Florida Department of Environmental Regulation

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

Lawton Chiles, Governor

Carol M. Browner, Secretary

March 11, 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: Applied Energy Services (AES)/Seminole Kraft Corporation
Cedar Bay Cogeneration Project
Federal Number: PSD-FL-137

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 to Tom Rogers or Barry Andrews at the above address or call them at (904)488-1344 at your earliest convenience.

Sincerely,

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

CHF/CP

Enclosure

cc: A. Kutyna, NE Dist.
C. Kirts, BESD
C. Shaver, NPS

Technical Evaluation
and
Preliminary Determination

Applied Energy Services (AES)/Seminole Kraft Corporation
Cedar Bay Cogeneration Project
Duval County, Florida

Permit No. PSD-FL-137

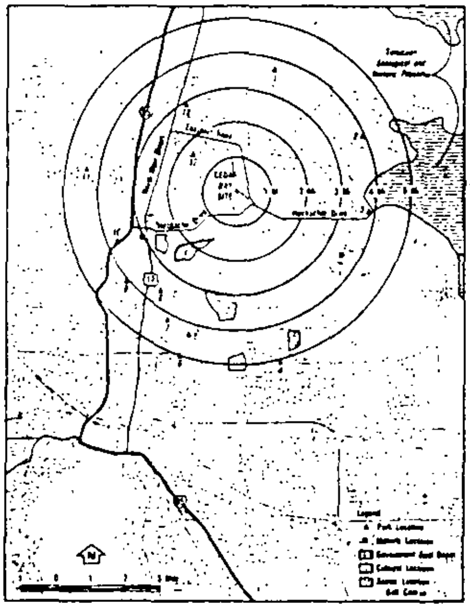
Department of Environmental Regulation
Division of Air Resources Management
Bureau of Air Regulation

October 29, 1990

NOTICE OF CERTIFICATION HEARING ON AN APPLICATION TO CONSTURCT AND OPERATE AN ELECTRICAL POWER PLANT TO BE LOCATED NEAR JACKSONVILLE, FLORIDA

1. Application number PA 88-24 for certification to authorize construction and operation of an electrical power plant near Jacksonville, Florida, and an associated transmission line from the Seminole Kraft Paper Mill site to Jacksonville Electric Authority's Eastport Substation is now pending before the Department of Environmental Regulation, pursuant to the Florida Electrical Power Plant Siting Act, Part II, Chapter 403, F.S. Certification of this power plant would allow construction and operation of a new source of air pollution which would consume an increment or air quality resources. The department review has resulted in an asessment of the prevention of significant deterioration impacts and a determination of Best Available Control Technology necessary to control the emission of air pollutants from this source.

2. The proposed 35 acre power plant site is located on the 425 acre Seminole Kraft Paper Mill site in northeastern Duval County. The site is aproximately seven and one-half miles northeast of downtown Jacksonville. The site will house three fluidized-bed, coal fired boilers, electrical generators, new chemical recovery boiler, multiple effect evaporators, smelt dissolving tanks, coal pile, cooling towers and related facilities. New turbines will be generating 42 MW of electricity for use in the paper mill and 225 MW for sale to Florida Power and Light Company. A short transmission line will connect the facility to an existing Jacksonville Electric Authority electrical substation.



SITE LOCATION – 5-MILE RADIUS WITH PARK, HISTORIC, GOVERNMENT, CULTURAL, AND SCENIC LOCATIONS (JACKSONVILLE, FLORIDA)

3. The Department of Environmental Regulation has evaluated the application for the proposed power plant. Certification of the plan would allow its construction and operation. The application and the department's evaluation is available for public inspection at the addresses listed below:

STATE OF FLORIDA DEPARTMENT OF ENVIRONMENTAL REGULATION
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

STATE OF FLORIDA DEPARTMENT OF ENVIRONMENTAL REGULATION
Northeast District Office
3426 Bills Road
Jacksonville, Florida 32207

CITY OF JACKSONVILLE
BIO-ENVIRONMENTAL SERVICES DIVISION
421 West Church Street
Jacksonville, Florida 32202-4111

ST. JOHNS RIVER WATER MANAGEMENT DISTRICT
P.O. Box 1429
Highway 100
Palatka, Florida 32077

4. Pursuant to Section 403.508, Florida Statutes, the certification hearing will be held by the Division of Administrative Hearings on February 5, 1990, at 10:00 a.m., in the First Coast Room of the Inn at Bay Meadows, 8050 Baymeadows Circle West Jacksonville, Florida, in order to take written and oral testimony on the effects of the proposed power plant or any other matter appropriate to the consideration of the site. There will be an opportunity for public testimony at 7:00 p.m. on February 7, 1990. Need for the facility has been predetermined by the Public Service Commission at a separate hearing. Written comments may be sent to Mr. Robert T. Benton (Hearing Officer) Division of Administrative Hearings, The Desoto Building, 1230 Apalachee Parkway, Tallahassee, Florida 32399-1550. This hearing will replace the hearing originally scheduled for January 8, 1990. During the period of February 6-9, the hearing will commence at 9:00 a.m. If the hearing is not completed by February 9, the Hearing will resume on February 19, 1990 at 10:00 a.m. at the Hospitality Inn, 7071 – 103rd. Street, Jacksonville, Florida.

4. Pursuant to 403.508(4), F.S.: "(a) Parties to the proceeding shall include: the applicant; the Public Service Commission; the Department of Community Affairs; the water management district as defined in Chapter 373, in whose jurisdiction the proposed electrical power plant is to be located; and the Department. (b) Upon the filing with the Department of a notice of intent to be a party at least 15 days prior to the date set for the land use hearing, the following shall also be parties to the proceeding:

1. Any county or municipality in whose jurisdiction the proposed electrical power plant is to be located.

2. Any state agency not listed in paragraph (a) as to matters within its jurisdiction.

3. Any domestic non-profit corporation or association formed in whole or in part to promote conservation or natural beauty; to protect the environment, personal health, or other biological values; to preserve historical sites; to promote consumer interests; to represent labor, commercial or industrial groups; or to promote orderly development of the area in which the proposed electrical power plant is to be located.

(c) Notwithstanding paragraph (4) (d), failure of an agency described in subparagraphs (4) (b) 1 and (4) (b) 2 to file a notice of intent to be a party within the time provided herein shall constitute a waiver of the right of the agency to participate as a party in the proceeding.

(d) Other parties may include any person, including those persons enumerated in paragraph (4) (b) who failed to timely file a notice of intent to be a party, whose substantiate interests are affected and being determined by the proceeding and who timely file a motion to intervene pursuant to Chapter 120, F.S., and applicable rules. Intervention pursuant to this paragraph may be granted at the discretion of the designated hearing officer and upon such conditions as he may prescribe any time prior to 15 days before the commencement of the certification hearing.

6. When appropriate, any person may be given an opportunity to present oral or written communications to the designated hearing officer. If the designated hearing officer proposes to consider such communication, then all parties shall be given an opportunity to cross-examine or challenge or rebut such communications.

7. Notices or petitions made prior to the hearing should be made in writing to:

Mr. Robert Benton
Division of Administrative Hearings
The Desoto Building
1230 Apalachee Parkway
Tallahassee, Florida 32399-1550

8. Those wishing to intervene in these proceedings must be represented by an attorney or other person who can be determined to be qualified to appear in administrative hearings pursuant to Chapter 120, F.S., or Chapter 17-1.21, FAC.

9. This Public notice is also provided in compliance with the federal Coastal Zone Management Act, as specified in 15 CFR Part 930, Subpart D. Public Comments on the applicant's federal consistency certification should be directed to the Federal Consistency Coordinator, Division of Environmental Permitting, Department of Environmental Regulation.

10. Pursuant to Section 403.511(2), F.S. AES/Cedar Bay seeks a variance from the water quality standards for aluminum, iron and phenol as contained in Chapter 17-3, F.A.C. for the purpose allowing construction dewatering discharge and for allowance of iron in cooling tower blowdown. The hearing officer will receive comments and testimony from the parties, the public and the affected agencies at the certification hearing.

11. On November 14, 1988, AES/Cedar Bay and Seminole Kraft Corporation applied to the DER to construct the aforementioned cogeneration project. The application is also subject to U.S. Environmental Protection Agency (EPA) regulations for Prevention of Significant Deterioration of air quality (PSD), codified at 40 CFR 52.21, and Florida Administrative Code Chapter 17-2.500. These regulations require that, before construction on a source of air pollution subject to PSD may begin, a permit must be obtained from DER. Such permit can only be issued if the new construction has been determined by DER to comply with the requirements of the PSD regulations, which are described in 40 CFR 52.21 and 17.2.500, F.A.C. These requirements include a restriction on incremental increases in air quality due to the new source and application of best available control technology (BACT).

The DER has been granted a delegation by EPA to carry out the PSD review of this source. Acting under that delegation, the DER has prepared a draft permit which is included in the DER's staff analysis report. The DER has made a preliminary determination that the proposed construction will comply with all applicable PSD regulations. The degree of Class II increment consumption that will result from the construction is:

Pollutant	Annual Average	24-Hr. Average	3-Hr. Average
Particulate	0.0%	0%	
Sulfur Dioxide	0%	0%	0%

The source is located approximately 60 kilometers from the nearest Class I area the, Okefenokee Wilderness area.

The degree of Class I increment consumption that will result from the construction and operation of the source is:

Pollutant	Annual Average	24-Hr. Average	3-Hr. Average
Particulate	0%	0%	
Sulfur Dioxide	0%	0%	0%

Construction and operation of the source will not cause a violation of any ambient air quality standard nor will it cause an exceedance of any PSD increment.

Because of replacement of old, poorly controlled emission with new sources that have higher stacks and highly efficient air pollutant control equipment, this project will result in a decrease in current air quality concentrations.

TABLE OF CONTENTS

State of Florida Department of Environmental Regulation -
(Applied Energy Services/Seminole Kraft Corporation)
Cedar Bay Cogeneration Project
Electric Power Plant Site Certification Review Case No. PA 88-24

I. SUMMARY

Facilities Overview

Applied Energy Services (AES) in partnership with Seminole Kraft Corporation (SKC) proposes to certify a 256 megawatt (MW), coal and wood bark fired, fluidized bed, cogeneration project. A 42 MW generating unit associated with a chemical recovery boiler, multiple effect evaporators, and a smelt dissolving tank will also be constructed at the SKC paper mill site northeast of Jacksonville under separate DER permits.* The fluidized bed project is known as the Cedar Bay Cogeneration Project (CBCP). The 256 MW unit would be tied into the JEA and Florida Power and Light (FPL) power network via new transmission lines. One 138 KV line will be necessary to transmit the power from the plant to the JEA and FPL systems. Fuel delivery for three fluidized bed boilers would use the existing SCX rail lines or be derived from pulp mill wastes. The project will be known as the Cedar Bay Cogeneration Project.

Approximately 35 acres of land would be required for the operation of the CBCP. This would be due to in part to the need for holding/storage areas for the coal, the flush limestone, for the spent limestone, and for the bottom ash and fly ash disposal areas. AES plans to ship a pelletized ash/limestone mixtures back to the coal mine to minimize the waste storage problem. Fluidized bed boiler design and fabric filters will be used to limit air emissions. Fly ash will be collected and mixed with spent limestone and bottom ash then mixed with water and pelletized before shipment back to the coal mine.

AES proposes to utilize fresh water cooling towers with the blowdown into the existing Seminole Kraft cooling water discharge to the St. Johns River. Plant service water and cooling water would come from SKC wells into the Floridian Aquifer until such time as reclaimed water should become available. Wastewaters other than cooling waters would be pumped to wastewater treatment units with ultimate disposal via the SKC oxidation pond and discharge system. The cooling water and other waste streams would be disposed of via the SKC which empties into the St. Johns River.

Air Impacts

Based on the control technologies AES and SKC have proposed to utilize, it is expected that the Cedar Bay Project and associated facilities will emit much less than the minimum technology based standards that apply to these type of facilities. Analysis of the predicted effects of plant emission indicates that no significant air quality impacts should occur.

* SKC has recently decided to eliminate this project and convert the paper mill to another type.

Replacement of old units at the SKC mill will result in a net improvement compaterd to existing ambient air quality.

Consumptive Use of Water

AES will have an adequate supply of fresh water from the SKC wells for its cooling tower system. Because there is some concern about the adequacy of the fresh water supply in Duval County and potential salt water intrusion into the drinking water aquifer, the future use of reclaimed water from the Jacksonville sewage treatment system is under investigation.

Waste and Wastewater Impacts

The AES solid waste holding area will cover no more than two acres. The pelletized ash/limestone will be stored in a lined area. Coal pile runoff will be collected and treated. Leachate from the existing papermill lime mud piles which has contributed amounts of heavy metals to the groundwater on the site will be eliminated by removing the lime mud to a secure landfill and by construction dewatering.

Discharges from the AES wastewater treatment systems will be into the SKC treatment system/oxidation pond. Discharge of cooling tower blowdown, and construction dewatering discharge will go to the existing SKC discharge and may on occasion contribute to temporary violations of state water quality standards for certain parameters when the St. Johns River exceeds the standards.

Biological Impacts

The thermal effluent from the AES Units will combine with the SKC discharge. At the worst it could slightly raise the temperature of the combined wastewater discharge during winter months. At the best, the AES cooling tower blowdown could decrease the temperature of the SKC waste water discharge by 0.3°F. Adverse impacts on estuarine organisms should be minimal.

The use of the existing pulp mill site and the proposed rail spur off the existing rail line does not constitute an important loss of wildlife habitat. The area designated for the Cedar Bay Project does not contain valuable habitat. Impact on the surrounding areas from this project should be minimal due to existing industrial development.

Sociological/Economic Impacts

Because the SKC site already has a pulp and paper mill operating, the addition of a new co-generation plant on adjacent property is not expected to create significant sociological impacts other than induced traffic delays caused by coal trains. For the same reason, the economic impacts should primarily be felt in terms of financing rather than in areawide support service demands or other local costs.

of the previously mentioned species could be slightly affected by plant-related activities as food and habitat losses become more widespread.

A species is defined by the Florida Department of Environmental Regulation as "important" if: 1) it is commercially or recreationally valuable; 2) it is rare, endangered, threatened, or protected; or 3) it has unique ecological value.

Those species observed on the proposed site that were found to be commercially or recreationally valuable were the Whitetail deer, the Eastern gray squirrel, the marsh rabbit, raccoon, opossum, and bobwhite quail.

Besides the biota already discussed in previous paragraphs, other species which are considered endangered or threatened at the site include the American alligator, common dolphin, the gopher tortoise, Florida gopher frog, the eastern indigo snake, osprey, wood stork, red cockaded woodpecker, and bald eagle.

The Florida Gopher Tortoise a species of unique ecological value since Gopher Tortoise burrows provide a habitat for no less than 30 animal species, some of which can live nowhere else. Among these commensals inhabiting the dens are the Florida Gopher Frog (RARE), that emerges from these burrows only at night. Although it has been assumed that indigo snakes are uncommon in Duval County, no data is available on the number of these snakes living in gopher tortoise burrows at the SKC site.

VI. FACILITY SPECIFIC CONCERNS

A. Air quality

1. Selected Fuel

The units are planned for coal-fired operation; however, provisions are being made in the design to allow for burning of wood waste as well. Based on a study of availability of coal, east of the Mississippi River, there are practical sources of coal adequate to meet the plant's needs over the anticipated life of the project (approximately 1,105,000 tons per year). In addition, partial supplies could be obtained from several foreign sources.

The plant is designed to retain the flexibility to change its' coal supply (to insure against disruptions in supply, local market upsets and to maintain competitive prices) with minimum reduction in efficiency and without violating air quality standards. Analyses of potential coal supplies were therefore necessary so that the plant could be designed to accomodate coals with a variety of characteristics. Coals from the above sources were analyzed to determine the ranges of characteristics and chemical constituents.

The air quality control system is designed on a "worst case" basis assuming the maximum sulfur (4 percent) and ash (18 percent) in the coal and a minimum heating value (10,500

BTU/lb). This approach assumes the sulfur and ash contents of the coal are 3.8 lb/MMBtu (Million Btu) and 17.1 lb/MMBtu, respectively. The ash remaining after the coal is burned is assumed to be 80 percent fly ash and 20 percent bottom ash. The above values were used to develop collection equipment efficiencies, investment estimate and long and short-term ground level ambient air quality concentrations. This approach requires a more sophisticated, complex, efficient and costly air quality control system than would be required on the basis of average coal characteristics.

The coal handling system will provide for delivery of coal by rail delivery directly to the plant by unit train or in trainload lots. A bottom car dumper will be used to unload coal from the trains on the power plant site proper. The system will also include the yard area coal storage, transfer system, coal silos, and the tripper floor distribution system.

The emission of air pollutants from the Cedar Bay/Seminole Kraft site are limited by Chapter 17-2, FAC, and by the New Source Performance Standards as imposed by the U.S. Environmental Protection Agency. In order to comply with these regulations, Cedar Bay plans to utilize washed coal with a fluidized limestone bed to control emission of sulfur oxides. Particulate matter will be controlled by a fabric filter.

When all of the units are operating at 100% of rated capacity, the plant will consume 145 tons per hour of coal and will emit 1913 pounds per hour of SO_2, 64 pounds per hour of particulates, and 925 pounds per hour of nitrogen oxides.

The stack height of 425 feet will assist the control equipment in reducing ambient air quality impacts. Only during rare meteorological conditions will stack emissions reach the ground close to the plant. The stack height insures dispersion and dilution of air pollutants before the pollutants reach ground level at some distance from the site.

2. Air Quality Impact Analysis

A. Introduction

The proposed Cedar Bay Cogeneration facility (modifications to the Seminole Kraft plant), located in Jacksonville, will emit in PSD-significant amounts seven pollutants. These are the criteria pollutants carbon monoxide (CO), nitrogen oxides (NOx), and lead (Pb) and non-criteria pollutants beryllium (Be, mercury (Hg), flouride (Fl) and sulfuric acid mist.

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

- An analysis of existing air quality;
- 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.

An analysis of existing air quality generally relies on preconstruction monitoring data collected in accordance with EPA-approved methods. The PSD increment and AAQS analysis depend on air quality dispersion modeling carried out in accordance with EPA guidelines.

Based on these required analyses, the Department has reasonable assurance that the proposed sources at the cogeneration facility, as described in this report and subject to the conditions of approval proposed herein, will not cause or contribute to a violation of any PSD increment or ambient air quality standard. The CBCP will reduce the site's potential contribution to S^{O}_{2} exceedances. A discussion of the modeling methodology and required analyses follows.

B. Modeling Methodology

The EPA-approved screening level model PTPLU-2 and the EPA documents entitled Procedures for Evaluating Air Quality Impact of New Stationary Sources (Volume 10-revised) were used to determine the highest predicted ground level concentration for various plant operating conditions.

The operating conditions of the circulating fluidized bed (CFB) boilers were evaluated at 50 and 75 percent load capacity plus the maximum designed for the plant. The maximum CFB operation was determined to be the worst case operating condition and is the only operating level included in the refined air quality modeling. The proposed kraft recovery boiler (KRB) and smelt dissolving tank (SDT) are not expected to operate at varying conditions and thus were not evaluated with screening level modeling, nor are they included in this certification.

The EPA-approved Industrial Source Complex Short-Term (ISCST) dispersion model was used in the refined 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 estimates 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 seperation 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. These features were used in the refined modeling analyses.

The modeling primarily used polar receptors with the proposed CFB boiler stack at the center. Radials were spaced at 10° increments from 10° to 360°. The initial receptor distances modeled were 0.979, 1.273, 1.664, 2.252, 2.937, 3.818, 5.091, 6.657, and 8.811 km. Depending on the applicable averaging times and pollutants, additional receptor distances were included at 80-meter intervals from 0.220 km to 0.940 km. These distances represent locations near the plant boundary.

The meteorological data used in the ISCST model consisted of five years (1981-1985) of hourly surface data taken at Jacksonville, FL. Mixing heights used in the model were based on upper air data from Waycross, Georgia.

Table 1 lists the significant and net emission rates for the proposed modification. Table 2 lists the stack parameters and emission rates for the proposed facility, as well as, a combined configuration of the existing Seminole Kraft sources. Carbon monoxide and lead were modeled using the maximum emissions for the facility alone. The NO_2 modeling was based on the net emission change (proposed minus existing) using an emission rate of 0.36 lb/MBtu which is higher than the revised proposed emission rate of 0.29/MBtu.

C. Analysis of Existing Air Quality

Preconstruction ambient air quality monitoring is required for all polutants 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 already exist and these data are representative of the proposed source area, then at the discretion of the Department these data may be used.

The predicted maximum air quality impacts of the proposed facility for those pollutants subject to PSD review are listed in Table 3. Sulfuric acid mist is not listed because there is no de minimus level for this pollutant.

