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BUREAU OF AIR REGULATION

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September 19, 2005 0537586

Florida Department of Environmental Protection
Title V Section; Bureau of Air Regulation
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Fl 32399-2400

Attention: Mr. Michael P. Halpin, P.E., Permitting North

RE: Cedar Bay Cogeneration facility
Title V Permit # 0310337-009-AC; PSD-FL-137A
Conditions of Certification PA 88-24
Request for Additional Information (RAI)

Dear Mr. Halpin:

This correspondence is being submitted on behalf of Cedar Bay Generating Company, L.P. (Cedar Bay) to provide the information requested in the Florida Department of Environmental Protection (FDEP) August 19, 2005 correspondence related to the co-firing 5 percent Tire Derived Fuel (TDF), increasing the coal sulfur content and clarifying the input limit for short-fiber rejects (SFR). The information is being provided in the same order as requested.

1. **RAI:** Please provide the FDEP with estimates for the change in emissions of any non-criteria pollutants which might be expected to increase as a result of the 5% TDF co-firing. The estimates should include polynuclear aromatic hydrocarbons (PAHs), dioxins, furans, hydrogen chloride, benzene, PCB's and any other pollutants for which Cedar Bay or its consultants might reasonably expect a change. Additionally, the analysis should estimate (where practical) related impacts to ambient air quality and corresponding health impacts.

Additional Information: The results of the TDF test burn submitted as Appendix B of the application indicated that the only potential changes in emissions from the facility would be associated with the sulfur and zinc contents of TDF. The sulfur content is only slightly higher than coal and since the heat content for TDF is about 25% higher than coal the uncontrolled sulfur dioxide (SO_2) emission rate is well within the requested equivalent uncontrolled SO_2 limit of 3.2 lb/MMBtu. Actual uncontrolled TDF SO_2 emission rate ranged from 2.1 to 2.8 lb/MMBtu. For trace metals, zinc oxide is an ingredient in tires and the emission rate was determined to be 0.0468 lb/hr. The concentrations of other trace metals in the co-fired fuel (i.e., 5%TDF co-fired with coal) were determined to be either less than that in coal or no difference. Indeed, the emission rates for lead, mercury and beryllium were either lower than previous tests or well within the emission rates for previous tests.

Emissions of PAHs, dioxins, furans, benzene and PCBs are primarily products of the combustion process. As part of the TDF test burn, total volatile organic compounds (VOCs) were measured. Compounds such as PAHs, benzene and other organics would be included in the general category of VOCs. The test data indicted that the total VOCs when co-firing 5% TDF with coal were generally less than previous tests. The higher heat content for TDF suggests that when co-firing 5% TDF the combustion process in the circulating fluidized bed boiler is not affected and indeed may be enhanced. The formation of dioxins and furans is again combustion related. The attached description of the combustion process and the formation of dioxins and furans indicate that co-firing 5% TDF will have no effect on dioxin and furan emissions. Similarly, PCBs (polychlorinated biphenyls) is a chlorine based compound and formed in the combustion process. With the average chlorine content of bituminous coal at about 0.1%, the minor amounts of chlorine in TDF will not influence emissions of chlorinated compounds or hydrogen chloride (HCL). These results are similar to that found by the U.S. Environmental Protection Agency (EPA) which states:

> "Based on the results of the RKIS test program, it can be concluded that, with the exception of zinc emissions, potential emissions from TDF are not expected to be very much different than from other conventional fossil fuels, as long as combustion occurs in a well designed, well-operated and well-maintained combustion device." EPA. 2005. Air Emissions from Scrap Tire Combustion. EPA-600/R-97-115. October 1997. (Note: the RKIS is a test device used by EPA. Test data for a variety of combustion tests are found in the reference.)

To put into perspective the air quality impacts of the Cedar Bay facility, an air quality modeling evaluation was conducted and is attached. The results of the modeling, using worst-case emissions indicates that the air quality impacts for the facility are very low and will continue to be low when co-firing 5% TDF with coal.

