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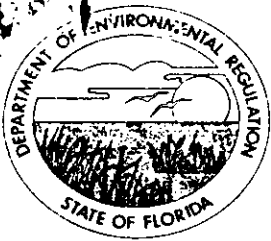
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# Florida Department of Environmental Regulation

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. Kutynow, NE Dist.  
C. Kirtz, 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

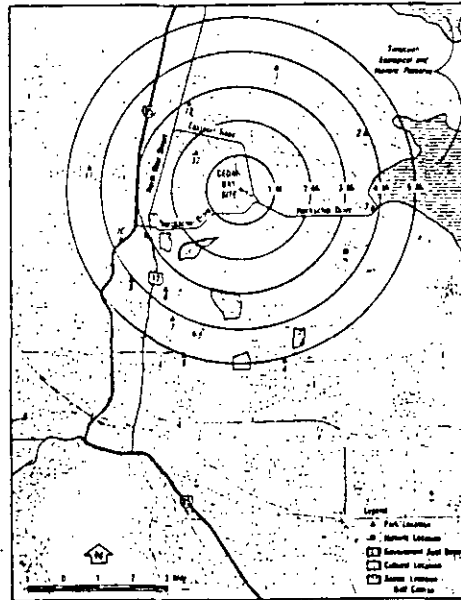
October 29, 1990

## NOTICE OF CERTIFICATION HEARING ON AN APPLICATION TO CONSTRUCT 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 of air quality resources. The department review has resulted in an assessment 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 approximately 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.

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:



APPENDIX 2  
SITE LOCATION - 5-MILE RADIUS WITH PARK,  
HISTORIC, GOVERNMENT, CULTURAL AND SCENIC LOCATIONS  
(JACKSONVILLE, FLORIDA)

Figure 2.2.1

### 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 substantive 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 blow-down. 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	<u>Annual Average</u>	<u>24-Hr. Average</u>	<u>3-Hr. Average</u>
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	<u>Annual Average</u>	<u>24-Hr. Average</u>	<u>3-Hr. Average</u>
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.

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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 compared 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 SO<sub>2</sub> 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 separation of sources, building wake downwash, and various other input and output features. A series of specific model features, recommended by the EPA, are referred to as the regulatory options. 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<sub>2</sub> 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 pollutants subject to PSD review. In general, one year of quality assured data using an EPA reference, or the equivalent, monitor must be submitted. Sometimes less than one year of data, but no less than four months, may be accepted when Departmental approval is given.

An exemption to the monitoring requirement can be obtained if the maximum air quality impact, as determined by air quality modeling, is less than a pollutant-specific "de minimus" concentration. In addition, if current monitoring data 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, NO<sub>x</sub>, 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<sup>3</sup> (annual) and 11.90 ug/m<sup>3</sup> (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<sup>3</sup>. This value is significantly less than the acceptable ambient concentration of 4.76 ug/m<sup>3</sup> (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 <sub>10</sub> )	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
<b>Proposed Sources</b>							
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	--	--	--
<b>Existing Composite Source Data</b>							
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 <sup>3</sup> )	De minimus Ambient Impact Level (ug/m <sup>3</sup> )
CO (8-hour)	25.0	575
NO <sub>2</sub> (Annual)	<0	14
SO <sub>2</sub> (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 expected to be significantly less than this value.

Table 4. Comparison of Total Impacts with the AAQS

<u>Pollutant and Averaging Time</u>	<u>Maximum Predicted Impact (ug/m<sup>3</sup>)</u>	<u>Existing Background (ug/m<sup>3</sup>)</u>	<u>Maximum Total Impact (ug/m<sup>3</sup>)</u>	<u>Florida AAQS (ug/m<sup>3</sup>)</u>
CO (1-hour)	94.1	13	107.1	40000
CO (8-hour)	25.0	6	31.0	10000
NO <sub>2</sub> (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, NO<sub>x</sub>, 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 NO<sub>x</sub>. 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<sup>3</sup> (the highest quarterly average between 1986 and 1987 in Duval County), this results in a total concentration of 0.43 ug/m<sup>3</sup> 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 explicitly modeled. These "background" concentrations were obtained from Department approved monitors near the Cedar Bay Site for 1986 (1985 for NO<sub>x</sub>).

#### 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

<u>Increment</u>	<u>Pollutant</u>	
	<u>Particulate</u>	<u>SO<sub>2</sub></u>
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

<u>Increment</u>	<u>Pollutant</u>	
	Particulate	SO <sub>2</sub>
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<sub>x</sub> 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<sup>3</sup> for an annual average and five ug/m<sup>3</sup> 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<sup>3</sup>, the EPA significance level. The maximum 24-hour TSP impact would be four ug/m<sup>3</sup>, which is less than the five ug/m<sup>3</sup> 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 nitrates; 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<sub>4</sub> (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<sub>4</sub> 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<sub>2</sub> 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  $0.6 \times 10^{-5}$  to  $4.8 \times 10^{-3}$  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  $2.4 \times 10^{-4}$  to  $3.6 \times 10^{-2}$  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  $6 \times 10^{-3}$  mg per kg of soil over the 40 year plant life. Naturally occurring 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  $1.02 \times 10^{-2}$  mg per kg of soil over the 40 year plant life under worst case conditions. Naturally occurring 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  $0.58 \times 10^{-4}$  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  $1.43 \times 10^{-2}$  mg per kg of soil over the 40 year plant life. Naturally occurring lead concentrations in soil averages about 10 ppm. Based on reported threshold concentrations of 10 ppm lead in solution culture, the addition of  $0.79 \times 10^{-2}$  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  $0.48 \times 10^{-4}$  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  $0.48 \times 10^{-4}$  mg per kg of soil is not considered to result in any adverse effect.