Based on the modeling results, no monitoring is required for CO, NOx, or Hg. Department lead monitoring results for 1986 through 1987 were used to determine existing lead levels. While the modeled impacts for Be and Fl are greater than their respective de minimus values, they are much below the Department guideline acceptable ambient concentrations of 0.0025 ug/m^3 (annual) and 11.90 ug/m^3 (24-hour), respectively. Therefore, monitoring for these pollutants is not necessary. Sulfuric acid mist was modeled and showed a maximum 24-hour concentration of 0.73 ug/m^3. This value is significantly less than the acceptable ambient concentration of 4.76 ug/m^3 (24-hour). Consequently, monitoring for this pollutant is not required.

D. AAQS Analysis

Given existing air quality in the area of the proposed facility, emissions from this facility are not expected to cause or contribute to a violation of an applicable AAQS. The results of the AAQS analysis are contained in Table 4.

Table 1. Significant and Net Emission Rates (Tons per Year)

Pollutant	Significant Emission Rates	Existing Emissions	Proposed Maximum Emissions*	Net Emissions	Applicable Pollutant
Carbon Monoxide	100	2933	4637	1704	YES
Nitrogen Dioxide	40	1522	6301	4779	YES
Sulfur Dioxide	40	5902	5525	-377	NO
Particulate Matter (PM)	25	875	812	-63	NO
Particulate Matter (PM_{10})	15	684	683	-1	NO
Ozone (VOC)	40	540	456	-84	NO
Lead	0.6	--	91	91	YES
Asbestos	0.007	--	<0.007	<0.007	NO
Beryllium	0.0004	--	1.5	1.5	YES
Mercury	0.1	--	3.4	3.4	YES
Vinyl Chloride	1.0	--	<1.0	<1.0	NO
Fluorides	3	--	1122	1122	YES
Sulfuric Acid Mist	7	--	322	322	YES
Total Reduced Sulfur	10	98	47	-51	NO

* Assumes a 100 percent capacity factor for the kraft recovery boiler, smelt dissolving tank, limestone dryers, and the multiple effects evaporator. Assumes a 93 percent capacity factor for the cogeneration plant.

Table 2. Stack Parameters and Emission Rates

Source	Stack Hgt. (m)	Exit Temp. (K)	Exit Vel. (m/s)	Stack Dia. (m)	Emission Rate (g/s)		
					NOx	CO	Pb
Proposed Sources							
Kraft Recovery Boiler	129.5	478	20.42	3.43	46.5	62.3	.006
CFB Boiler	129.5	403	33.22	4.27	145	76.4	2.8
Limestone dryer	9.1	355	21.34	1.04	0.6	0.1	--
Lime Kilns	22.9	339	10.36	1.13	--	--	--
Smelt Dissolving Tanks	73.1	344	14.32	1.5	--	--	--
Existing Composite Source Data							
Power Boilers	32.3	433	20.12	1.83	23.2	1.7	--
Bark Boilers	41.5	329	13.72	2.44	11.3	15.7	--
Kraft Boilers	38.4	344	16.76	2.74	9.2	66.9	--
Lime Kilns	22.9	339	10.36	1.13	--	--	--
Smelt Dissolving Tanks	37.8	344	4.27	1.22	--	--	--

Table 3. Maximum Air Quality Impacts for Comparison to the de minimus Ambient Levels

Pollutant and Averaging Time	Predicted Impact (ug/m^3)	De minimus Ambient Impact Level (ug/m^3)
CO (8-hour)	25.0	575
NO_2 (Annual)	<0	14
SO_2 (24-hour)	<0	13
Pb (3-month)	0.13 *	0.1
Be (24-hour)	0.0017	0.0005
Hg (24-hour)	0.004	0.25
Fl (24-hour)	1.375	0.25

* The Pb impact is based on a 24-hour modeling value and, therefore, the 3-month Pb average is expexted to be significantly less than this value.

Table 4. Comparison of Total Impacts with the AAQS

Pollutant and Averaging Time	Maximum Predicted Impact (ug/m^3)	Existing Background (ug/m^3)	Maximum Total Impact (ug/m^3)	Florida AAQS (ug/m^3)
CO (1-hour)	94.1	13	107.1	40000
CO (8-hour)	25.0	6	31.0	10000
NO_2 (Annual)	3.8	29	32.8	60
Pb (3-month)	0.13	0.3	0.43	1.5

Of the pollutants subject to review, only the criteria pollutants CO, NOx, and Pb have an AAQS. Dispersion modeling was performed as detailed earlier for the proposed facility. The results indicate that, except for Pb, the maximum impacts of these pollutants were less than the significant impact levels defined in Rule 17-2.100 (170), FAC. As such, no modeling of other sources was necessary for CO and NOx. For Pb, there is no significant impact defined in the rule. The maximum 24-hour Pb concentration was used as a conservative estimate of the quarterly concentration. When combined with the background concentration of 0.3 ug/m^3 (the highest quarterly average between 1986 and 1987 in Duval County), this results in a total concentration of 0.43 ug/m^3 which is well below the Pb AAQS. Therefore, no additional modeling for Pb was required.

The total impact on ambient air is obtained by adding a "background" concentration to the maximum modeled concentration. This "background" concentration takes into account all sources of a particular pollutant that are not explictly modeled. These "background" concentrations were obtained from Department approved monitors near the Cedar Bay Site for 1986 (1985 for NOx).

E. Additional Impacts on Soils and Vegetation

1) Impacts on Soils and Vegetation

The maximum ground-level concentrations predicted to occur for the criteria pollutants as a result of the proposed project and a background concentration will be at or below all applicable AAQS including the national secondary standards developed to protect public welfare-related values. As such, these pollutants are not expected to have a harmful impact on soils and vegetation.

2) Impact on Visibility

To ensure the protection of visibility in the Okefenokee Wilderness area (PSD Class 1 area) area a Level 1 visibility analysis was done for the proposed facility. The results of this analysis indicate that the emissions from this facility will not significantly alter the visibility in this area.

3) Growth-Related Air Quality Impacts

The proposed facility 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.

4) 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 width, whichever is less. The GEP stack height determination is dependent on the distance and orientation to the various buildings nearby the stack because the projected building width can change.

The applicant calculated the GEP heights for each proposed source based on the dimension of nearby buildings. The GEP height of 129.5m was used in the modelling for the circulating fluidized bed boiler.

3. Prevention of Significant Deterioration

Pursuant to Chapter 17-2, FAC, and 40 CFR 52.21, the Cedar Bay CFB units are subject to a review for the Prevention of Significant Deterioration (PSD) of air quality. The Clean Air Act Amendments of 1977 prescribe incremental limitations on the air quality impacts of a new source. The Department of Environmental Regulation has reviewed the PSD analysis submitted by AES and has found that the construction of the facility is not expected to violate state PSD regulations as contained in Section 17-204, FAC.

Additionally, the Preliminary Determination for Cedar Bay/Seminole Kraft was completed in December of 1989. Federal regulations on PSD (40 CFR 52.21) require the following air quality impacts to be addressed:

A. National Ambient Air Quality Standards
B. PSD increment impact
C. Visibility, soils and vegetation impacts
D. Impacts due to growth caused by the proposed source
E. Best Available Control Technology (BACT)
F. Class I area impacts

After their review, DER has made a preliminary determination that the construction can be approved provided certain conditions are met.

The predicted impact of the Cedar Bay Project on the Okefenokee Wilderness Area Class I area increments is presented in the following table:

TABLE 6

Increment	Pollutant Particulate	SO_2
Annual	20%	50%
24 Hour	10%	80%
3 Hour		72%

It appears that the Cedar Bay would not violate the Class I PSD increments in the Okefenokee.

The percent consumption of the applicable Class II PSD increments caused by the Cedar Bay Project and other new sources are present in the following table:

TABLE 7

Increment	Pollutant	
	Particulate	SO_2
Annual	12%	12%
24 Hour	46%	46%
3 Hour	N/A	65%

The plant emissions are not expected to violate the increments or cause significant deterioration of air quality in the Jacksonville area.

Nonattainment Areas

The extent of the contribution of the proposed plant to the formation of ozone and, therefore, its' impact on the Jacksonville ozone nonattainment areas cannot be estimated through modelling. However, because of the plant's low emission levels of NO_x and hydrocarbons (the primary precursors of ozone), it was assumed by AES that the impacts of the proposed plant on ozone concentrations in the Jacksonville area will not be significant.

The impact of the plant on the Jacksonville particulate nonattainment area was estimated through modelling and compared with the US EPA "significance levels" which are one ug/m^3 for an annual average and five ug/m^3 for a 24-hour average. The TSP nonattainment area basically covers the central downtown area and is at its' closest point six miles from the proposed plant.

The annual average impact was calculated using the total TSP emissions from the operation of the proposed plant including fugitive dust emissions from the coal handling, waste disposal and cooling towers. The results of the analysis indicate that the annual average TSP impact on the nonattainment area would be less than one ug/m^3, the EPA significance level. The maximum 24-hour TSP impact would be four ug/m^3, which is less than the five ug/m^3 EPA significance level.

It, therefore, appears that the proposed CBCP will not have a significant adverse effect on the downtown Jacksonville area.

Impacts on Visibility

The proposed power plant may have an impact on visibility in the area. Visibility is defined as the greatest distance at which it is just possible to see and identify with the unaided eye a prominent dark object against the sky at the horizon in the daytime or a known unfocused moderately intense light source at night. Visibility is diminished by four major processes: light scattering by gas molecules, light scattering by particles, light absorption by gases not naturally occurring in the atmosphere, and light absorption by particles.

Coal-fired power plants affect visibility through the three major combustion related pollutants: particulates, sulfur dioxide, and nitrogen dioxide. Visibility is decreased by particulates primarily through light scattering due to conversion of gaseous nitrogen dioxide to particulate nitrites; and by sulfur dioxide when it converts to particulate sulfates.

The frequency distribution of the visibility observed at Jacksonville Imeson Airport over a five-year period is summarized in the application. The average quarterly background visibility at Jacksonville Airport is seldom greater than twelve miles or less than two miles. Visibility conditions greater than or equal to those measured at Jacksonville can be expected at St. Augustine (70 km southeast) and the Okefenokee Class I area (60-70 km northwest). Using equations, the background conditions may be calculated and the SO_4 (sulfate) and TSP impacts at the Okefenokee Class I and St. Augustine historical areas may be estimated and that the visibility impacts at these areas may also be estimated. For purposes of this simplified analysis, it was necessary to assume that SO_4 and TSP are the only pollutants contributing to visibility reduction. It was also assumed that the background visibility is twelve miles. The calculated new visibility due to the CBCP was 11.7 miles.

This corresponds to a reduction of approximately two percent in the visual range at the Okefenokee Class I area during worst-case conditions.

Impacts on Soils and Vegetation

Eighteen trace elements were selected for review on the basis of reported high concentrations in coal, capability for volatilization during combustion, potential for toxicity, and existence of regulatory guidelines. Since a coal source analysis has not been provided, trace element concentrations in coal were obtained from a report on trace elements in coal samples from the eastern United States.

The predicted deposition rates were determined on the basis of coal consumption, trace element concentration, and SO_2 emission rates. Elements considered to be volatile were assumed to exit the stack in an uncontrolled manner. Those trace elements typically occurring as particulates or absorbed on particulates were also assumed to exit in an uncontrolled state. These assumptions were utilized due to the lack of information on the behavior of trace elements passing through an FGD system. In addition, the use of these assumptions introduced a degree of conservatism to the assessment.

Studies of model power plants in most cases predicted increases in soil trace element levels of less than 10 percent of the total endogenous concentrations over the life of the model plant. It was concluded that uptake by vegetation would not increase dramatically unless the forms of deposited trace elements were considerably more available than the endogenous forms.

The estimated increases ranged from 0.6×10^{-5} to 4.8×10^{-3} percent, using average soil background concentrations. The estimated increases over the 40 year life of the plant, assuming that the elements remained concentrated in the top 25 cm of soil over this period ranged from 2.4×10^{-4} to 3.6×10^{-2} percent. The assessment of these increases was based on a number of worst case conditions. Under these conditions there should not be a perceptible increase on an annual basis. Over the 40 year plant life, those elements exhibiting a higher percent increase relative to the others studied included: arsenic, boron, cadmium, lead, mercury, and molybdenum.

The estimated soil concentration increase for arsenic would be 6×10^{-3} mg per kg of soil over the 40 year plant life. Naturally occuring arsenic levels in soils average about 6 ppm. Soil arsenic concentrations greater than 2 ppm, soluble form, have been shown to produce injury symptoms on alfalfa and barley and as such no effect could be expected under worst case conditions.

The estimated soil concentration increase for boron would be 1.02×10^{-2} mg per kg of soil over the 40 year plant life under worst case conditions. Naturally occuring boron concentrations range from 2-1000 ppm with the highest levels found in saline and alkaline soils. The average value is considered to be about 10 ppm. Using a toxicity level of 0.5-10 ppm for plants sensitive to boron as a means for comparison, no adverse effects to sensitive species such as citrus would be expected under worst case operating conditions.

The estimated soil concentration increase for cadmium would be 0.58×10^{-4} mg per kg of soil concentration over the average background level of 0.06 ppm, which is high in comparison with the other elements addressed. Toxicity to plants is reported to occur when cadmium concentration in plant tissues reaches about 3 ppm and it is unlikely that the estimated soil concentration will be high enough for the accumulation of 2 ppm in leaf tissue within the vicinity of the proposed plant.

The estimated soil increase for lead would be 1.43×10^{-2} mg per kg of soil over the 40 year plant life. Naturally occurring lead concentrations in soil averages about 10 ppm. Based on reported threshhold concentrations of 10 ppm lead in solution culture, the addition of 0.79×10^{-2} mg lead per kg of soil to soils containing as much as 5 ppm lead should not result in any adverse effects. It is thought that lead enters the plant primarily through the leaf surface. However, the effect of such accumulations cannot be predicted due to the lack of information concerning the concentration of lead in plants due to leaf deposition.

The estimated soil increase for mercury would be 0.48×10^{-4} mg per kg of soil. Naturally occurring mercury concentrations in soil average 0.1 ppm. Most higher vascular plants are resistant to toxicity from high mercury concentrations even though high concentrations are present in plant tissue. Concentrations of 0.5-50 ppm are found to inhibit the growth of cauliflower, lettuce, potato, and carrots. The addition of 0.48 x 10^{-4} mg per kg of soil is not considered to result in any adverse effect.

The estimated soil increase for molybdenum would be 1.12 x 10^{-3} mg per kg of soil over the 40 year life. Naturally occurring background concentrations average about 2 ppm. Molybdenum toxicity is rarely ovserved in the field since most plants seem to be able to tolerate high tissue concentration. A Mo concentration of 5 ppm in nutrient solution was found to be toxic to clover and lettuce. It would appear to be unlikely that the contribution of Mo from the proposed plant would result in adverse effects.

4. Best Available Control Technology

Two applicants propose to install an integrated cogeneration power plant complex at the Seminole Kraft Corporation facility located in Jacksonville, Florida. The power complex will consist of three coal/bark fired circulating fluidized bed (CFB) boilers, the respective coal handling equipment and limestone dryers, to be owned and operated by AES Cedar Bay, Inc. and a kraft recovery boiler to be owned and operated by the Seminole Kraft Corporation.

The CFB boiler, rated at 3,189 MMBtu will burn fuel made up of approximately 96 percent coal and 4 percent bark. The boilers will generate steam to produce power from a turbine generator set. The CBCP will generate 225 MW of electricity for sale to FPL as well as low pressure process steam for SKC.

The recovery boiler, rated at 1,125 MMBtu/hr will replace three old recovery boilers. Also included in the project is the installation of a new smelt dissolving tank and a new set of evaporators which will replace three old smelt dissolving tanks and three old sets of evaporators, respectively. These units were recently permitted by the Department separately from the power plant siting proceeding.

EPA has determined that although the CFB cogeneration complex is being constructed on the Seminole Kraft Corporation's property, that the cogeneration facility and the kraft recovery boiler should be reviewed as two separate projects for air quality impact purposes.

The applicants have indicated that the maximum net total annual tonnage of regulated air pollutants emitted from the projects based on 8,760 hours per year operation and 93% capacity factor for the CFB complex to be as follows:

	Maximum Net Increase in Emissions (TPY)		PSD Signif. Emiss. Rate
Pollutant	AES Cedar Bay	Seminole Kraft	(TPY)
TSP	268	-140.7	25
PM10	265	-138.6	15
SO_2	4029	6.4	40
NOx	4683	1296.4	40
CO	2470	-160.0	100
VOC	208	-92.3	40

Pollutant	AES Cedar Bay	Seminole Kraft	(TPY)
TRS	-	-53.3	10
Pb	91	-0.16	0.6
Be	1.5	-0.012	0.004
Hg	3.4	-	0.1
H_2SO_4	308	-5.8	7
Fl	1122	-	3

Rule 17-2.500(2)(f)(3) of the Florida Administrative Code (F.A.C.) 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 NOx emissions from the smelt dissolving tank and the multiple effect evaporators are negligible and will not be considered as part of the BACT analysis. The emissions of heavy metals, H_2SO_4, VOC's, and fluorides from the limestone dryers are also negligible compared to that emitted from the CFB boiler and will not be considered in the BACT analysis for the AES CBCP.

BACT Determinations Requested by the Applicants

AES Cedar Bay (Fluidized bed boilers)

Pollutant	Determination
TSP	0.02
PM10	0.02
SO_2	0.6 (3 hour average)
	0.31 (12 month rolling average)
NOx	0.36
CO	0.19
VOC	0.016
Pb	0.007
Be	0.00011
Hg	0.00026
H_2SO_4	0.024
Fl	0.086

Seminole Kraft Corporation (Kraft Recovery Boiler) *

Pollutant	Determination
NOx	180 ppm (corrected to 8% oxygen)

* (deleted from power plant siting)

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, 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 cogeneration facilities can be grouped into categories based upon what control equipment and techniques that are available to control emissions from these facilities. Using this approach, the emissions are classified as follows:

- o Combustion Products (Particulates and Heavy Metals). Controlled generally by particulate control devices.

- 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 facilities 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" pollutants (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.

BACT Analysis:

Combustion Products

The CBCP complexes' projected emissions of particulate matter, PM10, lead, beryllium, and mercury 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 CFB boilers permitted in the United States. As this is the case, the applicants proposal for particulate emissions (0.02 lb/MMBtu) is representative of the most stringent BACT determinations and is thereby justified as being BACT for this facility.

In general, the BACT/LAER clearinghouse does not contain specific emission limits for lead, beryllium, and mercury from CFB boilers. BACT for heavy metals from these facilities is typicaly represented by the level of particulate control. As this is the case, the applicants proposal of 0.02 lb/MMBtu for particulate matter and PM10 is judged to represent BACT for lead, beryllium and mercury.

A review of the coal handling facilities indicates that all practical measures will be employed to control fugitive dust emissions. Fugitive dust associated with the handling of coal will be controlled with enclosures, water sprays, compaction, and bag filter dust collection. All coal conveyers not located underground or within enclosed buildings will have covers.

The control measures employed to minimize the fugitive dust measures from coal handling is judged to represent BACT for the facility.

Products of Incomplete Combustion

The emissions of carbon monoxide, volatile organic compounds and other organics from coal fired boilers are largely dependent upon the completeness of combustion. A review of the BACT/LAER Clearinghouse indicates that the emission levels of 0.19 lb/MMBtu and 0.016 lb/MMBtu for carbon monoxide and volatile organic compounds, respectively, are representatives of previous BACT determinations. In each case the BACT was represented by combustion control and proper fluidized bed operation. The emissions of carbon monoxide could be reduced by increasing the combustion temperatures in the CFB boiler. This, however, would lead to higher nitrogen oxides emissions and additional limestone would be needed for acid gas reduction resulting in a cost which would not warrant the additional carbon monoxide control. The use of combustion control in conjunction with the proposed acid gas control is also deemed as representing BACT for the other organic compounds which would be emitted from the facility.

BACT

Acid Gases

The emissions of sulfur dioxide, nitrogen dioxide, fluorides, and sulfuric acid mist, as well as other acid gases which are not "regulated" under the PSD Rule, represent significant potential pollutants which must be subjected to appropriate control. Sulfur dioxide emissions from coal fired boilers are directly related to the sulfur content of the coal which is combusted. The addition of "add on" control equipment and the utilization of combustion technolgies which serve to control sulfur dioxide emissions in the combustion chamber itself are other techniques that can be used to minimize emissions.

Sulfur Dioxide

The applicant has proposed the use of a CFB boiler to control sulfur dioxide emissions. Sulfur dioxide is removed in a CFB boiler by injecting limestone into the boiler bed. The limestone calcines to calcium oxide at the temperatures present in the fluidized bed. The calcium oxide then reacts with the SO_2 in the flue gas to form calcium sulfate. Sulfur dioxide is removed in this manner with efficiencies up to 90 percent based on a 30-day rolling average.

In keeping with the "top down" BACT approach the applicant has identified three alternative technologies that would control sulfur dioxide emissions.

1) Pulverized coal fired boiler followed by a wet limestone scrubber system designed for a maximum of 94 percent SO_2 removal on a 30-day rolling average basis.

2) Pulverized coal fired boiler followed by a wet limestone scrubber system designed for a maximum of 90 percent SO_2 removal on a 30-day rolling average basis.

3) Pulverized coal fired boiler followed by a lime spray dryer system designed for a maximum of 90 percent SO_2 removal on a 30-day rolling average basis.

