Florida Department of Environmental Regulation

Twin Towers Office Bldg. • 2600 Blair Stone Road • Tallahassee, Florida 32399-2400

Lawton Chiles, Governor

Carol M. Browner, Secretary

December 26, 1991

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

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

Dear Ms. Harper:

Re: Indiantown Cogeneration, L.P.
330 MW - Pulverized Coal-Fired Steam Electric Generator
Federal Number: PSD-FL-168

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 Tom Rogers or Barry Andrews 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/MH/mh

Enclosure

c: Isidore Goldman, Southeast Dist.
Tom Rogers, BAMA
Chris Shaver, NPS
Stephen A. Sorrentino, PG&E/Bechtel

Technical Evaluation
and
Preliminary Determination

Indiantown Cogeneration, L.P
330 MW - Pulverized Coal-Fired Steam Electric Generator
Martin County, Florida

Permit No. PSD-FL-168

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

December 26, 1991

Power Plant Site Certification
Review Case No. PA 90-31
INDIANTOWN COGENERATION PROJECT

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State of Florida Department of Environmental Regulation
Indiantown Cogeneration L.P.
Electric Power Plant Site Certification Review
Case No. PA90-31

I. INTRODUCTION

Pursuant to the Florida Power Plant Siting Act, Sections 403.501-519, Florida Statutes, the Indiantown Cogeneration, L.P. (ICL) applied in December of 1990 for certification of 330 MW pulverized coal-fired steam electric generating unit at a site located in Martin County immediately southeast of Caulkins Indiantown·Citrus Company (Caulkins).

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 Regulation (DER) 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 DER's companion rule, Chapter 17-17, F.A.C., identify minimum criteria which must be studied in the review of the proposed steam electric generation facility. These include: Accessibility to transmission corridors, proximity to transportation systems, cooling systems requirements, soil and foundation conditions, impact on water supplies, 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 DER's statutory charges. Accordingly, the Power Plant Siting

Act (PPSA) also requires the participation of certain other state agencies.

Concurrent with the review by the State, the U.S. Army Corps of Engineers also assesses the portions of the project that affect the wetlands to be crossed by the rail loop and water supply pipeline.

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 Indiantown Cogeneration, L.P. are attached in Appendix I.

II. SITE DESCRIPTION

A. Power Plant

The Indiantown Cogeneration, L.P. (ICL) project will be constructed in southwestern Martin County, Florida.

The site and its access facilities occupy Sections 26, 27, 34, and 35, Township 39 South, Range 38 East, Martin County, Florida. The site, which occupies approximately 232 acres, is located 9 miles east of Lake Okeechobee and about 3 miles northwest of the unincorporated town of Indiantown. To the north of the site are the Caulkins Citrus Processing Facility (Caulkins) and the vacant Florida Steel Corporation (FSC) site. Both of these facilities border State Road 710 and the CSX Railroad. The ICL project site is bounded on the west by Tampa Farm Products and on the south and east by unimproved industrially zoned land.

The site is currently unimproved and is zoned industrial. There are no existing buildings and the only structures on he site are the transmission towers in the FPL transmission line right-of-way.

Approximately 21 acres of the site will be used to construct the power block portion of the cogeneration plant. The power block includes the boiler, turbine generator, air pollution control equipment, cooling tower, water treatment facilities, lime and ash storage, and administration and maintenance buildings. Another 15 acres will be used for coal handling and storage facilities. A cooling water storage pond will be constructed on approximately 25 acres.

Within the site boundary are 23.9 acres of wetlands which will be preserved. Around each of the wetlands a 50 foot buffer zone will be maintained, accounting for an additional 8

The use of the existing railroad berm ROW for the pipeline route will minimize the wetlands impacts from the pipeline construction. However, waters of the State will be affected in at least six locations: Nubbin Slough, Henry Creek, Lettuce Creek, Myrtle Slough and two unnamed wetlands. The work at Nubbin Slough will include the construction of an intake structure. The other wetland areas listed above will be disturbed to construct aerial (trestle) pipe crossings of the wetland. ICL proposes to bury the pipeline along the railroad ROW with the exception of the aerial crossings listed above. If there are additional impact areas, they are expected to be the temporary disturbance of a wetland edge immediately adjacent to the railroad berm for the placement of the pipe.

C. Air Resources

The Indiantown Cogeneration, L.P. (ICL) proposes to construct a cogeneration project near Indiantown, Florida. The proposed plant is a pulverized-coal-fired facility that will produce approximately 330 megawatts (MW) of electricity for sale to the Florida Power and Light Company (FPL) and approximately 225,000 lb/hour of process steam for sale to the Caulkins Indiantown Citrus Company ("Caulkins"). The site, which occupies approximately 232 acres, is located 9 miles east of Lake Okeechobee and about 3 miles northwest of the community of Indiantown in southeastern Martin County.

