U.S. Generating Company

March 4, 1993

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Division of Air
Resources Management

Mr. Hamilton S. Oven, Jr.
Siting Coordination Office
Department of Environmental Regulation
2600 Blair Stone Road, Room 612
Tallahassee, FL 32399

Re: Cedar Bay Cogeneration Project, PA-88-24
Doah Case No. 88-5740

Dear Buck:

Attached are additional analyses which supplement the Control Technology Assessment (Section 4 of ENSR Consulting and Engineering's February, 1993, Air Quality Analysis). This supplementary information covers two issues:

Attachment 1: **Derating effect of controlling nitrogen oxides (NO_x) emission to 0.11 lb/mmBtu:** The first attachment addresses the cost effectiveness of derating the boiler to augment the effort to obtain lower NO_x emission rates from the CBCP by increasing the amount of ammonia injected to the SNCR system. Section 4 of the ENSR report indicated that the increased ammonia alone would impose a cost penalty of about $3,500 per ton under the assumption that this could reduce the NO_x emissions rate to 0.11 lb/MMbtu. As the attached memo indicated, 0.12 lb/MMbtu is the lowest emission rate expected to be achievable at the CBCP, even after derating the boiler, given the nitrogen content of fuel. As a result, the $3,500 per ton number may understate the cost associated with increased ammonia levels. In any event, when this figure is combined with the cost of about $6,500 per ton of NO_x removed through derating of the boiler, the total cost of achieving this reduced level of emissions is greater than $10,000 per ton. Even assuming that reductions of this magnitude could be achieved, they would not be cost-effective.

Attachment 2: **Economics of using a lower sulfur coal to achieve lower sulfur dioxide (SO_2) emissions:** The second attachment summarizes our evaluation of various alternative coal supplies for the CBCP. As you will note, two of these—Columbian and Eastern Kentucky—would result in a net increase in SO_2 emissions compared with the Costain Kentucky coal currently planned for the CBCP. For the others, the incremental costs per ton of potential SO_2 reductions range from about $9,000 to $34,000. This

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> analysis shows that, aside from the potential logistical and operation difficulties the use of these coals might pose for the CBCP, none of them offers a cost effective means of reducing SO_2 emissions. [In light of DER's prior determinations regarding the cost-effectiveness of efforts to reduce SO_2 emissions, none of these values is low enough to warrant a change to the CBCP coal supply.]

Please call me if you have any questions about this additional information.

Sincerely,

Mark V Carney

Mark V. Carney
Manager, Environmental Permitting

MVC/ldbr

cc: K. Fickett
G. Sams

Attachment 1

U.S. Generating Company

Memorandum

To:	M. V. Carney	**Date:**	March 4, 1993
Subject:	Cedar Bay - NO_x Emissions	**From:**	Gary F. Weidinger
Copies:	S. Jelinek, ENSR M. Teague, Hunton & Williams A. Nawaz, BPC G. P. Sams	**File:**	

The Cedar Bay Cogeneration Project currently has emissions guarantees of 0.17 #/10^6 Btu. I have evaluated an alternate that reduces our capacity to an equivalent level as Barbers Point and employs anhydrous ammonia to achieve a potential emission rate of 0.12 #/10^6 Btu. Cedar Bay is expected to be limited to 0.12 #/10^6 Btu NO_x emissions at the reduced output due to differences in the fuel nitrogen content between Barbers Point and Cedar Bay.

The results indicate that the cost of achieving this reduction is estimated to be at least $6,581 per ton removed.

In addition, it is important to note that our contractor has not been willing to offer guarantees at this level and that the conversion from aqueous to anhydrous ammonia would involve several public safety issues.

GFW:cmb

ATTACHMENT 2

CEDAR BAY PROJECT
COAL COST COMPARISON

		Powder River	Utah	Green River	Columbian	Eastern Kentucky	Eastern Kentucky	Costain Alabama	Costain Kentucky
Moisture	%	30.00	7.00	10.00	12.00	9.00	9.00	6.00	9.00
Ash	%	8.00	11.00	10.00	15.00	12.00	12.00	9.00	12.00
Sulfur	%	0.60	0.70	0.80	1.20	1.20	0.75	1.00	1.20
SO2	Lbs/mmBtu	1.46	1.27	1.52	2.12	2.00	1.25	1.60	1.97
Heat Cont.	Btu/lb	8200	11000	10500	11310	12000	12000	12500	12200
V.M.	%	35.00	40.00	40.00	23.00	35.00	35.00	31.00	-
Price	$/Ton	41.00	60.00	53.00	51.58	47.75	50.75	49.75	42.96
Price	$/mmBtu	2.50	2.73	2.52	2.28	1.99	2.11	1.99	1.79
Coal	T/hr	194.45	144.95	151.66	140.98	132.88	132.88	127.56	130.70
Ash	T/hr	15.56	15.95	15.19	21.16	15.95	15.95	11.48	15.68
Ca/S Ratio		6.00	4.80	4.60	3.50	3.50	4.70	3.70	3.50
Limestone	T/hr	21.28	16.41	18.82	19.95	18.80	15.78	15.90	18.49
SO2	T/hr	2.10	1.83	2.19	3.05	2.87	1.79	2.30	2.82
Total Waste	T/hr	30.42	27.61	28.67	36.16	30.09	27.21	23.32	29.60
Coal	$/hr	7972.50	8697.27	8048.43	7271.82	6344.78	6743.41	6346.11	5614.73
Limestone	$/hr	258.99	199.66	229.09	242.73	228.78	192.01	193.48	225.03
Waste	$/hr	773.70	702.25	729.00	919.54	765.29	691.83	592.91	752.75
Total	$/hr	9005.18	9599.18	9006.51	8434.09	7338.85	7627.24	7132.50	6592.50
Evaluated	$/mmBtu	2.82	3.01	2.82	2.64	2.30	2.39	2.24	2.07
SO2 Emissions	T/hr	0.233	0.203	0.243	0.338	0.319	0.199	0.255	0.314
Emission Reduction	T/hr	0.080	0.111	0.071	-0.025	-0.005	0.114	0.059	0.000
Reduction Cost	$/Ton	30,034	27,152	34,144	-	-	9,046	9,222	-

Notes:

Ash disposal costs for Columbian coal assumed to be $31/Ton - no back-haul saving
Columbian analysis is the Suspension Analysis
Cost for Columbian coal = Average price for 1/92 - 6/92 per FERC Form 423($36.58/ton)
plus $15/ton transportation to Cedar Bay
Alabaman coal analysis assumed to be same as Indiantown contract
Alabaman coal price based on separate contract, not Costain back-up
Costain Kentucky price assumed to be the same as SJRPP = $1.79/mmBtu per pro forma ($42.96/ton)
Ash disposal cost = $25.43/Ton per pro forma
Limestone cost = $12.17/Ton per pro froma
Prices as of end 1992
Actual average SJRPP price for 1/92 - 6/92 was $41.45/ton which includes foreign deliveries
SO2 removal = 90%

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,~~ 17-210, 17-296, 17-297, 17-302, 17-4, 17-5276, 17-601, 17-702, 17-312, 17-~~21~~532, 17-~~22~~550, 17-555, 17-25, and 17-610, 17-660, and 17-772, 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 17-296, and 17-297, F.A.C.. In addition to the foregoing, AESCB shall comply with the following conditions of certification as indicated.

A. Emission Limitations for AES CBCP 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.~~ The maximum charging rate to each of two CFBs of ~~short-fiber~~ recycle rejects from the SK recycling process shall not exceed 150 dry TPD, 54,750 dry TPY. This reflects a combined total of 300 dry TPD, and 109,500 dry TPY for the two CFBs that fire recycle rejects. The third CFB will not utilize recycle rejects, nor will it be equipped with handling and firing equipment for recycle rejects.

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%~~ 1.2% by weight on an annual basis. The sulfur content shall not exceed ~~3.3%~~ 1.7% 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%~~ 0.05% by weight. The fuel oil ~~or-natural-gas~~ shall normally only be used ~~only~~ for startups. During ~~the first-year-of~~ commercial operation the maximum annual oil usage shall not exceed ~~350,000~~ 1,900,000 gals./year, ~~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~~ 380 MMBtu/hr. for each ~~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.

h. To the extent that it is consistent with Condition II.A.1.b. and the following, CBCP shall burn all of the short fiber rejects generated by Seminole Kraft in processing recycled paper. No less than ninety (90) days prior to completion of construction, USG shall submit a plan to DER for conducting a 30-day test burn within one year after initial compliance testing. That test burn shall be designed to ascertain whether the CFBs can burn the rejects as as supplemental fuel without exceeding any of the limitations on emissions and fuel usage contained in Condition II.A. and without causing any operational problems which would affect the reliable operation (with customary maintenance) of the CFBs and without violating any other environmental requirements. CBCP shall notify DER and the Regulatory and Environmental Services Department (RESD) at least thirty (30) days prior to initiation of the test burn. The results of the test burn and CBCP's analysis shall be reported to DER and to the RESD within forty-five (45) days of completion of the test burn. DER shall notify CBCP within thirty (30) days thereafter of its approval or disapproval of any conclusion by CBCP that the test burn demonstrated that the rejects can be burned in compliance with this Condition of Certification.

2. Coal Fired Boiler Controls

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

a. Limestone injection and fuel sulfur limitations, for control of sulfur dioxide and acid gases.

b. Baghouse, for control of particulate matter and trace metals.

c. CBCP shall conduct a test to determine whether substantial additional removal of mercury can be obtained through an activated carbon injection system for mercury removal, as described in Exhibit 74 of the administrative record for the Lee County Resource Recovery Facility, which feeds carbon reagent into the CFB exhaust stream prior to the baghouse. Within one hundred eighty (180) days after initial compliance testing, ~~USG~~ CBCP shall conduct a test on one CFB to compare mercury emissions to the atmosphere with and without carbon injection. If the mercury emissions from the tested CFB are reduced by fifty (50) percent or more over final emissions without carbon injection, then ~~USG~~ CBCP shall install and operate a system to inject carbon into the exhaust gas stream of each CFB, prior to the baghouse. If the test demonstrates a reduction in actual mercury emissions from carbon injection of less than fifty (50) percent, then CBCP shall not be required to install or operate a carbon injection system for any of its CFBs, nor to conduct further testing of carbon injection.

d. Selective Non-catalytic Reduction (SNCR) for control of NOx

e. Good combustion characteristics, which are an inherent part of the CFB technology, for control of carbon monoxide and volatile organic compounds.

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

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

~~PM_{10}~~	~~0.020~~	~~21.3~~	~~86~~	~~257~~
~~H_2SO_4-mist~~	~~0.024~~	~~25.5~~	~~103~~	~~308~~
~~Fluorides~~	~~0.086~~	~~91.4~~	~~374~~	~~1122~~
~~Lead~~	~~0.007~~	~~7.4~~	~~30~~	~~91~~
~~Mercury~~	~~0.00026~~	~~0.276~~	~~1.13~~	~~3.4~~
~~Beryllium~~	~~0.00011~~	~~0.117~~	~~0.5~~	~~1.5~~

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

		Emission Limitations		
Pollutant	lbs/MMBtu	lbs/hr.	TPY	TPY for 3 CFBs
CO	0.175[1]	186[1]	758	2273
NOx	0.171	180.7[1]	736.1	2208
SO_2	0.24[2]	255.1[2]	--	--
	0.20[3]		866	2598
VOC	0.015	16.0	65	195
PM	0.018	19.1	78	234
PM_{10}	0.018	19.1	78	234
H2S04 mist	4.66e-04	0.50	2.0	6.1
Fluorides	7.44e-04	0.79	3.2	9.7
Lead	6.03e-05	0.06	0.26	0.78
Mercury	2.89e-05	0.03	0.13	0.38
Beryllium	8.70e-06	0.027	0.4	0.11

[Note: TPY represents a 93% capacity factor.]

1 Eight hour rolling average.

2 Three-hour rolling average.

3 Twelve-Month rolling average (MRA).

4. Ammonia (NH) slip from exhaust gases shall not exceed 10 ppmvd when burning coal at 100% capacity and 30 ppmvd when burning oil.

~~4.~~ 5. 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.~~ 6. 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.~~ 7. 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.~~ 8. Compliance Tests for each CFB

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

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

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

d. The compliance tests shall be conducted between 90-100% of the maximum licensed capacity and firing rate of <u>for</u> each permitted fuel.

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

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

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

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

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

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

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

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

(8) Method 8 for sulfuric acid mist.

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

(10) Method 10 for CO.

(11) Method 12 or 101A for lead.

(12) Method 13A or 13B for fluorides.

(13) Method 19 for sulphur dioxide removal efficiency pursuant to 40 CFR 60.48a.

~~(13)~~ (14) Method 18 or 25A for VOCs.