A review of alternatives 2 and 3 indicates that the level of sulfur dioxide control would be equivalent to that proposed by the applicant and no further review is needed. Alternative 1, however, would provide additional control of SO_2, thus a cost benefit analysis of using this type of control is warranted.

In order to justify the cost effectiveness of any air pollution control, the EPA has developed cost guidelines to obtain the highest reduction of emissions per dollar invested. Achievement of maximum emission reductions for capital invested is a major consideration when New Source Performance Standards (NSPS) are developed by the EPA. For SO_2 emissions, EPA has determined that cost of up to $2,000 per ton of emissions controlled ($1.00/lb) is reasonable for NSPS.

The use of a wet limestone scrubber having an efficiency of 94% has a levelized total annual cost (capital and operating) which is $7.72 million dollars greater than that of the proposed CFB boiler by the applicant. The applicant has indicated that the additional sulfur dioxide removal from using the wet scrubber would be 3,353 tons per year based on a 94% efficiency. In addition, the use of a wet limestone scrubber would eliminate the need for lime dryers which are expected to emit 38 tons per year of sulfur dioxide. Taking these reductions into consideration with the increased annual cost, the cost per ton of SO_2 controlled is approximately $2,277. This increased cost is not unreasonable based on the NSPS guideline of $2,000 per ton removal.

Another control alternative that should be considered is the use of coal with a lower sulfur content. A review of the BACT/LAER Clearinghouse indicates that BACT for CFB boilers has been established in some cases by limiting both the mass emission rate and the sulfur content of the fuel.

The applicant has indicated that the CFB boiler will fire coal with a sulfur content ranging from 1.7 to 3.3 percent which will result in the proposed SO_2 emission rates of 0.6 lb/MMBtu heat input and 0.31 lb/MMBtu heat input on a three hour and 12-month rolling average, respectively.

The BACT/LAER Clearinghouse indicates that the lowest determination for coal sulfur content is 0.5 percent for a CFB boiler, with other determinations ranging up to 3.0 percent taking into the consideration the availability of low sulfur coal.

Based on the previous cost benefit anlaysis of the wet scrubber alternative, it seems reasonable to investigate the cost of using a coal with a lower than proposed sulfur content which would result in the same emission rate as the wet scrubber option.

In order to provide the same level of control as the wet scrubber alternative, it has been determined that the CFB boiler would need to utilize coal with a sulfur content ranging from 1.0 to 2.0 percent. This would result in sulfur dioxide emission rate of 0.36 lb/MMBtu and 0.186 lb/MMBtu for a three-hour and 12-month rolling average, respectively.

Based on the capacity factor of 93 percent as provided by the applicant, the use of coal with an average annual sulfur content of 1.0 percent would result in an sulfur dioxide emission reduction of 1,653 tons/year. When this reduction is taken into consideration wit the increased cost of purchasing coal with a lower sulfur content the cost per ton of sulfur dioxide reduction can be determined.

In a recent application in which the cost of switching to a lower sulfur content coal was evaluated, the cost of switching from a 2.0 to 1.0% sulfur coal was determined to be $4.90 greater per ton of coal purchased. Using this figure as an approximation of using coal with an annual average sulfur content of 1.0% as compared to the proposed 1.7% the cost benefit analysis is computed as follows. Based on the applicant's maximum consumption rate of 248,000 lbs/hr and the 93% capacity factor, the increased cost of using 1.0% sulfur coal would be approximately $4.95 million. Taking this cost into consideration with the expected reduction the cost per ton of control would be $2,995. The actual cost would be slightly less than $2,995 when taking into consideration the greater heating value from lower sulfur content coal but would still be well above the $2,000 per ton guideline.

<u>NOx - CBCP</u>

The emissions of nitrogen oxides from coal fired boilers are controlled by combustion control and post combustion control equipment. In a CFB boiler, low combustion temperatures coupled with staged combustion effectively limit the formation of NOx. Low combustion temperatures primarily limit the formation of thermal NOx, and staged combustion (creating a reducing atmosphere in the lower portion of the boiler) inhibits the formation of fuel NOx.

The applicant has proposed the use of the CFB boiler with an emission limit of 0.29 lb/MMBtu as BACT for nitrogen oxides. The alternatives to further reduce NOx emissions are discussed and evaluated on a cost/benefit basis as follows:

> Post-combustion NOx control processes are based on the reaction of ammonia or urea with conversion of NOx to form nitrogen and water. Selective noncatalytic reduction and selective catalytic reduction technologies are the only technologies adequately demonstrated to be considered for installation on CFB boilers.
>
> Selective catalytic reduction (SCR) is a post-combustion method for control of NOx emissions which is being developed by a number of companies, principally in Japan and Europe. The SCR process combines vaporized ammonia with NOx in the presence of a catalyst to form nitrogen and water. The SCR process can achieve between 80 and 90 percent reduction of NOx. The vaporized ammonia is injected into the exhaust gases prior to passage through a catalyst bed. The optimum flue gas temperature range for SCR operation is approximately 700 to 850°F. The SCR catalyst is housed in a reactor vessel which is separate from the boiler.
>
> Selective noncatalytic reduction (SNCR) is another post-combustion method controlling NOx emissions. The process selectively reduces NOx by reaction with ammonia or urea without the use of a catalyst bed. A SNCR system could potentially reduce NOx emissions generated by a coal fired CFB boiler by 40 to 60 percent.

The applicant has indicated that a SCR system would remove an additional 3,645 tons of nitrogen oxides per year. When this removal rate is taken into consideration with the total levelized annual cost (capital and operating) of $14.35 million, the cost per ton of nitrogen oxides controlled is approximately $3,937. This is well above the NSPS guideline of $1,000 per ton, yet slightly less than one previous BACT determination in which post-combustion nitrogen oxides control was justified at a cost of approximately $4,200 per ton.

For SNCR, the applicant has indicated that an additional 2,430 tons of nitrogen oxides per year would be controlled at a total levelized annual cost of $4.11 million. This results in a cost per ton of nitrogen oxides controlled of approximately $1,691 which is above the NSPS guideline but below the cost of some previous BACT determinations.

Environmental Impact Analysis

A review of the impacts associated with the proposed CBCP and the recovery boiler installation indicates that there will be a reduction in the maximum annual air quality impacts. This reduction in the impacts would result from the replacement of three old power boilers and three old recovery boilers which are now causing higher impacts than what is expected from the new cogeneration/recovery boiler complex.

BACT DETERMINATION BY DER

Discussion

The Department has determined that the levels of control proposed by the applicant for the CFB cogeneration facility represents BACT in most cases. The review indicates that the level of particulate control clearly is justified as BACT for particulate matter, PM_{10}, and heavy metals. In addition, the levels of control proposed for the coal handling facilities, and for products of incomplete combustion also represents BACT.

A review of the proposed control for sulfur dioxide indicates that the inherent removal efficiency provided by the CFB boiler represents BACT. The analyses of alternative control technologies indicates that both the cost of using wet scrubbers and switching to a lower sulfur content coal are cost prohibitive based on current BACT cost of control guidelines. In addition to the greater cost of using wet scrubbing, such an alternative has the disadvantage of having to handle and dispose of the scrubber sludge produced. In addition to the greater cost of using a lower sulfur coal, such an alternative presents the difficulties encountered to establish a coal contract which allows for the handling and transport of ash produced by the CFB boiler.

The plant will be located in Duval County which is classified nonattainment for the pollutant ozone . It will be located in the area of influence of the Jacksonville particulate nonattainment area. However, the plant will not significantly impact the nonattainment area. The facility must comply with the provisions of 17-2.500 F.A.C. (Prevention of Significant Deterioration).

The proposed level of control for nitrogen oxides from the CFB cogeneration facility, under some circumstances would not be considered representative of BACT. The review of the costs associated with using post combustion controls indicates that the cost per ton of using selective noncatalytic reduction (SNCR) for NOx removal from CFB boiler does exceed the $1,000 guideline that is used for NSPS but is below that which has been justified as BACT for other facilities.

In general, the use of post combustion NOx controls has been a strategy which has been evaluated in every BACT review since the "top down" BACT policy was introduced by the EPA in December 1987. In each case, the use of post combustion controls was rejected due to being cost prohibitive, or on the basis that there was not sufficient operating experience for a particular technical application to demonstrate that the specific application was proven.

For the cases in which the use of post combustion controls was rejected because of being cost prohibitive, the cogeneration unit was being constructed for peaking purposes only. As this was the case, the facility in question would be operated well below full capacity (peaking units), thereby resulting in cost per ton figures which were well above what has been established as justifiable for BACT.

With regard to the technology being proven, both SCR and SNCR have had operating experience in both Japan and Europe. More recently, several facilities in California have been permitted with SNCR. Compliance testing has indicated that one of the facilities which is now operating (Corn Products) has passed its compliance test. Another operating facility (Cogeneration National) has had trouble meeting the NOx emission limitation while also maintaining compliance with the CO and SO_2 emission requirements. This plant has continued with adjustments targeted at achieving concurrent compliance.

The applicant has stated that SNCR systems emit various amine compounds formed by unreacted ammonia which represents a potential adverse human health effect. Although it has been demonstrated that ammonia slip does occur, this does not indicate that the technology has not been proven. The use of both SCR and SNCR as representing BACT is becoming more and more prevalent for internal combustion engines, boilers, and turbines.

EPA's recent BACT determinations for other facilities would tend to support incorporation of SNCR as BACT for nitrogen oxides control for the Cedar Bay facility. Another factor that would support higher than guideline treatment costs is the location of the proposed Cedar Bay/Seminole Kraft cogeneration venture. The site is located in an area which is designated as being nonattainment for ozone. Nitrogen oxides are known to be a precursor to ozone.

AES is locked into a fixed income source due to contracts approved by the Florida PSC. The additional costs of SNCR would cause the project to become financially unfeasible and result in stopping the project. Such an action would be detrimental since the project as proposed will result in overall reductions in air and water quality impacts.

Conclusion

Therefore, the department has concluded that in this particular case the levels of control proposed by the applicant are representative of BACT for this facility. With regard to nitrogen oxides emissions, the net benefits associated with the project as proposed do not justify additional control requirements which would serve to stop the project. The proposed emission level of 0.29 lbs/MMBtu is less than half the NOx level allowed by NSPS. In addition, a review indicates that this level will be the lowest NOx level established for a CFB without additional controls in the country.

Based on the information presented in the preceeding analysis, the emission limits for the Cedar Bay Cogeneration facility are established as follows:

Pollutant	AES Cedar Bay Determination (lb/MM Btu)
TSP	0.020
PM10	0.020
SO_2	0.60 (3 hour average)
	0.31 (12 month rolling average)
NOx	0.29
CO	0.19
VOC	0.016
Pb	0.0070
Be	0.00011
Hg	0.00026
H_2SO_4	0.024
Fl	0.086

Fugitive Dust

Fugitive dust is produced by a number of sources associated with the project. These include the coal handling system, limestone and spent limestone handling system, and pelletized waste handling systems. Also since fresh water cooling towers will be used, EPA has indicated that dissolved and suspended solids in the small droplets fraction (less than 50 microns diameter) of cooling tower drift would be considered fugitive dust in the impact assessment. The following paragraphs describe the control systems and/or methods proposed as BACT for these fugitive dust sources.

Coal Handling Fugitive Dust Collection

Control and collection of fugitive particulates in the coal handling system will be accomplished by several different methods, including totally enclosed conveying systems, water spray dust suppression systems, and dust collection systems utilizing fabric filters.

The coal unloading facility will have dry dust collection systems capable of 99.9 percent control efficiency on the unloader receiving hoppers. All conveyors will be totally enclosed and each transfer point fitted with dry dust collection systems, with the exception of the stacker-reclaimer which will be fitted with a water spray dust suppression system capable of 97 percent efficiency.

Coal will be unloaded at the plant site by a bottom car dumper which will be housed in an unloading building with a wet dust suppression system. This is expected to have a dust control efficiency of 97 percent. From the delivery point, totally enclosed belt conveyors will be used to transport the coal to the coal handling building. Surge bins in the coal handling building will be vented with fabric filter dust collectors (efficiency of 99.9 percent), and similar collectors will be located at all conveyor discharge points. Conveyors between the coal handling building and the stacker-reclaimer will be enclosed, but coal dust associated with these conveyors will be controlled by a water spray dust suppresion system. Dust releases in the stacker-reclaimer area (active coal pile) will be controlled by wetting agents for an efficiency of at least 90 percent. Dust releases from the inactive coal pile will also be controlled by wetting agents.

All conveyors from the coal handling building to the power house will be enclosed, and fabric filter dust collectors will be utilized to vent the storage silos in the power house and all conveyor transfer points. Tripper conveyors will be enclosed in a gallery.

Limestone Fugitive Dust Collection

Control and collection of fugitive dust particulates from the limestone addition system for the boilers will be accomplished by appropriate types of fabric filter dust collectors.

Limestone will be transported at the site by totally enclosed belt conveyors. All silos and hoppers utilized by the limestone system will be vented to fabric filter dust collectors. Similar collectors will be located at all conveyor discharge points.

All fabric filter dust collectors in the lime or limestone additive system will have an efficiency of at least 99.9 percent.

Control and Collection of Fugitive Fly Ash Particulates

In the fly ash handling system, fugitive fly ash particulate will be controlled at all transfer and discharge locations by fabric filters. The fly ash handling system consists essentially of ash hoppers located beneath the flue gas particulate collection equipment. Pneumatic conveyors are utilized to transfer fly ash to and from ash storage silos, and to mixers which prepare the ash and FGD wastes for disposal. Pneumatic conveyors are by their nature enclosed. Discharge for the conveyor's blower(s) will be equipped with fabric filters with greater than 99 percent collection efficiency.

Cooling Tower Drift

The dissolved and suspended solids in the small droplet size fraction of fresh water cooling tower drift is considered by EPA to contribute to total suspended particulates. This contribution is minimized by using high efficiency drift eliminators in the two natural draft towers (which limit drift to approximately .005 percent of circulating water flow) and by maintaining the cycles of concentration of the circulating water to a low level such as a maximum of 1.5. Additionally, a drift eliminator will be provided to mitigate the potential effects of blow-through. Upon reviewing the preceeding information, the Department also finds that the CBCP will not contribute to significant adverse air quality impacts.

5. Acid Rain

Rainfall acidity levels across Florida and other parts of the country have been ascribed in part to the air emissions from coal-fired power plants. Hence the requirement for emission controls on these plants, designed to reduce the potential acid causing factors. Generally, sulfur dioxide and oxides of nitrogen are believed to be the primary man-made agents contributing to rainfall acidification. However, a great deal remains unknown about the amount that these two gases contribute to the problem, as well as how and where the acidification takes place.

It should be noted that rainfall under unpolluted conditions tends to be somewhat acidic, on the order of pH 5.0. It appears that after a certain amount of time, estimated to be on the order of 1-4 days, these gases interact with sunlight, water vapor, ammonia, and many other chemical compounds in the atmosphere, which converts them to sulfuric acid and nitric acid. Scientists around the world are studying the rate of these reactions, which catalytic aids (sunlight, water, etc.) have the most effect driving the conversion, ways to prevent the end acidic product from affecting the environment, where the end product eventually makes it's impacts, and numerous other questions relating to the conversion reactions. It is generally agreed that the entire cause-effect-control relationship is very complex.

One feature that will mitigate some of the impact of the project is that stringent sulfur emission controls will be required prior to the plant going into operation. These units will thus have less impact than that of other units which do not employ those emission controls. The Cedar Bay units will utilize flue gas desulfurization via a fluidized bed of limestone sulfur emissions. Oxides of nitrogen will be controlled by boiler design. Such control will also help mitigate the rainfall acidification problem. In balancing the need for power with the environmental impacts from the operation of the plant, at this time, the required use of the fluidized bed and boiler controls seems to be the most relevant and effective way of addressing the unit's contribution to rainfall acidification.

Construction of new coal fired units may have a slightly positive effect on the acid rain problem in Florida. Data collected during the Florida Sulur Oxides Study indicated that the conversion of sulfur dioxide to sulfuric acid forms two to three times faster in the exhaust plume from an oil fired plant than from a coal fired plant. Oil fired power plants in Florida do not have emission controls for sulfur oxides or nitrogen oxides in most instances. As new coal fired power plants are built with pollution control devices, and as these new coal plants replace the oil plants that emit greater quantities of

SO_x and NO_x, then air pollution levels and acidic rainfall may decrease.

6. Coal Dust from Trains

The movement of coal supply trains to the proposed plant from coal mines outside the state will result in increased fugitive dust levels in areas near the railroad tracks. These increases in fugitive dust levels will be primarily the result of road bed dust emissions and coal dust blowing from the exposed coal contained within each hopper car. The only other quantifiable emissions associated with the coal trains result from the diesel locomotive emissions, which are relatively minor.

For an impact analysis of the coal trains as they move through Jacksonville, it was assumed that trains will travel 500 miles from the mines and that there will be a maximum of one train every three days with 90 cars per train, and a maximum of 106 tons of coal per car. An estimated one percent of coal by weight will be lost as fugitive dust over a journey of about 500 miles with an estimated 90 percent of the total losses escaping during the first few hours of train transit. This implies that only 0.1 percent of the original coal weight will be dispersed as fugitive dust during the rest of the trip, and only a small fraction of the 0.1 percent will be dispersed in the Jacksonville area.

The fugitive dust emissions from agitated road bed dust in the Jacksonville area were estimated using USEPA Publication AP-42 (1979), assuming that the road bed dust emissions are conservatively approximated by emissions from motor vehicles traveling on unpaved roads and that each train will travel at an average speed of ten miles per hour.

The 24-hour average TSP level in the Jacksonville area resulting from the operation of one coal train per day (a conservative estimate) was calculated to be 22 ug/m^3 at a distance of 100 meters downwind of the railroad tracks under light wind conditions. When added to the Jacksonville area background level of 50 ug/m^3, this total is relatively small compared to the National Ambient Air Quality secondary standard and Florida standard of 150 ug/m^3. It is noteworthy that the amount of the fugitive coal dust which was esimated to blow off the coal cars is about half of the expected emissions resulting from agitation of roadbed dust. This is primarily because of the very conservative method that was employed to estimate roadbed dust emissions.

B. Availability of Water

The primary source of water for the plant will be surface groundwater from the Floridan aquifer. Fresh groundwater or reclaimed water from Jacksonville sewage treatment plants will be used as makeup to the recirculating cooling water system. Groundwater will be used for plant potable water supply, fire protection system, plant service water system, and influent to the demineralized water system. Quantitative estimates for water requirements are expressed as annual average and/or maximum flows, whichever best describe system operation. In all

Appendix I. RECOMMENDED CONDITIONS OF CERTIFICATION

Appendix II-A. Public Service Commission Report
Appendix II-B. Department of Community Affairs Report
Appendix II-C. St. Johns River Water Management District Report
Appendix II-D. Jacksonville, Bio-Environmental Services Division Report

State of Florida Department of Environmental Regulation
AES Cedar Bay, Inc./Seminole Kraft Corp.
Cedar Bay Cogeneration Project
PA 88-25

CONDITIONS OF CERTIFICATION (Revised 1/8/91)

TABLE OF CONTENTS

Page no.

Revised 01/08/91

STATE OF FLORIDA DEPARTMENT OF ENVIRONMENTAL REGULATION

AES CEDAR BAY, INC./SEMINOLE KRAFT CORP.
CEDAR BAY COGENERATION PROJECT
PA 88-24

CONDITIONS OF CERTIFICATION

When a condition is intended to refer to both AES Cedar Bay, Inc. and Seminole Kraft Corp., the term "Cedar Bay Cogeneration Project" or the abbreviation "CBCP" or the term "permittees" will be used. Where a condition applies only to AES Cedar Bay, Inc. the term "AES Cedar Bay, Inc." or the abbreviation "AESCB" or the term "permittee," where it is clear that AESCB is the intended responsible party, will be used. Similarly, where a condition applies only to Seminole Kraft Corp., the term "Seminole Kraft Corp." or the abbreviation "SK" or the term "permittee," where it is clear that SK is the intended responsible party, will be used. The Department of Environmental Regulation may be referred to as DER or the Department. BESD represents the City of Jacksonville, Bio-Environmental Services Division. SJRWMD represents the St. Johns River Water Management District.

I. GENERAL

The construction and operation of CBCP shall be in accordance with all applicable provisions of at least the following regulations of the Department: Chapters 17-2, 17-3, 17-4, 17-5, 17-6, 17-7, 17-12, 17-21, 17-22, 17-25 and 17-610, Florida Administrative Code (F.A.C.) or their sucessors as they are renumbered.

II. AIR

The construction and operation of AESCB shall be in accordance with all applicable provisions of Chapters 17-2, F.A.C.. In addition to the foregoing, AESCB shall comply with the following conditions of certification as indicated.