The proposed facility includes one main boiler and one steam generator, and an auxiliary boiler operated during lightoff and startup of the main boiler or if the main boiler is down and process steam is required for Caulkins Citrus Processing. The primary source of air emissions will be the main boiler, firing coal. Secondary air emission sources include the auxiliary boiler firing natural gas or No. 2 fuel oil, and the material handling systems. The operation of these units will result in significant net emissions increases of regulated air pollutants over the current emissions levels and thus, is subject to review by the Department under the prevention of significant deterioration (PSD) regulations (Rule 17-2.500, Florida Administration Code).

The proposed project will be located in a Class II PSD area. The nearest Class I area is the Everglades National Park which is approximately 145 kilometers south of the proposed project. At this distance, the proposed project is not expected to influence the Class I area and no analysis was completed. The pollutant emissions estimated by the applicant, considering control equipment, indicate that the following ten compounds will be emitted in PSD-significant amounts: carbon monoxide (CO), nitrogen oxides (NOx), volatile organic compounds (VOC), particulate matter (PM and PM10), and sulfur dioxide (SO2), and the non-criteria pollutants beryllium (Be), mercury (Hg), fluorides (F-), and inorganic arsenic (As). Table 1 lists the significant and net emission rates for the proposed facility.

The air quality impact analysis required by the PSD regulations for these pollutants include:

* An analysis of existing air quality;
* A PSD increment analysis (NO2, PM and SO2 only);
* An Ambient Air Quality Standards (AAQS) analysis;
* An analysis of impacts on soils, vegetation, and visibility and of growth-related air quality impacts; and
* A "Good Engineering Practice" (GEP) stack height determination.

The analysis of existing air quality generally relies on preconstruction monitoring data collected with EPA-approved methods. The AAQS analysis depends on the air quality dispersion modeling carried out in accordance with EPA guidelines.

Based on these required analyses, the Department has reasonable assurance that the proposed facility, as described in this report and subject to the conditions of approval proposed herein, will not cause or contribute to violation of any PSD increment or ambient air quality standard. A discussion of the modeling methodology and required analysis follows.

1. Modeling Methodology

The EPA-approved Industrial Source Complex Short-Term (ISCST) dispersion model was used in the air quality impact analysis. This model determines ground-level concentrations of inert gases or small particles emitted into the atmosphere by point, area, and volume sources. The model incorporates elements for plume rise, transport by the mean wind, Gaussian dispersion, and pollutant removal mechanisms such as deposition and transformation. The ISCST model allows for the separation of sources, building wake downwash, and various other input and output features. A series of specific model features, recommended by the EPA, are referred to as the regulatory options. The applicant used all of the regulatory options in each modeling scenario.

The applicant conducted screening modeling, for the purpose of defining the worst-case operating conditions and the significant impact area, and refined modeling to ensure that the highest concentrations were identified. For both sets of modeling runs the applicant received prior approval from the Department on the by submitting a modeling protocol.

For the modeling, five years of sequential hourly meteorological data were used. The surface and upper-air data were National Weather Service (NWS) data collected in West Palm Beach, Florida, about 26 miles east-northeast of the proposed facility, during the period 1982-1986. Since five years of data were used, the highest second-high short-term predicted concentrations are compared with appropriate ambient standards or PSD increments. For the annual averages the highest predicted yearly average was compared to the standards.

The screening phase modeling used a polar receptor grid centered on the plant's main stack. The grid system consisted of 612 receptors surrounding the facility at 36 direction radials, each separated by 10° increments, from 0.5 kilometers to 4.5 kilometers at successive 250-meter intervals. This coarse-mesh receptor grid provides sufficient resolution and downwind coverage to determine the extent of the significant impact area for each pollutant and the locations of all critical receptors to be evaluated in the further refined modeling.

The initial screening modeling identified the worst-case operating condition (considering five operating conditions varying load and fuel types) to be the main boiler at full load and the auxiliary boiler firing No. 2 fuel oil. Table 2 and Table 3 summarize the stack and emission characteristics of

Table 1. Significant and Net Emission Rates (Tons per Year) for the Proposed Project.