2. The PSD regulations (under the provisions commonly known as the "WEPCO rule") allow a source undertaking a non-routine change that could affect emissions at an electric utility steam generating unit to lawfully avoid the major source permitting process by using the unit's representative actual annual emissions to calculate emissions following the change if the source submits information for 5 years following the change to confirm its pre-change projection. The FDEP wishes to confirm that Cedar Bay requests the application of the WEPCO provision, and commits to not exceeding PSD thresholds beyond the 2003-2004 emission levels for PM, PM_{10}, SO_2, NO_X, CO, VOC and SAM. Concerning the attendant application, should the FDEP gain reasonable assurance that the PSD thresholds will not be triggered, permit conditions will be crafted to ensure same.

Additional Information: As described in the application, Cedar Bay has proposed a permit condition that would meet the requirements of the WEPCO rule (please refer to Section 3.0, pages 10 and 11). The proposed condition was structured to be similar to recent FDEP permit authorizations that included the requirements codified in 40 CFR Parts 52.21(b)(21)(v) and 52.21(b)(33). In addition, Cedar Bay has proposed within the condition the means for complying with the WEPCO rule (i.e., CEMs and stack tests). Together, these provide the FDEP reasonable assurance that the PSD thresholds will not be exceeded.

3. The FDEP is appreciative of the analyses provided to help explain the requested permit change dealing with 3.2 lb/MMBtu as an equivalent SO_2 emission limit, in lieu of the existing coal sulfur limitations. Even so, the FDEP remains unclear as to the anticipated changes in scrubbing required. Please answer the following questions, based on coal-only combustion, except where otherwise specified:

   A. Utilizing actual historical scrubbing efficiencies and the historical (average) coal heat content, estimate the controlled and uncontrolled lb/MMBtu SO_2 emissions based upon the 1.7% sulfur "shipment limitation".

Additional Information: Table RAI-3 contains the requested information. Please note that Cedar Bay is proposing to increase SO_2 removal efficiency to limit annual SO_2 emissions to the proposed annual limitation that would not exceed the PSD threshold. The controlled SO_2 emissions will be similar to the existing emission rates regardless of the sulfur input, which would not exceed an equivalent uncontrolled emission rate of 3.2 lb/MMBtu. The SO_2 control system for each unit maintains the SO_2 emissions within compliance levels by controlling the limestone feed rate. The basic limestone feed rate set point is derived from the coal feeder demand signal, which generates a limestone-to-coal ratio. The ratio decreases with load and has been adjusted to observed steady state ratios. These ratios are then adjusted by the SO_2 controller to maintain SO_2 emissions to an operator-entered set point in lbs/mmBtu. Table RAI-3 contains the annual average SO_2 removal efficiencies for 1.7 percent sulfur coal (i.e., 93.8 percent). This is within the ability of the SO_2 control system as provided in the Foster Wheeler Report (Figure 3).

   B. Utilizing the same historical scrubbing efficiencies and heat content identified above, estimate the controlled and uncontrolled lb/MMBtu SO_2 emissions based upon the 1.2% sulfur "annual limitation".

Additional Information: Table RAI-3 contains the requested information.

   C. Utilizing the same historical scrubbing efficiencies and heat content identified above, estimate the maximum percent sulfur content of coal which could be combusted in order to yield an uncontrolled 3.2 lb/MMBtu emission level.

Additional Information: Table RAI-3 contains the requested information.

   D. Utilizing the same historical scrubbing efficiencies and heat content identified above, estimate the controlled and uncontrolled lb/MMBtu SO_2 emissions for coal plus 35% petcoke as compared to coal plus 5% TDF.

Additional Information: Table RAI-3 contains the requested information. The co-firing of TDF and Petroleum Coke (if implemented) would be limited to an uncontrolled SO_2 emission rate of 3.2 lb/MMBtu. Therefore the calculations would be the same as for RAI 3C above.

4. Please confirm that the purpose of the requested change in the short fiber rejects (SFR) condition is simply to make accounting easier and that 840,000 lb/day and 139,200 tons/yr are roughly equivalent to 420 yd^3/day (wet) and 139,176 yd^3/yr (wet).