A. Emission Limitations for AES Boilers

1. Fluidized Bed Coal Fired Boilers (CFB)

a. The maximum coal charging rate of each CFB shall neither exceed 104,000 lbs/hr, 39,000 tons per month (30 consecutive days), nor 390,000 tons per year (TPY). This reflects a combined total of 312,000 lbs/hr, 117,000 tons per month, and 1,170,000 TPY for all three CFBs.

b. The maximum wood waste (primarily bark) charging rate to the No. 1 and No. 2 CFBs each shall neither exceed 15,653 lbs/hr, nor 63,760 TPY. This reflects a combined total of 31,306 lbs/hr, and 127,521 TPY for the No. 1 and No. 2 CFBs. The No. 3 CFB will not utilize woodwaste, nor will it be equipped with wood waste handling and firing equipment.

c. The maximum heat input to each CFB shall not exceed 1063 MMBtu/hr. This reflects a combined total of 3189 MMBtu/hr for all three units.

d. The sulfur content of the coal shall not exceed 1.7% by weight on an annual basis. The sulfur content shall not exceed 3.3% by weight on a shipment (train load) basis.

e. Auxiliary fuel burners shall be fueled only with natural gas or No. 2 fuel oil with a maximum sulfur content of 0.3% by weight. The fuel oil or natural gas shall be used only for startups. The maximum annual oil usage shall not exceed 160,000 gals/year, nor shall the maximum annual natural gas usage exceed 22.4 MMCF per year. The maximum heat input from the fuel oil or gas shall not exceed 1120 MMBtu/hr for the CFBs.

f. The CFBs shall be fueled only with the fuels permitted in Conditions 1a, 1b, and 1e above. Other fuels or wastes shall not be burned without prior specific written approval of the Secretary of DER pursuant to condition XXI, Modification of Conditions.

g. The CFBs may operate continuously, i.e, 8760 hrs/yr.

2. Coal Fired Boiler Controls

The emissions from each CFB shall be controlled using the following systems:

a. Limestone injection, for control of sulfur dioxide.

b. Baghouse, for control of particulate.

3. Flue gas emissions from each CFB shall not exceed the following:

		Emission Limitations		
Pollutant	lbs/MMBtu	lbs/hr	TPY	TPY for 3 CFBs
CO	0.19	202	823	2468
NOx	0.29	308.3	1256	3767
SO_2	0.60 (3-hr avg.)	637.8	--	--
	0.31 (12 MRA)	329.5	1338	4015
VOC	0.015	16.0	65	195
PM	0.020	21.3	87	260
PM_{10}	0.020	21.3	86	257

H_2SO_4 mist	0.024	25.5	103	308
Fluorides	0.086	91.4	374	1122
Lead	0.007	7.4	30	91
Mercury	0.00026	0.276	1.13	3.4
Beryllium	0.00011	0.117	0.5	1.5

Note: TPY represents a 93% capacity factor. MRA refers to a twelve month rolling average.

4. Visible emissions (VE) shall not exceed 20% opacity (6 min. average), except for one 6 minute period per hour when VE shall not exceed 27% opacity.

5. Compliance with the emission limits shall be determined by EPA reference method tests included in the July 1, 1988 version of 40 CFR Parts 60 and 61 and listed in Condition No. 7 of this permit or by equivalent methods after prior DER approval.

6. The CFBs are subject to 40 CFR Part 60, Subpart Da; except that where requirements within this certification are more restrictive, the requirements of this certification shall apply.

7. Compliance Tests for each CFB

a. Initial compliance tests for PM/PM_{10}, SO_2, NOx, CO, VOC, lead, fluorides, mercury, beryllium and H_2SO_4 mist shall be conducted in accordance with 40 CFR 60.8 (a), (b), (d), (e), and (f).

b. Annual compliance tests shall be performed for PM, SO_2 and NOx, commencing no later than 12 months from the initial test.

c. Initial and annual visible emissions compliance tests shall be determined in accordance with 40 CFR 60.11(b) and (e).

d. The compliance tests shall be conducted between 90-100% of the maximum liscensed capacity and firing rate of each permitted fuel.

e. The following test methods and procedures of 40 CFR Parts 60 and 61 or other DER approved methods with prior DER approval shall be used for compliance testing:

(1) Method 1 for selection of sample site and sample traverses.

(2) Method 2 for determining stack gas flow rate.

(3) Method 3 or 3A for gas analysis for calculation of percent O_2 and CO_2.

(4) Method 4 for determining stack gas moisture content to convert the flow rate from actual standard cubic feet to dry standard cubic feet.

(5) Method 5 or Method 17 for particulate matter.

(6) Method 6, 6C, or 8 for SO_2.

(7) Method 7, 7A, 7B, 7C, 7D, or 7E for nitrogen oxides.

(8) Method 8 for sulfuric acid mist.

(9) Method 9 for visible emissions, in accordance with 40 CFR 60.11.

(10) Method 10 for CO.

(11) Method 12 for lead.

(12) Method 13B for fluorides.

(13) Method 25A for VOCs.

(14) Method 101A for mercury.

(15) Method 104 for beryllium.

8. Continuous Emission Monitoring for each CFB

AESCB shall use Continuous Emission Monitors (CEMS) to determine compliance. CEMS for opacity, SO_2, NOx, CO, and O_2 or CO_2, shall be installed, calibrated, maintained and operated for each unit, in accordance with 40 CFR 60.47a and 40 CFR 60 Appendix F.

a. Each continuous emission monitoring system (CEMS) shall meet performance specifications of 40 CFR 60, Appendix B.

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

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

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

e. Opacity monitoring system data shall be reduced to 6-minute averages, based on 36 or more data points, and gaseous CEMS data shall be reduced to 1-hour averages, based on 4 or more data points, in accordance with 40 CFR 60.13(h).

f. For purposes of reports required under this certification, excess emissions are defined as any calculated average emission concentration, as determined pursuant to Condition No. 10 herein, which exceeds the applicable emission limit in Condition No. 3.

9. Operations Monitoring for each CFB

a. Devices shall be installed to continuously monitor and record steam production, and flue gas temperature at the exit of the control equipment.

b. The furnace heat load shall be maintained between 70% and 100% of the design rated capacity during normal operations.

c. The coal, bark, natural gas and No. 2 fuel oil usage shall be recorded on a 24-hr (daily) basis for each CFB.

10. Reporting for each CFB

a. A minimum of thirty (30) days prior notification of compliance test shall be given to DER's N.E. District office and to the BESD (Bio-Environmental Services Division) office, in accordance with 40 CFR 60.

b. The results of compliance test shall be submitted to the BESD office within 45 days after completion of the test.

c. The owner or operator shall submit excess emission reports to BESD, in accordance with 40 CFR 60. The report shall include the following:

(1) The magnitude of excess emissions computed in accordance with 40 CFR 60.13(h), any conversion factors used, and the date and time of commencement and completion of each period of excess emissions (60.7(c)(1)).

(2) Specific identification of each period of excess emissions that occurs during startups, shutdowns, and malfunctions of the furnace boiler system. The nature and cause of any malfunction (if known) and the corrective action taken or preventive measured adopted (60.7(c)(2)).

(3) The date and time identifying each period during which the continuous monitoring system was inoperative except for zero and span checks, and the nature of the system repairs or adjustments (60.7(c)(3)).

(4) When no excess emissions have occured or the continuous monitoring system has not been inoperative, repaired, or adjusted, such information shall be stated in the report (60.7(c)(4)).

(5) The owner or operator shall maintain a file of all measurements, including continuous monitoring systems performance evaluations; monitoring systems or monitoring device calibration; checks; adjustments and maintenance performed on these systems or devices; and all other information required by this permit recorded in a permanent form suitable for inspection (60.7(d)).

d. Annual and quarterly reports shall be submitted to BESD as per F.A.C. Rule 17-2.700(7).

11. Any change in the method of operation, fuels utilized, equipment, or operating hours or any other changes pursuant to F.A.C. Rule 17-2.100, defining modification, shall be submitted for approval to DER's Bureau of Air Regulation.

B. AES - Material Handling and Treatment

1. The material handling and treatment operations may be continuous, i.e. 8760 hrs/yr.

2. The material handling/usage rates shall not exceed the following:

Material	Handling/Usage Rate TPM	TPY
Coal	117,000	1,170,000
Limestone	27,000	320,000
Fly Ash	28,000	336,000
Bed Ash	8,000	88,000

Note: TPM is tons per month based on 30 consecutive days, TPY is tons per year.

3. The VOC emissions from the maximum No. 2 fuel oil utilization rate of 240 gals/hr, 2,100,000 gals/year for the limestone dryers; and 8000 gals/hr, 160,000 gals/year for the three boilers are not expected to be significant.

4. The maximum emissions from the material handling and treatment area, where baghouses are used as controls for specific sources, shall not exceed those listed below (based on AP-42 factors):

Source	Particulate Emissions lbs/hr	TPY
Coal Rail Unloading	neg	neg
Coal Belt Feeder	neg	neg

Coal Crusher	0.41	1.78
Coal Belt Transfer	neg	neg
Coal Silo	neg	neg
Limestone Crusher	0.06	0.28
Limestone Hopper	0.01	0.03
Fly Ash Bin	0.02	0.10
Bed Ash Hopper	0.06	0.25
Ash Silo	0.06	0.25
Common Feed Hopper	0.03	0.13
Ash Unloader	0.01	0.06

The emissions from the above listed sources and the limestone dryers are subject to the particulate emission limitation requirement of 0.03 gr/dscf. However, neither DER nor BESD will require particulate tests in accordance with EPA Method 5 unless the VE limit of 5% opacity is exceeded for a given source, or unless DER or BESD, based on other information, has reason to believe the particulate emission limits are being violated.

5. Visible Emissions (VE) shall not exceed 5% opacity from any source in the material handling and treatment area, in accordance with F.A.C. Chapter 17-2.

6. The maximum emissions from each of the limestone dryers while using oil shall not exceed the following (based on AP-42 factors, Table 1, 3-1, Industrial Distillate, 10/86):

	Estimated Limitations		
Pollutant	lbs/hr	TPY	TPY for 2 dryers
PM/PM_{10}	0.25	1.1	2.2
SO_2	5.00	21.9	43.8
CO	0.60	2.6	5.2
NOx	2.40	10.5	21.0
VOC	0.05	0.2	0.4

Visible emissions from the dryers shall not exceed 5% opacity. If natural gas is used, emissions limits shall be determined by factors contained in AP-42 Table 1. 4-1, Industrial 10/86.

7. The maximum No. 2 fuel oil firing rate for each limestone dryer shall not exceed 120 gals/hr, or 1,050,000 gals/year. This reflects a combined total fuel oil firing rate of 240 gals/hr, and 2,100,000 gals/year, for the two dryers. The maximimum natural gas firing rate for each limestone dryer shall not exceed 16,800 CF per hour, or 147 MMCF per year

8. Initial and annual Visible Emission compliance tests for all the emission points in the material handling and treatment area, including but not limited to the sources specified in this permit, shall be conducted in accordance with the July 1, 1988 version of 40 CFR 60, using EPA Method 9.

9. Compliance test reports shall be submitted to BESD within 45 days of test completion in accordance with Chapter 17-2.700(7) of the F.A.C.

10. Any changes in the method of operation, raw materials processed, equipment, or operating hours or any other changes pursuant to F.A.C. Rule 17-2.100, defining modification, shall be submitted for approval to DER's Bureau of Air Regulation (BAR).

C. Requirements For the Permittees

1. Beginning one month after certification, AESCB shall submit to BESD and DER's BAR, a quarterly status report briefly outlining progress made on engineering design and purchase of major equipment, including copies of technical data pertaining to the selected emission control devices. These data should include, but not be limited to, guaranteed efficiency and emission rates, and major design parameters such as air/cloth ratio and flow rate. The Department may, upon review of these data, disapprove the use of any such device. Such disapproval shall be issued within 30 days of receipt of the technical data.

2. The permittees shall report any delays in construction and completion of the project which would delay commercial operation by more than 90 days to the BESD office.

3. Reasonable precautions to prevent fugitive particulate emissions during construction, such as coating of roads and construction sites used by contractors, regrassing or watering areas of disturbed soils, will be taken by the permittees.

4. Fuel shall not be burned in any unit unless the control devices are operating properly, pursuant to 40 CFR Part 60 Subpart Da.

5. The maximum sulfur content of the No. 2 fuel oil utilized in the CFBs and the two unit limestone dryers shall not exceed 0.3 percent by weight. Samples shall be taken of each fuel oil shipment received and shall be analyzed for sulfur content and heating value. Records of the analyses shall be kept a minimum of two years to be available for DER and BESD inspection.

6. Coal fired in the CFBs shall have a sulfur content not to exceed 3.3 percent by weight. Coal sulfur content shall be determined and recorded in accordance with 40 CFR 60.47a.

7. AESCB shall maintain a daily log of the amounts and types of fuel used and copies of fuel analyses containing information on sulfur content and heating values.

8. The permittees shall provide stack sampling facilities as required by Rule 17-2.700(4) FAC.

9. Prior to commercial operation of each source, the permittees shall each submit to the BAR a standardized plan or procedure that will allow that permittee to monitor emission control equipment efficiency and enable the permittee to return malfunctioning equipment to proper operation as expeditiously as possible.

D. Contemporaneous Emission Reductions

This certification and any individual air permits issued subsequent to the final order of the Board certifying the power plant site under 403.509, F.S., shall require, that the following Seminole Kraft Corporation sources be permanently shut down and made incapable of operation, and shall turn in their operation permits to the Division of Air Resources Management's Bureau of Air Regulation, upon completion of the initial compliance tests on the AESCB boilers: the No. 1 PB (power boiler), the No. 2 PB, the No. 3 PB, the No. 1 BB (bark boiler),and the No. 2 BB. BESD shall be specifically informed in writing within thirty days after each individual shut down of the above referenced equipment. This requirement shall operate as a joint and individual requirement to assure common control for purpose of ensuring that all commitments relied on are in fact fulfilled.

III. WATER DISCHARGES

Any discharges into any waters of the State during construction and operation of AESCB shall be in accordance with all applicable provisions of Chapters 17-3, and 17-6, F.A.C., and 40 CFR, Part 423, Effluent Guidelines and Standards for Steam Electric Power Generating Point Source Category, except as provided herein. Also, AESCB shall comply with the following conditions of certification:

A. Plant Effluents and Receiving Body of Water

For discharges made from the AESCB power plant the following conditions shall apply:

1. Receiving Body of Water (RBW) - The receiving body of water has been determined by the Department to be those waters of the St. John's River or Broward River and any other waters affected which are considered to be waters of the State within the definition of Chapter 403, Florida Statutes.

2. Point of Discharge (POD) - The point of discharge has been determined by the Department to be where the effluent physically enters the waters of the State in the St. John's River via the SKC discharge outfall 001, which is the existing main outfall from the paper mill emergency overflow to the Broward River

3. Thermal Mixing Zones - The instantaneous zone of thermal mixing for the AESCB cooling system shall not exceed an area of 0.25 acres. The temperature at the point of discharge

State of Florida Department of Environmental Regulation
AES Cedar Bay, Inc./Seminole Kraft Corp.
Cedar Bay Cogeneration Project
PA88-5740
CONDITIONS OF CERTIFICATION

CONTENTS

CONTENTS (continued)

STATE OF FLORIDA DEPARTMENT OF ENVIRONMENTAL REGULATION

AES CEDAR BAY, INC./SEMINOLE KRAFT CORP.
CEDAR BAY COGENERATION PROJECT
PA 88-5740

CONDITIONS OF CERTIFICATION

When a condition is intended to refer to both AES Cedar Bay, Inc. and Seminole Kraft Corp., the term "Cedar Bay Cogeneration Project" or the abbreviation "CBCP" or the term "permittees" will be used. Where a condition applies only to AES Cedar Bay, Inc. the term "AES Cedar Bay, Inc." or the abbreviation "AESCB" or the term "permittee," where it is clear that AESCB is the intended responsible party, will be used. Similarly, where a condition applies only to Seminole Kraft Corp., the term "Seminole Kraft Corp." or the abbreviation "SK" or the term "permittee," where it is clear that SK is the intended responsible party, will be used.

I. AIR

The construction and operation of Cedar Bay Cogeneration Project shall be in accordance with all applicable provisions of Chapters 17-2, 17-4, 17-5, and 17-7, Florida Administrative Code. In addition to the foregoing, each permittee shall comply with the following conditions of certification as indicated.

A. Emission Limitations for AESCB Sources Units 1, 2 and 3.

Base on each unit

1. Based on a combined maximum heat input of 3,189 million Btu per hour, stack emissions from the three circulating fluidized bed boilers shall not exceed the following when burning coal:

   a. SO_2--0.6 lb per million Btu heat input, maximum three-hour average, 0.31 lb/MMBtu on a 12-month rolling average.

   b. NO_x--0.36 lb per million Btu heat input.

   c. Particulates--0.02 lb per million Btu heat input.

   d. Visible emissions--20 percent (six-minute average), except one six-minute period per hour of not more than 27 percent opacity.

test methods.

112889

CFB Nos 1, 2 and 3

2. The height of the boiler exhaust stack for SJRPP Unit 1 and 2 shall not be less than 425 feet above grade.

435 in application

3. Particulate emissions from the coal handling facilities:

   a. The permittee shall not cause to be discharged into the atmosphere from any coal processing or conveying equipment, coal storage system or coal transfer and loading system processing coal, visible emissions which exceed 10 percent opacity. Particulate emissions shall be controlled by use of control devices.

   b. The permittee must submit to the Department within thirty (30) days after it becomes available, copies of technical data pertaining to the selected particulate emissions control for the coal handling facility. These data should include, but not be limited to, guaranteed efficiency and emission rates, and major design parameters such as air/cloth ration and flow rate. The Department may, upon review of these data, disapprove the use of any such device if the Department determines the selected control device to be inadequate to meet the emission limits specified in 3(a) above. Such disapproval shall be issued within 30 days of receipt of the technical data.

4. Particulate emissions from limestone and fly ash handling shall not exceed the following:

   a. Limestone silos--0.050 lb/h.

   b. Limestone hopper/transfer conveyors--0.65 lb/h.

   c. Fly ash handling system--0.2 lb/h.

5. Visible emissions from the following facilities shall be limited to 10 percent opacity: (a) limestone and fly ash handling system, (b) limestone day silos, and (c) fly ash silos.

6. Compliance with opacity limits of the facilities listed in Condition 5 will be determined by EPA reference Method 9 (Appendix A, 40 CFR 60).

7. Construction shall reasonably conform to the plans and schedule given in the application.

BESD

8. The permittee shall report any delays in construction and completion of the project which would delay commercial operation by more than 90 days to the Department's Northeast District office.

9. Reasonable precautions to prevent fugitive particulate emissions during construction, such as coating of roads and construction sites used by contractors, regrassing or watering areas of disturbed soils, will be taken by the permittee.

10. Coal shall not be burned in the units unless both baghouse and limestone injection are operating properly except as provided under 40 CFR Part 60 Subpart Da.

LAET PM 0.03 g/dscf 5% VE or 98% control

11. The two unit limestone dryers shall fire No. 2 fuel oil with a maximum sulfur content of 0.3 percent by weight. Samples of all fuel oil fired in the boilers shall be taken and analyzed for sulfur content and heating value. Accordingly, samples shall be taken of each fuel oil shipment received. Records of the analyses shall be kept a minimum of two years to be available for FDER's inspection.

12. The same quality No. 2 fuel oil, used for the limestone dryers, shall be used for the CFB boilers during startup and low load operation.

13. (Deleted)

Need ash? ? 1.7 too

14. Coal fired in the CFB boilers shall have an ash content not to exceed 18 percent and a sulfur content not to exceed 3.3 percent by weight. Coal sulfur content shall be determined and recorded in accordance with 40 CFR 60.47a.

15. (Deleted)

16. AESCB shall keep records of the frequency, duration, firing rate, and manner of operation of the limestone dryers.

B. Emission Limitations for SK Sources

(Later)

C. Air Monitoring Program

1. AESCB shall install and operate continuously monitoring devices for each CFB boiler exhaust for sulfur dioxide, nitrogen oxide, carbon monoxide, carbon dioxide, and opacity. The monitoring devices shall meet the applicable requirements of Section 17-2.710, FAC, and 40 CFR 60.47a. The opacity monitor may be placed in the ductwork following the baghouses.

2. SK shall install and operate (to be completed later).

3. AESCB shall maintain a daily log of the amounts and types of fuel used and copies of fuel analyses containing information on sulfur content, ash content, and heating values.

4. The permittees shall provide stack sampling facilities as required by Rule 17-2.700(4) FAC.

5. (Deleted)

6. Prior to commercial operation of each source, the permittees shall each submit to the Department a standardized plan or procedure that will allow that permittee to monitor emission control equipment efficiency and enable that permittee to return malfunctioning equipment to proper operation as expeditiously as possible.

D. Stack Testing

1. Within 60 calendar days after achieving the maximum capacity at which each CFB unit will be operated, but no later than 180 ~~oper-~~
Calendar ~~ating~~ days after initial startup, AESCB shall conduct performance tests for particulates SO_2, NO_x, and visible emissions during normal operations near (\10 percent) maximum heat input and furnish the Department a written report of the results of such performance tests within 45 days of completion of the tests. The performance tests will be conducted in accordance with the provisions of 40 CFR 60.46a, 48a, and 49a.

