COVERSHEET

TO: Syed Arif

TELECOPY NUMBER: (904) 922-6979

FROM: Tom Davis

DATE: 12/10/93 CHARGE NO.: 90263-0502

WE ARE TRANSMITTING 13 PAGES, INCLUDING COVERSHEET. IF THE TRANSMISSION WAS NOT COMPLETE OR IF THE MESSAGE WAS NOT LEGIBLE, PLEASE IMMEDIATELY.

904/332-0444--SWITCHBOARD

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904/332-6733--FACSIMILE MACHINE (Accounting)

COMMENTS: Syed, corrections to BACT write-up. There were no changes to Pages 43-46, 49, 51, 56, and 57. Please call me if you have any questions.

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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/m3) 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.

3. Best Available Control Technology

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 ~~a nominal 150 MW combustion turbine (CT), initially fueled with No. 2 fuel oil and will serve as a peaking unit for a maximum of 10 percent capacity factor during its first year of operation. After a year, it will be converted to~~ 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. ~~After conversion,~~ 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 A-7.

Table A-7

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
150/190-MW advanced CT[a]	First Half ~~January~~ 1994[b]	July ~~1995~~ 1996
CG & HRSG/ST for 260-MW IGCC unit[a]	~~January 1994[b]~~	~~July 1996~~
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 - 150 MW when operated in ~~simple-cycle CT or~~ CC mode and fired on fuel oil.
~~b - Construction activities may be initiated prior to this date if all applicable regulatory permits are obtained prior to December 1993.~~

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 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 A-8. A simplified flow chart for the operation of the IGCC systems at the site is attached (Figures 1 - 3).

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 A-9.

Table A-9

Maximum Annual Emissions from IGCC Unit CT for Various Operating Configurations

Pollutant	~~Initial Year (tpy)[a]~~	Demonstration Period (tpy)~~[b]~~ a	Post-Demonstration Period (tpy)~~[c]~~ b
PM	~~20.1~~	315	315
SO_2	~~49.1~~	2,269	~~2,269~~ 1,564
NO_x	~~164.7~~	2,908	1,044
CO	~~86.7~~	~~434~~ 430	~~429~~ 430
VOC	~~28.0~~	~~39.8~~ 38.5	~~39.8~~ 38.5
H_2SO_4	~~5.1~~	241	241
Pb	~~0.053~~	~~0.14~~ 0.13	0.067
Fluorides	~~0.033~~	0.92	0.92
Hg	~~0.0031~~	0.11	0.017
Be	~~0.0025~~	0.0029	0.0029

~~a - Based on 10 percent maximum annual capacity factor firing fuel oil in simple cycle mode.~~

a ~~b~~ - 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 ~~c~~ - 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.

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

4. 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 ~~30~~ 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

	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 ~~10.7~~ 11.2 tpy
2 - Maximum of 1000 hours of operation per year

Annual pollutant emissions are shown in Table ~~1~~ A-8 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).

5. 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.

(excluding H_2SO_4)

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
0.013 level of ~~0.037~~ lbs/MMBtu for syngas for the IGCC unit ~~exceeds~~ is consistent with
the particulate limit for recent determinations of coal fired boiler. The applicant proposed PM/PM_{10} emission level of ~~0.014~~ 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.

7. <u>Products of Incomplete Combustion</u>

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.

a. 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 SO_2 emission level of 0.17 ~~0.247~~ lbs/MMBtu for syngas ~~exceeds~~ the SO_2 limit for recent determinations of coal fired boilers.
is consistent with Best-demonstrat

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 ~~0.247~~ 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.

b. 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 ~~$6,272~~ 4,935 per ton of NO_x removed for a

9. 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.

10. BACT Determination by DEP

a. 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 ~~0.037~~ lb/MMBtu is accepted for IGCC hot cleanup testing conducted under the Cooperative agreement with the US DOE. 0.013

For IGCC operation following the 2-year demonstration period ~~the PM/PM_{10} emission limit of 0.037 lbs/MMBtu is high compared to Indiantown cogeneration facility emission limit of 0.018 lbs/MMBtu. Since the proposed emission levels exceeds recent BACT determinations for similar facilities,~~ particulate emissions control for the IGCC unit will be limited to ~~0.018~~ 0.013 lb/MMBtu.

b. 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.

c. 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, ~~estimates for the incremental increase in cost for use of low sulfur coals for syngas product can be justified. Therefore,~~ SO_2 emissions ~~following the demonstration period~~ shall not exceed the 0.17 lbs/MMBtu limit established in a recent BACT determination for the Indiantown Cogeneration facility. ~~The 0.17 lbs/MMBtu limit shall apply during the 2-year demonstration period to any IGCC unit operations not conducted as a part of the demonstration requirements of the US DOE cooperative agreement.~~

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.

d. Acid Gases - Nitrogen Oxides

The annualized cost per ton for NO_x removal of ~~$6,272~~ 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. ① ~~Therefore, the IGCC NO_x emission limit is 12.5 ppmvd during the demonstration and post-demonstration periods, and that SCR shall be used to meet 12.5 ppmvd NO_x emission limit.~~

(Additional paragraph ②)

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:

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① 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.