Additional Information: The FDEP's comment is correct on the reason for the change in determining the amount of SRF fired. Using a mass basis for accounting for the amount of SFR co-fired is more accurate than the current volume based limit.

Please contact me if you have any questions on the information in the application. Your expeditious handling is appreciated.

Sincerely,

GOLDER ASSOCIATES

SEAL

Kennard F. Kosky, P.E.
Professional Engineer No. 14996

Enclosures

cc: Martin Kreft, Cedar Bay Generating Company
Hamilton Oven, FDEP, Siting
Jeffery Walker, Cedar Bay Generating Company
Chris Kirts, P.E., FDEP Northeast District
Dot Mathias, Northside Civic Association

Table RAI-3. Information on Uncontrolled and Controlled SO_2 Emissions and Removal Efficiencies

Parameter	Units	RAI Response		
		3A	3B	3C&3D
Average Heating Value[a]	Btu/lb	12,121.4	12,121.4	12,121.4
Coal Sulfur Content	%	1.7	1.2	1.94
Historical SO_2 Removal[a]	%	88.84%	88.84%	88.84%
Uncontrolled SO_2 Emissions	lb/MMBtu	2.80	1.98	3.20
Controlled SO_2 Emissions with Historical SO_2 Removal	lb/MMBtu	0.31	0.22	0.36
Annual Emissons Cap	tons	2,012.5	2,012.5	2,012.5
Coal Usage	tons	940,000	940,000	940,000
Controlled SO_2 Emissions	lb/MMBtu	0.177	0.177	0.177
Required SO_2 Removal	%	93.70%	91.08%	94.48%

[a] Based on 2000-2004 data.

Dioxin Control in Coal-Fired Boilers

The control of dioxins in coal-fired boilers occurs from two mechanisms: the efficiency of combustion and a sulfur to chlorine ratio of greater than one.

Good combustion practices decrease the formation of dioxins by the complete oxidation of organic compounds and carbonaceous solids that are the precursors to dioxin formation. Good combustion practices include residence time, high temperature and turbulence. These are the three combustion parameters that are prevalent in a CFB boiler due to the nature of a fluidized bed providing excellent residence time and turbulence. A bed temperature of 1800 degrees Fahrenheit (°F) and a one to two second residence time will destroy most gas-phase compounds.

Dioxins are formed in the temperature range of 500 to 1100 (°F) and are destroyed at higher temperatures.

Another method for low dioxin emissions is a sulfur to chlorine (S/Cl) ratio of greater than one. The presence of sulfur will short-circuit the formation of dioxins by converting the chlorine gas released during fuel burning into hydrogen chloride (HCl) which is not effective in the formation of dioxins which requires free chlorine. Sulfur dioxide with chlorine and water gives sulfates and HCL. The HCl is then controlled with the limestone in the CFB.

Coal-fired plants have very low dioxin emissions due to good combustion efficiency and a S/Cl ratio of much greater than one (typically 35 to 500). A CFB will combust TDF with the same efficiency as coal and TDF has an S/Cl ratio of approximately 8. With the limitation of TDF to be burned in the Cedar Bay boilers being less than 20 percent of the heat input, the combined fuel has S/Cl that is much greater than one.

The reason that a municipal waste combustor (MWC) has inherently high dioxin emissions is that it does not meet the two criteria described above. Because of the inconsistency of the fuel, a boiler may have areas that do not meet high temperatures even though residence time and turbulence are present in the boiler. Temperatures may not reach greater than 1100 (°F). In addition, municipal waste has very little sulfur and potentially high chlorine content and therefore the S/Cl is much less than one.