Pollutant	Significant Emission Rate	Existing Emission	Proposed Maximum Emission	Net Emission Change	Applicable Pollutant (Yes/No)
Criteria Pollutants					
CO	100	0	1858.4	1858.4	Yes
NO_2	40	0	2850.5	2850.5	Yes
SO_2	40	0	2629.4	2629.4	Yes
PM (TSP)	25	0	306.1	306.1	Yes
PM_{10}	15	0	276.2	276.2	Yes
VOC	40	0	56.6	56.6	Yes
Pb	0.6	0	0.152	0.152	No
Non-Criteria Pollutants					
Asbestos	0.007	0	0	0	No
Be	0.0004	0	0.041	0.041	Yes
F-	3	0	22.26	22.26	Yes
Hg	0.1	0	0.172	0.172	Yes
Vinyl Chloride	1.0	0	0	0	No
Total Reduced Sulfur	10	0	0	0	No
Hydrogen Sulfide	10	0	0	0	No
Reduced Sulfur Compunds	10	0	0	0	No
Sulfuric Acid Mist	7	0	6.51	6.51	No
Other Pollutants Regulated Under Clean Air Act					
Benzene	N/A	0	0	0	No
As	N/A	0	0.766	0.766	Yes

Table 2. Stack Parameters for the Proposed Facility.

Source	Height (m)	Exit Temperature (K)	Exit Velocity (m/s)	Diameter (m)
Main Boiler	150.9	333.2	30.5	4.88
Aux. Boiler	27.4	533.2	31.4	1.68

Table 3. Maximum Pollutant Emissions for the Proposed Project.

Pollutant	Annual Rate[a] (TPY)		Short-Term Rate (lb/hr)	
	Main Boiler	Aux. Boiler	Main Boiler	Aux. Boiler
CO	1651.1	23.7	377.0	47.3
NO_x	2551.5	34.1	582.6	68.2
PM[b]	270.2	0.7	61.7	1.4
SO_2	2551.2	8.85	582.6	17.7
VOC	N/A	0.32	N/A	0.63
Be	0.041	N/A	0.0094	N/A
F-	22.26	N/A	5.08	N/A
Hg	0.172	N/A	0.039	N/A
As	0.766	N/A	0.175	N/A

[a] Maximum annual emissions are based on the maximum hourly emission rate: 8,760 hrs/yr for the main boiler and 1,000 hrs/yr for the auxiliary boiler, with an annual load factor of 100% for both boilers.

[b] PM and PM_{10} emission rates are assumed to be the same.

this worst-case condition. This worst-case condition was used in further screening and refined modeling.

The refined modeling was conducted using a fine-grid (100-meter resolution) centered over each of the receptors which had the highest, second-high short-term concentrations.

Impacts due to fugitive particulate emissions from the material handling systems were estimated near the plant property lines. Fugitive dust tends to be released near ground level with insignificant plume rise. As a result, higher particulate concentrations are expected to occur in the nearby area. Therefore, 72 discrete receptors were placed along the ICL property line and one downwind ring distance (100 meters) beyond the ICL property line at each 10° azimuth direction using the main stack as the origin.

The results of these model runs, as shown on Table 4, show that for particulate matter and carbon monoxide the maximum predicted concentrations are less than the defined significant impact levels for these pollutants. As such, no further modeling analyses for these two pollutants is required. However, for SO2 and NO2 further modeling analyses are required since the maximum predicted concentrations are greater than their defined significant impact levels. The radii of the significant impact areas were identified to be 4.25 km for SO2 (24-hour average) and 4.5 km for NO2 (annual average). None of the other pollutants emitted have defined significant impact levels.

A more detailed description of the modeling methodology and analysis, along with the model output, is contained in the ICL application. The Department has reviewed the applicant's analysis and found that it conforms with the guidelines established by the EPA and followed by the Department.

2. Analysis of Existing Air Quality

Preconstruction ambient air quality monitoring is required for all pollutants subject to PSD review. In general, one year of quality assured data using an EPA reference, or the equivalent monitor must be submitted. Sometimes less than one year of data, but no less than four months, may be accepted when Departmental approval is given.

An exemption to the monitoring requirement can be obtained if the maximum air quality impact, as determined by air quality modeling, is less than a pollutant-specific "de minimus" concentration. In addition, if current monitoring data exists and these data are representative of the proposed source area, then at the discretion of the Department these data may be used.

The maximum predicted ambient impacts of the proposed facility for those pollutants subject to PSD review are listed in Table 5. The monitoring "de minimus" level for each pollutant is also listed. Inorganic arsenic is not listed in Table 5 because there is no "de minimus" level for this pollutant. All pollutants have maximum predicted impacts below their respective "de minimus" values. Therefore, specific preconstruction monitoring is not required for any pollutant.

The applicant has, however, used the available monitoring data located in Martin and the surrounding counties to develop existing background concentrations for the proposed facility area. These background values have been used to develop the maximum total concentrations for comparison with the ambient air quality standards.

3. PSD Increment Analysis (NO2, PM and SO2)

The PSD increment represents the amount that new sources in an area may increase ambient ground-level concentrations of a pollutant. The purpose of these increment limitations is to prevent areas which currently have good air quality from being significantly degraded. If an area currently has ambient concentrations near the ambient air quality standards for NO2, PM and SO2, then the increased emissions from new sources must not cause or contribute to a violation of the ambient air quality standard and the allowed increments would be reduced to prevent such exceedances.