② 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.

d. Excluding sulfuric acid mist.

Pollutant	Emission Limitations – 7F CT							
	IGCC Post Demonstration				IGCC 2-year Demonstration			
	Fuel	Basis	lb/hr	tpy[a]	Fuel	Basis	lb/hr	tpy[b]
NO_x	Oil	42 ppmvd	311	N/A	Oil	42 ppmvd	311	N/A
	Syngas	~~12.5~~ 25 ppmvd	~~111.25~~ 222.5	~~522~~ 1,044	Syngas	~~12.5~~ 81 ppmvd	~~111.25~~ 664.2	~~522~~ 2,908.3
VOC[c]	Oil	~~0.0090~~ 0.028 lb/MMBtu	32	N/A	Oil	~~0.0090~~ 0.028 lb/MMBtu	32	N/A
	Syngas	0.0017 lb/MMBtu	3	~~39.8~~ 38.5	Syngas	0.0017 lb/MMBtu	3	~~39.8~~ 38.5
CO	Oil	~~30~~ 40 ppmvd	99	N/A	Oil	~~30~~ 40 ppmvd	99	N/A
	Syngas	25 ppmvd	98	~~429~~ 430.1	Syngas	25 ppmvd	99	~~434~~ 430.1
PM/PM_{10} d	Oil	~~0.014~~ 0.009 lb/MMBtu	17	N/A	Oil	~~0.014~~ 0.009 lb/MMBtu	17	N/A
	Syngas	~~0.018~~ 0.013 lb/MMBtu	~~35~~ 17	~~153~~ 74.5	Syngas	~~0.037~~ 0.013 lb/MMBtu	~~72~~ 17	~~315~~ 74.5
Pb	Oil	~~3.09E-5~~ 5.90 lb/MMBtu	0.101	N/A	Oil	~~3.09E-5~~ 5.30 lb/MMBtu	0.101	N/A
	Syngas	~~1.98E-6~~ 2.41 lb/MMBtu	0.0035	0.067	Syngas	~~1.98E-6~~ 1.15E-5 lb/MMBtu	~~0.0035~~ 0.023	~~0.067~~ 0.13
SO_2	Oil[e] ~~d~~	~~0.047~~ 0.048 lb/MMBtu	92.2	N/A	Oil	~~0.047~~ 0.048 lb/MMBtu	92.2	N/A
	Syngas	0.17 lb/MMBtu	~~373~~ 357	~~1634~~ 1563.7	Syngas	0.247 lb/MMBtu	518	2269

ES: 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.

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

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.

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 9, 1993

Mr. Christian M. Hoberg
U.S. Environmental Protection Agency,
Region IV
345 Courtland Street, N.E.
Atlanta, Georgia 30365

Re: Tampa Electric Co. Polk Power Station -- National Park Service comments

Dear Mr. Hoberg:

The purpose of this letter is to respond to the National Park Service letter dated July 26, 1993 (copy enclosed) from Mr. James Pulliam, Regional Director, to Mr. Heinz Mueller, Chief of the Environmental Policy Section in the EPA Region IV office. In summary, the National Park Service (NPS) believes that Tampa Electric Co. failed to adequately address sulfate and nitrate deposition in the Chassahowitzka National Wilderness Area, a designated Class I area located 120 kilometers to the northwest, in its application for the construction of the new Polk Power Station. In addition, the NPS is concerned with mercury and beryllium deposition in the Class I area. The NPS wants the applicant to complete additional MESOPUFF II modeling to quantify the deposition and concentration of these pollutants in the Class I area and to evaluate the effects on the air quality related values of the area.

The Department believes it is inappropriate to require this additional analysis from the applicant at this point in the permitting process, given that the applicant has followed all the agreements and protocols that were originally agreed to. At the time the applicant was developing its modeling protocol with the Department, the details of what constituted an adequate analysis of the PSD increments and air quality related values for distant Class I areas were evolving. The Department consulted with the NPS to assure that its concerns would be addressed. But at that time only a handful of persons throughout the country were very knowledgeable about the MESOPUFF II model, and there were no well thought-out procedures and guidance available from the EPA, the NPS, or the Department. The applicant was required to use the MESOPUFF II model to evaluate concentrations in the Class I area, but not deposition.

The Department currently requires that applicants follow the analysis and modeling procedures contained in the IWAQM phase I report. These requirements include analysis of deposition on the Class I areas. If you would like to discuss this issue further, please call me at (904) 488-0114.

Sincerely,

Thomas G. Rogers

Thomas G. Rogers
Administrator
Air Modeling and Assessment

TGR/tr

cc: Clair Fancy