~~(14)~~ (15) Method 101A, EPA Method 29 or 108 for mercury.

~~(15)~~ (15) Method 104 for beryllium.

(17) Method 201 or 201A for PM10 emissions.

~~(18) Method ____ for NH3.~~

8\. 9. Continuous Emission Monitoring for each CFB

~~AESCB~~ CBCP shall use Continuous Emission Monitoring

Systems (CEMS) to determine compliance. CEMS for opacity, SO_2, NOx, CO, and O_2 or CO_2, shall be installed, calibrated, maintained and operated for each unit, in accordance with 40 CFR 60.47a and 40 CFR 60 Appendix F, except as may be specifically authorized by DER.

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 17-297, F.A.C., and 40 CFR 60.49a and 60.7. 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 or of a process 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.~~ 10. 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.~~

b.~~c.~~ The coal, ~~rejects,-bark,-natural-gas~~ and No. 2 fuel oil usage shall be recorded on a 24-hr (daily) basis for each CFB. Recycle rejects usage on a volumetric basis shall be estimated for each 24-hour period in which rejects are burned.

~~10.~~ 11. 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 BRESD ~~(Bio-Environmental-Services Division)~~ office, in accordance with 40 CFR 60.8.

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

c. The owner or operator shall submit excess emission reports to BRESD, 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 (40 CFR 60.7(c)(1)).

(2) Specific identification of each period of excess emissions that occurs during startups, shutdowns, and malfunctions of the furnace boiler system. The nature and cause of any malfunction (if known) and the corrective action taken or preventive measured adopted (40 CFR 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 (40 CFR 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 (40 CFR 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 (40 CFR 60.7~~(d)~~ (e)).

d. Annual and quarterly reports shall be submitted to BRESD as per F.A.C. Rule 17-~~2.700(7)~~ 297.450.

~~11.~~ 12. Any change in the method of operation, fuels utilized, equipment, or operating hours or any other changes pursuant to F.A.C. Rule 17-212.100, defining modification, shall be submitted for approval to DER's Bureau of Air Regulation.

B. AES CBCP - Material Handling and Treatment

1. The material handling and treatment operations including coal and limestone unloading buildings, coal and limestone reclaim hoppers, coal crusher house, limestone dryer, fly and bed ash silos, ash pelletizer, pellet curing silo, coal and limestone day silos, conveyors, storage areas and related equipment, may be operated continuously, i.e. 8760 hrs/yr, except that the limestone crushers/dryers may be operated for no more than 8 hours per day at maximum capacity on an annual average.

2. The material handling/usage rates for coal, limestone, fly ash, and bed ash 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~~ and 750,000 gals/year for the limestone dryers; and 8000 gals/hr., ~~160,000~~ and 1,900,000 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~~

4. Material handling sources shall be regulated as follows:

a. The material handling and treatment area sources with either fabric filter or baghouse controls are as follows:

Coal Crusher Building
Coal Silo Conveyor
Limestone Pulverizer/Conveyor
Limestone Storage Bin
Bed Ash Hopper
Bed Ash Silo
Fly Ash Sil
Bed Ash Bin
Fly Ash Bin
Pellet Vibratory Screen
Pelletizing Ash Recycle Tank
Pelletizing Recycle Hopper
Cured Pellet Recycle Conveyor
Pellet Recycle Conveyor

The emissions from the above listed sources are subject to the particulate emission limitation requirement of 0.03 gr/dscf.

b. The PM emissions from the following process, equipment, and/or facility in the material handling and treatment area sources shall be controlled using wet suppression/removal techniques as follows:

Coal Car Unloading

Ash Pellet Hydrator

Ash Pellet Curing Silo

Ash Pelletizing Pan

~~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 BRESD 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 BRESD, 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 listed in Condition II. B.4., in accordance with F.A.C. Chapter 17-296. Neither DER nor RESD 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 RESD, based on other information, has reason to believe the particulate emission limits are being violated.

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

	Estimated Limitations		
Pollutant	lbs/hr.	TPY	TPY for 2 dryers
PM/PM_{10}	~~0.25~~ 0.24	~~1.1~~ 0.32	~~2.2~~ 0.64
SO_2	~~5.00~~ 0.85	~~21.9~~ 1.15	~~43.8~~ 2.3
CO	0.60	~~2.6~~ 0.81	5.2 1.62
NOx	2.40	~~10.5~~ 3.25	~~21.0~~ 6.5
VOC	0.05	~~0.2~~ 0.06	~~0.4~~ 0.12

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 with maximum sulfur content of .05% by weight firing rate for each limestone dryer shall not exceed 120 gals/hr., or ~~1,050,000~~ 350,400 gals/year. This reflects a combined total fuel oil firing rate of 240 gals/hr., and ~~2,100,000~~ 700,800 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 BRESD

within 45 days of test completion in accordance with Chapter 17-~~2.700(7)~~ 297.450 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 17-212.100, 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~~ CBCP shall submit to BRESD 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 BRESD 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 BRESD inspection.

6. Coal fired in the CFBs shall have a sulfur content not to exceed ~~3.3~~ 1.7 percent by weight on a shipment (train load) basis. Coal sulfur content shall be determined and recorded in accordance with 40 CFR 60.47a.

7. ~~AESCB~~ USG 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)~~ 297.345 F.A.C.

9. Prior to commercial operation of each ~~source~~ CFB, 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, ~~within 30 days of written confirmation by DER of the successful~~ upon upon completion of the initial compliance tests on the AESeB CBCP 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. BRESD 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.

Seminole Kraft Corporation may construction natural gas-fired steam boilders at the SK mill provided that emissions from the generation of steam generated by Seminole Kraft for its own use shall not exceed the following on an annual basis nor shall steam generation exceed 375,000 lbs./hr. when burning oil:

	Tons Per Year	
CO	157	563
NO	449	310

SO2 765

E. Mercury Control Test Program

USG shall conduct a mercury control test program on one unit of the CBCP. The test program will include the testing of carbon injuection between the boilder and the fabric filter. Carbon forms to be tested may include activated carbon with or without additives and pulverized coal with or without aditives. USG, after consultation with the DER, RESD and EPRI, shall submit a mercury control test protocol to DER for approval by December 1, 1993. The test shall be conducted within 240 days of acheiving commercial operaiton of the CBCP. Results of the test shall be submitted to the DER within 90 days of completion.

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 17-301, 17-302 and 17-660, 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, AESeB CBCP shall comply with the following conditions of certification:

A. Plant Effluents and Receiving Body of Water

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

PREFACE

The Air Quality Analysis prepared by ENSR Consulting and Engineering is separated into five sections. The first two sections show that, on balance, the air quality impacts of the CBCP as proposed to be modified and the addition of the three proposed package boilers scheduled for the Seminole Kraft facility necessary to provide 640,000 pounds of steam per hour are less than the air quality impacts of the Seminole Kraft recycling operation without the CBCP and that the air quality impacts of the CBCP as proposed to be modified along with the three proposed package boilers at full capacity will be less than Cedar Bay as certified. The third section demonstrates that the CBCP as proposed to be modified will comply with certain nonprocedural agency standards. The fourth section presents a review of air emission control technologies. The fifth section demonstrates that the CBCP as proposed to be modified will not adversely impact soils, vegetation or visibility.

TOTAL STEAM CAPACITY OF SKC'S 3 NEW PACKAGE BOILERS IS 436,750 lb/hr IF WE ADD THE 380,000 lb/hr FROM CBCP, TOTAL IS 816,750 lb/hr (vs. 640,000) HOW WILL THIS AFFECT IMPACT ANALYSIS OF CBCP? (NOTE: IT MAY BE OFFSET BY THE FACT THAT CBCP WAS PROBABLY MODELED USING THE ASSUMPTION OF OIL FIRING FULL TIME.)

In Section 1, "Net Emissions Changes," the total annual tons of pollutants emitted are compared. This comparison is presented in terms similar to those used in the presentation before the Siting Board regarding issuance of the Board's Order Instituting Modification Proceedings.

In Section 2, "Net Air Quality Impacts," dispersion modeling of the air quality impacts at multiple receptor points is compared to demonstrate the net air quality improvement associated with the CBCP.

In Section 3, "The CBCP's Compliance with Prevention of Significant Deterioration (PSD) Increments and Ambient Air Quality Standards (AAQS), and Comparison to Draft Air Toxics No Threat Levels (NTLs)," information is presented to demonstrate that the CBCP as proposed to be modified will comply with PSD increments and AAQS, both of which are nonprocedural agency standards. For informational purposes, air quality impacts due to the air toxic emissions of the CBCP are compared to Florida's draft air toxics NTLs.

In Section 4, "Control Technology Assessment," a review of the air emissions control technologies and emission rates proposed for the combustion sources and aggregate materials handling equipment at the CBCP is presented. This section contains technical and economic analyses of the controls for air emission sources for the project. For the circulating fluidized bed boilers, these controls include: boiler design and selective non-catalytic reduction for control of nitrogen oxides, fabric filtration for control of particulate matter and trace metals, boiler design and operation for control of carbon monoxide and volatile organic compounds, and limestone injection for control of sulfur dioxide and acid gases.

Section 5, "Additional Analyses", demonstrates that the CBCP will not have an adverse impact on soils, vegetation, or visibility in either the area surrounding the facility, the Timucuan Preserve or the two PSD Class I areas: the Okefenokee and Wolf Island Wilderness Areas. This section also demonstrates that the CBCP cooling tower will not cause any significant fogging or icing on nearby transportation routes.

EXECUTIVE SUMMARY

The objective of the information presented in this document is to provide data useful for assessing:

1) whether, on balance, the air pollutant emissions and air quality impacts of the Cedar Bay Cogeneration Project (CBCP), as proposed to be modified, and the addition of the three new proposed package boilers scheduled for the Seminole Kraft Corporation (SKC) site necessary to provide 640,000 lb. of steam per hour for SKC's use, will be less than the emissions and air quality impacts of the future SKC recycling operation, providing 640,000 lb. of steam per hour for SKC's use without the CBCP.

2) whether, on balance, the permitted air pollutant emissions and air quality impacts of the CBCP, as proposed to be modified, and the addition of the three new proposed package boilers scheduled for the SKC site at their permitted capacity, will be less than the emissions and air quality impacts of the CBCP as certified;

3) whether, on balance, the permitted air pollutant emissions and air quality impacts of the CBCP, as proposed to be modified, and the addition of the three new proposed package boilers scheduled for the SKC site at their permitted capacity, will be less than the emissions and air quality impacts of the future SKC recycling operation at permitted capacity without the power plant;

4) whether the CBCP, as proposed to be modified, would either cause or contribute to a violation of an ambient air quality standard (AAQS) or cause or contribute to a violation of the allowable Prevention of Significant Deterioration (PSD) increments, in either the region surrounding the facility (a PSD Class II area) or the two distant PSD Class I areas. The two PSD Class I areas are the Okefenokee and Wolf Island Wilderness areas in Georgia. In addition, information is presented to provide data useful for assessing whether the CBCP would produce air toxics concentrations above the Draft Florida No Threat Levels (NTLs);

5) whether the CBCP, as proposed to be modified, would induce significant indirect pollutant emissions as result of directly related growth, create adverse impacts on soils, vegetation or visibility, and whether the cooling tower vapor plume would cause significant fogging or icing on nearby transportation routes; and

6) updated information on air emission controls and emission rates. The lower air pollutant emission rates for the CBCP CFB boilers, and the inclusion of a new add-on technology (selective non-catalytic reduction) may require some changes to the original conditions of certification and air permit. To provide the State and EPA with accurate and updated information on the project for review of the proposed changes, ENSR, on behalf of U.S. Generating Company, developed a technical review of the air emission controls and emission rates.

The "CBCP as certified" refers to the facility as described in the Final Order and Power Plant Site Certification PA 88-24 dated February 11, 1991 and the March 28, 1991 Final Determination by the FDER, Permit No. PSD-FL-137. The "CBCP as proposed to be modified" refers to the facility as described in the Amended Petition for Modification of Certification filed with the Division of Administrative Hearings on July 22, 1992, plus further improvements proposed by the CBCP.

The "future SKC Recycling Operation without the power plant" refers to the two bark and three oil-fired boilers presently at the SKC site as they could be operated should the CBCP not be. In this hypothetical future case, without the CBCP, it is ENSR's understanding that the exhausts of the three power boilers would be combined and exhausted through a newly constructed 125-foot stack to lessen susceptibility to aerodynamic downwash effects caused by nearby structures.