The estimated soil increase for molybdenum would be  $1.12 \times 10^{-3}$  mg per kg of soil over the 40 year life. Naturally occurring background concentrations average about 2 ppm. Molybdenum toxicity is rarely observed 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:

Pollutant	Maximum Net Increase in Emissions (TPY)		PSD Signif. Emiss. Rate (TPY)
	AES Cedar Bay	Seminole Kraft	
TSP	268	-140.7	25
PM10	265	-138.6	15
SO <sub>2</sub>	4029	6.4	40
NO <sub>x</sub>	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 <sub>2</sub> SO <sub>4</sub>	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<sub>2</sub>SO<sub>4</sub>, 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 <sub>2</sub>	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 <sub>2</sub> SO <sub>4</sub>	0.024
Fl	0.086

Seminole Kraft Corporation (Kraft Recovery Boiler) \*

<u>Pollutant</u>	<u>Determination</u>
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 (SO<sub>x</sub>, NO<sub>x</sub>, HCl, F1). Controlled generally by gaseous control devices.

Grouping the pollutants in this manner facilitates the BACT analysis because it enables the equipment available to control the type or group of pollutants emitted and the corresponding energy, economic, and environmental impacts to be examined on a common basis. Although all of the pollutants addressed in the BACT analysis may be subject to a specific emission limiting standard as a result of PSD review, the control of "nonregulated" air pollutants is considered in imposing a more stringent BACT limit on a "regulated" 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 typically 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 technologies 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<sub>2</sub> 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<sub>2</sub> 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<sub>2</sub> 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<sub>2</sub> 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<sub>2</sub>, 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<sub>2</sub> 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<sub>2</sub> 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<sub>2</sub> 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 analysis 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 with 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.

#### NOx - CBCP

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<sub>10</sub>, 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 NO<sub>x</sub> 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<sub>2</sub> 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 preceding analysis, the emission limits for the Cedar Bay Cogeneration facility are established as follows:

<u>Pollutant</u>	<u>AES Cedar Bay</u>	<u>Determination</u>	<u>(lb/MM Btu)</u>
TSP		0.020	
PM10		0.020	
SO <sub>2</sub>		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 <sub>2</sub> SO <sub>4</sub>		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 suppression 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 preceding 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 its 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 Sulfur 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<sub>x</sub> and NO<sub>x</sub>, 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<sup>3</sup> 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<sup>3</sup>, this total is relatively small compared to the National Ambient Air Quality secondary standard and Florida standard of 150 ug/m<sup>3</sup>. It is noteworthy that the amount of the fugitive coal dust which was estimated 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

CONDITIONS OF CERTIFICATION

(Revised 1/8/91)

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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 successors 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:

Pollutant	lbs/MMBtu	Emission Limitations		
		lbs/hr	TPY	TPY for 3 CFBs
CO	0.19	202	823	2468
NOx	0.29	308.3	1256	3767
SO <sub>2</sub>	0.60 (3-hr avg.)	637.8	--	--
	0.31 (12 MRA)	329.5	1338	4015
VOC	<u>0.015</u>	<u>16.0</u>	<u>65</u>	<u>195</u>
PM	0.020	21.3	87	260
PM <sub>10</sub>	0.020	21.3	86	257

H <sub>2</sub> SO <sub>4</sub> 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<sub>10</sub>, SO<sub>2</sub>, NO<sub>x</sub>, CO, VOC, lead, fluorides, mercury, beryllium and H<sub>2</sub>SO<sub>4</sub> 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<sub>2</sub> and NO<sub>x</sub>, 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 licensed 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<sub>2</sub> and CO<sub>2</sub>.

(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<sub>2</sub>.

(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<sub>2</sub>, NO<sub>x</sub>, CO, and O<sub>2</sub> or CO<sub>2</sub>, 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 measures 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 occurred 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):

Pollutant	lbs/hr	Estimated Limitations	
		TPY	TPY for 2 dryers
PM/PM <sub>10</sub>	0.25	1.1	2.2
SO <sub>2</sub>	5.00	21.9	43.8
CO	0.60	2.6	5.2
NO <sub>x</sub>	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 maximum 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

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

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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.*

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:

*Base on each unit*

- a. SO<sub>2</sub>--0.6 lb per million Btu heat input, maximum three-hour average, 0.31 lb/MMBtu on a 12-month rolling average.
- b. NO<sub>x</sub>--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.*

CFB Nos 1, 2 & 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.

0.03 g/dscf LACT

Comprehensive?

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).

New ref.

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

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✓ 5/1

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- 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.
- 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)
- 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.

or  
98%  
control  
EACZ  
PM = 0.038 / day  
5% VE

Need ask? ? 1.7 ton

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<sub>2</sub>, NO<sub>x</sub>, 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<sub>x</sub> and SO<sub>2</sub> 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. AESD
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,

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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.