The proposed project is to be located in a Class II area and must meet the increments defined for this class. All of the emissions of NO2, PM and SO2 at the proposed ICL facility will consume increments. The increased ground-level PM concentrations due to the ICL facility alone has been shown, from the dispersion modeling, to be less than the defined significant impact levels for all averaging times (see Table 4). As such, no other increment consuming sources were evaluated for PM. For NO2 and SO2, considering all increment consuming sources that may contribute to the significant impact area of the proposed facility site, the modeling results indicate the proposed facility does not contribute to a violation of the PSD Class II increments. Table 6 summarizes the modeling results and the comparisons to the PSD Class II increments standards.

Table 4. Maximum Predicted Concentrations for Comparison to the Significant Impact Levels ($\mu g/m^3$).

Pollutant	Averaging Time	Maximum Predicted Concentration	Significant Impact Levels	Significant Pollutant (Yes/No)
CO	1-hour	78.2	2000.0	No
	8-hour	50.9	500.0	
NO_2	Annual	4.4	1.0	Yes
SO_2	3-hour	24.7	25.0	Yes
	24-hour	11.6	5.0	
	Annual	1.2	1.0	
PM[a]	24-hour	3.35	5.0	No
	Annual	0.26	1.0	

[a] PM and PM_{10} concentrations are assumed the be the same.

Table 5. Maximum Predicted Concentration for Comparison to the De Minimus Ambient Levels ($\mu g/m^3$).

Pollutant	Averaging Time	Maximum Predicted Concentration	De Minimus Ambient Level	Monitoring Pollutant (Yes/No)
CO	8-hour	50.9	575.0	No
NO_2	Annual	4.4	14.0	No
SO_2	24-hour	11.6	13.0	No
PM (TSP)	24-hour	3.3	10.0	No
PM_{10}	24-hour	3.3	10.0	No
VOC	Tons per Year	56.6 TPY	100.0 TPY	No
Be	24-hour	0.0001	0.001	No
F-	24-hour	0.0007	0.25	No
Hg	24-hour	0.05	0.25	No

Table 6. PSD Class II Increment Analysis.

Pollutant	Averagin g Time	Proposed Project Increment[a]	All PSD Cosuming Increment[b]	Maximum Impact Location[c]	PSD Class II Increment
NO_x	Annual	4.42	6.53	(0.3, 100)	25.0
SO_2	3-hour	0.0	176.8	(3.6, 310)	512.0
	24-hour	0.0	49.4	(3.0, 280)	91.0
	Annual	0.53	3.98	(3.5, 270)	20.0

Note: All increments are in $\mu g/m^3$.

[a] Concentration contributed by the proposed project at the maximum impact location[c].

[b] Maximum concentration contributed by all the PSD consuming sources that will influence the significant impact area.

[c] Where the maximum concentration occurred. Shown within the parentheses are distance (km) and direction (degrees) relative to the main boiler stack of the proposed project.

4. Ambient Air Quality Standards (AAQS) Analysis

Of the pollutants subject to review, only CO, NO2, PM, SO2, and ozone have AAQS with which to compare. In general, the total ambient air quality impact for each pollutant is obtained by adding the estimated background concentration to the maximum predicted modeled concentrations of the proposed facility and the background sources. In the case of the ICL facility, the predicted maximum concentration increases of CO and PM are less than the significant impact levels defined in the State regulations (see Table 4). As such, no further modeling for other sources is required for CO and PM. A significant impact level for ozone is not defined. Ozone is a photochemically formed pollutant resulting mainly from motor vehicle emissions. The regulated pollutant for ozone formation is volatile organic compounds (VOC) which cannot be modeled for source-specific applications. Ozone, by way of VOC's, is regulated through BACT. Table 7 summarizes the estimates of the predicted maximum air quality concentrations for these pollutants in the vicinity of the proposed ICL facility.

Beryllium (Be), mercury (Hg), fluorides (F-), and inorganic arsenic (As) do not have an AAQS. However, these pollutants were modeled and the results were compared to the Department's acceptable ambient concentrations ("no-threat" levels). Table 8 summarizes the results of this analysis. The predicted concentrations for each of these pollutants is less than their respective "no-threat" levels.

Given existing air quality in the area of the proposed facility, emissions from the proposed facility are not expected to cause or contribute to a violation of an AAQS.

5. Additional Impacts Analysis

a. Impacts on Soils and Vegetation

The maximum ground-level concentration predicted to occur for each pollutant as a result of the proposed project, including a background concentration, will be below the applicable AAQS including the national secondary standards developed to protect public welfare-related values. As such, this project is not expected to have a harmful impact on soils and vegetation.

b. Impact on Visibility

The EPA Level-1 visibility screening analysis

Table 7. Ambient Air Quality Standards (AAQS) Analysis.