The "addition of the three new proposed package boilers scheduled for the SKC site necessary to provide the 640,000 lb of steam for SKC's use" refers to three package boilers proposed by SKC capable of producing a total of 375,000 lb/hr of steam. For purposes of the technical analyses, it is assumed that the 640,000 lb/hr steam requirement is met by the CBCP supplying 380,000 lb/hr and the SKC package boilers supplying 260,000 lb/hr.

max cap of SKC's 3 pkg boilers is 174.7 x 3 = 524 lb/hr = 436,750 lb/hr

The "addition of the three new proposed package boilers scheduled for the SKC site at their permitted capacity" refers to these same boilers producing a total of 375,000 lb/hr of steam.

The proposed SKC package boilers will be capable of accommodating either fuel oil or natural gas. Not yet permitted, these boilers will, according to the SKC permit application, fire No. 2 distillate fuel oil with a maximum sulfur content of 0.5% and an annual average sulfur content of 0.3%.

NAT. GAS w/ OIL BACKUP (MAX 30 DAYS)

In making the assessments for pollutant emissions, the maximum annual emissions of health criteria pollutants, other regulated pollutants, and non-regulated air toxics pollutants are compared. To compare the air quality impacts, evaluate compliance with the AAQS and PSD increments, compare the air quality impacts to the draft NTLs, evaluate soils, vegetation and visibility impacts, and characterize cooling tower impacts, comprehensive atmospheric dispersion modeling was performed in accordance with EPA and Florida DER Guidelines.

Table ES-1 illustrates the difference in annual pollutant emissions between CBCP as proposed to be modified plus the SKC package boilers, and the future SKC recycling operation (both cases at 640,000 lb/hr steam usage by SKC). This table demonstrates the decreases or increases in the actual annual emissions of four categories of pollutants by operating the CBCP and the SKC package boilers and shutting down the SKC power and bark boilers. The health criteria and PSD increment pollutants are those for which ambient air quality standards or PSD increments have been established. The total regulated pollutants include the criteria and all PSD regulatory pollutants. Non-regulated air toxics represent twenty different compounds emitted by the sources in question which are included in the list of 751 compounds cited in Florida's Draft Air Toxics Permitting Strategy. In aggregating health criteria, PSD increment and regulated pollutants, TSP and PM-10 are treated as individual pollutants exclusive of one another, although PM-10 are a portion of TSP. Because PM-10 and TSP are also treated exclusively when comparing ambient impacts (the health criteria standards address PM-10 while the PSD increments address TSP), the emissions comparisons treats them as different pollutants for consistency with the standards and PSD increments.

The comparisons of annual emissions shown in Table ES-1 assume that the SKC package boilers always fire fuel oil. To the extent that they fire natural gas on an annual basis, the decreases in emissions would be greater. As shown in Table ES-1 decreases in air pollutant emissions are achieved by the CBCP, as proposed to be modified, in each category, except non-regulated air toxics.

How much would be offset by the new SKC steam capacity of 816,750 lb/hr?

A comparison of air quality impacts between the CBCP, as proposed to be modified plus the SKC package boilers, and the SKC recycling operation without the CBCP (both cases at 640,000 lb/hr steam usage by SKC) is summarized in Table ES-2. The table summarizes the changes due to the CBCP as proposed to be modified and the SKC package boilers for each criteria pollutant as well as total air toxics. Three values are listed for each pollutant: 1) the change to the maximum predicted concentration of the pollutant anywhere (higher, lower or insignificant maximum concentration); 2) the net effect on air quality on a regional basis in terms of the highest predicted pollutant concentrations (improved, insignificant, or degraded); and 3) the percent of locations for which modeling was performed which showed a net benefit in terms of the highest concentrations. A total of 1008 locations, referred to as "model receptors," were addressed. The majority of these fall within 10 kilometers of the CBCP, but a portion extend as far as [illegible] kilometers. As shown in Table ES-2, the CBCP as proposed to be modified and the SKC package boilers result in either lower or insignificant maximum concentrations of all criteria pollutants and total air toxics, a net

TABLE ES-1

CBCP as Proposed to be Modified Plus SKC Package Boilers vs. SKC Recycling (Both Cases at 640,000 lb/hr Steam for SKC) Net Change in Annual Emissions Due To CBCP and SKC Package Boilers Firing Oil

Pollutants Category	Net Change
Health Criteria and PSD Increments	Decrease 343 tons
Total Regulated	Decrease 594 tons
Total Non-Regulated Air Toxics	Increase 29 tons
Total Pollutants	Decrease 565 tons

TABLE ES-2

CBCP as Proposed to be Modified Plus SKC Package Boilers
vs.
SKC Recycling
(Both Cases at 640,000 lb/hr Steam)
Air Quality Changes Due to CBCP Plus SKC Package Boilers Firing Oil[a]

Pollutant	Maximum Concentration	Net Regional Air Quality Effect	Percent of Locations with Air Quality Benefit
3-hour SO_2	Lower	Improved	97.6
24-hour SO_2	Lower	Improved	98.2
Annual SO_2	Lower	Improved	99.5
24-hour PM-10	Lower	Improved	98.2
Annual PM-10	Higher	Insignificant	91.4
1-hour CO	Insignificant	Insignificant	Not applicable
8-hour CO	Insignificant	Insignificant	Not applicable
Annual NO_2	Lower	Improved	99.6
Monthly Pb	Insignificant	Insignificant	Not applicable
Annual Pb	Insignificant	Insignificant	Not applicable
8-hour Air Toxics	Lower	Improved	99.6
24-hour Air Toxics	Lower	Improved	99.6
Annual Air Toxics	Lower	Improved	99.6
[a]See Section 2			

F:\PUB\PROJECTS\5402027\851.EST

United States Department of the Interior

FISH AND WILDLIFE SERVICE
75 Spring Street, S.W.
Atlanta, Georgia
30303

TAKE PRIDE IN AMERICA

December 24, 1992

RECEIVED

DEC 28 1992

Division of Air Resources Management

Mr. C. H. Fancy
Chief, Bureau of Air Regulation
Florida Department of
Environmental Regulation
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Dear Mr. Fancy:

We have reviewed the November 1992 Cedar Bay Cogeneration Project (CBCP) Air Quality Analysis that ENSR prepared to support the proposed modification of the CBCP Power Plant Site Certification (PPSC) issued on February 11, 1991. We appreciate having an opportunity to comment on this project. As you know, the proposed CBCP would be located near Jacksonville, approximately 45 km southeast of the Okefenokee Wilderness Area (WA) and 90 km southwest of the Wolf Island WA, both Class I air quality areas administered by the Fish and Wildlife Service. We understand that the modification would include the installation of better control technology on the CBCP boilers, resulting in a decrease in proposed emissions from the facility as currently certified.

ENSR's analysis shows that emissions from the CBCP as proposed to be modified, combined with the three recently proposed boilers for the Seminole Kraft Corporation (SKC) in Jacksonville, would be lower than either the CBCP as certified, or the existing SKC boilers and auxiliary equipment as they would be operated if the CBCP were not constructed. We are pleased to see that the proposed modification should result in an environmental benefit for the region. However, we believe that emissions could be reduced even further than those proposed in the modification.

We agree that selective noncatalytic reduction to control nitrogen oxide emissions, and circulating fluidized bed and fabric filtration to control sulfur dioxide (SO_2) emissions represent best available control technology; however, we believe better SO_2 emission rates than those proposed can be achieved. For example, the 0.24 pounds per million Btu (lb/MMBtu) 3-hour average rate proposed in ENSR's analysis is less stringent that the recently permitted Keystone Cogeneration project in New Jersey (0.16 lb/MMBtu, 1-hour average) or the proposed Indiantown Cogeneration project in Florida (0.17 lb/MMBtu, 1-hour average).

Therefore, to be consistent with other recently proposed and permitted projects, we recommend that the SO_2 emission limits for the CBCP be lowered accordingly.

ENSR performed SO_2 and nitrogen dioxide Prevention of Significant Deterioration (PSD) increment analyses for the Okefenokee and Wolf Island WAs, but they failed to assess potential effects of emissions from the CBCP on air quality related values in the Class I areas. Using the information provided in the Air Quality Analysis, we performed a visibility analysis for the closest area, the Okefenokee WA. Our modeling results show that both the CBCP as certified and the CBCP as proposed to be modified fail the conservative Level 1 VISCREEN analysis. However, we also performed a Level 2 analysis on the CBCP as proposed to be modified, and the results indicate that the facility would have low potential to cause visibility impairment due to plumes in the Okefenokee WA.

While we still recommend lower SO_2 emission limits to further reduce emissions from the CBCP, based on the overall emission reductions, ENSR's Class I increment analyses, and our visibility analyses, we support the current proposal to modify the facility as certified. However, because the net environmental benefit described in ENSR's analysis is contingent upon SKC's 5 existing boilers and auxiliary equipment (e.g. recovery boilers, lime kilns, and smelt dissolving tanks) being shut down once the CBCP begins operation, we recommend that the modified PPSC and PSD permit contain permit conditions detailing the required shut down of the existing equipment.

We ask that you send us copies of the State's preliminary determinations for the modified PPSC and PSD permit when they become available. In the meantime, if you have any questions regarding this matter, please contact Tonnie Maniero of our Air Quality office in Denver at 303/969-2071.

Sincerely yours,

James W. Pulliam, Jr.
Regional Director

cc: M. Finn
B. Mitchell
B. Owen
A. Ratjma
R. Robinson
J. Harper, EPA
R. Donelan

HOPPING BOYD GREEN & SAMS
ATTORNEYS AND COUNSELORS
123 SOUTH CALHOUN STREET
POST OFFICE BOX 6526
TALLAHASSEE, FLORIDA 32314
(904) 222-7500
FAX (904) 224-8551

December 2, 1992

BY FEDERAL EXPRESS

Ms. Jewell A. Harper
Chief, Air Enforcement Branch
U.S. Environmental Protection Agency, Region IV
345 Courtland St. N.E.
Atlanta, GA 30365

DEC 03 1992
D. E. R.
SITING COORDINATION

RE: Cedar Bay Cogeneration Project
Site Certification No. PA-88-24
Air Permit No. PSD-FL-137

Dear Ms. Harper:

As you may be aware, the Florida Power Plant Siting Board recently issued an order instituting modification proceedings for the Cedar Bay Cogeneration Project Site Certification in Jacksonville, Florida. The modification hearing is currently scheduled to begin January 19, 1993. At the request of the Florida Department of Environmental Regulation, we are providing you a copy of the Air Quality Analysis prepared by ENSR Consulting and Engineering in support of the modification proceedings. The Certification Order for the Project was originally issued in February of 1991, and the Prevention of Significant Deterioration permit was issued in March of 1991. A separate request for revision to the PSD permit will be submitted in the near future.

If you have any questions, please do not hesitate to contact us.

Sincerely,

Gary P. Sams
Angela R. Morrison

cc: ✓Hamilton S. Oven, Jr., FDER
Richard T. Donelan, Jr., FDER
Land Manager, Okefenokee Wilderness Area
Land Manager, Wolf Island Wilderness Area
Brian Mitchell, National Park Service, Lakewood, CO
Max Linn, FDER

I N T E R O F F I C E   M E M O R A N D U M

Date:	12-Nov-1992 01:38pm EST
From:	Hamilton Buck Oven TAL OVEN_H
Dept:	Office of Secretary
Tel No:	904/487-0472
SUNCOM:	Room 612-D

TO: See Below

Subject: Cedar Bay Technical Meeting

U.S. Energy has requested a technical meeting to discuss the Cedar Bay project. They would like to meet at 2:00 p.m. on November 16. The meeting will be held in the Secretary's Conference Room. Please advise if you can attend.

Distribution:

TO:	Richard Donelan TAL	(DONELAN_R)
TO:	Clair Fancy TAL	(FANCY_C)
TO:	Max Linn TAL	(LINN_M)
TO:	Al Rushanan TAL	(RUSHANAN_A)
TO:	Jan Mandrup-Poulsen TAL	(MANDRUP_J)
TO:	Craig Diltz TAL	(DILTZ_C)
TO:	Daryll Joyner TAL	(JOYNER_D)
TO:	Bruce Mitchell TAL	(MITCHELL_B)
TO:	Bob Leetch JAX	(LEETCH_B)
TO:	Ernie Frey JAX	(FREY_E)

Patty ASSIGN TO BRUCE AND MAX LINN

11/10/92

State of Florida
DEPARTMENT OF ENVIRONMENTAL REGULATION

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

Interoffice Memorandum

TO: Clair Fancy
Al Rushanan

FROM: Buck Oven

DATE: November 9, 1992

SUBJECT: AES Modification Review PA 88-24
Module 8184

Enclosed please find materials from U.S. Energy concerning the proposed modifications to the Cedar Bay Project. Please have the appropriate staff review and comment. I would appreciate responses by December 1, 1992.