Air Quality Evaluation

The Environmental Protection Agency (EPA) has issued Ambient Air Quality Standards (AAQS) for various air pollutants including sulfur dioxide (SO_2), particulate matter with an aerodynamic diameter of 10 microns (PM_{10}), nitrogen dioxide (NO_2) and carbon monoxide (CO). AAQS are designed to protect the public welfare of the general public, with an adequate margin of safety. The protection of public welfare includes the effects of air pollution on soils, vegetation and wildlife. Indeed, the foundation for the AAQS is the federal Clean Air Act (CAA), which clearly establishes the requirements of the AAQS as stated by the EPA (2005):

> "The Clean Air Act, which was last amended in 1990, requires EPA to set National Ambient Air Quality Standards (NAAQS) for wide-spread pollutants from numerous and diverse sources considered harmful to public health and the environment. The Clean Air Act established two types of national air quality standards. Primary standards set limits to protect public health, including the health of 'sensitive' populations such as asthmatics, children, and the elderly. Secondary standards set limits to protect public welfare, including protection against visibility impairment, damage to animals, crops, vegetation, and buildings. The Clean Air Act requires periodic review of the science upon which the standards are based and the standards themselves." http://www.epa.gov/ttn/naaqs/.

In areas where the air quality meets the AAQS, such as all of Florida, Prevention of Significant Deterioration (PSD) Increments have been established by EPA as incremental amounts of impacts that are allowed for new sources. The PSD Class II Increments are designed to protect the ambient air from being degraded and have been established for three air pollutants: SO_2, PM_{10}, and NO_2. These PSD Increments are more stringent than the AAQS and are less than 50 percent of the AAQS. The Florida Department of Environmental Protection (FDEP) has adopted AAQS and PSD Increments and requires new major sources to demonstrate compliance with these limits using air dispersion modeling.

To address the FDEP request, EPA and FDEP approved models were used to predict maximum air quality impacts for the facility. The air dispersion model used plant emissions and exhaust characteristics, five-years of meteorological data and receptor locations to determine the facility's impacts relative to the EPA and FDEP AAQS and PSD Class II Increments. The maximum permitted emissions were used in determining impacts.

The results of the air dispersion modeling analysis showing the maximum predicted concentrations for the Project is presented in Table 1. This table presents the maximum impacts for each averaging time for which there is an AAQS and PSD Increment. Concentrations are presented in micrograms of each pollutant per cubic meter of air (ug/m^3). As shown in the table, the maximum impacts range from 0.02 to 2.4 percent of the AAQS, which is designed to protect the health and welfare with an adequate margin of safety. The maximum impacts range from 0.1 to 6.9 percent of the PSD Class II Increments, which are designed to protect ambient air from degradation. The maximum predicted impacts shown in Table 1 are for a single location using five years of meteorological data. The impacts at other locations and times would be lower than the concentrations shown.

The maximum concentrations for certain trace elements were predicted. The trace elements evaluated included those with current emission limits (lead, mercury and beryllium) and zinc, for which there are higher concentrations in tire-derived fuel (TDF). With the exception of lead, there are no FDEP or EPA ambient air quality standards for the trace metals. For lead, the maximum impact of the facility will be over 5,000 times less than the air standard set to protect public health. While there are no air quality standards for the other trace elements, the EPA has reference air concentrations and there are occupational guidelines that can be compared to the maximum predicted concentrations for the Cedar Bay facility. This comparison is shown in Table 2, which shows a comparison with the EPA Reference Concentrations for Chronic Inhalation Exposure (RfC) and occupational Threshold Limit Values (TLV), Time Weighted Average (TWA). The EPA RfC is based on a lifetime of exposure and the comparison is shown against the maximum annual concentration predicted over a 5-year period. This comparison provides worst-case since predicted concentration for four of the five years will be lower that shown in the table. In addition, concentrations at other locations will be much less than the maximum predicted concentrations, which typically occur near the plant and in one discrete location. The TLV-TWA represents levels of 8-hour (hr) occupational exposure that are considered levels that workers can be exposed day after day without adverse health effects. The maximum 8-hr concentrations that occur over a 5-year period are also compared to the TLV-TWA in Table 2. Again, this comparison is extremely conservative since the predicted maximum 8-hr concentration from the facility will be much less than the average 8-hr exposure and levels at other locations will be less than the location of maximum impact.