2. Performance tests for the CFBs shall be conducted and data reduced in accordance with methods and procedures outlined in Section 17-2.700 FAC.

3. Performance tests for the CFBs shall be conducted under such conditions as the Department shall specify based on representative performance of the facility. AESCB shall make available to the Department such records as may be necessary to determine the conditions of the performance tests.

4. AESCB shall provide 30 days prior notice of the initial performance tests for the CFBs in order to afford the Department the opportunity to have an observer present.

5. CFB stack tests for particulates NO_x and SO_2 and visible emissions shall be performed annually in accordance with Conditions C.2, 3, and 4 above.

6. SK shall perform the following stack test: (Later).

E. Reporting

1. For the CFBs, AESCB shall report stack monitoring, fuel usage and fuel analysis data to the Department's Northeast District Office on a quarterly basis commencing with the start of commercial operation in accordance with 40 CFR, Part 60, Section 60.7, and in accordance with Section 17-2.08, FAC.

2. (Deleted)

3. Beginning one month after certification, each permittee shall submit to the Department a quarterly status report briefly outlining progress made on engineering design and purchase of major pieces of air pollution control equipment on their respective sources. All reports and information required to be submitted under this condition shall be submitted to the Administrator of Power Plant Siting, Department of Environmental Regulation, 2600 Blair Stone Road, Tallahassee, Florida 32301.

F. Contemporaneous Emission Reductions

This certification and any individual air permits issued subsequent to the final order of the Board certifying the power plant site under 403.509, F.S., shall require, as a federally enforceable condition, any source offered for contemporaneous emission reduction credits (offsets) to be permanently removed from operation. That requirement shall operate as a joint and individual requirement to assure common control for purpose of ensuring that all contemporaneous emission reductions relied on are in fact made.

II. WATER DISCHARGES

Any discharges into any waters of the State during construction and operation of AESCB shall be in accordance with all applicable provisions of Chapter 17-3, Florida Administrative Code, and 40 CFR, Part 423, Effluent Guidelines and Standards for Steam Electric Power Generating Point Source Category, except as provided herein. Also, AESCB shall comply with the following conditions of certification.

A. Plant Effluents and Receiving Body of Water

For discharges made from the power plant the following conditions shall apply:

1. Receiving Body of Water (RBW)

   The receiving body of water has been determined by the Department to be those waters of the St. John's River and any other waters affected which are considered to be waters of the State within the definition of Chapter 403, Florida Statutes.

2. Point of Discharge (POD)

   The point of discharge has been determined by the Department to be where the effluent physically enters the waters of the State in the St. John's River or Broward River.

3. Thermal Mixing Zones

   The instantaneous zone of thermal mixing for the cooling systems shall not exceed an area of __ acres. The temperature at the point of discharge into the St. John's River shall not be greater than ___ degrees F. The temperature of the water at the edge of the mixing zone shall not exceed the limitations of Paragraph 17-3.05(1)(d). Cooling tower blowdown shall not exceed __ degrees F as a 24-hour average.

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION IV
345 COURTLAND STREET, N.E.
ATLANTA, GEORGIA 30365

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JUL 5 1990
DER-BAQM

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4APT-AE

Mr. Clair H. Fancy, P.E., Chief
Bureau of Air Regulation
Florida Department of Environmental Regulation
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

RE: Ambient Air Quality Analysis Workplan
Applied Energy Services (AES)
Cedar Bay Cogeneration Project

Dear Mr. Fancy:

In a letter from Ms. Julie Blunden to Lewis Nagler of my staff dated June 8, 1990, we received a copy of the proposed air quality analysis workplan for the above referenced project. The proposed workplan appears acceptable to us (assuming that the emissions inventory to be used in the analysis is acceptable) with the following exceptions.

On page 3-5 of the workplan, AES states that ... "FDER has indicated that approximately 1,400 tpy of VOC are available as a new source allowance in Duval County." As you are aware, on May 26, 1988, EPA notified your Agency and the Governor that the Florida SIP was inadequate to achieve the ozone standard in six Florida counties, including Duval. Therefore, any growth allowances alotted by the SIP are no longer available. This policy has been clearly expressed in the March 10, 1986, memorandum from Darryl Tyler, Director, Control Programs Development Division (enclosed). It was also our understanding that any emissions offsets (VOC) or ambient offsets (SO_2) needed by AES would be obtained through various boiler shutdowns at the Seminole Kraft Corporation.

On pages 4-3 through 4-6, the workplan lists estimated particulate emission rates from various material handling and storage operations. Some of the control efficiencies referenced in this section suggest that precipitation will achieve a 100 percent control of fugitive emissions. This degree of control should be justified or corrected.

If you have any questions concerning this letter, please contact Mark Armentrout of my staff at (404) 347-2904.

Sincerely yours,

Brian L. Beals, Chief
Source Evaluation Unit
Air, Pesticides and Toxics
Management Division

Enclosure

cc: Julie Blunden
Development Manager
AES/Cedar Bay, Inc.
1001 North 19th Street
Arlington, VA 22209

B. Andrews
M. Linn
B. Owen
A. Kutyna, NE Dist.
R. Roberson, BESD
C. Shaver, NPS

JOINT PUBLIC NOTICE

U.S. Environmental Protection Agency
Region IV
Water Management Division - Facilities Performance Branch
345 Courtland Street, N.E.
Atlanta, Georgia 30365
404/347-3004

in conjunction with

Florida Department of Environmental Regulation
Twin Towers Office Building, 2600 Blair Stone Road
Tallahassee, Florida 32301
904/488-1344

Public Notice No. 90FL277 May 31, 1990

NOTICE OF PUBLIC INFORMATION HEARING

ON

NOTICE OF PROPOSED ISSUANCE OF NATIONAL POLLUTANT DISCHARGE ELIMINATION SYSTEM PERMIT, DRAFT ENVIRONMENTAL IMPACT STATEMENT, AND NOTICE OF CONSIDERATION FOR STATE CERTIFICATION OF THE NPDES PERMIT

The U.S. Environmental Protection Agency (EPA) proposes to issue a National Pollutant Discharge Elimination System (NPDES) permit to AES Cedar Bay, Inc.; 1001 North 19th Street, Suite 2000, Arlington, VA 22209; for its Cedar Bay Cogeneration Project; 9469 Eastport Road, Jacksonville, FL 32218. The application, NPDES No. FL0041173, describes two point source and eight internal discharges from construction and operation of the facility to the Broward (approximate latitude 30° 25', longitude 81° 37') and St. Johns Rivers (approximate latitude 30° 25', longitude 81° 36'). All wastes to the St. Johns River will be via the Seminole Kraft Corporation discharge diffuser system (NPDES No. FL0000400). These reaches of the Rivers are classified as Class III Waters - Recreation - Propagation and maintenance of a Healthy, Well-Balanced Population of Fish and Wildlife. The facility will generate and transmit electricity (SIC 4911).

A Draft Environmental Impact Statement (EIS) will be made available to the public on or about June 8, 1990, by the EPA.

In order to solicit further public participation on the proposed project, EPA will co-chair with FDER a public hearing on the Draft Environmental Impact Statement, the proposed issuance of the NPDES permit, and the Florida certification of the NPDES permit. The hearing will begin at 7:00 p.m. on July 12, 1990, at the Oceanway Community Center, 12216 West Sago Avenue, Jacksonville, FL. Individuals with handicaps requiring special assistance should contact Ms. Diane Barrett, Public Notice Coordinator, at 404/347-3004 by June 28, 1990, so that reasonable accommodations can be made.

Both oral and written comments will be accepted at the public hearing and a transcript of the proceedings will be made. For the accuracy of the record, written comments are encouraged. The Hearing Officer reserves the right to fix reasonable limits on the time allowed for oral statements.

The proposed NPDES permit contains limitations on the amounts of pollutants allowed to be discharged and was drafted in accordance with the provisions of the Clean Water Act (33 U.S.C. Section 1251 et seq.) and other lawful standards and regulations. The pollutant limitations and other permit conditions are tentative and open to comment from the public.

Persons wishing to comment upon or object to any aspects of permit issuance or the Draft Environmental Impact Statement are invited to submit same in writing, postmarked no later than July 23, 1990, to the Office of Public Affairs, Environmental Protection Agency, 345 Courtland Street, N.E., Atlanta, GA 30365, Attention: Ms. Diane Barrett. Pursuant to 40 CFR 124.13, any person who believes any condition of the permit is inappropriate must raise all reasonably ascertainable issues and submit all reasonably available arguments in full, supporting their position, by the close of the comment period. The public notice number and NPDES number should be included in the first page of comments.

A final EIS will be published after the close of the public comment period. Reviewers should be aware that EPA will not reprint the material contained in the Draft EIS for the Final EIS. The Final EIS will comprise a summary of the Draft EIS, the EPA decision on the preferred alternative, responses to comments received on the Draft EIS, the transcript of the public hearing (or a summary thereof), other relevant information or evaluations developed after publication of the Draft EIS, and a copy of the proposed NPDES permit.

After consideration of all written comments; all comments, statements and data presented at the public hearing; and of the requirements and policies in the Act and appropriate regulations, the EPA Regional Administrator will make a determination regarding the permit issuance. If the determination is substantially unchanged from that announced by this notice, the EPA Regional Administrator will so notify all persons submitting written comments and all persons participating in the hearing. If the determinations are substantially changed, the EPA Regional Administrator will issue a public notice indicating the revised determination. Request(s) for evidentiary hearing may be filed after the Regional Administrator makes the above-described determinations. No issues shall be raised by any party that were not submitted to the administrative record as part of the preparation of and comment on the draft permit, unless good cause for the failure to submit them in accordance with 40 CFR 124.76. Additional information regarding an evidentiary hearing is available in 40 CFR 124, Subpart E, or by contacting the Office of the Regional Counsel at the above EPA address or at telephone number 404/347-2335.

A fact sheet which outlines the applicant's proposed discharges and the EPA proposed pollutant limitations and conditions is available at no charge by writing the EPA address above. The administrative record, including (1) application, (2) the Draft Environmental Impact Statement (which includes items 3-5) (3) fact sheet, (4) draft permit, (5) a sketch showing the exact location of the discharges, (6) comments received, and (7) additional information on hearing procedures is available by writing the EPA address above, or for review and copying at 345 Courtland Street N.E., 3rd floor, Atlanta, Georgia, between the hours of 8:15 a.m. and 4:30 p.m., Monday through Friday. Copies will be provided at a minimal cost per page. Copies of the Draft EIS, fact sheet and other information will be available for review at reading rooms in the following locations in Jacksonville, Florida: (1) Public Library, Main Branch, 122 N. Ocean Street, 32202; (2) Highland Branch Public Library, 1826 Dunn Avenue; and (3) San Mateo Elementary School, 600

Baisden Road. A limited number of copies of the Draft EIS are available from Ms. Marion Hopkins, Federal Activities Branch, at the EPA address noted above (Telephone: 404/347-3776, FAX: 404/347-5056).

EPA has requested FDER to certify the discharge(s) in accordance with the provisions of Section 401 of the Clean Water Act (33 U.S.C. Section 1341). Comments on issuance of certification must be submitted to the FDER address above, Attn: Mr. H.S. Oven, Jr., Director, Siting Coordination Section, by July 23, 1990. As described above, the FDER will co-chair the hearing in order to receive comments relative to state certification.

Please bring the foregoing to the attention of persons who you know will be interested in this matter. If you would like to be added to our public notice mailing list, submit your name and mailing address to the Office of Public Affairs at the EPA address above.

###

UNITED STATES
ENVIRONMENTAL PROTECTION AGENCY
REGION IV
345 COURTLAND STREET
ATLANTA, GEORGIA 30365

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PRADEEP RAVAL, ENGINEER
FLORIDA DEPT. OF ENVR. REGULATION
BUREAU OF AIR QUALITY MGMT
2600 BLAIR STONE ROAD
TALLAHASSEE FL 32399

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FEB 23 1990
DER - BAQM

February 16, 1990

Hamilton S. Oven
Chief, Power Plant Siting
Department of Environmental Regulation
2600 Blair Stone Rd.
Tallahassee, Florida 32399-2400

Dear Buck:

During a call with Pradeep Raval earlier this week, he requested that I submit a summary of our concerns related to air with the Cedar Bay Cogeneration Project's Conditions of Certification. Although the transcript of last week's hearing is unavailable, I believe all substantive concerns with the air conditions are addressed below. At this time, I believe that AES Cedar Bay and DER have agreed on all of the air conditions with the incorporation of the modifications provided by Steve Wolf to you in a letter dated February 16, 1990.

The points of concern and their resolutions are as follows:

- II.A.1.a and b - These conditions as stated could potentially limit AES Cedar Bay's power production by restricting the fuel feed rates while the facility remains well within the annual emission limits.
  Resolution - Change the fuel feed rates to reflect worst case coal quality as discussed in Steve Wolf's letter to you dated February 16, 1990.

- II.A.1.e - AES Cedar Bay wishes to remain flexible in the fuel used for the limestone dryers and during start-up. Therefore, we would like to have the option to use cleaner burning natural gas as an alternative to fuel oil.
  Resolution - DER agrees.

- II.A.3 - Limiting emissions on each boiler at a 93% capacity factor rather than on the three CFB's combined limits our flexibility to perform maintainence and to run a more reliable boiler more than 93% of the time while limiting power production on a less reliable boiler.
  Resolution - DER is unable to change this condition.

- II.A.9.b - In order to accomodate flexibility in our electric contract, AES Cedar Bay will maintain furnace heat load between 70% (rather than 80%) and 100% of design rated capacity during normal operations.
  Resolution - DER agrees.

- II.B.2 - Again, the material handling usage rates could limit power production because these figures are not based on worse case coal.
  Resolution - Incorporate worst case coal numbers provided in Steve Wolf's letter to you dated February 16, 1990.

AES/CedarBay Inc.

1001 North 19th Street • Arlington, Virginia 22209 • (703) 522-1315 • Telecopier—(703) 528-4510

- II.B.4 - Calculation of the emission rates from the materials handling facility on a #/hr basis were of concern. To calculate hourly emissions by dividing the annual rates by the number of hours per year would be inaccurate as the materials handling facilities will not be operated on a continuous basis.
  Resolution - It is AES Cedar Bay's understanding that the AP 42 emission factors are based on design capacities for the belts which would be an accurate method of calculation.

- II.B.6 - The limestone dryer emissions presented a concern similar to that concerning the materials handling emissions.
  Resolution - It is AES Cedar Bay's understanding that the limestone dryer emissions are based on the oil firing rate which would be an accurate method of calculation.

- II.C.4 - 40 CFR 60 Subpart BB refers to kraft recovery boilers and should be deleted from the conditions of certification.
  Resolution - DER agrees.

Thank you and the air staff for your diligent help in resolving all of these issues. Please do not hesitate to give me a call if you have any questions.

Sincerely,

Julie

Julie Blunden
Development Manager

cc: Betsy Hewitt, DER
Clare Fancy, DER
Richard L. Maguire, City of Jacksonville
Kathryn Mennella, St. Johns River Water Management District
William Bostwick, Esq.
Terry Cole, Oertel, Hoffman, Fernandez & Cole

TELEFAX

DATE: 2/16

TO: Buck Oven

ORGANIZATION: DER

TELEFAX NUMBER: 904 487 4938

FROM: J Blunden

NUMBER OF PAGES TO FOLLOW: 4

MESSAGE: see you Monday evening or Tues.

THE AES CORPORATION
1001 NORTH 19TH STREET
ARLINGTON, VA 22209
PHONE: 703/522-1315
FAX: 703/528-4510

February 16, 1990

Hamilton S. Oven
Chief, Power Plant Siting
Florida Department of Environmental Regulation
2600 Blair Stone Road
Tallahassee, FL 32399-2400

Dear Buck,

AES Cedar Bay representatives met with the DER staff Thursday, February 8, 1990 to discuss conditions of certification regarding the Cedar Bay Cogeneration Project. As a result of that meeting, AES-CB has agreed to provide this written request for changes to certain conditions in order that the conditions reflect actual operating parameters that were not identified in the application.

1. The maximum coal feed rates currently written into the conditions (Section II.A.1.a and II.B.2) do not reflect the "worse case" coal quality that can be expected. AES-CB has reviewed the coal specifications and determined that the worse case coal provided will have a heat content of 11,500 Btu/lb at 10% moisture. Additional moisture can be absorbed by the coal while being stored on-site. Assuming that a reasonable maximum moisture content in the coal pile is 20%, the resulting heat content will be 10,250 Btu/lb.

   The associated maximum coal feed rates follow. The maximum rates assume the worse case coal would exist 1 month each year.

   - 104,000 lbs/hour each CFB
   - 312,000 lbs/hour all three CFB's

   - 39,000 tons/month each CFB
   - 117,000 tons/month all three CFB's

   - 390,0000 tons/year each CFB
   - 1,170,000 tons/year all three CFB's

2. As discussed, the furnace heat load shall be maintained between 70% and 100% of design rated capacity during normal operations. (II.A.9.b)

3. As an alternate in conditions II.A.1.e and II.B.7, AES-CB would like the opportunity to add the following flow rates for natural gas should it become available as an economical alternative to fuel oil for firing the limestone dryer and startup burners.

Auxilliary fuel burners:
22.4 million cubic feet per year

Limestone Dryers each:
16,800 cubic feet per hour
147 million cubic feet per year

Limestone Dryers total:
33,600 cubic feet per hour
294 million cubic feet per year

Thank you and the air staff for your cooperation in resolving the concerns of AES Cedar Bay with these air conditions.

Sincerely,

Steve Wolf /LB

Steve Wolf
Engineering Manager

February 16, 1990

Hamilton S. Oven
Chief, Power Plant Siting
Department of Environmental Regulation
2600 Blair Stone Rd.
Tallahassee, Florida 32399-2400

Dear Buck:

During a call with Pradeep Raval earlier this week, he requested that I submit a summary of our concerns related to air with the Cedar Bay Cogeneration Project's Conditions of Certification. Although the transcript of last week's hearing is unavailable, I believe all substantive concerns with the air conditions are addressed below. At this time, I believe that AES Cedar Bay and DER have agreed on all of the air conditions with the incorporation of the modifications provided by Steve Wolf to you in a letter dated February 16, 1990.

The points of concern and their resolutions are as follows:

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  Resolution - Change the fuel feed rates to reflect worst case coal quality as discussed in Steve Wolf's letter to you dated February 16, 1990.

- II.A.1.e - AES Cedar Bay wishes to remain flexible in the fuel used for the limestone dryers and during start-up. Therefore, we would like to have the option to use cleaner burning natural gas as an alternative to fuel oil.
  Resolution - DER agrees.

- II.A.3 - Limiting emissions on each boiler at a 93% capacity factor rather than on the three CFB's combined limits our flexibility to perform maintainence and to run a more reliable boiler more than 93% of the time while limiting power production on a less reliable boiler.
  Resolution - DER is unable to change this condition.

- II.A.9.b - In order to accomodate flexibility in our electric contract, AES Cedar Bay will maintain furnace heat load between 70% (rather than 80%) and 100% of design rated capacity during normal operations.
  Resolution - DER agrees.

- II.B.2 - Again, the material handling usage rates could limit power production because these figures are not based on worse case coal.
  Resolution - Incorporate worst case coal numbers provided in Steve Wolf's letter to you dated February 16, 1990.

AES/CedarBay Inc.

- II.B.4 - Calculation of the emission rates from the materials handling facility on a #/hr basis were of concern. To calculate hourly emissions by dividing the annual rates by the number of hours per year would be inaccurate as the materials handling facilities will not be operated on a continuous basis.
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  Resolution - DER agrees.

Thank you and the air staff for your diligent help in resolving all of these issues. Please do not hesitate to give me a call if you have any questions.

Sincerely,

Julie

Julie Blunden
Development Manager

cc: Betsy Hewitt, DER
Clare Fancy, DER
Terry Cole, Oertel, Hoffman, Fernandez & Cole

standards and reduce ambient concentrations of NO_X in Jacksonville. However, an additional cost for NO_X emission reductions of more than $4 million per year was not anticipated. This additional cost would render the project unfinacable, and thus result in project cancellation.

The Environmental Protection Agency and Florida definitions of BACT state that it be 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 to be achievable though application of production processes and available methods, systems and techniques for control of each pollutant. These systems and techniques may include fuel cleaning or treatment, or innovative fuel combustion techniques such as CFB boilers. In this case there are energy, environmental, economic and other costs to the State of Florida should this project be halted due to a requirement for the use of SNCR.

A determination of need for his facility has been found by the FPSC. This need for additional electric capacity was dramatically reinforced by the rolling blackouts during the recent cold snap which found many families without electricity on Christmas morning. Without this facility, FPL's capacity margin will be further reduced in the near term, threatening electricity supply during peak loads. In the long term, FPL would replace this facility with another elsewhere in Florida. This hypothetical facility is less likely to offer the environmental benefits associated with the Cedar Bay Cogeneration Project.