Encl:

Max Linn may need to see some of this

RESPONSE TO CITY OF JACKSONVILLE REGULATORY AND ENVIRONMENTAL SERVICES DEPARTMENT (RESD) MEMORANDUM OF SEPTEMBER 21, 1992 RE: AIR AND WATER ISSUES

A. Air Issues - Paragraph A of July 22, 1992 RESD Memorandum

1. Method For Testing Coal Sulfur Content In Unit Train Deliveries

Air Permit No. AC PSD-FL-137 specifies in Specific Condition C.6 and the Conditions of Certification specify in Condition II.G.6. that "Coal sulfur content shall be determined and recorded in accordance with 40 CFR 60.47a," which refers to Method 19. The Cedar Bay Cogeneration Project will comply with state and federal requirements for assessing the sulfur content of the coal.

2. Method For Testing Sulfur Content of No. 2 Fuel Oil

Although the air permit does not specify a test method, it does require that samples be taken of each fuel oil shipment and that sulfur content and heating value be determined. The Cedar Bay Cogeneration Project will comply with state and federal requirements for assessing the sulfur content of the samples.

3. Specification of Averaging Periods and CEM Data Use For Compliance Demonstration

Sulfur Dioxide

The Cedar Bay Cogeneration Project will satisfy Specific Condition A.8. of the Air Permit and Condition II.A.8. of the Conditions of Certification requiring the use of CEMs for compliance. Specifically, we will determine SO_2 on a short term basis (i.e. 3 hour average) by the CEMs and by the annual compliance test. The CEM system samples the flue gas every few minutes and will calculate the average SO_2 emitted over the averaging time specified, in this case 3 hours. On a long term basis (30 day and 12 month rolling averages), we will use the CEMs and coal sampling data. We will also determine the sulfur content of the coal on a daily basis. This in turn will be used with the data produced by the CEM system to calculate a percent reduction for that day. Each day, the 30 day rolling average will be recalculated by the CEM data management system. In order to calculate a 12 month rolling average, the Cedar Bay Cogeneration Project will have to start with monthly block averages and then calculate the first true "rolling average" in the 13th month of operation.

We do not agree that any future misunderstanding could result from not repeating the requirements of the NSPS. We are aware of the requirements of the NSPS and will comply fully.

Nitrogen Oxide

The Cedar Bay Cogeneration Project will satisfy Specific Condition A.8. of the Air Permit and Condition II.A.8. of the Conditions of Certification requiring the use of CEMs for compliance. Specifically, CEMs will be used to monitor NO_x continuously and determine compliance with the allowable emissions rate on a 30-day rolling average.

In order to comply with the NSPS requirement to determine a 30 day rolling average, NO_x emissions data from the CEM will be combined into a 24 hour average. The 30 day rolling average will be determined from the daily NO_x emissions. The 24 hour average will be determined from 24 one hour averages produced by the CEM system. This is consistent with Specific Condition A.8.e. of the Air Permit and Condition II.A.8.e. of the Conditions of Certification that "gaseous CEM data shall be reduced to 1-hour averages..."

Carbon Monoxide

Although there is no NSPS requirement for CO, we will handle the data and compliance reporting as described above for NO_x.

B. Air Issues - Paragraph B of July 22, 1992 RESD Memorandum

1. (a) Support Documentation For Modified Emissions

The Cedar Bay Cogeneration Facility Air Quality Analysis (November 1992) being prepared by ENSR Consulting and Engineering for the Cedar Bay cogeneration facility will provide the requested information pertaining to the air quality impacts resulting from modification of the facility's emissions. A draft copy of Sections 1 through 3 of the referenced report is being provided with this submittal. Information pertaining to the mechanisms and control technologies by which these emission modifications will be achieved will be presented in the Air Emission Control Review currently being prepared by ENSR.

(b) Air Quality Modeling Submittal

The Cedar Bay Cogeneration Facility Air Quality Analysis will document the modeling conducted of the Cedar Bay operational impacts for combustion sources during normal full power operation. To facilitate the AQD's review of the air quality modeling, computer discs of the analyses conducted will be provided by ENSR. ENSR has been directed by the Cedar Bay Cogeneration Project to work closely with the AQD's scientists during their technical review of Cedar Bay's air impacts.

2. NOx Emission Rate Backup

An Air Emissions Control Review Report being prepared by ENSR will present data on the NO_x emission rate for other cogeneration plants. The emission data base in the Air Emissions

Control Review Report will include information on other AES operating facilities. The Cedar Bay Cogeneration Project has made a decision to install selective non-catalytic reduction (SNCR) control of NO_x emissions from the start of the project operation.

3. Fuel Use Assumptions Used In Air Quality Modeling

The Cedar Bay Cogeneration Project will combust coal and will use #2 fuel oil or natural gas for Cedar Bay plant startup. Modeling analysis is being conducted based on coal, which is the worst-case fuel. The heat input for #2 fuel oil or natural gas would be less than the heat input for coal, so the higher coal heat input value is being used in the modeling. The Seminole Kraft Corporation (SKC) three package boilers will run on either #2 fuel oil or natural gas. The modeling analysis will evaluate the impacts from both fuel types.

4. Cedar Bay Mercury Emission Rates

The AES Cedar Bay mercury emission rate as certified was 2.6×10^{-4} lb/MMBtu. Bechtel has indicated that the mercury emission rate for the Cedar Bay CFBs as operated by the Cedar Bay Cogeneration Project will be 0.304×10^{-4} lb/MMBtu. The CFB mercury emission rate as proposed by the Cedar Bay Cogeneration Project is 88 percent lower than the AES Cedar Bay previously approved emission rate.

To predict the maximum emission rates, statistical data from a large number of sources was utilized (Ref. EPA-450/2-89). Based on 3527 samples of Eastern Bituminous coal, a predicted uncontrolled mercury concentration was established.

A review of literature and plant-specific boiler/emission control device(s) data was then utilized to establish a value for mercury removal efficiency. Our review indicated that 40 to 70%

mercury is removed in the baghouse. Bechtel utilized a 64% removal rate to establish a 0.304×10^{-4} lb/MMBtu mercury emission.

The original mercury emission rate of 2.6×10^{-4} lb/MMBtu may have been based on a very large percent of mercury in the coal. The current coal supply and the reference quoted previously indicate that the mercury content of the coal is significantly lower. This, coupled with the removal efficiencies expected in the baghouse, allows us to offer an 88 percent reduction in mercury emissions.

The mercury emission rate as proposed by the Cedar Bay Cogeneration Project does not account for possible further reduction of mercury through injection of carbon into the exhaust gas stream prior to the baghouse.

The Cedar Bay Cogeneration Project is currently investigating the basis for the reference to a 50 percent reduction "cut point" for determining the success of the carbon injection control test.

Based on the evaluation included in the draft Air Quality Analysis being provided in this submittal, the Cedar Bay Cogeneration Project has demonstrated that mercury emissions at the proposed levels will not exceed the No Threat Levels established in Florida's draft Air Toxics Permitting Strategy, thus indicating that the public's health will not be adversely impacted.

5. <u>Compliance Testing For Use of Short Fiber Rejects As Fuel Component</u>

The proposed modification is to allow the combustion of short fiber rejects. All compliance testing will be preceded by development of a testing protocol, including operating conditions, test methods and procedures. The protocol will be prepared in accordance with 40 CFR 60.8(b). If any of the proposed methods or procedures are different than EPA approved methods, approval will be obtained in advance.

6. <u>Time Basis For Recording of Facility Fuel Components</u>

The Cedar Bay Cogeneration Project is currently evaluating the specific material handling methods for combustion of short fiber rejects. A full description on how they will be used will be provided to the AQD once this evaluation is completed. Concurrently, an evaluation of the time basis for recording fuel components will also be provided.

7. <u>Unit "Operational" Status</u>

There are different connotations attached to the various milestones of a new power facility such as startup, operation and commercial operation. The definitions of these milestones are of significance only with respect to a regulatory requirement or contract agreement with which the Cedar Bay Cogeneration Project is honoring. Cedar Bay Cogeneration Project is evaluating the historical correspondence on this comment and will respond at a later date.

C. Water Issues

1. <u>The Water Quality Division (WQD) Did Not Receive Exhibit 1 As Referenced</u>

The Cedar Bay Cogeneration Project has contacted AES to determine what the referenced Exhibit 1 consists of. Once this determination has been made, a copy of the Exhibit 1 material will be forwarded to the WQD.

2. (a) WQD Supports Reuse of SKC Wastewater and Cedar Bay Site Stormwater

Appendix A to the Cedar Bay Cogeneration Facility Surface Water and Groundwater Analysis Report (October 1992) prepared by ENSR Consulting and Engineering contains a treatment system water balance prepared by Bechtel. The water balance illustrates how the SKC wastewater will be used for the cooling tower makeup supply. In addition, the Cedar Bay Cogeneration Project will be using site stormwater collected in the two detention ponds for facility water supply. Appendix C to the referenced ENSR Report provides a description of the Cedar Bay site stormwater management plan. The plan specifies the water pumping rate from the detention ponds to the facility.

(b) Proposed Zero Discharge Wastewater System

Appendix B to the ENSR October 1992 Report contains a description of the zero discharge wastewater system for the Cedar Bay facility. The associated environmental benefits of the zero discharge system are discussed in the ENSR Report.

3. Appropriate Monitoring and Reporting Must Still Accompany The Activities of Reuse, Any Wastewater Pre and Post Treatment, Solid Waste Disposal, Chemical Waste Disposal, etc.

Cedar Bay Cogeneration Project will comply with all applicable requirements for monitoring and reporting of wastewater or waste generation, reuse or disposal. Prior to facility startup, the Cedar Bay Cogeneration Project will be preparing an environmental compliance manual to be used during the Cedar Bay cogeneration facility operation. The compliance manual will include the monitoring and reporting procedures that will be followed to ensure that all environmental regulatory requirements are adhered to.

4. Cedar Bay Phase 2 Wastewater Treatment

The Cedar Bay Cogeneration Project, with the assistance of Bechtel, will be conducting a comprehensive engineering evaluation of the "Phase 2" wastewater treatment system option in which Cedar Bay provides treatment for all of the SKC wastewater and discharges the quantities not used by the cogeneration facility for cooling through a new NPDES permitted outfall. The engineering review will commence once SKC has achieved a stabilized recycle mill operation with both paper machines running and the wastewater has been analyzed. The quality data for the SKC recycle mill wastewater stream is a key parameter upon which the analysis will be based.

The engineering review will include a comparative environmental benefits analysis between the Phase 1 zero discharge closed-loop cooling water system and the Phase 2 plan. The Cedar Bay Cogeneration Project will review the results of the engineering evaluation with both the DER and RESD Water Quality Division. The information provided both agencies will include sufficient detail (i.e. engineering specifications, calculations and environmental comparative criteria results) to facilitate independent assessments of the two alternative treatment systems.

5. Feasibility of Zero Discharge System

Appendix B to the ENSR October 1992 Report provides a concept engineering description prepared by Bechtel of the Cedar Bay zero discharge cooling water system. As referenced previously, Bechtel will be preparing engineering details for the zero discharge system once the requisite quality data is available for the wastewater produced by the SKC recycle operation.

The Cedar Bay Cogeneration Project is in the process of determining the availability of engineering data for the Gainesville and Orlando operating systems that have been previously referred to by AES Cedar Bay.

Appendix A to the ENSR October 1992 Report contains a water balance for the Cedar Bay facility prepared by Bechtel. The projected stormwater input to the facility's cooling system is contained in the Appendix C Stormwater Management Plan design prepared by Bechtel.

The Cedar Bay Cogeneration Project will be providing information pertaining to disposal of treatment system sludges once the SKC recycle mill wastewater data is available. This will enable a characterization of the treatment plant sludges and a determination of the associated landfill requirements.

6. Zero Discharge System Plan

As referenced in the information provided to review comment 5, Appendix B to the ENSR October 1992 Report provides a concept engineering description of the Cedar Bay zero discharge cooling water system.

7. Treatment and Disposal of Chemical Cleaning Wastes

Condition III A 9 can remain as it is in the February 1991 Site Certification and will be fully complied with by Cedar Bay Cogeneration Project. The discharge which is a subject of this condition will be fully characterized as the project moves closer to becoming operational. The nature of the chemicals and, ultimately, the discharge will be determined as the Cedar Bay Cogeneration Project chooses chemical suppliers and methods for cleaning and flushing of equipment in preparation for startup. This cleaning is done once in preparation for startup of the boiler. We can provide specific information as to the characteristics and volume of wastewater several months prior to the time of discharge. In addition, the proper method of disposal will be determined by the characteristics and volume of wastewater.

8. Water Treatment System Waste Storage

The Cedar Bay Cogeneration Project, with engineering assistance from Bechtel, is in the process of developing the design, material handling and disposal requirements of the zero discharge system. The engineering information will be provided the WQD once it is prepared.

9. (Previously Provided Response By AES Cedar Bay Was Indicated As Complete By WQD.)