As shown in Table 2, the maximum predicted annual concentrations are from about 1,800 to over 8,000 times lower than the EPA RfC for beryllium and mercury, respectively. When comparing the maximum predicted impacts to the TLV-TWA, the maximum impacts range from about 3,000 times lower than the TLV-TWA for beryllium to over 3 million times lower for zinc. For beryllium, the modeled emissions reflect the maximum permitted emission rate, which is over 40 times higher than the maximum emission rate observed during historical stack tests. The modeled emissions for lead and mercury also reflect the maximum permitted emission rate, which is over 6 and 20 times higher, respectively, than actual emission rates observed in previous stack test data. Therefore, the comparison of the maximum predicted impacts from the Cedar Bay facility to the EPA RfC and TLV-TWA are extremely conservative.

Table 1. Maximum Pollutant Concentrations Predicted for the Cedar Bay Generating Station

Pollutant	Averaging Time	Maximum Concentration (ug/m^3)	AAQS (ug/m^3)	AAQS (%)	PSD Class II Increment (ug/m^3)	PSD Class II Increment (%)
Criteria Air Pollutants						
SO2	Annual	0.36	60	0.6%	20	1.8%
	24-Hour	6.3	260	2.4%	91	6.9%
	3-Hour	29.2	1300	2.2%	512	5.7%
PM10	Annual	0.02	50	0.04%	17	0.1%
	24-Hour	0.4	150	0.25%	30	1.3%
NO2	Annual	0.20	100	0.20%	25	0.8%
CO	8-Hour	9.5	10,000	0.09%	NA	NA
	1-Hour	17	40,000	0.04%	NA	NA
Pb	Quarterly	0.00027	1.5	0.02%	NA	NA

Note: PSD = Prevention of Significant Deterioration
AAQS = Ambient Air Quality Standard
NA = Not applicable

Table 2. Comparison of Maximum Impacts of SWSLPP Trace Metals with EPA Reference Concentrations and Occupational Threshold Limit Values

Trace Metal	Maximum Concentration (ug/m^3)	Averaging Time	EPA RfC (ug/m^3)	Occupational TLV-TWA (ug/m^3)
Beryllium	0.000011	Annual	0.02	
	0.000643	8-hour		2
Lead	0.000068	Annual	No RfC[a]	
	0.003856	8-hour		50
Mercury	0.000034	Annual	0.3	
	0.001928	8-hour		25
Zinc[b]	0.000053	Annual	No RfC	
	0.003007	8-hour		10,000

RfC = Reference Concentration for Chronic Inhalation Exposure
The RfC is an estimate of the continuous inhalation exposure to the human population (including
TLV = Threshold Limit Values, TWA = Time Weighted Average
TLV-TWA based on American Conference of Governmental Industrial Hygienists (ACGIH)
[a] Lead has an ambient air standard of 1.5 ug/m^3 on an averaging time of a calendar quarter
[b] provided as zinc oxide based on February 2005 stack tests

Table 1. Comparative Chemical and Emissions Characteristics for Coal and TDF

Characteristic	Cedar Bay Coal	TDF	Combination
Proximate Analysis (% as received)	2003 annual average		
Moisture	6.49	0.62	6.20
Ash	10.89	4.78	10.59
Volatile	33.21	66.64	34.87
Fixed Carbon	49.35	27.96	48.29
Ultimate Analysis (% as received)			
Carbon	68.85	83.27	69.56
Hydrogen	4.35	7.09	4.49
Nitrogen	1.32	0.24	1.27
Sulfur	0.96	1.83	1.00
Ash	11.14	4.78	10.83
Moisture	7.05	0.62	6.73
Oxygen	6.41	2.17	6.20
CFB Performance			
Heat Content (Btu/lb)	12,000	14,700	12,135
Mass Percentage	95.0%	5.0%	100.0%
Heat Input by Fuel (tons/hr)	41.6	2.2	43.8
Percentage by Heat Input	94%	6%	100%
Heat Input by Fuel (MMBtu/hr)	999.2	63.8	1,063.0
Unit heat Input (MMBtu/hr) - permitted	1,063		