AES Cedar Bay provides the Seminole Kraft Corporation with an opportunity to retire the paper mill's outdated power boilers. Without AES Cedar Bay, Jacksonville will not benefit from the ground level improvements in NO_X, nor the ambient VOC, SO_2 or particulate matter improvements offered by the project. Also, a FPL replacement plant will emit additional NO_X elsewhere in the State. If the cogeneration facility is replaced by a base-load pulverized coal unit, this facility would be very likely to demonstrate NO_X control to be unpracticable due to the very high costs of applying SNCR to a PC unit and the fact that this technology is not proven on PC units. Actually, the AES Cedar Bay facility will not only reduce ambient NO_X in Jacksonville, produce 225 MW of power for

Florida, and use innovative fuel combustion technology, but will have the lowest permitted NO_X emission rate of any coal-fired unit in the State.

In addition, there are also environmental concerns associated with the use of SNCR. Units equipped with this technology have had problems with high ammonia slip. It is also likely that use of SNCR technology will increase PM 10 emissions and possibly CO emissions. It is unclear that a requirement for the use of an SNCR technology on this project would result in a net environmental benefit.

Accordingly, AES Cedar Bay has proposed BACT for this project to be the use of CFB boilers to meet a NO_X emission limitation of 0.29 lb/MBtu. This project is important for the State of Florida from both energy security and environmental perspectives. A requirement for the use of SNCR on AES Cedar Bay risks losing the Cedar Bay Cogeneration Project and its benefits to Florida.

We look forward to discussing this matter further with your staff on Friday, January 5.

Sincerely,

J Blunden

Julie Blunden
Development Manager

cc: Hamilton S. Oven
Clare Fancy
Barry Andrews ✓ cc r'cd 1-4-90 RRN
Terry Cole
Steve Day
Pradeep Raval
Max Linn
A. Kutyna - NE Dist.
S. Pace - BESQ
CHF / BT / SP
W. Aronson - EPA
C. Shaver - NPS

1-9-90 RRN

Issue

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DEC 12 1989

DER - BAQM

December 12, 1989

BY HAND DELIVERY

Mr. Barry Andrews
Florida Department of
Environmental Regulation
2600 Blair Stone Road
Tallahassee, Fl 32399-2400

Dear Barry:

Thank you for taking the time to meet with me this morning. The Best Available Control Technology analysis you are preparing will have far-reaching effects on our cogeneration project, and I enjoyed the opportunity to learn more about your review.

As we discussed, AES feels that SNCR (thermal denox) is not warranted for the Cedar Bay project for the following reasons:

- Proposed NO_x emissions from the cogeneration plant are 0.36 lb/MMBtu; well below the NSPS level of 0.6 lb/MMBtu.

- At 0.36 lb/MMBtu, the cogeneration plant will actually improve ambient NO_x concentrations in the surrounding area.

- Costs for SNCR control would be around $1600/ton of additional NO_x removal -- well above the $1000/ton guideline that has been used previously.

- The proposed project will also improve air quality for other pollutants -- while providing new electrical capacity needed for Florida's growth. If this project does not go forward, another new power plant will have to be built to supply the state's demand for power. Any other power plant would surely have much more impact on the environment than the Cedar Bay project.

AES/Cedar Bay Inc.

1925 North Lynn Street • Arlington, Virginia 22209 • (703) 522-1315 • Telecopier – (703) 528-4510

Florida Rules specify that BACT should be considered by the Department on a case by case basis taking into account energy, environmental and economic impacts. The "top down" approach, although not yet incorporated into Florida law, is not necessarily in conflict with Florida's rule that consider all three of these imports. I urge you to consider that:

- From an energy standpoint this project will provide needed electricity at significant savings to ratepayers. National and state policy encourages cogeneration projects like AES Cedar Bay because they are thermodynamically efficient. The Florida Public Service Commission favors coal plants like this one as a way to reduce Florida's dependence on imported oil.

- This project is a net benefit to the environment. It is located at an existing industrial site, and will improve air quality in the area. If the cogeneration plant is not built, the paper mill will continue to run their old, environmentally outdated boilers.

- There are many economic benefits associated with the construction and operation of this project. Hundreds of jobs will be created, and the plant will contribute millions of dollars each year in taxes. Florida ratepayers will benefit from power provided below the utility "avoided cost".

Installation and operation of a SNCR system would result in additional costs to AES Cedar Bay of over $4 million each year. The cogeneration project is no longer economically viable if this additional cost is factored in. Lenders would not be willing to loan AES the money for the plant; therefore we would have to cancel the project. We believe these costs for a SNCR system is not justified under the DER rules on the EPA top down analysis when energy, environmental and the above cuts are considered.

I think you will agree that it doesn't make sense to cancel a project that offers so much for Florida -- particularly when it would be the cleanest coal plant in the state!

In the spirit of compromise we are willing, for purposes of settling this issue, to offer to reduce our emission rate to 0.29 lb/MMBtu over an annual averaging period. I believe this proposal would eliminate any question on the issue of SNCR, while still allowing the project to move forward.

Please let me know what you think of this proposal. I look forward to hearing from you soon.

Sincerely,

Terry Cole for

Jeffrey V. Swain
Project Director

cc: Hamilton S. Oven

Cedar Bay

ogen dioxide to particulate nitrites; and by sulfur dioxide when it converts to particulate sulfates.

The frequency distribution of the visibility observed at Jacksonville Imeson Airport over a five-year period is summarized in the application. The average quarterly background visibility at Jacksonville Airport is seldom greater than twelve miles or less than two miles. Visibility conditions greater than or equal to those measured at Jacksonville can be expected at St. Augustine (70 km southeast) and the Okefenokee Class I area (60-70 km northwest). Using equations, the background conditions may be calculated and the SO_4 (sulfate) and TSP impacts at the Okefenokee Class I and St. Augustine historical areas may be estimated st that the visibility impacts at these areas may also be estimated. For purposes of this simplified analysis, it was necessary to assume that SO_4 and TSP are the only pollutants contributing to visibility reduction. It was also assumed that the background visibility is twelve miles. The calculated new visibility due to the SJRPP was 10.8 miles.

This corresponds to a reduction of approximately ten percent in the visual range at the Okefenokee Class I area during worst-case conditions.

4. Best Available Control Technology

Two applicants propose to install an integrated cogeneration power plant complex at the Seminole Kraft Corporation facility located in Jacksonville, Florida. The power complex will consist of three coal/bark fired circulating fluidized bed (CFB) boilers, the respective coal handling equipment and limestone dryers, to be owned and operated by AES Cedar Bay, Inc. and a kraft recovery boiler to be owned and operated by the Seminole Kraft Corporation.

The CFB boiler, rated at 3,189 MMBtu will burn fuel made up of approximately 96 percent coal and 4 percent bark. The boilers will generate steam to produce power from a turbine generator set. The CBCP will generate 225 MW of electricity for sale to FPL as well as low pressure process steam for SKC.

The recovery boiler, rated at 1,125 MMBtu/hr will replace three old recovery boilers. Also included in the project is the installation of a new smelt dissolving tank and a new set of evaporators which will replace three old smelt dissolving tanks and three old sets of evaporators, respectively.

EPA has determined that although the CFB cogeneration complex is being constructed on the Seminole Kraft Corporation's property, that the cogeneration facility and the kraft recovery boiler should be reviewed as two separate projects for air quality impact purposes.

The applicants have indicated that the maximum net total annual tonnage of regulated air pollutants emitted from the projects based on 8,760 hours per year operation and 93% capacity factor for the CFB complex to be as follows:

Pollutant	Maximum Net Increase in Emissions (TPY) AES Cedar Bay	Seminole Kraft	PSD Signif. Emiss. Rate (TPY)
TSP	268	-140.7	25
PM10	265	-138.6	15
SO_2	4029	6.4	40
NOx	4683	1296.4	40
CO	2470	-160.0	100
VOC	208	-92.3	40
TRS	-	-53.3	10
Pb	91	-0.16	0.6
Be	1.5	-0.012	0.004
Hg	3.4	-	0.1
H_2SO_4	308	-5.8	7
Fl	1122	-	3

Rule 17-2.500(2)(f)(3) of the Florida Administrative Code (F.A.C.) 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 NOx emissions from the smelt dissolving tank and the multiple effect evaporators are negligible and will not be considered as part of the BACT analysis. The emissions of heavy metals, H_2SO_4, VOC's, and fluorides from the limestone dryers are also negligible compared to that emitted from the CFB boiler and will not be considered in the BACT analysis for the AES CBCP.

BACT Determinations Requested by the Applicants

AES Cedar Bay

Pollutant	Determination
TSP	0.02
PM10	0.02
SO_2	0.6 (3 hour average)
	0.31 (12 month rolling average)
NOx	0.36
CO	0.19
VOC	0.016
Pb	0.007
Be	0.00011
Hg	0.00026
H_2SO_4	0.024
Fl	0.086

Seminole Kraft Corporation

Pollutant	Determination
NOx	180 ppm (corrected to 8% oxygen)

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, 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 cogeneration facilities can be grouped into categories based upon what control equipment and techniques that are available to control emissions from these facilities. Using this approach, the emissions are classified as follows:

- o Combustion Products (Particulates and Heavy Metals). Controlled generally by particulate control devices.
- 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 facilities 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" pollutants (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.

BACT Analysis

Combustion Products

The CBCP complexes' projected emissions of particulate matter, PM10, lead, beryllium, and mercury 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 CFB boilers permitted in the United States. As this is the case, the applicants proposal for particulate emissions (0.02 lb/MMBtu) is representative of the most stringent BACT determinations and is thereby justified as being BACT for this facility.

In general, the BACT/LAER clearinghouse does not contain specific emission limits for lead, beryllium, and mercury from CFB boilers. BACT for heavy metals from these facilities is typicaly represented by the level of particulate control. As this is the case, the applicants proposal of 0.02 lb/MMBtu for particulate matter and PM10 is judged to represent BACT for lead, beryllium and mercury.

A review of the coal handling facilities indicates that all practical measures will be employed to control fugitive dust emissions. Fugitive dust associated with the handling of coal will be controlled with enclosures, water sprays, compaction, and bag filter dust collection. All coal conveyers not located underground or within enclosed buildings will have covers.

The control measures employed to minimize the fugitive dust measures from coal handling is judged to represent BACT for the facility.

Products of Incomplete Combustion

The emissions of carbon monoxide, volatile organic compounds and other organics from coal fired boilers are largely dependent upon the completeness of combustion. A review of the BACT/LAER Clearinghouse indicates that the emission levels of 0.19 lb/MMBtu and 0.016 lb/MMBtu for carbon monoxide and volatile organic compounds, respectively, are representatives of previous BACT determinations. In each case the BACT was represented by combustion control and proper bed operation. The emissions of carbon monoxide could be reduced by increasing the combustion temperatures in the CFB boiler. This, however, would lead to higher nitrogen oxides emissions and additional limestone would be needed for acid gas reduction resulting in a cost which would not warrant the additional carbon monoxide control. The use of combustion control in conjunction with the proposed acid gas control is also deemed as representing BACT for the other organic compounds which would be emitted from the facility.

Acid Gases

The emissions of sulfur dioxide, nitrogen dioxide, fluorides, and sulfuric acid mist, as well as other acid gases which are not "regulated" under the PSD Rule, represent significant potential pollutants which must be subjected to appropriate control. Sulfur dioxide emissions from coal fired boilers are directly related to the sulfur content of the coal which is combusted. The addition of "add on" control equipment and the utilization of combustion technolgies which serve to control sulfur dioxide emissions in the combustion chamber itself are other techniques that can be used to minimize emissions.

The applicant has proposed the use of a CFB boiler to control sulfur dioxide emissions. Sulfur dioxide is removed in a CFB boiler by injecting limestone into the boiler bed. The limestone calcines to calcium oxide at the temperatures present in the fluidized bed. The calcium oxide then reacts with the SO_2 in the flue gas to form calcium sulfate. Sulfur dioxide is removed in this manner with efficiencies up to 90 percent based on a 30-day rolling average.

In keeping with the "top down" BACT approach the applicant has identified three alternative technologies that would control sulfur dioxide emissions.

1) Pulverized coal fired boiler followed by a wet limestone scrubber system designed for a maximum of 94 percent SO_2 removal on a 30-day rolling average basis.

2) Pulverized coal fired boiler followed by a wet limestone scrubber system designed for a maximum of 90 percent SO_2 removal on a 30-day rolling average basis.

3) Pulverized coal fired boiler followed by a lime spray dryer system designed for a maximum of 90 percent SO_2 removal on a 30-day rolling average basis.

A review of alternatives 2 and 3 indicates that the level of sulfur dioxide control would be equivalent to that proposed by the applicant and no further review is needed. Alternative 1, however, would provide additional control of SO_2, thus a cost benefit analysis of using this type of control is warranted.

In order to justify the cost effectiveness of any air pollution control, the EPA has developed cost guidelines to obtain the highest reduction of emissions per dollar invested. Achievement of maximum emission reductions for capital invested is a major consideration when New Source Performance Standards (NSPS) are developed by the EPA. For SO_2 emissions, EPA has determined that cost of up to $2,000 per ton of emissions controlled ($1.00/lb) is reasonable for NSPS.

The use of a wet limestone scrubber having an efficiency of 94% has a levelized total annual cost (capital and operating) which is $7.72 million dollars greater than that of the proposed CFB boiler by the applicant. The applicant has indicated that the additional sulfur dioxide removal from using the wet scrubber would be 3,353 tons per year based on a 94% efficiency. In addition, the use of a wet limestone scrubber would eliminate the need for lime dryers which are expected to emit 38 tons per year of sulfur dioxide. Taking these reductions into consideration with the increased annual cost, the cost per ton of SO_2 controlled is approximately $2,277. This increased cost is not unreasonable based on the NSPS guideline of $2,000 per ton removal.

Another control alternative that should be considered is the use of coal with a lower sulfur content. A review of the BACT/LAER Clearinghouse indicates that BACT for CFB boilers has been established in some cases by limiting both the mass emission rate and the sulfur content of the fuel.

The applicant has indicated that the CFB boiler will fire coal with a sulfur content ranging from 1.7 to 3.3 percent which will result in the proposed SO_2 emission rates of 0.6 lb/MMBtu heat input and 0.31 lb/MMBtu heat input on a three hour and 12-month rolling average, respectively.

The BACT/LAER Clearinghouse indicates that the lowest determination for coal sulfur content is 0.5 percent for a CFB boiler, with other determinations ranging up to 3.0 percent taking into the consideration the availability of low sulfur coal.

Based on the previous cost benefit anlaysis of the wet scrubber alternative, it seems reasonable to investigate the cost of using a coal with a lower than proposed sulfur content which would result in the same emission rate as the wet scrubber option.

In order to provide the same level of control as the wet scrubber alternative, it has been determined that the CFB boiler would need to utilize coal with a sulfur content ranging from 1.0 to 2.0 percent. This would result in sulfur dioxide emission rate of 0.36 lb/MMBtu and 0.186 lb/MMBtu for a three-hour and 12-month rolling average, respectively.

Based on the capacity factor of 93 percent as provided by the applicant, the use of coal with an average annual sulfur content of 1.0 percent would result in an sulfur dioxide emission reduction of 1,653 tons/year. When this reduction is taken into consideration wit the increased cost of purchasing coal with a lower sulfur content the cost per ton of sulfur dioxide reduction can be determined.

In a recent application in which the cost of switching to a lower sulfur content coal was evaluated, the cost of switching from a 2.0 to 1.0% sulfur coal was determined to be $4.90 greater per ton of coal purchased. Using this figure as an approximation of using coal with an annual average sulfur content of 1.0% as compared to the proposed 1.7% the cost benefit analysis is computed as follows. Based on the applicant's maximum consumption rate of 248,000 lbs/hr and the 93% capacity factor, the increased cost of using 1.0% sulfur coal would be approximately $4.95 million. Taking this cost into consideration with the expected reduction the cost per ton of control would be $2,995. The actual cost would be slightly less than $2,995 when taking into consideration the greater heating value from lower sulfur content coal but would still be well above the $2,000 per ton guideline.

The emissions of nitrogen oxides from coal fired boilers are controlled by combustion control and post combustion control equipment. In a CFB boiler, low combustion temperatures coupled with staged combustion effectively limit the formation of NOx. Low combustion temperatures primarily limit the formation of thermal NOx, and staged combustion (creating a reducing atmosphere in the lower portion of the boiler) inhibits the formation of fuel NOx.

The applicant has proposed the use of the CFB boiler with an emission limit of 0.36 lb/MMBtu as BACT for nitrogen oxides. The alternatives to further reduce NOx emissions are discussed and evaluated on a cost/benefit basis as follows:

> Post-combustion NOx control processes are based on the reaction of ammonia or urea with conversion of NOx to form nitrogen and water. Selective noncatalytic reduction and selective catalytic reduction NOx reduction technologies are the only technologies adequately demonstrated to be considered for installation on CFB boilers.
>
> Selective catalytic reduction (SCR) is a post-combustion method for control of NOx emissions which is being developed by a number of companies, principally in Japan and Europe. The SCR process combines vaporized ammonia with NOx in the presence of a catalyst to form nitrogen and water. The SCR process can achieve between 80 and 90 percent reduction of NOx. The vaporized ammonia is injected into the exhaust gases prior to passage through a catalyst bed. The optimum flue gas temperature range for SCR operation is approximately 700 to 850°F. The SCR catalyst is housed in a reactor vessel which is separate from the boiler.
>
> Selective noncatalytic reduction (SNCR) is another post-combustion method controlling NOx emissions. The process selectively reduces NOx by reaction with ammonia or urea without the use of a catalyst bed. A SNCR system could potentially reduce NOx emissions generated by a coal fired CFB boiler by 40 to 60 percent.

The applicant has indicated that a SCR system would remove an additional 4,525 tons of nitrogen oxides per year. When this removal rate is taken into consideration with the total levelized annual cost (capital and operating) of $14.35 million, the cost per ton of nitrogen oxides controlled is approximately $3,171. This is well above the NSPS guideline of $1,000 per ton, yet less than previous BACT determinations in which post-combustion nitrogen oxides control was justified at costs up to approximately $4,200 per ton.

For SNCR the applicant has indicated that an additional 3,017 tons of nitrogen oxides per year would be controlled at a total levelized annual cost of $4.11 million. This results in a cost per ton of nitrogen oxides controlled of approximately $1,362 which is just slightly above the NSPS guideline and well below the cost of previous BACT determinations.

For the kraft recovery boiler, a review of recent BACT determinations for nitrogen oxides indicates that the emissions rate proposed by the applicant does not represent BACT. The rationale for establishing BACT at a lower than proposed level is presented as follows:

The applicant has indicated that an emission rate of 180 ppm corrected to 8% oxygen is representative of BACT taking into consideration guarantees common to all potential manufacturers, the black liquor fuel analysis, and performance deterioration based on a 24-hour average.

A review of the BACT/LAER Clearinghouse indicates a wide range of NOx limitations. Although several of the most recent BACT determinations range from 50-80 ppm corrected to 8% oxygen, none of the facilities listed utilize NOx reduction systems operating downstream from a kraft recovery boiler. However, in keeping with the "top down" BACT analysis, "add on" control equipment will be evaluated as part of the analysis.

The two types of control that are typically utilized for NOx reduction are selective catalytic reduction (SCR) and Thermal De NOx. Each of these technologies utilizes ammonia injection as the means to react with and thereby reduce the concentrations of NOx in the gas stream. Although these technologies have not been utilized for this type of application the economics of using such equipment should be addressed.

The applicant has indicated that using Thermal DeNOx as a control increase for NOx results in a cost of $2,000 per ton of NOx reduced. Although this costs is not excessive compared to recent BACT determinations in which NOx removal was justified at costs up to approximately $4,200 per ton, the use of Thermal DeNOx as a control measure has not been demonstrated on Kraft recovery boilers and hence has not been seriously considered as BACT for recent determinations. Similarly SCR has not been used in Kraft recovery boiler applications and should not be considered as BACT for these facilities.

Although "add on" NOx controls have not been utilized for kraft recovery boilers, a survey of the most recent BACT determinations indicates that kraft recovery boiler manufacturers are capable of limiting NOx emissions to suprisingly low levels (generally 53 to 75 ppm @ 8% oxygen) by equipment design.

Discussions with the BACT coordinators from other states which have pulp and paper industry indicate that all of the known manufacturers of kraft recovery boilers have proposed or agreed to meet NOx emission limitations which fall within the range discussed above. Although many of these facilities were just recently permitted and have yet to be constructed and tested, there is sufficient data available to suggest that these limitations can indeed be met.

In a technical study completed by the National Council of the Paper Industry for Air and Stream Improvement, Inc. (NCASI), several large kraft recovery furnaces (boilers) were tested for NOx emissions. The publication entitled "A Study of Nitrogen

Oxides Emissions from Large Kraft Recovery Furnaces" provides evidence that NOx emissions can be held to levels which are now being proposed by kraft recovery boiler manufacturers.

The NCASI report focused on the NOx emissions from four large kraft recovery boilers, with three of the units being located in the southeastern United States. The size of the units tested ranged from firing rates of 3.18 - 4.06 million pounds of black liquor solids (BLS) per day. This is comparable to the proposed kraft recovery boiler which has a firing of 4.1 million pounds of BLS per day.