10. Land Acquisition Funding

The Cedar Bay Cogeneration Project will be reviewing the land acquisition options that are available with the Siting Board, DER and City of Jacksonville. The option of using the Jacksonville Environmental Land Acquisition Trust Fund (the RESD identified preferred vehicle) will be included in the discussions.

11. Water Balance Diagrams

Bechtel is planning to pump up to 500 gallons per minute (gpm) from both the storage area runoff pond and yard area runoff pond after rainfall events to the Cedar Bay wastewater treatment facility (Appendix C to ENSR October 1992 Report). After treatment, the water will be used in the cooling tower operation.

J.C. Generating Company

October 23, 1992

VIA FEDERAL EXPRESS

Mr. Curt Barton
Stone Container Corporation
1979 Lakeside Parkway
Suite 300
Tucker, GA 30084

Dear Mr. Barton:

On October 22, 1992, ENSR Consulting and Engineering, received, from David Buff of KBN Engineering, stack and emissions parameters, associated with the Seminole Kraft bark boilers (2), power boilers (3), recovery boilers (3), smelt dissolving tanks (3), lime kilns (3) and the proposed package boilers (3), representative of the operating scenarios discussed at our meeting on Monday, October 19. Specifically, the following information was either obtained from or verified by KBN:

- Table 2-1 Design Parameters for New Package Boilers
- Table 2-3 Future Maximum Emissions of Regulated Pollutants for Each Package Boiler
- Table 2-4 Future Maximum Non-Regulated Pollutant Emissions for Proposed Package Boilers
- Table 1 Design Parameters for New Package Boilers - 70% Load
- Table 2 Future Maximum Emissions of Regulated Pollutants for Each Package Boiler - 70% Load
- Table 3 Future Maximum Non-Regulated Pollutant Emissions for Proposed Package Boilers - 70% Load
- Table 4 Maximum Regulated Pollutant Emissions for SKC Existing Sources - Case 1

- Table 5 Maximum Non-Regulated Pollutant Emissions for SKC Existing Sources - Case 1
- Table 6 Maximum Regulated Pollutant Emissions for SKC Existing Sources - Case 2
- Table 7 Maximum Non-Regulated Pollutant Emissions for SKC Existing Sources - Case 2
- Table 8 Stack Parameters of SKC Existing Sources - Case 1
- Table 9 Stack Parameters for SKC Existing Sources - Case 2

We are requesting, with this correspondence, your written confirmation that the information contained in the attached tables is valid for the operating conditions represented. U.S. Generating Company intends to utilize this data in air quality modeling analyses associated with the Cedar Bay modification certification process.

I appreciate your efforts in responding to our requests for confirmation/verifications of data. If you have any questions, please don't hesitate to call.

Sincerely,

Mark V Carney

Mark V. Carney
Manager, Environmental Permitting

cc: M. Riddle
L. Stanley
A. Koleff
K. Fickett
CB Team

Table 2-1. Design Parameters for New Package Boilers

Parameter	Units	No. 2 Fuel Oil (per boiler)	Natural Gas (per boiler)
Steam Flow	lb/hr	125,000	125,000
Steam Pressure	psi	650	650
Steam Temperature	°F	709	750
Heat Input	MMBtu/hr	164.5	174.7
Furnace Volume	ft^3	1,674	1,674
Heat Release Rate	Btu/hr-ft^3	98,268	104,361
Fuel Heating Value	Btu/gal	138,960	–
	Btu/lb	19,300 [a]	–
	Btu/scf	–	1,000
Fuel Flow	lb/hr	8,523	–
	gal/hr	1,184	
	scf/hr	–	174,700
Exhaust Gas:			
Temperature	°F	345	330
Moisture	%	10	10
Flow Rate	lb/hr	158,040	161,570
	acfm	53,366	53,541
	scfm	31,502	31,606
Common Stack [b]			
Diameter	ft	8.00	8.00
Velocity	ft/s	53.08	53.26
Height	ft	200	200

[a] Density of No. 2 fuel oil is approximately 7.2 lb/gal.
[b] All three boilers will exhaust into a common stack. Velocity shown is total all three boilers.

Table 2-3. Future Maximum Emissions of Regulated Pollutants for Each Package Boiler

	No. 2 Fuel Oil (0.5%S)				Natural Gas						
Regulated Pollutant	Emission Factor	Ref	Activity Factor	Hourly Emissions (lb/hr)	Emission Factor	Ref.	Activity Factor	Hourly Emissions (lb/hr)	Maximum Hourly Emissions (lb/hr)	Maximum Annual Emissions per Boiler (TPY)	Total Annual Emissions Three Boilers (TPY)
Particulate (TSP)	2 lb/1000 gal	1	1,192 gal/hr	2.4	5 lb/MM scf	1	0.1747 MM scf/hr	0.9	2.4	10.4	31.3
Particulate (PM10)	50 % of PM	1	--	1.2	5 lb/MM scf	1	0.1747 MM scf/hr	0.9	1.2	5.2	15.7
Sulfur dioxide											
Maximum	0.5 lb/MM Btu	2	164.5 MM Btu/hr	82.3	0.6 lb/MM scf	1	0.1747 MM scf/hr	0.1	82.3	--	--
Annual Average	0.3 lb/MM Btu	2	164.5 MM Btu/hr	49.4				--	--	216.2	648.5
Nitrogen oxides	0.2 lb/MM Btu	3	164.5 MM Btu/hr	32.9	0.2 lb/MM Btu	3	174.7 MM Btu/hr	34.9	34.9	153.0	459.1
Carbon monoxide	400 ppm	4	53,366 acfm	61.0	400 ppm	4	53,541 acfm	61.2	61.2	268.2	804.6
Volatile org. compds.	0.2 lb/1000 gal	1	1,192 gal/hr	0.24	1.4 lb/MM scf	1	0.1747 MM scf/hr	0.24	0.24	1.1	3.2
Lead	8.9 lb/10^12 Btu	5	164.5 MM Btu/hr	0.0015	--		--	--	0.0015	0.0064	0.019
Mercury	3.4 lb/10^12 Btu	6	164.5 MM Btu/hr	0.00056	0.014 lb/10^12	6	174.7 MM Btu/hr	2.4E-06	0.00056	0.0024	0.0073
Beryllium	2.5 lb/10^12 Btu	5	164.5 MM Btu/hr	0.00041	--		--	--	0.00041	0.0018	0.0054
Fluorides	32 lb/10^12 Btu	7	164.5 MM Btu/hr	0.0053	--		--	--	0.0053	0.023	0.069
Sulfuric acid mist	2.07 lb/1000 gal	1	1,192 gal/hr	2.5	--		--	--	2.5	10.8	32.4
Total reduced sulfur	--		--	--	--		--	--	--	--	--
Asbestos	--		--	--	--		--	--	--	--	--
Vinyl Chloride	--		--	--	--		--	--	--	--	--

References:

1. Compilation of Air Pollutant Emission Factors, AP-42, September 1988.
2. Based on sulfur content of No. 2 distillate fuel oil and NSPS.
3. Equivalent to NSPS for Industrial Boilers, 40 CFR 60, Subpart Db.
4. Based on boiler manufacturer's information.
5. Toxic Air Pollutant Emission Factors- A Compilation For Selected Air Toxic Compounds and Sources, Second Edition. EPA-450/2-90-011 (1990).
6. Based on Mercury Emissions to the Atmosphere in Florida (KBN, 1992).
7. Emissions Assessment of Conventional Stationary Combustion Systems: Volume IV: Industrial Combustion Sources. EPA-600/7-81-003 (1981).

Table 2-4. Future Maximum Non-Regulated Pollutant Emissions for Proposed Package Boilers

Non-regulated Pollutants	No. 2 Fuel Oil (0.5%S) Emission Factor (lb/10^{12} Btu)	Ref	Activity Factor (MMBtu/hr)	Hourly Emissions per boiler (lb/hr)	Maximum Annual Emissions per boiler (TPY)	Total Annual Emissions Three boilers (TPY)
Antimony (Sb)	--		--	--	--	--
Arsenic (As)	4.2	1	164.5	0.0007	0.0030	0.0091
Barium (Ba)	2.7	2	164.5	0.0004	0.0019	0.006
Bromine (Br)	7.0	3	164.5	0.0012	0.0050	0.015
Cadmium (Cd)	10.5	1	164.5	0.0017	0.0076	0.023
Chlorine (Cl)	637.0	3	164.5	0.1048	0.46	1.38
Chromium (Cr)	47.5	1	164.5	0.0078	0.034	0.10
Copper (Cu)	280.0	1	164.5	0.0461	0.20	0.61
Indium (In)	--		--	--	--	--
Manganese (Mn)	9.8	2	164.5	0.0016	0.0071	0.021
Molybdeum (Mo)	48.8	3	164.5	0.0080	0.035	0.11
Nickel (Ni)	170	1	164.5	0.0280	0.12	0.37
Phosphorous (P)	106.0	2	164.5	0.0174	0.076	0.23
Selenium (Se)	11.3	2	164.5	0.0019	0.0081	0.024
Silver (Ag)	--		--	--	--	--
Tin (Sn)	330.0	3	164.5	0.0543	0.24	0.71
Zirconium (Zr)	--		--	--	--	--

Notes: Maximum heat input is 164.5 MMBtu/hr per boiler for No. 2 Distillate Oil.

References:

1. Toxic Air Pollutant Emission Factors- A Compilation For Selected Air Toxic Compounds and Sources, Second Edition. EPA-450/2-90-011 (1990).
2. Emissions Assessment of Conventional Stationary Combustion Systems: Volume V (EPA-600/7-81-003, 1981), based on distillate oil.
3. Emissions Assessment of Conventional Stationary Combustion Systems: Volume V (EPA-600/7-81-003, 1981), based on residual oil.

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Table 1. Design Parameters for New Package Boilers - 70% Load

Parameter	Units	No. 2 Fuel Oil (per boiler)	Natural Gas (per boiler)
Steam Flow	lb/hr	86,663	86,663
Steam Pressure	psi	650	650
Steam Temperature	^oF	715	758
Heat Input	MMBtu/hr	113.93	121.46
Furnace Volume	ft^3	1,674	1,674
Heat Release Rate	Btu/hr-ft^3	68,060	72,555
Fuel Heating Value	Btu/gal	138,960	--
	Btu/lb	19,300 ^a	--
	Btu/scf	--	1,000
Fuel Flow	lb/hr	5,903	--
	gal/hr	820	
	scf/hr	--	121,457
Exhaust Gas:			
Temperature	^oF	323	317
Moisture	%	10	10
Flow Rate	lb/hr	109,467	112,315
	acfm	35,954	36,606
	scfm	21,224	21,609
Common Stack^b			
Diameter	ft	8.00	8.00
Velocity	ft/s	35.76	36.41
Height	ft	200	200

^a Density of No. 2 fuel oil is approximately 7.2 lb/gal.
^b All three boilers will exhaust into a common stack.
Velocity shown is total all three boilers.

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Table 2. Future Maximum Emissions of Regulated Pollutants for Each Package Boiler - 70% Load

Regulated Pollutant	No. 2 Fuel Oil (0.5%S) Emission Factor	Ref	Activity Factor	Hourly Emissions (lb/hr)	Natural Gas Emission Factor	Ref.	Activity Factor	Hourly Emissions (lb/hr)	Maximum Hourly Emissions (lb/hr)	Maximum Annual Emissions per Boiler (TPY)	Total Annual Emissions Three Boilers (TPY)
Particulate (TSP)	2 lb/1000 gal	1	820 gal/hr	1.6	5 lb/MM scf	1	0.1215 MM scf/hr	0.6	1.6	7.2	21.5
Particulate (PM10)	50 % of PM	1	--	0.8	5 lb/MM scf	1	0.1215 MM scf/hr	0.6	0.8	3.6	10.8
Sulfur dioxide											
Maximum	0.5 lb/MM Btu	2	113.9 MM Btu/hr	57.0	0.6 lb/MM scf	1	0.1215 MM scf/hr	0.1	57.0	--	--
Annual Average	0.3 lb/MM Btu	2	113.9 MM Btu/hr	34.2				--	--	149.7	449.0
Nitrogen oxides	0.2 lb/MM Btu	3	113.9 MM Btu/hr	22.8	0.2 lb/MM Btu	3	121.5 MM Btu/hr	24.3	24.3	106.4	319.3
Carbon monoxide	400 ppm	4	35,594 acfm	41.9	400 ppm	4	36,606 acfm	43.4	43.4	190.0	570.0
Volatile org. compds.	0.2 lb/1000 gal	1	820 gal/hr	0.16	1.4 lb/MM scf	1	0.1215 MM scf/hr	0.17	0.17	0.75	2.24
Lead	8.9 lb/10^12 Btu	5	113.9 MM Btu/hr	0.0010	--		--	--	0.0010	0.0044	0.013
Mercury	3.4 lb/10^12 Btu	6	113.9 MM Btu/hr	0.00039	0.014 lb/10^12	6	121.5 MM Btu/hr	1.7E-06	0.00039	0.0017	0.0051
Beryllium	2.5 lb/10^12 Btu	5	113.9 MM Btu/hr	0.00028	--		--	--	0.00028	0.0012	0.0037
Fluorides	32 lb/10^12 Btu	7	113.9 MM Btu/hr	0.0036	--		--	--	0.0036	0.016	0.048
Sulfuric acid mist	2.07 lb/1000 gal	1	820 gal/hr	1.7	--		--	--	1.7	7.4	22.3
Total reduced sulfur	--		--	--	--		--	--	--	--	--
Asbestos	--		--	--	--		--	--	--	--	--
Vinyl Chloride	--		--	--	--		--	--	--	--	--

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References:
1. Compilation of Air Pollutant Emission Factors, AP-42, September 1988.
2. Based on sulfur content of No. 2 distillate fuel oil and NSPS.
3. Equivalent to NSPS for Industrial Boilers, 40 CFR 60, Subpart Db.
4. Based on boiler manufacturer's information.
5. Toxic Air Pollutant Emission Factors- A Compilation For Selected Air Toxic Compounds and Sources, Second Edition. EPA-450/2-90-011 (1990).
6. Based on Mercury Emissions to the Atmosphere in Florida (KBN, 1992).
7. Emissions Assessment of Conventional Stationary Combustion Systems: Volume IV: Industrial Combustion Sources. EPA-600/7-81-003 (1981).