Table 2. Coal Sulfur Content and SO_2 Removal, Limestone and Ash Amounts
Typical Coal Heat Content

Parameter	Units	Data	Basis and Limits [a]
Heat Input	MMBtu	1,063	Limit in Condition A.1.
Heat Content	Btu/lb	12,000	Typical heat content of coal
Coal Usage	lb/hr	88,583	Limit of 104,000 lb/hr, Condition A.3.(b)
Coal SO_2	lb/MMBtu	3.2	Proposed
Coal Sulfur	%	1.92	Calculated sulfur content
Coal Ash	%	11.55	Tyical ash
SO_2 Emission LImit	lb/MMBtu	0.2	Limit in Condition A.5.
SO_2 Removal	%	93.8%	Calculated removal
SO_2 Removed	lb/hr	3,189	(3.2 - 0.2) x 1,063 lb/MMBtu
Limestone	lb/hr	17,000	Based on Foster Wheeler Report Figure 4
Ash	lb/hr	10,231	Ash % x Fuel Usage
Total Ash	lb/hr	27,231	Limestone + Ash
Annual			
Limestone	tons/yr/unit	67,014	Based on 90% heat input capacity factor [b]
	tons/yr/plant	201,042	275,000 tons/yr limit in Condition B.1.b.
Total Ash	tons/yr/unit	107,346	Based on 90% heat input capacity factor [b]
	tons/yr/plant	322,038	424,000 tons/yr fly ash and bed ash
Fly Ash [c]	tons/yr/plant	293,055	336,000 tons/yr limit in Condition B.1.b.
Bed Ash [c]	tons/yr/plant	28,983	88,000 tons/yr limit in Condition B.1.b.

[a] Conditions refer to Final Title V Permit No. 0310337-007-AV

[b] Conservative maximum based on historical average of 81% from 1997 through 2004; maximum was 84%

[c] Based on average 2002 through 2004 of 91% fly ash and 9% bed ash of total ash; data based on truck scales.

Table 3. Coal Sulfur Content and SO_2 Removal, Limestone and Ash Amounts
Low Coal Heat Content

Parameter	Units	Data	Basis and Limits
Heat Input	MMBtu	1,063	Limit in Condition A.1.
Heat Content	Btu/lb	10,221	Typical heat content of coal
Coal Usage	lb/hr	104,000	Limit of 104,000 lb/hr, Condition A.3.(b)
Coal SO_2	lb/MMBtu	3.2	Proposed
Coal Sulfur	%	1.64	Calculated sulfur content
Coal Ash	%	11.55	Typical ash
SO_2 Emission LImit	lb/MMBtu	0.2	Limit in Condition A.5.
SO_2 Removal	%	93.8%	Calculated removal
SO_2 Removed	lb/hr	3,189	(3.2 - 0.2) x 1,063 lb/MMBtu
Limestone	lb/hr	17,000	Based on Foster Wheeler
Ash	lb/hr	12,012	Ash % x Fuel Usage
Total Ash	lb/hr	29,012	Limestone + Ash
Annual			
Limestone	tons/yr/unit	67,014	Based on 90% heat input capacity factor [b]
	tons/yr/plant	201,042	275,000 tons/yr limit in Condition B.1.b.
Total Ash	tons/yr/unit	114,365	Based on 90% heat input capacity factor [b]
	tons/yr/plant	343,096	424,000 tons/yr fly a fly ash 88,000 bed ash
Fly Ash [c]	tons/yr/plant	312,217	336,000 tons/yr limit in Condition B.1.b.
Bed Ash [c]	tons/yr/plant	30,879	88,000 tons/yr limit in Condition B.1.b.

[a] Conditions refer to Final Title V Permit No. 0310337-007-AV

[b] Conservative maximum based on historical average of 81% from 1997 through 2004; maximum was 84%

[c] Based on average 2002 through 2004 of 91% fly ash and 9% bed ash of total ash; data based on truck scales.