Based on the NOx emission studies completed, the NCASI report concluded the following:

1) NOx emissions from large kraft recovery boilers were not size dependent.

2) NOx emissions ranged from 0.06 to 0.11 lbs/million Btu heat input.

Based on the applicant's maximum BLS input of 4.1×10^6 lb/day (170,833.3 lb/hr) a comparison of the proposed NOx emission limit can be made with the NCASI test results.

The applicant has estimated the maximum hourly NOx emission to be 369.3 pounds. Taking this into account with the BLS heating value of 4,522 Btu per pound, the calculated emission rate on a heat input basis is approximately 0.48 lbs per million Btu. This emission level ranges from approximately 4 to 8 times greater than that observed by the NCASI study.

Environmental Impact Analysis

A review of the impacts associated with the proposed CBCP and the recovery boiler installation indicates that there will be a reduction in the maximum annual impacts. This reduction in the impacts will be attributed to the replacement of three old power boilers and there old recovery boilers which are now exhibiting higher impacts than what will be expected from the new cogeneration/recovery boiler complex.

Discussion

The Department has determined that the levels of control proposed by the applicant for the CFB cogeneration facility represents BACT in most cases. The review indicates that the level of particulate control clearly is justified as BACT for particulate matter, PM_{10}, and other heavy metals. In addition, the levels of control proposed for the coal handling facilities, and for products of incomplete combustion is also representation of BACT.

A review of the proposed control for sulfur dioxide indicates that the inherent removal efficiency provided by the CFB boiler represents BACT. The analyses of alternative control technologies indicates that both the cost of using wet scrubbers and switching to a lower sulfur content coal are cost prohibitive based on BACT cost of control guidelines. In addition to the greater cost of using wet scrubbing, such an alternative has the disadvantage of having to handle and dispose of the scrubber sludge produced. In addition to the greater cost of using a lower sulfur coal, such an alternative presents the difficulties encountered to establish a coal contract which allows for the handling and transport of ash produced by the CFB boiler.

Section 17-2.03 Florida Administrative Code (FAC) and Section 169, 424SC 7401 require evaluation of proposed air pollutant emission control equipment and a determination as to whether or not an applicant will utilize the Best Available Control Technology (BACT) for each pollutant.

The installation of a high efficiency Fabric Filter to control particulate emission from the boilers, bag filters to control particulate emissions from fly ash handling, and liquid spray and bag filter systems to control particulate emissions from coal handling and lime and limestone handling all represent BACT.

The use of washed low sulfer coal and the fluidized bed boiler using limestone to achieve a 90% reduction of the potential sulfur oxide emissions would comply with requirements under 40 CFR Part 60, Federal New Source Performance Standards.

The use of boiler design controls which limit flame temperature and oxygen availability in order to control the formation of nitrogen oxides in the boiler to 0.6 pounds per million BTU is considered to be BACT. Likewise, the use of boiler controls to limit the emission of carbon monoxide is also considered BACT.

The Department of Environmental Regulation, having considered (a) all available scientific, engineering and technical material, (b) existing emission control standards of other states, and (c) the social and economic impact of the application to be used by AES to be the Best Available Control Technology, as shown in the following:

The proposed facility will consist of three 85.3 megawatt coal-fired electric utility steam generating

units to be located in Jacksonville, Florida. The units will be designed for coal and wood wask firing.

Kraft recovery boiler emissions of total reduced sulfur (TRS), SO_2, NO_x, CO and VOC will be controlled by proper boiler design and combustion controls. Particulate emissions will be controlled by an electrostatic precipitator.

Gas from the smelt dissolving tank will be vented to a wet scrubber for particulate and TRS emission control. The smelt dissolving tank will not emit significant quantities of SO_2, NO_x and CO.

Best Available Control Technology Analysis Summary:

The following is a summary of results from the BACT analysis:

- The pollutant applicability analysis concluded that the criteria pollutants--SO_2, NO_x, CO, and lead--requires a BACT analysis. The noncriteria pollutants--beryllium, mercury, flourides, and sulfuric acid mist--also require a BACT analysis.
- BACT determinations are based on the use of a "top-down" approach.
- No_x emission limiting techniques of lowering combustion temperatures and excess combustion air are counterproductive relative to CO emissions.

Cogeneration Plant:

- The Cedar Bay Cogeneration Plant will generate 2,300,00 lb/h of steam at the maximum design conditions. The largest commercial CFB boiler produces 925,000 lb/h of steam. There are numerous pulverized coal (PC) fired boilers operating that are larger than three CFB boilers (each providing 33 percent of the total capacity), to a single full-capacity PC boiler.
- Flue gas desulfurization alternatives are evaluated on a total air quality control system (AQCS) basis. The AQCS contains FGD and particulate removal equipment, as well as waste disposal. SO_2 removal alternatives evaluated consistent with a top-down approach include the following.
  - ---One PC boiler followed by a wet limestone scrubber system designed for 94% SO_2 removal.
  - ---Three CFB boilers designed for 90% SO_2 removal.
  - ---PC boiler followed by a wet limestone scrubber system designed for 90% SO_2 removal.
  - ---PC boiler followed by a lime spray dryer system designed for 90% SO_2 removal.
- A PC boiler/wet limestone scrubber air quality control system (AQCS) designed to meet 94% SO_2 removal requirement has the highest total levelized annual cost. Additional costs result in an incremental removal cost of $2,300 per ton to go from 90% percent with a CFB boiler AQCS to 94% SO_2 removal. Based on economics, energy, and environmental considerations, a CFB boiler AQCS designed to meet a 90% SO_2 removal requirement represents BACT. BACT regarding noncriteria pollutants is accomplished as a result of FGD and particulate removal operations.
- CFB boilers have lower NO_x emission levels than PC boilers (0.36 lb/MBtu as compared to 0.40 lb/MBtu). A CFB or a PC boiler should be capable of meeting a CO emission rate of 0.19

lb/MBtu (CFB boiler) or 0.11 lb/MBtu (PC boiler) while meeting previously discussed NO_x and SO_2 emission levels.

- Selective catalytic reduction (SCR), and selective noncatalytic reduction (Thermal DeNOx) NO_x emission control technologies are the only technologies adequately demonstrated to be considered for installation. There is no publicly available operating experience with the use of either of these two technologies downstream of a coal fired CFB boiler. Problems presented by the use of these systems include equipment fouling, poor control and distribution of the ammonia injected, ammonia slip and the subsequent release of ammonia to the environment, and limited equipment life. Despite lack of experience and technical problems, a technical and economic analysis was performed for thoroughness of analysis.
- Installation of a 90% efficient SCR system on a CFB or PC boiler would result in an incremental NO_x reduction cost of $6,800.00 and $6,200.00 per ton, respectively. Installation of a 60% efficient Thermal DeNOx system on a CFB or PC boiler would result in an incremental NO_x reduction cost of $1,400.00 and $1,200.00 per ton, respectively.
- Consideration of environmental factors also supports the selection of combustion controls as BACT for NO_x. Use of an SCR or a Thermal DeNOx system will result in the emission of various amine compounds formed by the unreacted ammonia exiting these NO_x reduction systems. This represents a potential adverse human health effect, since many amine compounds are known or suspected carcinogens. Therefore, based on economic, energy, and environmental considerations, BACT for NO_x and CO emissions from the cogeneration plant is a CFB boiler with combustion controls to meet an NO_x and CO emission requirement of 0.36 lb/MBtu and 0.19 lb/MBtu, respectively.

Kraft Recovery Boiler

- Sulfur dioxide emissions from the kraft recovery boiler (KRB) are controlled by creating conditions (vigorous burning at high temperature) which minimize the initial SO_2 release from the black liquor, and by simultaneously creating conditions (vigorous burning and high lower furnace temperature) which are favorable for capturing SO_2 by reaction with alkaline sodium carbonate (NA_2CO_3) particles. Relatively large quatities of NA_2CO_3 are released during black liquor combustion.
- Manufacturers indicate that current KRB designs can consistently meet an SO_2 emission requirement of 180 ppmvd corrected to 8 percent oxygen (approximately 0.48 lb/MBtu).
- In addition to combustion controls, SO_2 emissions can be controlled by a flue gas desulferization system. Currently, there are no kraft recovery boilers with supplemental FGD systems. A wet sodium scrubber FGD system designed for 90 percent SO_2 removal would result in an incremental removal cost of $2,900 per additional ton of SO_2 removed. Therefore, based on economics and energy use, an SO_2 emission limit of 180 ppmvd corrected to 8 percent oxygen represents BACT.

• Despite a complete lack of operating experience, a Thermal DeNOx nitrogen oxide reduction system is evaluated for use downstream of the KRB. Differential levelized annual costs result in an incremental NO_x reduction cost of $2,000 per ton. As previously discussed, the consideration of environmental factors also supports the selection of combustion controls as BACT. Therefore, based on economics, energy and environmental considerations, a NO_x emission limit of 180 ppmvd corrected to 8 percent oxygen represents BACT.

• BACT for CO emissions from the KRB is proper boiler design and operation (consistent with previously proposed NO_x and SO_2 emission requirements) to meet a CO emission limit of 400 ppmvd corrected to 8 percent oxygen.

Pollutant	Emission Limit
Pulp Mill-Recovery Boiler	
Particulate Matter	0.044 gr/dscf
SO_2	180 ppmvd @ 8% O_2
NO_x	180 ppmvd @ 8% O_2
CO	400 ppmvd @ 8% O_2
TRS	5 ppmvd @ 8% O_2
Smelt Dissolving Tank	
Particulate	0.2 lb/ton BLS
TRS	0.033 lb/ton BLS
Multiple Effects Evaporators	
TRS	5 ppmvd @ 10% O_2

The plant will be located in Duval County which is classified nonattainment for the pollutant Ozone (17-2.16(1)(c) F.A.C.). It will be located in the area of influence of the Jacksonville particulate nonattainment area (17-2.13(1)(b) F.A.C.), however, the plant will not significantly impact the nonattainment area and is, therefore exempt from the requirements of Section 17-2, 17 & 18 & 19 with respect to particulate emissions. The facility must comply with the provisions of 17-2.04 F.A.C. (Prevention of Significant Deterioration).

The proposed level of control for nitrogen oxides from both the CFB cogeneration facility and the kraft recovery boiler, however, are not representative of BACT. The review of the costs associated with using post combustion controls indicates that the cost per ton of using selective noncatalytic reduction (SNCR) for NOx removal from CFB boiler just slightly exceeds the $1,000 guideline that is used for NSPS and is well below that which has been justified as BACT for other facilities.

In general, the use of post combustion NOx controls has been a strategy which has been evaluated in every BACT review since the "top down" BACT policy was introduced by the EPA in December 1987. In each case, the use of post combustion controls was rejected due to being cost prohibitive, or on the basis that there was not sufficient operating experience for a particular technical application to demonstrate that the specific application was proven.

For the cases in which the use of post combustion controls was rejected because of being cost prohibitive, the cogeneration unit was being constructed for peaking purposes only. As this was the case, the facility in question would be operated well below full capacity (peaking units), thereby resulting in cost per ton figures which were well above what has been established as justifiable for BACT.

With regard to the technology being proven, both SCR and SNCR have had operating experience in both Japan and Europe. More recently, several facilities in California have been permitted with SNCR. Compliance testing has indicated that one of the facilities which is now operating (Corn Products) has passed its compliance test. Another operating facility (Cogeneration National) has had trouble meeting the NOx emission limitation while also maintaining compliance with the CO and SO_2 emission requirements. This plant has continued with adjustments targeted at achieving coincidental compliance.

The applicant has stated that SNCR systems emit various amine compounds formed by unreacted ammonia which represents a potential adverse human health effect. Although it has been demonstrated that ammonia slip does occur this does not indicate that the technology has not been proven. The use of both SCR and SNCR as representing BACT is becoming more and more prevalent for internal combustion engines, boilers, and turbines. Based on the experience that has been demonstrated on other facilities and the cost effectiveness, it has been determined that the Cedar Bay Cogeneration facility should incorporate SNCR as BACT for nitrogen oxides control.

For the kraft recovery boiler, it has been determined that NOx emission limitation of 75 ppm by volume, corrected to 8% oxygen, is representative of the levels that are being proposed in recent applications as BACT for boilers supplied by all known manufacturers. In addition, this level is supported by the NCASI report which showed NOx emissions ranging from 37 to 60 ppm, corrected to 8% oxygen, for all of the facilities tested over a three hour period.

In addition to the reasons stated above, the use of better than proposed nitrogen oxides control is further substantiated based on the location of the proposed Cedar Bay/Seminole Kraft cogeneration venture. The Seminole Kraft Corporation is located in an area which is designated as being nonattainment for ozone. Nitrogen oxides are known to be a precursor to ozone and should be controlled to the greatest extent which is deemed to be justified.

BACT Determination by DER

Based on the information presented in the preceeding analysis, the Department determines that the circulized fluidized bed boiler in conjunction with a baghouse and selective noncatalytic reduction represents BACT for the Cedar Bay Facility. The emission limits for the Cedar Bay cogeneration facility and the Seminole Kraft Corporation recovery boiler are established as follows:

AES Cedar Bay

Pollutant	Determination (lb/MM Btu)
TSP	0.02
PM10	0.02
SO_2	0.6 (3 hour average)
	0.31 (12 month rolling average)
NOx	0.144*
CO	0.19
VOC	0.016
Pb	0.007
Be	0.00011
Hg	0.00026
H_2SO_4	0.024
Fl	0.086

Seminole Kraft Corporation

Pollutant	Determination
NOx	75 ppm by vol., corrected to 8% oxygen

*Limitation based on using selective non catalytic reduction with a NOx removal efficiency of 60 percent.

Fugitive Dust

Fugitive dust is produced by a number of sources associated with the project. These include the coal handling system, limestone and spent limestone handling system, and pelletized waste handling systems. Also since fresh water cooling towers will be used, EPA has indicated that dissolved and suspended solids in the small droplets fraction (less than 50 microns diameter) of cooling tower drift would be considered fugitive dust in the impact assessment. The following paragraphs describe the control systems and/or methods proposed as BACT for these fugitive dust sources.

Coal Handling Fugitive Dust Collection

Control and collection of fugitive particulates in the coal handling system will be accomplished by several different methods, including totally enclosed conveying systems, water spray dust suppression systems, and dust collection systems utilizing fabric filters.

The coal unloading facility will have dry dust collection systems capable of 99.9 percent control efficiency on the unloader receiving hoppers. All conveyors will be totally enclosed and each transfer point fitted with dry dust collection systems, with the exception of the stacker-reclaimer which eill be fitted with a water spray dust suppression system capable of 97 percent efficiency.

Coal will be unloaded at the plant site by a rotary car dumper which will be housed in an unloading building with a wet dust suppression system. This is expected to have a dust control efficiency of 97 percent. From the delivery point, totally enclosed belt conveyors will be used to transport the coal to the coal handling building. Surge bins in the coal handling building will be vented with fabric filter dust collectors (efficiency of 99.9 percent), and similar collectors will be located at all conveyor discharge points. Conveyors between the coal handling building and the stacker-reclaimer will be enclosed, but coal dust associated with these conveyors will be controlled by a water spray dust suppresion system. Dust releases in the stacker-reclaimer area (active coal pile) will be ocntrolled by wetting agents for an efficiency of 90 percent. Dust releases from the inactive coal pile will also be controlled by wetting agents.

All conveyors from the coal handling building to the power house will be enclosed, and fabric filter dust collectors will be utilized to vent the storage silos in the power house and all conveyor transfer points. Tripper conveyors will be enclosed in a gallery.

Limestone Fugitive Dust Collection

Control and collection of fugitive dust particulates from the limestone addition system for the boilers will be accomplished by appropriate types of fabric filter dust collectors.

Limestone will be transported at the site by totally enclosed belt conveyors. All silos and hoppers utilized by the limestone system will be vented to fabric filter dust collectors. Similar collectors will be located at all conveyor discharge points.

All fabric filter dust collectors in the lime or limestone additive system will have an efficienct of 99.9 percent.

Control and Collection of Fugitive Fly Ash Particulates

In the fly ash handling system, fugitive fly ash particulate will be controlled at all transfer and discharge locations by fabric filters. The fly ash handling system consists essentially of ash hoppers located beneath the flue gas particulate collection equipment. Pneumatic conveyors are utilized to transfer fly ash to and from ash storage silos, and to mixers which prepare the ash and FGD wastes for disposal. Pneumatic conveyors are by their nature enclosed. Discharge for the conveyor's blower(s) will be equipped with fabric filters with greater than 99 percent collection efficienct.

Cooling Tower Drift

The dissolved and suspended solids in the small droplet size fraction of fresh water cooling tower drift is considered by EPA to contribute to total suspended particulates. This contribution is minimized by using high efficiency drift eliminators in the two natural draft towers (which limit drift to approximately .005 percent of circulating water flow) and by maintaining the cycles of concentration of the circulating water to a low level such as a maximum of 1.5. Additionally, a drift eliminator will be provided to mitigate the potential effects of blow-through. Upon reviewing the preceeding information, the Department also finds that the CBCP will not contribute to significant adverse air quality impacts.

5. Acid Rain

In recent years the increase of rainfall acidity levels across Florida and other parts of the country has been ascribed in part to the air emissions from coal-fired power plants. Hence the requirement for emission controls on these plants, designed to reduce the potential acid causing factors. Generally, sulfur dioxide and oxides of nitrogen are believed to be the primary anthropogenic agents contributing to rainfall acidification. However, a great deal remains unknown about the amount that these two gases contribute to the problem, as well as how and where the acidification takes place.

It should be noted that rainfall under unpolluted conditions tends to be somewhat acidic, on the order of pH 5.6-5.7. This is due to the absorption of water in the atmosphere. Also, neither sulfur dioxide nor nitrogen dioxide in and of themselves are acidic. It appears that after a certain amount of time, estimated to be on the order of 3-4 days, these gases interact with sunlight, water vapor, ammonia, and many other chemical compounds in the atmosphere, which converts them to sulfuric aqcid and nitric acid. Scientists around the world are studying the rate of these reactions, which catalytic aids (sunlight, water, etc.) have the most effect driving the conversion, ways to prevent the end acidic product from affecting the environment, where the end product eventually makes it's impacts, and numerous other questions relating to the conversion reactions. It is universally agreed that the entire cause-effect-control relationship is very complex.

There are three issues relevant to the licensing of the Cedar Bay/Seminole Kraft Projects as emission sources in relation to acidic rainfall. These are: (1) why is the problem of concern, (2) what will be the projects contribution to the regional, state and country wide problem, and (3) what controls are required to mitigate the problem?

First, the following effects have been ascribed to above-normal acidic rainfall. Acid rain is listed as a cause for destabilization of clay minerals, reduction of soil cation exchange capacity, promotion of chemical denudation of soils, and promotion of runoff. Vegetational effects tend to be quite varied, ranging from a few cases of reported beneficial effects, to the more prevalent harmful effects. The harmful effects include foilage damage, alteration of responses to pathogens, symbionts and saprophytes, leaching of essential materials from

For Routing To Other Than The Addressee
To Pradeep Location
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From: Date

State of Florida
DEPARTMENT OF ENVIRONMENTAL REGULATION

Interoffice Memorandum

TO: Steve Smallwood

FROM: Clair Fancy

DATE: November 21, 1989

SUBJ: Applied Energy Services

This is to update you on the status of the application for the cogeneration project at Applied Energy Services (AES).

About one year ago, Seminole Kraft and Applied Energy Services submitted applications under the Power Plant Siting Act to construct a cogeneration facility to replace the old boilers at Seminole Kraft and also to rehabilitate the recovery boilers and associated equipment for compliance with the TRS rule. Due to the time constraints in complying with the TRS rule, Seminole Kraft pulled from the site certification the TRS portion of the application. This is currently being reviewed and the Intent to Issue should go out this week.

With regards to the AES project, EPA informed the Department recently that there may be some complications in issuing this permit. Since that time, there has been some positive developments that may allow for the issuance of the permit.

There are three issues as to whether or not the Applied Energy Services cogeneration project is subject to PSD review. These are contiguous plant property, SIC grouping, and common control. It is clear that the AES project and the Seminole Kraft facility are on contiguous property. EPA has suggested that if 50 percent of the steam produced by AES goes to the pulp mill, then they would be under the pulp and paper SIC code. If not, it would be under a different SIC code and would therefore be subject to PSD. Seventy-eight percent (78%) of the steam will go for outside power generation and twenty two percent (22%) will go for Seminole Kraft. However, it is my understanding that the heat distribution will be appoximately 50-50. EPA is looking into this now. Seminole Kraft and AES are not under common financial control, however, since they will be sharing the facility and

Seminole Kraft will not be able to operate without AES supplying steam, this may be considered common control by EPA. EPA Region IV personnel are going to discuss both of these issues with Headquarters next week. Wayne Aronson, of EPA Region IV, agrees that AES should be permitted as it will cause an air quality improvement in the Jacksonville area. He also agrees that EPA should take a look at cogeneration facilities not being subject to PSD review and intends to ask Headquarters to investigate this. We sent the modeling parameters to EPA and they will do a screening analysis this week.