Table 3. Future Maximum Non-Regulated Pollutant Emissions for Proposed Package Boilers @ 70% Load.

Non-regulated Pollutants	Emission Factor (lb/10¹² Btu)	Ref	Activity Factor (MMBtu/hr)	Hourly Emissions per boiler (lb/hr)	Maximum Annual Emissions per boiler (TPY)	Total Annual Emissions Three boilers (TPY)
	No. 2 Fuel Oil (0.5%S)					
Antimony (Sb)	--		--	--	--	--
Arsenic (As)	4.2	1	113.9	0.0005	0.0021	0.0063
Barium (Ba)	2.7	2	113.9	0.0003	0.0013	0.004
Bromine (Br)	7.0	3	113.9	0.0008	0.0035	0.010
Cadmium (Cd)	10.5	1	113.9	0.0012	0.0052	0.016
Chlorine (Cl)	637	3	113.9	0.0726	0.32	0.95
Chromium (Cr)	47.5	1	113.9	0.0054	0.024	0.07
Copper (Cu)	280.0	1	113.9	0.0319	0.14	0.42
Indium (In)	--		--	--	--	--
Manganese (Mn)	9.8	2	113.9	0.0011	0.0049	0.015
Molybdeum (Mo)	48.8	3	113.9	0.0056	0.024	0.07
Nickel (Ni)	170.0	1	113.9	0.0194	0.08	0.25
Phosphorous (P)	106.0	2	113.9	0.0121	0.053	0.16
Selenium (Se)	11.3	2	113.9	0.0013	0.0056	0.017
Silver (Ag)	--		--	--	--	--
Tin (Sn)	330.0	3	113.9	0.0376	0.16	0.49
Zirconium (Zr)	--		--	--	--	--

References:

1. Toxic Air Pollutant Emission Factors- A Compilation For Selected Air Toxic Compounds and Sources, Second Edition. EPA-450/2-90-011 (1990).
2. Emissions Assessment of Conventional Stationary Combustion Systems: Volume V (EPA-600/7-81-003, 1981), based on distillate oil.
3. Emissions Assessment of Conventional Stationary Combustion Systems: Volume V (EPA-600/7-81-003, 1981), based on residual oil.

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Table 4. Maximum Regulated Pollutant Emissions for SKC Existing Sources - Case 1

Regulated Pollutant	Emission Factors Oil		Emission Factors Bark	PB1	PB2	PB3	BB1	BB2	~~Totals~~	Total Tons/Year^a
Steam Flow (lb/hr)				100,000	145,000	145,000	125,000	125,000	640,000	
Heat Input (MMBtu/hr)				137	198	198	193	193	919	
Fuel Type				Oil	Oil	Oil	Bark	Bark		
	(lb/10^6 Btu)		(lb/10^6 Btu)	Emissions (lb/hr)						
Particulate (TSP)	0.1	0.1	0.2	13.7	19.8	19.8	38.60	38.60	130.50	571.6
Particulate (PM10)	0.071	0.1	0.174	9.7	14.1	14.1	33.6	33.6	105.0	459.9
Sulfur Dioxide	1.1	0.55	0.063	150.7	217.8	217.8	12.1	12.1	610.4	2,673.7
Nitrogen oxides	0.447	0.447	0.300	61.2	88.4	88.4	57.9	57.9	353.9	1,550.0
Carbon Monoxide	0.033	0.033	1.250	4.6	6.6	6.6	241.3	241.3	500.3	2,191.2
Volatile Org. Compds.	0.0051	0.005	0.170	0.7	1.0	1.0	32.9	32.9	68.5	300.1
	(lb/10^12 Btu)		(lb/10^12 Btu)							
Lead	28.0	28.0	90.0	0.00384	0.00554	0.00554	0.01737	0.01737	0.0497	0.22
Mercury	3.2	0.83	3.0	0.00044	0.00063	0.00063	0.00058	0.00058	0.0029	0.013
Beryllium	4.2	0.25	0.0	0.00058	0.00083	0.00083	0	0	0.0022	0.010
Fluorides	118	118	--	0.016	0.023	0.023	--	--	0.063	0.28
Sulfuric Acid Mist	24000	24000	2.0	3.29	4.75	4.75	0.00039	0.00039	12.79	56.03
Total reduced sulfur	--	--	--	--	--	--	--	--	--	--
Asbestos	--	--	--	--	--	--	--	--	--	--
Vinyl Chloride	--	--	--	--	--	--	--	--	--	--

^a Based on 8,760 hr/yr operation.

Table 5. Maximum Non-Regulated Pollutant Emissions for SKC Existing Sources - Case 1

Non-Regulated Pollutant	Emission Factors Oil PB (lb/10^12 Btu)	Emission Factors Oil BB (lb/10^12 Btu)	Bark (lb/10^12 Btu)	PB1	PB2	PB3	BB1	BB2	Totals	Total Tons/Year^a
Steam Flow (lb/hr)				100,000	145,000	145,000	125,000	125,000	640,000	
Heat Input (MMBtu/hr)				137	198	198	193	193	919	
Fuel Type				Oil	Oil	Oil	Bark	Bark		
				Emissions (lb/hr)						
Antimony (Sb)	14.4	14.4	0.0	0.00197	0.00285	0.00285	0.0	0.0	0.008	0.034
Arsenic (As)	19.0	1.9	0.0	0.00260	0.00376	0.00376	0.0	0.0	0.010	0.044
Barium (Ba)	14.4	14.4	102.3	0.00197	0.00285	0.00285	0.01974	0.01974	0.047	0.21
Benzene (Be)	--	--	2,468.3	0.0	0.0	0.0	0.476	0.476	0.953	4.17
Benzo(a)pyrene	--	--	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Bromine (Br)	4.0	4.0	9,346.6	0.00055	0.00079	0.00079	1.80	1.80	3.61	15.81
Cadmium (Cd)	15.7	3.96	6.8	0.00215	0.00311	0.00311	0.00132	0.00132	0.011	0.048
Hydrogen Chloride (HCl)	--	--	22,750 ^b	0.0	0.0	0.0	4.39	4.39	8.78	38.46
Chromium (Cr)	21.0	1.68	18.2	0.00288	0.00416	0.00416	0.00351	0.00351	0.018	0.080
Cobalt (Co)	--	--	480.7	0.0	0.0	0.0	0.093	0.093	0.19	0.81
Copper (Cu)	278.0	25.2	36.4	0.038	0.055	0.055	0.007	0.007	0.16	0.71
Formaldehyde	405.0	405.0	634.7	0.055	0.080	0.080	0.122	0.122	0.46	2.02
Indium (In)	15.2	15.2	801.1	0.0021	0.0030	0.0030	0.155	0.155	0.32	1.39
Manganese (Mn)	26.0	2.86	59.1	0.0036	0.0051	0.0051	0.011	0.011	0.037	0.16
Molybdeum (Mo)	15.2	15.2	1,602.3	0.0021	0.0030	0.0030	0.3092	0.3092	0.63	2.74
Nickel (Ni)	1,260.0	50.4	71.6	0.173	0.249	0.249	0.014	0.014	0.70	3.06
Phosphorous (P)	252.8	252.8	340.9	0.035	0.050	0.050	0.066	0.066	0.27	1.17
Polycyclic Org. Matter	9.2	9.2	250.0	0.0013	0.0018	0.0018	0.0483	0.0483	0.10	0.44
Selenium (Se)	2.4	2.4	0.0	0.00033	0.00048	0.00048	0.0	0.0	0.001	0.006
Silver (Ag)	0.8	0.8	28.4	0.00011	0.00016	0.00016	0.00548	0.00548	0.011	0.050
Thallium (Tl)	-	-	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Tin (Sn)	2.4	2.4	1,014.8	0.00033	0.00048	0.00048	0.19585	0.19585	0.39	1.72
Vanadium	3,014.0	602.9	73.9	0.413	0.597	0.597	0.014	0.014	1.63	7.16
Zirconium (Zr)	11.2	11.2	587.5	0.002	0.002	0.002	0.113	0.113	0.23	1.02

^a Based on 8,760 hr/yr operation.
^b Reflects chlorine content of bark and recycled fiber rejects, and 50% scrubber removal efficiency for HCl.

Table 6. Maximum Regulated Pollutant Emissions for SKC Existing Sources - Case 2

10/22/92
skcemis1

Regulated Pollutant				Steam Flow (lb/hr) / Heat Input (MMBtu/hr) / Fuel Type	PB1	PB2	PB3	BB1	BB2	Totals	
				Steam Flow (lb/hr)	135,000	180,000	180,000	72,500	72,500	640,000	
				Heat Input (MMBtu/hr)	185	246	246	112	112	901	
				Fuel Type	Oil	Oil	Oil	Bark/Oil^b	Bark/Oil^b		
	Oil PB	Oil BB	Bark		Emissions (lb/hr)						Total Tons/Year^a
	(lb/10^6 Btu)		(lb/10^6 Btu)								
Particulate (TSP)	0.1	0.1	0.2		18.5	24.6	24.6	16.8	16.8	101.3	443.7
Particulate (PM10)	0.071	0.1	0.174		13.1	17.5	17.5	15.3	15.3	78.8	344.9
Sulfur Dioxide	1.1	0.55	0.063		203.5	270.6	270.6	34.3	34.3	813.3	3,562.3
Nitrogen oxides	0.447	0.447	0.300		82.6	109.9	109.9	41.8	41.8	386.0	1,690.8
Carbon Monoxide	0.033	0.033	1.250		6.2	8.2	8.2	71.9	71.9	166.3	728.4
Volatile Org. Compds.	0.0051	0.005	0.170		0.9	1.3	1.3	9.8	9.8	23.1	101.2
	(lb/10^12 Btu)		(lb/10^12 Btu)								
Lead	28.0	28.0	90.0		0.00518	0.00689	0.00689	0.00661	0.00661	0.03	0.14
Mercury	3.2	0.83	3.0		0.00059	0.00079	0.00079	0.00021	0.00021	0.00	0.011
Beryllium	4.2	0.25	0.0		0.00078	0.00103	0.00103	0.00001	0.00001	0.00	0.013
Fluorides	118	118	--		0.0218	0.0290	0.0290	0.0066	0.0066	0.09	0.41
Sulfuric Acid Mist	24000	24000	2.0		4.44	5.90	5.90	1.34	1.34	18.94	82.9
Total reduced sulfur	--	--	--		--	--	--	--	--	--	--
Asbestos	--	--	--		--	--	--	--	--	--	--
Vinyl Chloride	--	--	--		--	--	--	--	--	--	--

^a Based on 8,760 hr/yr operation.
^b 50/50 Bark/oil on a heat input basis.