Table 4. Comparative Chemical and Emissions Characteristics for Typical Coal and TDF (With Proposed Coal Sulfur Limit Equivalent to 3.2 lb/MMBtu)

Characteristic	Cedar Bay Coal	TDF	Combination
Proximate Analysis (% as received)			
Moisture	6.49	0.62	6.20
Ash	10.89	4.78	10.59
Volatile	33.21	66.64	34.87
Fixed Carbon	49.35	27.96	48.29
Ultimate Analysis (% as received)			
Carbon	68.85	83.27	69.56
Hydrogen	4.35	7.09	4.49
Nitrogen	1.32	0.24	1.27
Sulfur	1.9	1.83	1.90
Ash	11.14	4.78	10.83
Moisture	7.05	0.62	6.73
Oxygen	6.41	2.17	6.20
CFB-C Performance			
Heat Content (Btu/lb)	12,000	14,700	12,135
Mass Percentage	95.0%	5.0%	100.0%
Heat Input by Fuel (tons/hr)	41.6	2.2	43.8
Percentage by Heat Input	94%	6%	100%
Heat Input by Fuel (MMBtu/hr)	999.2	63.8	1,063.0
Unit heat Input (MMBtu/hr) - permitted	1,063		
Sulfur Dioxide Emissions			
Sulfur dioxide (uncontrolled; lb/hr with TDF)	3,164.2	158.8	3,323.0
Sulfur dioxide Uncontrolled Emission Rate (lb/MMBtu)	3.2	2.5	3.1
Sulfur dioxide (uncontrolled; lb/hr coal only)	3,366.2	0.0	3,366.2
Difference (lb/hr)			-43.2

Table 5. Annual Emissions for Cedar Bay Cogeneration Facility

Parameter	2000	2001	2002	2003	2004
			Boiler A (TPY)		
Particulate Matter	58.72	64.36	22.63	13.43	21.46
PM_{10}	48.09	21.34	21.24	8.51	29.70
Sulfur Dioxide	650.52	631.20	649.80	677.90	659.55
Nitrogen Oxides	594.40	551.40	561.80	581.10	618.14
Carbon Monoxide	179.16	177.60	173.79	189.28	178.32
Volatile Organic Compounds	4.97	25.02	24.19	26.41	25.92
Sulfuric Acid Mist	0.11	0.11	0.16	0.18	0.17
			Boiler B (TPY)		
	2000	2001	2002	2003	2004
Particulate Matter	66.06	68.41	27.72	50.38	67.52
PM_{10}	60.22	32.48	22.53	48.29	62.16
Sulfur Dioxide	670.98	624.50	641.20	661.57	638.45
Nitrogen Oxides	597.58	544.64	534.40	555.06	571.30
Carbon Monoxide	157.65	150.70	137.81	114.61	126.07
Volatile Organic Compounds	8.93	11.70	21.57	22.61	22.28
Sulfuric Acid Mist	0.12	0.11	0.16	0.16	0.16
			Boiler C (TPY)		
	2000	2001	2002	2003	2004
Particulate Matter	63.42	69.15	21.56	28.70	22.26
PM_{10}	56.91	38.54	20.12	18.03	21.23
Sulfur Dioxide	643.63	645.80	627.80	654.40	653.14
Nitrogen Oxides	587.06	560.90	546.00	571.79	606.62
Carbon Monoxide	179.20	156.20	145.03	135.29	138.96
Volatile Organic Compounds	3.35	11.96	11.75	12.45	12.00
Sulfuric Acid Mist	0.12	0.11	0.16	0.17	0.16
			Boilers A, B, and C (TPY)		
	2000	2001	2002	2003	2004
Particulate Matter	188.20	201.93	71.90	92.52	111.24
PM_{10}	165.22	92.36	63.89	74.83	113.09
Sulfur Dioxide	1965.13	1901.50	1918.80	1993.87	1951.14
Nitrogen Oxides	1779.04	1656.94	1642.20	1707.95	1796.06
Carbon Monoxide	516.01	484.50	456.62	439.18	443.35
Volatile Organic Compounds	17.25	48.68	57.51	61.46	60.19
Sulfuric Acid Mist	0.35	0.34	0.48	0.51	0.50