Pollutant	Averaging Time	Maximum Predicted Impact	Monitored Background Impact	Total Impact	Florida AAQS
CO[a]	1-hour	78.2	8001	8079	40000
	8-hour	50.9	5715	5766	10000
NO_2	Annual	6.1	5.4	11.5	60
SO_2	3-hour	182.0	61.0	243.0	1300
	24-hour	48.5	12.6	61.1	260
	Annual	6.88	1.3	8.2	60
PM[a,b]	24-hour	3.3	39.0	42.3	150
	Annual	0.26	13.3	13.6	60
PM_{10}[a,b]	24-hour	3.3	39.0	42.3	150
	Annual	0.26	13.3	13.6	50

Note: All impacts are in $\mu g/m^3$.

[a] Only the proposed project are counted.
[b] PM and PM10 are assumed to be the same.

Table 8. "No-Threat" Level Analysis.

Pollutant	Averaging Time	Maximum Predicted Impact ($\mu g/m^3$)	"No-Threat" Level ($\mu g/m^3$)
Be	8-hour	0.00021	0.02
	24-hour	0.000092	0.005
	Annual	0.000009	0.0004
F-	8-hour	0.11	25.0
	24-hour	0.05	6.0
Hg	8-hour	0.0015	0.1
	24-hour	0.00066	0.024
As	8-hour	0.0039	2.0
	24-hour	0.0015	0.5
	Annual	0.00017	0.0002

was performed by the applicant for impact on the Everglades National Park area, located 145 km to the south. The results indicate that no impact on visibility is expected in this area as a result of the proposed facility.

c. Growth-Related Air Quality Impacts

The proposed project is not expected to significantly change employment, population, housing or commercial/industrial development in the area to the extent that an air quality impact will result.

6. GEP Stack Height Determination

Good Engineering Practice (GEP) stack height means the greater of: (1) 65 meters or (2) the maximum nearby building height plus 1.5 times the building height or projected width, whichever is less. For the proposed ICL facility, both the main boiler stack and the auxiliary boiler stack are located within the area of influence for the boiler building. The height of the boiler building is 60.96 meters and represents the lesser dimension of the height and width. The calculated GEP stack height, thus, is 152.4 meters. The actual height of the main boiler stack is 150.9 meters, and the height of the auxiliary boiler stack is 27.4 meters. Since both stacks are less than the GEP stack height, the building downwash effect was included in the modeling analysis in every scenario.

7. Best Available Control Technology (BACT) Determination

PG&E/Bechtel Generating Company is proposing to install an operate a coal-fired cogeneration facility near Indiantown, Florida in Martin County. The facility will generate a nominal 330 net megawatts (MW).

The major combustion equipment will consist of a pulverized coal (PC) boiler and an auxiliary boiler. The PC boiler is rated at 3,422 MMBtu/hr (coal) and the auxiliary boiler is rated a 342 MMBtu/hr (#2 fuel oil) and 358 MMBtu/hr (natural gas). The applicant has discussed the BACT's separately. The applicant has indicated the maximum annual tonnage of regulated air pollutants emitted from the facility based on 100 percent capacity and type of fuel fired at ISO conditions to be as follows:

Post-it® Fax Note 7671	Date 12/22/97 # of pages ▶ 11
To Colin Campbell	From Willard Hanks
Co./Dept. RTP Enviro	Co. FL DEP
Phone #	Phone # 850/488-1344
Fax # 919/845-1424	Fax #

PC BOILER	Potential Emissions (tons/yr)	PSD Significant Emissions(tons/yr)
NO_x	2549	40
SO_2	2549	40
PM	270	25
PM_{10}	270	15
CO	1648	100
VOC	54	40
H_2SO_4	6.5	7
Be	0.041	0.0004
Hg	0.172	0.1
Pb	0.28	0.6
As	0.765	--
HF	22.36	3

AUXILIARY BOILER Pollutant	#2 fuel oil Emissions (tons/yr)	
NO_x	34	40
SO_2	9	40
PM	0.7	25
PM_{10}	0.7	15
CO	24	100
VOC	0.31	40
Be	2.0×10^{-5}	0.0004
Hg	2.6×10^{-4}	0.1
Pb	1.8×10^{-2}	0.6
As	3.4×10^{-3}	--

Florida Administrative Code Rule 17-2.500(2)(f)(3) requires a BACT review for all regulated pollutants emitted in an amount equal to or greater than the significant emission rates listed in the previous table. The BACT requirements are intended to insure that a proposed facility will incorporate air pollution control systems that reflect the latest techniques (including fuel cleaning or treatment or innovative fuel combustion) used in the particular industry. An evaluation of the air pollution control techniques and systems is required including a consideration for energy requirements, environmental and economic impact.