Table 7. Maximum Non-Regulated Pollutant Emissions for SKC Existing Sources - Case 2

10/22/92
skcemis1

Regulated Pollutant				PB1	PB2	PB3	BB1	BB2	~~Totals~~	
		Steam Flow (lb/hr)		135,000	180,000	180,000	72,500	72,500	640,000	
		Heat Input (MMBtu/hr)		185	246	246	112	112	901	
		Fuel Type		Oil	Oil	Oil	Bark/Oil^b	Bark/Oil^b		
	Emission Factors Oil PB (lb/10^12 Btu)	Emission Factors Oil BB (lb/10^12 Btu)	Emission Factors Bark (lb/10^12 Btu)	Emissions (lb/hr)						Total Tons/Year^a
Antimony (Sb)	14.4	14.4	0.0	0.00266	0.00354	0.00354	0.00081	0.00081	0.011	0.050
Arsenic (As)	19.0	1.9	0.0	0.00352	0.00467	0.00467	0.00011	0.00011	0.013	0.057
Barium (Ba)	14.4	14.4	102.3	0.00266	0.00354	0.00354	0.00653	0.00653	0.023	0.100
Benzene (Be)	--	--	2,468.3	0.0	0.0	0.0	0.138	0.138	0.28	1.21
Benzo(a)pyrene	--	--	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Bromine (Br)	4.0	4.0	9,346.6	0.00074	0.00098	0.00098	0.524	0.524	1.05	4.60
Cadmium (Cd)	15.7	3.96	6.8	0.00290	0.00386	0.00386	0.00060	0.00060	0.012	0.052
Hydrogen Chloride (HCl)	--	--	22,750 ^c	0.0	0.0	0.0	1.27	1.27	2.55	11.16
Chromium (Cr)	21.0	1.68	18.2	0.00389	0.00517	0.00517	0.00111	0.00111	0.016	0.072
Cobalt (Co)	--	--	480.7	0.0	0.0	0.0	0.027	0.027	0.054	0.24
Copper (Cu)	278.0	25.2	36.4	0.0514	0.0684	0.0684	0.0034	0.0034	0.20	0.85
Formaldehyde	405.0	405.0	634.7	0.0749	0.0996	0.0996	0.0582	0.0582	0.39	1.71
Indium (In)	15.2	15.2	801.1	0.0028	0.0037	0.0037	0.0457	0.0457	0.10	0.45
Manganese (Mn)	26.0	2.86	59.1	0.0048	0.0064	0.0064	0.0035	0.0035	0.025	0.11
Molybdeum (Mo)	15.2	15.2	1,602.3	0.0028	0.0037	0.0037	0.0906	0.0906	0.19	0.84
Nickel (Ni)	1260.0	50.4	71.6	0.2331	0.3100	0.3100	0.0068	0.0068	0.87	3.80
Phosphorous (P)	252.8	252.8	340.9	0.0468	0.0622	0.0622	0.0332	0.0332	0.24	1.04
Polycyclic Org. Matter	9.2	9.2	250.0	0.0017	0.0023	0.0023	0.0145	0.0145	0.035	0.15
Selenium (Se)	2.4	2.4	0.0	0.00044	0.00059	0.00059	0.00013	0.00013	0.002	0.008
Silver (Ag)	0.8	0.8	28.4	0.00015	0.00020	0.00020	0.00164	0.00164	0.004	0.017
Thallium (Tl)	--	--	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Tin (Sn)	2.4	2.4	1,014.8	0.00044	0.00059	0.00059	0.05696	0.05696	0.12	0.51
Vanadium	3014.0	602.9	73.9	0.558	0.741	0.741	0.038	0.038	2.12	9.27
Zirconium (Zr)	11.2	11.2	587.5	0.0021	0.0028	0.0028	0.0335	0.0335	0.07	0.33

^a Based on 8,760 hr/yr operation.
^b 50/50 Bark/Oil on a heat input basis.
^c Reflects chlorine content of bark and recycled fiber rejects, and 50% scrubber removal efficiency for HCl.

(16.66H

Table 8. Stack Parameters for SKC Existing Sources - Case 1

	PB1	PB2	PB3	BB1	BB2	Totals
Steam Flow (lb/hr)	100,000	145,000	145,000	125,000	125,000	640,000
Heat Input (MMBtu/hr)	137	198	198	193	193	919
Fuel Type	Oil	Oil	Oil	Bark	Bark	
Stack height (ft)	106	106	106	136	136	
Stack diameter (ft)	6.00	7.00	7.00	8.08	8.08	
Flow rate (acfm)	57,762	88,537	88,537	132,000	132,000	
Temperature (deg.F)	360	330	330	138	138	
Velocity (fps)	34.05	38.34	38.34	42.91	42.91	
Stack height (m)	32.3	32.3	32.3	41.5	41.5	
Stack diameter (m)	1.83	2.13	2.13	2.46	2.46	
Temperature (deg.K)	455	439	439	332	332	
Velocity (m/s)	10.38	11.69	11.69	13.08	13.08	

Basis: 1991 stack tests

Table 9. Stack Parameters for SKC Existing Sources - Case 2

	PB1	PB2	PB3	BB1	BB2	Totals
Steam Flow (lb/hr)	135,000	180,000	180,000	72,500	72,500	640,000
Heat Input (MMBtu/hr)	185	246	246	112	112	901
Fuel Type	Oil	Oil	Oil	Bark/Oil^b	Bark/Oil^b	
Stack height (ft)	106	106	106	136	136	
Stack diameter (ft)	6.00	7.00	7.00	8.08	8.08	
Flow rate (acfm)	78,000	110,000	110,000	76,601	76,601	
Temperature (deg.F)	360	330	330	138	138	
Velocity (fps)	45.98	47.64	47.64	24.90	24.90	
Stack height (m)	32.3	32.3	32.3	41.5	41.5	
Stack diameter (m)	1.83	2.13	2.13	2.46	2.46	
Temperature (deg.K)	455	439	439	332	332	
Velocity (m/s)	14.01	14.52	14.52	7.59	7.59	

Basis: 1991 stack tests

10/22/92
skcstk1

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

4APT-AEB

OCT 19 1992

RECEIVED

OCT 22 1992

Division of Air Resources Management

Mr. Clair Fancy, P.E.
Air Resources Management Division
Florida Department of Environmental Regulation
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

RE: Alternative Continuous Emission Monitor Span Values Proposed for the AES Cedar Bay Cogeneration Plant

Dear Mr. Fancy:

The purpose of this letter is to provide you with our determination regarding the referenced proposal which was submitted for the AES Cedar Bay Cogeneration Plant by Black and Veatch, Inc. A copy of the proposal from Black and Veatch is enclosed, and based upon our review of the proposal, we would have no objection to approval of the alternative NO_x and SO_2 monitor span values. If the Florida Department of Environmental Regulation does approve the alternative monitor span values, the approval should be contingent upon the condition that the AES Cedar Bay Cogeneration Plant will use higher monitor span values if actual NO_x or SO_2 concentrations in the exhaust stack at the facility ever exceed the approved alternative span values.

According to selection criteria contained in 40 C.F.R. §60.47a, the appropriate NO_x and SO_2 monitor span values for the AES Cedar Bay Cogeneration Plant would be 1000 ppm and 1300 ppm, respectively. Applicable emission standards at the facility effectively limit actual concentrations of NO_x and SO_2 in the exhaust stack to approximately 180 ppm and 260 ppm, respectively. Because the AES Cedar Bay Cogeneration Plant anticipates that actual NO_x and SO_2 concentrations in the exhaust stack will be at the extreme lower end of the monitoring range if the span values specified in 40 C.F.R. §60.47a are used, the company has proposed alternative NO_x and SO_2 monitor span values of 400 ppm and 500 ppm, respectively.

Based upon the applicable emission standards and expected emission rates for the AES Cedar Bay facility, we believe that monitor span values proposed by Black and Veatch will allow the company to measure emission rates more accurately than they could if the span values specified in 40 C.F.R. §60.47a were used. Therefore, we would not object if your agency approves the alternative monitor span values proposed by Black and Veatch.

The only concern that we have regarding the proposed alternative monitor span values is the possibility that the company would be unable to quantify the magnitude of any exceedances if actual SO_2 or NO_x concentrations are higher than monitor span value. Therefore, we recommend that if the alternative span values proposed for the AES Cedar Bay Cogeneration Plant are approved by the Florida DER, the approval should be made contingent upon the ability of the monitoring system to quantify emission concentrations during all periods of facility operation. If the actual SO_2 or NO_x concentrations in the exhaust stack ever exceed the monitor span value at the facility, the company should be required to switch to a higher span value that would enable it to quantity emissions during all periods of operation.

If you have any questions about the determination provided in this letter, please contact Mr. David McNeal of my staff at 404/347-5014.

Sincerely yours,

Jewell A. Harper, Chief
Air Enforcement Branch
Air, Pesticides and Toxics
Management Division

Enclosure

BLACK & VEATCH

8400 Ward Parkway, P.O. Box No. 8405, Kansas City, Missouri 64114 (913) 339-2000

Multipower Associates
AES Cedar Bay Cogeneration Plant

B&V Project 15637
B&V File 62.0204
September 11, 1992

FEDERAL EXPRESS

U.S. Environmental Protection Agency
Region IV Headquarters
345 Courtland Street
Atlanta, Georgia 30365

Subject: Flue Gas Monitoring Equipment

Attention: Ms. Jewell Harper

Gentlemen:

We are in the process of selecting analyzers for the continuous emissions monitoring (CEM) system for the Cedar Bay Cogeneration Plant. Federal requirements (40 CFR 60 Subpart Da) dictate that the NO_x, and SO_2 analyzers have span ranges of 1000 ppm and 1300 ppm (50 percent of the uncontrolled SO_2 emission rate), respectively.

The NO_x and SO_2 emission limits permitted for the plant are approximately 180 ppm and 260 ppm (uncorrected), respectively. Emission levels actually measured for similar circulating fluidized bed boilers (while firing coal) indicate emission levels lower than these permitted emission levels. In addition, expected NO_x and SO_2 emission limits while firing #2 fuel oil (during startup and low load operation) are anticipated to be only 75 ppm and 170 ppm respectively.

Analyzers designed to meet Federally required limits of 1000 ppm and 1300 ppm would operate in the lower extreme of the full scale range possibly compromising relative accuracy. Uncontrolled NO_x emissions from a circulating fluidized would never be as high as 1000 ppm. To increase accuracy of measurements during normal operation without compromising top end scale levels, we propose to use a NO_x analyzer with a 0 to 400 ppm range, and a SO_2 analyzer with a 0 to 500 ppm range. These analyzer ranges will help ensure the relative accuracy of the system, while providing the range required to define the magnitude of a violation.

U.S. EPA Region IV
Jewell Harper

B&V Project 15637
September 11, 1992

We have previously requested variance from the Florida Department of Environmental Regulation (DER) for the NO_x and SO_2 analyzer ranges required by the EPA regulations (reference the attached B&V letter dated April 24, 1992). The Florida DER has reserved judgement on this issue pending a ruling from the EPA. We would appreciate your variance request by September 29, 1992 to support the project equipment manufacturing schedules. Should you have any questions regarding this request, please contact John Cochran at (913) 339-2190.

Very truly yours,

BLACK & VEATCH

MaPerz for

H. L. Jacobs

Encosures
gtb

cc: Mr. Dave McNeal, U.S. EPA Region IV
Mr. C. H. Fancy, Florida Bureau of Air Regulation
Mr. Jim Manning, City of Jacksonville
Mr. Paul Stinson, AES
Mr. R. C. Wilson
Ms. K. Lee, Enviroplan

~~DBM~~
→ File

BLACK & VEATCH

[illegible] Parkway, P.O. Box [illegible], Kansas City, Missouri [illegible]

Multipower Associates
AES Cedar Bay Cogeneration Plant

B&V Project 15637
B&V File 62.0203
April 24, 1992

Florida Department of Environmental Regulations
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Subject: Continuous Emissions Monitor Analyzer Ranges

Attention: Mr. C. H. Fancy
Chief - Bureau of Air Regulation

Gentlemen:

We are in the process of selecting analyzers for the continuous emissions monitoring (CEM) system for the Cedar Bay Cogeneration Plant. Federal requirements (40 CFR 60 Subpart Da) dictate that the NO_x and SO_2 analyzers have span ranges of 1000 ppm and 1300 ppm (50 percent of the uncontrolled SO_2 emission rate), respectively.

The NO_x and SO_2 emission limits for the plant are approximately 180 ppm and 260 ppm (uncorrected), respectively. Analyzers designed to meet Federal requirements would operate in the lower extreme of the full scale range possibly compromising relative accuracy. Furthermore, uncontrolled NO_x emissions from a circulating fluidized bed boiler would never be as high as 1000 ppm. Therefore, we propose to use a NO_x analyzer with a 0 to 400 ppm range, and a SO_2 analyzer with a 0 to 500 ppm range. These analyzer ranges will help ensure the relative accuracy of the system, while providing the range required to define the magnitude of a violation.

I believe this request is consistent with the requirements of Section 17-2.710 of the Florida Air Pollution Rules. We would appreciate approval for this variance request by May 29, 1992 to support the project equipment manufacturing schedules. Should you have any questions regarding this request please contact John Cochran at 913-339-2190.