If the facility is subject to PSD, it now appears as though it will be permittable. 40 CFR 51 165 (b) states that if the contribution of SO_2 from a source exceeds one microgram per cubic meter on an annual basis that it is considered significant and that the modeling needs to be done. Fortunately, this regulation allows the issuance of the PSD permit, even if air quality standards are being exceeded, if it can be clearly demonstrated that there will be an offset in ambient concentration and an overall improvement in air quality. This project clearly meets this criteria so the modeled nonattainment status, if it exists, will not prohibit the issuance of the PSD permit. The other major criteria with the PSD regulations is the BACT analysis. EPA feels that the cogeneration facility with the fluidized bed is BACT for a boiler of this type. The only question would be whether or not DeNox would be required.

I intend to closely monitor this situation with EPA, BAR staff, and the Siting Coordination Section to attempt to meet all the necessary dates. If some of these issues cannot be resolved prior to the detailed site certification's required public notice date, we can include some general information with regards to air quality and have more information to present at the hearing. As all sources certified under the Power Plant Siting Act also need PSD permits, I feel confident that the BAR can prepare a PSD permit that can be approved simultaneously with the approval of the site certification, probably in April or May.

CHF/kt

cc: B. Oven
B. Andrews
B. Thomas
P. Raval

CONDITION OF CERTIFICATION

1. Common Control

This certification and any individual air permits issued subsequent to the final order of the Board certifying the power plant site under 403.509, F.S., shall require, as a federally enforceable condition, any source offered for contemporaneous emission reduction credits (offsets) to be permanently removed from operation. That requirement shall operate as a joint and individual requirement to assure common control for purpose of insuring that all contemporaneous emission reductions relied on are in fact made.

Features of Common Control

This certification and any individual permits issued by the Secretary, as a joint application for site certification, is found to be on the same piece or contiguous property and provides for the retirement of the same type of sources as offsets or reduction credits for the construction of new sources. Old kraft recovery boilers, evaporators, smelt dissolving tanks, power and bark boilers will be retired after NSPS recovery boilers, smelt tanks, evaporators and cogeneration power boilers are brought on line.

- This project will be certified jointly under one set of conditions.

- Seminole Kraft dictates steam extraction from AES Cedar Bay's turbine.

- Seminole Kraft owns the land on which the cogeneration facility will be built.

- AES Cedar Bay leases land from Seminole Kraft for the power plant site.

- AES Cedar Bay relies on bark from Seminole for boiler fuel.

- AES Cedar Bay also intends to use surplus lime from the paper making process for injection to react with SO_2, if practicable.

- AES Cedar Bay uses Seminole Kraft rail lines and rights-of-way.

- AES Cedar Bay relies on Seminole Kraft deep wells for water supply.

- Seminole Kraft relies on AES Cedar Bay for demineralizer water.

- AES Cedar Bay relies on Seminole Kraft for lime softened water.

- AES Cedar Bay relies on Seminole Kraft for a potion of wastewater treatment.

- AES Cedar Bay is not economically feasible without the sale of steam to Seminole Kraft.

The overall design of the project will make Seminole Kraft and AES Cedar Bay integral and inseparable parts of each other, therefore constituting common control.

Precedent

Precedent exists for new source review of two companies as a single facility under EPA approved rules. In California, Sacrament Municipal Utility District and Campbell Soup Company were considered a single facility in their PSD review and analysis dated August 9, 1988 issued in EPA Region IX. The conditions of this permit are similar and pertinent to the Cedar Bay Cogeneration Project.

The modifications to the Seminole Kraft pulp mill are categorized under the "Major Group" 26-Paper and Allied Products. The cogeneration project is categorized under the "Major Group" 49-Electric, Gas, and Sanitary Services. Moreover, it is clearly stated in the Site Certification Application that the new recovery boiler/smelt tank will be owned and operated by Seminole Kraft, and the new power facility will be owned and operated by Cedar Bay.

In discussing this matter with your staff, it was discovered that DER's general definition of "facility" (17-2.100) is different than the federal definition in that the requirement for the pollutant emitting activities to belong to the same industrial grouping is not included in DER's definition. However, our review of DER's PSD rules, 17-2.500, clearly indicates this "Major Group" criteria in determining applicability for new major sources. Our review of this section of the federally approved regulations for Florida suggests that DER's PSD applicability criteria for a new "facility" is premised upon the same factors as the federal regulations. Therefore, we have concluded that no deficiency exists in DER's PSD rules regarding the applicability of a new "facility".

Based on the above facts, we have concluded that Seminole Kraft and Cedar Bay are two separate and distinct facilities and may not "net" interchangeably under the federally approved Prevention of Significant Deterioration (PSD) rules for Florida. However, for purposes of nonattainment new source review (NSR) requirements, offset credit may be used by either facility as long as the reductions in volatile organic compound (VOC) emissions are made federally enforceable. (Offset credit should not be confused with "netting" as defined under both sets of regulations, i.e., in determining applicability.)

If you have any questions concerning this matter, please call Mark Armentrout of my staff at (404) 347-2864.

Sincerely yours,

Wayne J. Aronson / for

Bruce P. Miller, Chief
Air Programs Branch
Air, Pesticides, and Toxics
Management Division

copied: P. Raval
B. Andrews
M. Zinn
G. Kuberski, NE Dist.
B. Peck, BESD
CHF/BT

YELLOW FILE COPY.

MEMORANDUM

DATE: OCT 27 1989

SUBJECT: Use of Leftover Netting Credits

FROM: Bruce P. Miller, Chief
Air Programs Branch

TO: Gary McCutchen, Chief
New Source Review Section (MD-15)

We have been asked by KBN Engineering and Applied Sciences, Inc., a consulting firm representing the Seminole Kraft Company, to provide EPA's policy for addressing leftover emission credits not used during a netting transaction. Based on our conversations with other Regional Offices, it would appear that there is some inconsistency in EPA's position on this matter.

As you will see from the attached letter from KBN (October 2, 1989), Seminole Kraft is proposing to construct a new recovery boiler and smelt dissolving tank at its existing kraft pulp mill located in Jacksonville, Florida. As part of the project, three existing recovery boilers and smelt dissolving tanks will be shut down to generate contemporaneous emission decreases. From the table attached with KBN's letter, there will be a net decrease of several pollutants and a significant net emissions increase for only oxides of nitrogen. The Florida Department of Environmental Regulation (DER) has taken the position that the leftover emission decreases may not be carried over to be used in future netting/offsetting transactions and that the slate is wiped clean for those pollutants. This is based on their interpretation of 40 CFR 51.166(b)(3)(iii) which states that... "An increase or decrease in actual emissions is creditable only if the reviewing authority has not relied on it in issuing a permit for the source under regulations approved pursuant to this section, which permit is in effect when the increase in actual emissions from the particular change occurs."

In your review of this matter, we ask that you address the following questions:

1. Can the facility use the leftover contemporaneous emission reductions in future netting transactions? If yes, can these emission credits be sold or otherwise used by a separate facility (with a different major SIC number) under any circumstances? For example, if a new major power plant under separate ownership would locate on Seminole kraft property for the purpose of supplying power both to the pulp mill and to other facilities, could the leftover emission credits be used by the power plant under any circumstances?

2. If Seminole Kraft is allowed to use the leftover emission credits in future netting transactions, is the five year netting timeframe opened for all pollutants even though a future modification may be major for only a limited number of pollutants? For example, if a future project involves an increase of 35 tons of sulfur dioxide and 50 tons of particulate matter per year, would the facility be required to perform a PSD review for sulfur dioxide because of the previous contemporaneous increase of 6.4 tons per year?

Since we must provide KBN and the Florida DER a response to these issues as soon as possible, we request that you respond to these questions by November 10, 1989. If you need any additional information, please contact Mark Armentrout of my staff at (FTS) 257-2864.

Attachment

MARMENTROUT/CDW/10/23/89 DOC: 24-MB-GM
ARMENTROUT ~~AMX~~ 10/20 ARONSON WD 10/20 MILLER WA for BMn 10/24

Briefing Paper for Winston Smith/Bruce Miller

ISSUE: The Florida DER is proposing to allow netting credits (created by the shutdown of existing pulp mill sources at Seminole kraft) to be used at a separate "facility" (AES/Cedar Bay) and thus net out of PSD. The Florida DER is allowing this action by misconstruing their definition of "facility" under the PSD rules.

BACKGROUND: Seminole kraft and AES/Cedar Bay have jointly applied for a permit under the Power Plant Siting Act to perform the following activities:

1. Shutdown three existing recovery boilers and associated smelt tanks and numerous steam boilers at Seminole kraft.

2. Construct one new recovery boiler and smelt tank.

3. Construct a power generation facility consisting of three circulating fluidized bed boilers for supplying process steam to Seminole kraft and 225 mw of electricity for sale to the JEA.

It is clearly stated in the application that the new recovery boiler/smelt tank will be owned and operated by Seminole kraft. It is also stated that the new power facility, to be constructed on Seminole kraft property, will be owned and operated by AES/Cedar Bay.

There is an inconsistency between the federal definition of "facility" and that of the Florida DER. EPA's definition includes the following criteria for defining a "facility": All pollutant emitting activities that are,

a) on contiguous or adjacent property,
b) under control of the same person (or persons under common control), and
c) belong to the same "Major Group", i.e., have the same first two digit SIC code.

Florida's definition of facility does not require that the pollutant emitting units belong to the same "Major Group"; otherwise, their regulation is identical.

By either definition and in review of the preamble to the promulgation of the term "facility", it is apparent that the kraft pulp mill and power facility should be considered two distinct "facilities". This is based on the meaning of "under control of the same person (or persons under common control)". Therefore, emission netting may only be applied within each separate facility.

Wayne (Mike)

Please prepare a response ASAP. Make sure that any response is coordinated & agreed to by Fla. first. Bruce

KBN

October 2, 1989
89026

AIR PROGRAMS BRANCH
RECEIVED
OCT 4 1989
EPA-REGION IV
ATLANTA, GA.

Bruce P. Miller, Chief
Air Programs Branch
U.S. Environmental Protection Agency Region IV
345 Courtland Street
Atlanta, GA 30365

Dear Mr. Miller:

The purpose of this letter is to solicit EPA opinion and comment on a PSD issue related to the accumulation of contemporaneous emission increases and decreases. A disagreement has risen recently with the Florida Department of Environmental Regulation (FDER) over the interpretation of PSD regulations in this area.

It should first be mentioned that FDER has repeatedly stated in the past that the Florida PSD rules were written with the intent of being equivalent to (not more stringent than) EPA PSD regulations. The question regarding accumulation has been raised on several past PSD projects, the most recent being Seminole Kraft's proposed recovery boiler application (submitted separately from the Applied American Energy Services cogeneration application). I will use the Seminole Kraft application, submitted in August 1989, for example discussion purposes.

Seminole Kraft is proposing to construct a new recovery boiler (RB) and associated smelt dissolving tank (SDT). As part of the project, the three old RBs and SDTs will be shutdown, providing contemporaneous emission offsets. Review of the plant history for the last five years revealed only one additional contemporaneous change at the plant - the shutdown of an old lime slaker and construction of a new lime slaker. This change resulted in a net decrease in particulate matter (PM) emissions.

The construction of the new RB and SDT will cause emission increases for several pollutants, while the shutdown of the old RBs/SDTs will result in contemporaneous emission decreases. The resulting source applicability determination is shown in Table 4-4 attached. As indicated, there is a significant net increase in emissions of only nitrogen oxides (NO_x), and therefore NO_x is subject to PSD review. There is a net increase in emissions of sulfur dioxide (SO_2), but these increases are less than PSD significant emission rates, and therefore this pollutant is not subject to PSD review. There is a net decrease in emissions of all other regulated pollutants and therefore these pollutants are not subject to PSD review.

The basic question to be resolved is whether the net decreases determined for the pollutants not requiring PSD review can be used in the future as contemporaneous reductions to offset increases due to other, separate projects at the Seminole Kraft plant. It is FDER's position that once a PSD permit is issued for the plant, the "slate is wiped clean", and all pollutant increase/decreases are set to zero. They claim that in issuing the PSD permit, they "relied upon" the emission decreases, and therefore they cannot be used in the future to offset other increases. Other than this reason, they provided no other justification or substantiation to support this position, either in their own rules or EPA PSD rules.

I disagree with this position, and in fact can find no basis for this position either in the PSD regulations (40 CFR 52.21) or in the preamble to the various PSD regulations issued by EPA in the past. First of all, PSD regulations only apply to PSD pollutants, in this case NO_x. It is agreed that the issuance of a PSD permit for NO_x results in "wiping the slate clean" for NO_x, and emissions of NO_x for future PSD applicability determinations is set to zero.

However, a PSD permit is not issued for non-PSD pollutants. Only a construction permit is issued for non-PSD pollutants - in Seminole Kraft's case, for all pollutants except NO_x. Therefore, emissions of these non-PSD pollutants were not "relied upon" in issuing a PSD permit. EPA states in the preamble to the PSD regulations (Federal Register, August 7, 1980) that "A reviewing authority "relies" on an increase or decrease when, after taking the increases or decreases into account, it concludes that the proposed project would not cause or contribute to a violation of an increment or ambient standard" (pg. 52699). In the case of a PSD pollutant, this criteria is satisfied since an air quality review is required for the PSD pollutant. However, for non-PSD pollutants, an air quality review is not required. Again, in Seminole Kraft's case, an air quality review is only required for the PSD pollutant- NO_x. What was relied upon in issuing the PSD permit is the shutdown of the existing RBs/SDTs. This will be required by a federally enforceable permit condition.

There is no regulatory basis for "wiping the slate clean" for non-PSD pollutants. The net emission reductions for these pollutants should be able to be applied during the future five-year contemporaneous period. These are not "paper" offsets, but reductions in real actual emissions.

This treatment of non-PSD pollutants is no different than any other non-PSD construction permit issued. For example, the replacement of slakers at Seminole Kraft in 1987 resulted in a net decrease in PM emissions. A FDER construction permit was required for the project. The net decrease in PM emissions was creditable and could be used in the future 5-year contemporaneous period to offset other PM increases at the plant. The net decreases resulting from the Seminole Kraft RB project should be treated no differently - they are non-PSD pollutants requiring only a construction permit. There is no regulatory authority or basis for "wiping the slate clean" for non-PSD pollutants.

The fact that FDER addresses all pollutants in the PSD permit is only for convenience. However, an additional benefit is that net emissions reductions can be documented. This documentation also prevents any possible "double counting" of emission decreases since the Technical Evaluation/Preliminary Determination and Final Determination document in writing the net emissions decreases resulting from the project.

Not true

EPA discusses the concept of "accumulation" in its preamble to the PSD regulations (Federal Register, August 7, 1980, pg. 52702). It is clear from this discussion that changes at a major stationary source are accumulated to determine if PSD review applies: "... a series of individually <u>de minimis</u> changes at a major stationary source would be accumulated within a contemporaneous time frame to see if a review would be required." This would be applied on a pollutant specific basis. Accumulation should apply to decreases as well as increases. Obviously, a change which results in a decrease in emissions would be a <u>de minimis</u> change.

It is also noted that the FDER's position of wiping the slate clean for all pollutants once a PSD permit is issued for any pollutant will actually be counter productive to reducing emissions and installing newer, less polluting equipment. This is because, if this policy is retained, sources will only shutdown the minimum number of sources necessary to just avoid PSD review. There will be no benefit whatsoever to shutting down additional units, since in effect no reduction credit will be given for these shutdowns.

EPA comment is solicited on these PSD aspects of accumulation and contemporaneous emissions changes. It is requested that legislative and regulatory citations be included to support EPA's position.

I would also like to take this opportunity to comment on one related aspect of PSD rules, that of using actual emissions as a basis for offset credit. The problem with using actual emissions is that this is a significant incentive for industry to emit as much as possible now, within the limits of their permits, so that their PSD emission baseline is higher. The higher baseline provides greater opportunity to escape future PSD review. There is no incentive whatsoever for minimizing emissions. Unfortunately, industry has come to realize this after being exposed to PSD regulations for the past ten years, and I am sure this has led to greater emissions that otherwise would have occurred. EPA should revise their rules to allow the use of allowable emissions, or some reasonable level above actual emissions, for PSD baseline purposes, or devise some other incentive for industry to minimize their current emissions without being penalized.

KBN

Mr. Bruce Miller
October 2, 1989
Page Four

Thank you for your consideration of this matter. I look forward to your response to these comments.

Sincerely,

David A. Buff

David A. Buff, M.E., P.E.
Principal Engineer

DAB:mah

cc: Curtis Barton
Terry Cole

September 12, 1989

RECEIVED
SEP 13 1989
DER - BAQM

Mr. Hamilton S. Oven
Department of Environmental Regulation
Siting Coordination Section
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Dear Mr. Oven:

The following are responses to the questions and comments listed in the BESD letter of July 12, 1989 (copy enclosed), regarding the Environmental Assessment Report by Dames and Moore dated July 7, 1989.

1. Comment:
   BESD States that "There is presumptive evidence, based on the subject report results, that certain surface water quality standards (metals listed above) for Class III predominantly marine waters FAC Rule 17-3 are being exceeded at the boundary of Seminole Kraft property adjacent to the Broward River."

   Response:
   The report indicates that ground water standards are being exceeded at some wells in the area of the Seminole Kraft plant site. The report also states that ground water migration is toward the rivers (Broward River included). However, we have no evidence that surface water quality standards (Class III marine) are being exceeded near the plant boundary as a result of ground water migration or any plant activities.

2. Comment:
   BESD asks what tasks and/or laboratory procedures did Dames and Moore undertake to overcome the presence of dissolved gases which made certain results inconclusive in the earlier ERM-South report.

   Response:
   In order to determine what methods would be required to produce conclusive results, Dames & Moore sent to Savannah Labs preliminary samples taken December 8, 1988, from existing monitoring wells drilled for ERM. Savannah Labs ran tests on these samples and found, according to Janet Pruitt, that conclusive results could be obtained in each set of tests. Ms. Pruitt related that foaming and emulsions occurred, but Savannah Labs uses techniques which produce conclusive results, despite these tendencies, without raising detection limits.

AES/CedarBay Inc.
1001 North 19th Street • Arlington, Virginia 22209 • (703) 522-1315 • Telecopier -- (703) 528-4510

Response:
Seminole Kraft's new lime mud process with clarifier will settle out lime wastes. The decant water will go to Seminole Kraft's industrial wastewater treatment system. Since the effluent from the lime mud settling ponds is currently being directed to Seminole Kraft's treatment system, this mode of operation is essentially unchanged. Therefore, the use of the planned clarifier will have no significant additional impact on heavy metals in the waste stream.

6. Comment:
BESD believes the minimum criteria for all ground water in FAC Rule 17-3.402 apply to the area of the southern most fuel oil tank and fuel oil contaminated soil which is not included in the AESCB project site.

Response:
Seminole Kraft has submitted a proposed cleanup program to DER. The program was approved by DER and plans for cleanup are underway.

Sincerely,

Julie Blunden
Development Manager

LRA:rs
Enclosure

cc: Robert S. Pace, BESD

Pradeep

RECEIVED

DER - BAQM

April 17, 1989

FEDERAL EXPRESS

Mr. Hamilton S. Oven, Jr.
Administrator, Siting Coordination Section
Division of Air Resources Management
Department of Environmental Regulation
2000 Blair Stone Road
Tallahassee, Florida 32399

Dear Mr. Oven:

Enclosed are responses to Florida DER comments on the Cedar Bay Cogeneration Project's Site Certification Application. An additional copy of each respective set of comments and responses is being sent separately to the originating group.

If you have any questions on this material, please let me know.

Sincerely,

Julie Blunden
Development Manager

LRA:rs
Enclosure

cc: Mr. Paul Darst, Florida Department of Community Affairs
Mr. Al Bishop, Florida DER, Point Source Evaluation Section
Mr. Richard S. Levin, St. Johns River Water Management District,
Marine Mammals Section, Florida Department of Natural Resources
Mr. Robert S. Pace, Jacksonville, Department of Health, Welfare, & Bio-Environmental Services
Mr. Daryll Joyner, Florida DER, Point Source Evaluation Section

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ATTACHMENT B

EMISSION COMPLIANCE TEST METHODS

	Performance Parameter	Referenced Test Code
1	Carbon Dioxide (CO)	40 CFR Part 60 Method 10
2	Nitrogen Oxides (NO_x)	40 CFR Part 60 Method 7
3	Sulfur Dioxide (SO_2)	40 CFR Part 60 Method 6
4	Total Suspended Particulate (TSP)	40 CFR Part 60 Method 5 or 17
5	Lead (Pb)	40 CFR Part 60 Method 12
6	Beryllium (Be)	40 CFR Part 61 Method 104
7	Mercury (Hg)	40 CFR Part 61 Method 101
8	Fluorine	40 CFR Part 60 Method 13A or 13B
9	Sulfuric Acid Mists (SO_3)	40 CFR Part 60 Method 8
10	Total Reduced Sulfur (TRS)	40 CFR Part 60 Method 16A
11	Non-Methane Hydrocarbons	40 CFR Part 60 Method 25A or 25B
12	Opacity	40 CFR Part 60 Method 9 or Appendix B Specification 1