a. BACT Determination Requested by the Applicant

The applicant has suggested that BACT for the PC boiler be the following emission limitations and method of controls:

PC BOILER Pollutant	Determination lb/MMbtu	METHOD OF CONTROL
NO_x	0.17	Selective Non-Catalytic Reduction (SNCR)
SO_2	0.17	Lime Spray Drying
CO	0.11	Combustion Control
VOC	0.0036	Combustion Control
PM and PM_{10}	0.018	Fabric Filter
Be	2.73×10^{-6}	Fabric Filter
Hg	11.4×10^{-6}	Lime Spray Drying
As	51.1×10^{-6}	Fabric Filter

For the auxiliary boiler BACT is represented by clean fuel firing (natural gas and #2 fuel oil with 0.05% sulfur, by weight) and limited operating hours per year (max. 1000 hrs/yr on #2 fuel oil and max. 4000 hrs/yr on natural gas).

b. BACT Determination Procedure

In accordance with Florida Administrative Code Chapter 17-2, Air Pollution, 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, than 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 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:

- Combustion Products (e.g., Particulates). Controlled generally by good combustion of clean fuels and baghouse filters.

- Products of Incomplete Combustion (e.g., CO). Controlled generally by proper combustion techniques.

- Acid Gases (e.g., NO_x). Controlled generally by gaseo 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.

c. BACT Analysis

Combustion Products - PC Boiler

The projected emissions of particulate matter, PM_{10}, beryllium, and mercury from the Indiantown facility surpass the significant emission rates given in Florida Administrative Code Rule 17-2.500, Table 500-2. A review of the BACT/LAER Clearinghouse indicates that the particulate emission rates range from 0.011 (LAER) to 0.05 lb/MMbtu for other coal-fired boilers. In general, the BACT/LAER Clearinghouse does not contain specific emission limits for beryllium and mercury from coal-fired boilers. BACT for heavy metals from these facilities is typically represented by the level of particulate control. The control options for controlling PM, PM_{10}, Be and Hg from these coal-fired boilers are approximately 65% that use fabric filter baghouses and 35% that use electrostatic precipitators (ESP). Wet control techniques were not considered to be feasible due to the limited availability of limited clean water and lack of wastewater treatment and disposal capability at the Indiantown site. Baghouses provide better control of fine particulate. When it is used with a lime spray dryer additional SO_2 control results.

A PM/PM_{10} emissions limitation of 0.018 lb/MMBtu from the PC Boiler firing coal is reasonable as BACT for the Indiantown facility. Gore-Tex bags, instead of conventional fabric, were considered at an additional cost of $832,000 to reduce 90 tons/year of emissions. The $9,244/ton incremental cost was considered excessive.

Therefore, BACT for controlling PM, PM10, Be, and Hg on the PC boiler is the use of a fabric filter with conventional bags.

Combustion Products - Auxiliary Boiler

Emissions of particulate matter (PM) from oil-fired boilers comes from the ash in the fuel and incomplete fuel combustion. The auxiliary boiler will operate a maximum of 1000 hrs/yr on #2 fuel oil and a maximum of 4000 hrs/yr on natural gas. PM_{10} is expected to be 95% of the total particulate emission rate. Again the most available control technology is either fabric filters or electrostatic precipitators. The applicant contacted several fabric filter vendors and was unable to find one that would provide this equipment for an oil-fired boiler. An evaluation of ESP indicates that 99% control (removing 3.5 tpy) can be obtained but at a cost of $137,000/ton of PM removed. Therefore, it is not considered to represent BACT for PM on the auxiliary boiler.

Products of Incomplete Combustion PC and Auxiliary Boilers

The emissions of carbon monoxide (CO) and volatile organic compounds (VOC) exceed PSD significant emission rate of 100 tpy and 40 tpy respectively. The PC boiler emissions of CO and VOC are controlled by either good combustion (minimizing pollutant formation) or flue gas catalytic oxidation of the CO and VOC. A review of the BACT/LAER Clearinghouse indicates that the emission levels of 0.11 and 0.0036 lb/MMBtu for CO and VOC, respectively, are achievable by a combustion control system are representative of previous BACT determinations.

Catalytic oxidation has never been applied to either coal-fired or oil-fired boilers. However, it has been used as the most stringent control for CO and VOC for combustion turbines. The catalyst vendors indicate flue gas particulate plugs the catalyst system on coal-fired units and is not feasible for oil-fired units due to sulfur, ash, and trace element concentrations.

Use of an oxidation catalyst system in either the proposed Indiantown PC boiler or the fuel oil-fired auxiliary boiler is considered technically infeasible.