Very truly yours,

BLACK & VEATCH

Hobart L Jacobs
Hobart L. Jacobs

jrc

cc: Mr. Hamilton S. Oven, FDER
Mr. Jim Manning, City of Jacksonville
Mr. Steve Wolf, AES
Mr. R. C. Wilson

DER - AES Meeting
9/2/92

Buck Oven	DER	487-0472
~~OWEN WILLIAMS~~	~~AES~~	~~751-1955~~
DAVID KEHRES	AES	904-751-4326
MARK WOODRUFF	AES	(904) 751-1007
Jerry Owen	DER	904-448-4330 x301
Jan Mandrup-Poulsen	DER	(904) 488-4520
BOB LEETCH	DER-JAX	(904) 448-4330 X 307
Craig Diltz	DER-Tally	(904) 488-4522
Daryll Joyner	DER/PSES	904-488-0780
LARRY Curtin	HLK/AES	904-224-7000
AL RUSHANAN	DER	904/488-4520
PHIL CORAM	FDER	904/488-4522
JOHN KOOGLER	K&A/AES	904/377-5822
Bruce Mitchell	FDER/DARM/BAR	904-488-1344
Preston Lewis	FDER/Air	904/488-1344
Tom Rogers	" "	"
Max Linn	" "	"
Richard Donelan	DER-OGC	904/488-9730
Clair Fancy	DER-BAR	904 488 1344

Mark E. Woodruff, P.E.
Senior Project Engineer

AES Cedar Bay, Inc.
P.O. Box 26329
Jacksonville, FL 32226-6329
904-757-6382
Fax: 904-751-1008

David Kehres
Senior Project Engineer

AES Cedar Bay, Inc.
P.O. Box 26329
Jacksonville, FL 32226-6329
904-751-4326
Fax: 904-751-1008

9-2-92 Meeting on AES/Cedar Bay Project 10:00 am →

MC: Buck Owen - PPS

[Mark Woodruff] - concern on the modeling requirements to substantiate the change in the Gov's Order.

① before case

SKC - gen. @ 5 boilers / recycle facility
3 oil-fired boilers
2 BBs

② after case

~~limestone dryer and~~ 3 CFBs (AES)
new SKC:
3 pkg boilers and limestone dryer

* retire new RB construction permit - ✓ letter to Secretary on "not going to build" promise; Probably, should include a "specific" condition on the new RB for surrendering the C.P.

[Mar] - a full modeling run will have to be conducted; however, there has been a modeled SO_2 violation!!!

[Richard] that will be eventually considered.

[Mark] concerned over the comparison senario of one tall stack plumage (original cert) vs. separate stack impact (new SKC source & AES CFBs)

[Richard] might be acceptable to end-up with a greater impact of the original impact of the CFBs but less than the baseline! will still be questioned!! will have to evaluate technical assumptions!!! will need to look into Natural Gas availability to the new SKC pkg. boilers!!!!

[Mark] - currently, AES negotiators are only looking at using distillate oil in the SKC pkg. boilers, not N.G. (attempting to evaluate worst case)
"S" % content @ 0.3%, by weight

[Richard] - concern on SO_2 violation
[Max] = AAQS number 24-hr ambient std - increment does not exist

[General] original AES-Cedar Bay project was permitted with the known AAQS SO_2 violation;

[Tom] - trying to focus on the proposed net changes to try to see if there is an improvement; DCAQD is currently reviewing permits to reduce pollutant emissions (i.e., SO_2) and to develop an accurate inventory for modeling; need to show that AES was not a significant contributor to an AAQS violation; concern @ Hg, Cd, etc. toxics??

[Buck] supposedly shows ↓ in emissions
[Mark] relooking at actual coal suppliers for AES for trace metals, etc. vs Table 33 of original certification and impacts
[Max] need to ✓ no threat levels on toxics thru modeling;

[Richard] NOx!? continue with boiler design as BACT without any control : 0.17 lb/10^6 Btu vs. 0.29 lb/10^6 Btu;

[Mark] < 0.1 lb/10^6 Btu @ the Hawaii plant - has SNCR tech.

[Richard] - there will be a condition addressing the proposed SEC new pkg. boilers and subject to the cert. board scrutiny;

[Mark] SEC has essentially bought-off on
① steam
② pollutant range on SO_2, NO_x & CO
③ # of boilers

[Max / Tom] - to ✓ Class I areas out to 200 km for NPS regard

[Max] - send Modeling Protocol to DER for approval
① grid
② sources/emissions
③ analysis direction
④ etc.

[John Koyler] stack hts of proposed new SEC boilers is not known yet

TABLE 2
ALLOWABLE EMISSION LIMITS
185.5 MW Simple Cycle GE Frame FA Combustion Turbine

Pollutant	Standard Oil Firing	Each Unit lb/hr[a]	Total 2 Units T/yr	Basis
NO_x	42 ppmv at 15% oxygen-dry basis	334	1132[a]	BACT
SO_2	No. 2 fuel oil with 0.2% max. sulfur	407	1176[c]	BACT
PM/PM_{10}	0.01 lb/MMBtu	17	58[b]	BACT
VOC	-	9	31[b]	BACT
CO	25 ppm	79	268[b]	BACT
Sulfuric Acid Mist	No. 2 fuel oil with 0.2% max. sulfur	28	81[c]	BACT
Fluorines (FR)	-	6.13×10^{-2}	0.20[b]	Application
Mercury (Hg)	3.0×10^{-6} lbs/MMBtu	5.66×10^{-3}	0.02[b]	Application
Lead (Pb)	8.9×10^{-6} lbs/MMBtu	1.68×10^{-2}	0.06[b]	Application
Inorganic Arsenic	4.20×10^{-6} lbs/MMBtu	7.9×10^{-3}	0.02[b]	BACT
Beryllium (Be)	2.5×10^{-6} lbs/MMBtu	4.72×10^{-3}	0.02[b]	BACT

(a) Emission rates based on 59°F and 15% O_2 at peak load.

(b) Equivalent to 3,390 hours per year at peak load (38.7% capacity factor) and 59°F.

(c) Total TPY for SO_2 assumes 33% capacity factor and fuel with a maximum sulfur content of 0.2%. Refer to Specific Condition No. 5 for listed capacity factors vs. sulfur content in oil.

TABLE 1
ALLOWABLE EMISSION LIMITS
92.9 MW Simple Cycle GE Frame EA Combustion Turbine

Pollutant	Standard Oil Firing	Each Unit lb/hr[a]	Total 4 Units T/yr	Basis
NO_x	42 ppmv at 15% oxygen-dry basis	182	1232[a]	BACT
SO_2	No. 2 fuel oil with 0.2% max. sulfur	222	1283[c]	BACT
PM/PM_{10}	0.01 lb/MMBtu	15	102[b]	BACT
VOC	-	5	34[b]	BACT
CO	25 ppm	54	366[b]	BACT
Sulfuric Acid Mist	No. 2 fuel oil with 0.2% max. sulfur	18	106[c]	BACT
Fluorines (FR)	-	3.34×10^{-2}	0.23[b]	Application
Mercury (Hg)	3.0×10^{-6} lbs/MMBtu	3.09×10^{-3}	0.02[b]	Application
Lead (Pb)	8.9×10^{-6} lbs/MMBtu	9.16×10^{-3}	0.06[b]	Application
Inorganic Arsenic	4.2×10^{-6} lbs/MMBtu	4.32×10^{-3}	0.03[b]	BACT
Beryllium (Be)	2.5×10^{-6} lbs/MMBtu	2.57×10^{-3}	0.02[b]	BACT

(a) Emission rates based on 59°F and 15% O_2 at peak load.

(b) Equivalent to 3,390 hours per year at peak load (38.7% capacity factor) and 59°F.

(c) Total TPY for SO_2 assumes 33% capacity factor and fuel with a maximum sulfur content of 0.2%. Refer to Specific Condition No. 5 for listed capacity factors vs. sulfur content in oil.

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

State of Florida
DEPARTMENT OF ENVIRONMENTAL REGULATION

Interoffice Memorandum

TO: Richard Donelan
Office of General Counsel

THROUGH: Robert E. Heilman, P.E., Chief RH
Bureau of Water Facilities Planning and Regulation

FROM: Phil M. Coram, P.E., Administrator
Industrial Wastewater Section

DATE: August 5, 1992

SUBJECT: AES Cedar Bay/Seminole Kraft Project
Recommended Changes to Specific Conditions
and Review Comments

Craig Diltz, Daryll Joyner, and Jan Mandrup-Poulsen met to review the proposed AES Cedar Bay (AESCB) Petition for Modification of Certification (July 13, 1992 version). Attached are the specific changes to the language contained in the petition they believe should be incorporated to clarify the Department's intent in several areas. The reviewers also wish to express the following concerns requiring your attention prior to granting final approval of the Conditions of Certification.

1) Please provide us with a copy of the Zero Discharge Plan referred to on page 24.

2) Our initial evaluation of the "total treatment option" is there may not be a net environmental improvement with the additional treatment proposed by the AESCB. The added removal of BOD, TSS, and color from the Seminole Kraft Corporation discharge may not compensate for the release of higher concentrations of a variety of metals and nutrients from the AESCB water treatment system. The limited potential of this option does not concern the review group as they consider the zero discharge option acceptable. However, if the intent of the siting board was for AESCB to develop an option that significantly improves upon the zero discharge plan, then the total treatment option is not acceptable. Our question to you is, what was the understanding of the Siting Board when they agreed to the "Zero-Plus" Option?

If treatment in excess of the zero discharge option was anticipated, then we would recommend AESCB provide the funds necessary for Seminole Kraft to install a clarifier of sufficient size to treat (for BOD and TSS) the remaining flow from the Seminole Kraft facility. This requirement would probably have to be put into effect immediately to minimize the added cost to AESCB. Installing the clarifier would eliminate the need for AESCB to secure a NPDES permit. The cost to install the added clarifier capacity should only be calculated as that beyond which AESCB would have paid to install the 3.6 million gallon clarifier already planned for use in pretreatment. We estimate a cost of about $8.4 million for the additional clarifier.

If this approach is adopted, the added treatment of Seminole Kraft's discharge combined with maintaining zero discharge from AESCB would obviously provide a net environmental benefit. Any other type of added treatment whereby AESCB then starts to discharge would require a very detailed, parameter-by-parameter evaluation to determine whether the change produced a net environmental benefit. If additional treatment is required by the board and AESCB wants to be able to discharge, we need to develop and agree on a method to evaluate the "net environmental benefit" of any proposed changes.

If it was not the intent of the board to require additional treatment, then the text in the Conditions of Certification regarding the total treatment option (III.A.2) could simply be dropped as applicants always have the right to petition for modification.

Give me a call if you wish to discuss this further.

PMC/jmp

Attachment

cc: Richard Harvey
Al Bishop
Richard Drew
Craig Diltz
Daryll Joyner

Proposed Revisions to Conditions of Certification

III. WATER DISCHARGES

A. Plant Effluents and Receiving Body of Water

1. AESCB shall not discharge any coal pile runoff, cooling system, demineralizer regeneration, floor drainage, or any other process *similar* wastewaters from the operation of the AESCB facility into any waters of the State. AESCB shall install a closed-loop cooling water system in accordance with technical specifications set forth in the Zero Discharge System Plan submitted by AESCB to the Department during the hearing *and* (attached as Exhibit to these Conditions of Certification) and in accordance with engineering plans as reviewed and approved by the Department.

2. Pursuant to the*at* Zero Discharge System Plan, AESCB shall make available to Seminole Kraft at least *up to* 500 gpm of reclaimed water that has been treated to a quality satisfactory for use in condenser cooling for Seminole Kraft's turbine generator so that Seminole Kraft may reduce its ground water consumption by this amount.

3*2*. AESCB may *shall* continue to seek a permit from U.S. EPA for the discharge of cooling water and process wastewater to the St. Johns *or the Broward River.* If an NPDES permit can be obtained, and if DER determines that it will result in a net environmental improvement over the Zero Discharge System Plan, AESCB shall apply for a modification of these Conditions of Certification to allow it to install and operate equipment to treat all of the process wastewater and cooling water generated by Seminole Kraft, up to 12 mgd, in a chemically assisted clarification unit....

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Meeting Attendance Record

Project: AES / Cedar Bay　　Date: 7/16/92

Subject: COC Modifications

Name	Affiliation / Position	Phone Number
Steve Palmer	SCO	7-0472
Dana D. Minerva	Sec's Office	8-4805
Jan Mandrup-Poulsen	Water Fac. Reg. Section	8-4520
Craig Diltz	Ind. Waste	84522
DARYLL JOYNER	Point Source Evaluation	8-0780
PRESTON LEWIS	DER/DARM/BAR	8-1344
Bruce Mitchell	FDER/DARM/BAR	8-1344
R. T. Donelan Jr.	DER-OGC	8-9730