Therefore, the applicant concluded that combustion controls be considered BACT to minimize the formation and emission of both CO and VOC without adverse economic, energy or environmental impacts. Furthermore, combustion controls are the most stringent control alternatives applicable to PC and fuel oil-fired units.

Acid Gases - PC Boiler

The emissions of sulfur dioxide (SO_2), nitrogen dioxide (NO_x), fluorides (HF), and sulfuric acid mist (H_2SO_4), as well as other acid gases which are not regulated under the PSD Rule, represent significant potential air pollutant emissions which must be subject to appropriate control. Sulfur dioxide emissions from coal fired boilers are directly related to the sulfur content of the fuel. The addition of "add on" control equipment and the utilization of combustion technologies which serve to control sulfur dioxide emissions during combustion are other techniques that can be used to minimize emissions.

SO2 and Acid Gases

The applicant elected to discuss SO_2, HF and H_2SO_4 removal methods together since they are common. Emissions of sulfur oxides and acid gases (H_2SO_4 and HF) are generated in fossil-fuel fired sources from the release in the furnace of sulfur and fluorine present in the fuel. Sulfur compounds are formed when the organic and pyritic sulfur is oxidized, forming primarily SO_2 and smaller quantities of SO_3 and SO_4. SO_3 further reacts with water present in the flue gas to form H_2SO_4. Uncontrolled emissions of SO_2 are affected only by the fuel sulfur content.

The control of SO_2 and acid gas emissions is accomplished primarily by removing these pollutants from the flue gas by wet or dry scrubbing. Wet scrubbing achieves high levels of removal of SO_2/acid gas and is comparable to dry scrubbing. Wet scrubbing is accomplished by passing the flue gas through a scrubbing liquid in a water saturated environment. The pollutants become a part of the liquid slurry and treated in a wastewater treatment and disposal system. The three reagents are sodium-based, calcium-based and dual-alkali. Regardless of the reagent used, they are all recycled to reduce the water consumption and the reagent requirements.

The wet scrubbing advantage over dry scrubbing includes a reduction of the reagent consumption because of easier recycling and ability to operate at low temperatures. The two main disadvantages are: 1) The amount of water required for wet scrubbing and 2) The difficulty in treating the slurry due to acidic and/or high-chloride levels requiring percolation through limestone beds, evaporation ponds and deep well injection. Other methods of treating the slurry such as reverse osmosis , electrodialysis and flash evaporation/ crystallization are more sophisticated and more costly. The use of wet scrubbers causes a low scrubber outlet temperature (120 - 130^{o} F) causing visible moisture plumes. Wet scrubbing also results in significant repairs due to corrosion, erosion and scaling of wet scrubber equipment, piping, pumps, fans, and valves. The wet slurry eventually must be disposed of, further complicating the use of wet scrubbing as an alternative. Generally wet scrubbers are more expensive than spray dryer scrubbers not only to purchase and but to operate as well.

Spray dryer absorbers located upstream of the particulate removal device is the other predominant method for removing SO_2/acid gases. A spray dryer achieves comparable levels of pollutant removal and is less mechanically complex. The reagent is produced as a dry solid waste which can be returned directly to the coal mine for disposal.

Limestone injection is employed with circulating fluidized bed (CFB) boilers but is not technically applicable for a PC boiler.

Both wet and dry scrubbers are capable of achieving the most stringent control possible. By firing maximum 2% sulfur coal and obtaining 95% removal of SO_2/acid gases a 0.17 lb/MMBtu emission rate can be obtained at Indiantown. Total capital cost to achieve 0.17 lb/MMBtu is estimated a $67,828,000 for wet limestone and $32,271,000 for the spray drying scrubbers. Total annual costs are estimated at $31,395,000/yr and $25,383,000/yr respectively. Wet scrubbing uses more energy than the spray drying method.

The applicant concluded that the spray dryer would be BACT for the PC boiler. This method of control can reduce the emissions to 0.17 lb/MMBtu for SO_2/acid gas and is more economical and more energy efficent.

NOx

The emissions of nitrogen oxides represent a significant proportion of the total emissions and need to be controlled if deemed appropriate. The applicant has stated that BACT for nitrogen oxides will be met by using Selective Non-Catalytic Reduction (SNCR) to limit emissions to 0.17 lb/MMBtu.

The alternative methods applicable to PC Boilers for controlling NO_x are combustion controls, selective non-catalytic reduction (SNCR), and selective catalytic reduction (SCR).

A review of the EPA's BACT/LAER Clearinghouse indicates that the lowest NO_x emission limit established to date for a coal-fired boiler is 0.44 lb/MMBtu. This level of control was accomplished through the use of combustion techniques.

SCR 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 SCR process has not been applied to domestic coal-fired sources but has been used in Japan and Europe starting in 1980. About 25 utility boilers are operating in Japan with up to 80% removal efficiency. About twice as many utility boilers are operating in Europe with removal efficiencies up to 90%. SCR on combustion turbines can achieve up to 90% reduction of NO_x with a new catalyst. As the catalyst ages, the maximum NO_x reduction will decrease to approximately 86 percent.

SCR has never been applied to a commercial-scale unit firing domestic coals and never applied in Japan or Europe to a commercial PC boiler using a baghouse for particulate control. Furthermore, using this technology would increase annual operating cost by $8,961,400/yr and $5,978/ton of NO_x controlled. Therefore, the applicant states that SCR is not considered BACT because of the uncertainty of the application and the high cost.

The SNCR process is based on a gas phase homogeneous reaction between NO_x in the flue gas and either injected ammonia or urea to form gaseous nitrogen and water vapor. These systems do not employ a catalyst and, therefore, operate at higher temperatures than SCR systems. The two commercially available SNCR processes are NO_xOUT by EPRI and DeNO_x by Exxon Corporation. Of the two technologies only DeNO_x has been used on PC boilers. The applicant states that the use of DeNO_x has some risk since it has not been applied to a facility like Indiantown but it has been applied to a number of CFB facilities.

Based on vendor information and relevant experience it is expected that NO_x can be controlled to 0.17 lb/MMBtu. The annual cost is estimated at $4,244,400 reducing the emissions by 1499 tons/yr. Therefore, the applicant estimated the cost of reducing NO_x emissions to be $2,899/ton which is considered economically justifiable for BACT.

Acid Gases - Auxiliary Boiler

The auxiliary boiler is expected to operate about 5000 hrs/yr (4000 hrs/yr using natural gas and 1000 hrs/yr using #2 fuel oil with 0.05% Sulfur, by weight). The applicant is proposing to control SO_2 and acid gas emissions by the use of low sulfur oil to meet a maximum of 0.052 lb/MMBtu.

The cost of applying wet scrubbing to reduce the emissions is estimated to be $65,523/ton which is not considered economical. This method would also produce a significant amount of solid waste and result in adverse energy impacts. For NO_x control SCR, SNCR and Flue Gas Recirculation (FGR) were evaluated and the cost per ton of NO_x reduced were $5,623, $6,189 and $4,007 respectively. The applicant considered these cost excessive for previous BACT determinations for this type of facility.

d. Environmental Impact Analysis - PC Boiler

The use of a fabric filter to control particulate emission from the PC boiler does not appear to have any negative environmental impacts. However, the energy impact is considered significant since about 1250 KW of energy is required to operate the fabric filter.

The use of SNCR to control NO_x has a potential environmental impact associated with residual ammonia in the flue gas and safety associated with ammonia storage. Both of these concerns are expected to be minimized by close monitoring and control along with good operating/safety procedures.

e. BACT Determination by DER

Based on the information presented by the applicant and the studies conducted the Department believes that the use of a fabric filter for particulate control, SNCR for NOx control, and dry spray scrubbing for SO_2/acid gas control is justifiable as BACT. Therefore, the Department accepts the applicant's BACT recommendations as shown in the following table:

Pollutant	Emission Limit	Maximum Emissions Tons/year(a)	Method of Control
NO_x	0.17 lbs/MMBtu	2549	SNCR
SO_2	0.17 lbs/MMBtu	2549	Spray Drying
PM	0.018 lbs/MMBtu	270	Fabric Filter
PM_{10}	0.018 lbs/MMBtu	270	Fabric Filter
CO	0.11 lbs/MMBtu	1648	Combustion
VOC	0.0036 lbs/MMBtu	54	Combustion
H_2SO_4	0.0004 lbs/MMBtu	6	Spray Drying
Be	2.73×10^{-6} lbs/MMBtu	0.041	Fabric Filter
Hg	11.4×10^{-6} lbs/MMBtu	0.172	Spray Drying
Pb	18.7×10^{-6} lbs/MMBtu	0.28	Spray Drying
As	51.1×10^{-6} lbs/MMBtu	0.765	Fabric Filter
HF	0.002 lbs/MMBtu	22.36	Spray Drying

(a) Maximum total emissions are based on the maximum hourly emission rate and 8760 hrs/yr

For the auxiliary boiler BACT will be represented by a limitation on hours of operation and the use of clean fuels (maximum 1000 hours/year firing #2 fuel oil with 0.05% sulfur, by weight, and 4000 hours/year firing natural gas).

Auxiliary Boiler (#2 fuel oil) Pollutant	Maximum Emissions (tons/yr)
NO_x	34
SO_2	9
PM	0.70
PM_{10}	0.70
CO	24
VOC	0.31
Be	2.0×10^{-5}
Hg	2.6×10^{-4}
Pb	1.8×10^{-2}
As	3.4×10^{-3}