	Boilers A, B, and C (TPY)			
	2000-2001	2001-2002	2002-2003	2003-2004
Particulate Matter	195.06	136.91	82.21	101.88
PM_{10}	128.79	78.13	69.36	93.96
Sulfur Dioxide	1,933.32	1,910.15	1,956.34	1,972.51
Nitrogen Oxides	1,717.99	1,649.57	1,675.08	1,752.01
Carbon Monoxide	500.26	470.56	447.90	441.27
Volatile Organic Compounds	32.96	53.10	59.49	60.83
Sulfuric Acid Mist	0.34	0.41	0.49	0.50

Source: 2001 through 2004 Annual Operating Reports.

October 5, 2005 Revised Draft

I. Proposal for the future of Nuclear Energy in Florida

Structure of initiative shall be through a Governor's Executive Order, with a balanced representation of executive and legislative branch, power industry and advocacy groups. With some exceptions, the Executive Order can be patterned after Governor Bush's Executive Order establishing the Energy Study 2020 Commission: http://www.myflorida.com/myflorida/government/taskandcommissions/energy_commission/executiveOrder.html
The notable exceptions are:

A) The Nuclear Energy Task Force shall be comprised of eight members. Potential membership includes:

Legislative Branch – [one member from the House - Ken Littlefield (or designee), Donna Clark, Mitch Needleman or Gus Bilirakis; and, one member from the Senate - Lee Constantine (or designee), Dennis Jones or Paula Dockery]
Nuclear Security – [Jerry Paul, Deputy Director NNSA]
Environmental Advocacy – [Eric Draper, Audubon]
Business/Financial Community – [J. Hyatt Brown, Bill Frederick, Susan Martinez, Tracy Duda Chapman, or a member of the Council of 100]
Industry – [I can suggest 3 or 4 retired executives from FPL (power generation); others??]
DEP – [Mimi Drew, Mollie Palmer]
PSC (suggested chair) - [Jim Dean, Director of Office of Strategic Analysis and Governmental Affairs]

Administrative support to be provided by DEP – Siting Office:
Administrative Assistant – [Karen Skinner??]

B) The Task Force shall determine appropriate means by which Florida can encourage the addition of safe nuclear-fueled power plants to be built within Florida in an efficient, affordable and reliable manner. Based on its findings, the Task Force shall make recommendations to encourage greater deployment of nuclear-fueled plants, including statutory changes, if necessary.

C) The Task Force shall make recommendations by January 31, 2006 to the President of the Senate, the Speaker of the House of Representatives, and the Governor via a written report

II. What are the reasons for forming the Task Force?

A) Florida's growing need for new baseload capacity

B) No nuclear plants have been built in Florida since 1983

C) Supply interruptions from recent hurricanes have brought to light Florida's overdependence upon natural gas and oil-generated electricity, and the associated supply risks

D) Natural gas and oil prices have increased dramatically

E) Increasingly stringent environmental issues with respect to fossil fuels (CAIR, CAMR)

F) Nuclear has the lowest incremental operating cost within Florida's fleet of power plants

III. What are some of the issues to the addition of nuclear energy in Florida?

A) Regulatory
   1) Need determination and bid rule at PSC
   2) Prudency review and rate base treatment
   3) Rate Aspects
      a. Pre-construction recovery mechanisms AFUDC, CWIP
      b. Alternative recovery mechanisms
   4) Permitting on the state level
      a. Thermal
      b. Water Usage
      c. Emissions (nil)
      d. Plant Siting – There are unique risks and costs related to getting a new reactor sited and prepared for construction, including specific site designs. Does PPSA need to uniquely accommodate nuclear?
   5) Permitting and Construction Issues:
      a. Risk of costs of an extended construction period, commissioning delays, or a complete stop to operations because of an intervention (e.g., a lawsuit), material or labor issues.
      b. Risks of additional costs arising from a shift in regulations that affects siting, construction, operations, and security.

B) Technology
   6) Security measures and costs involved
   7) Design approval by Nuclear Regulatory Commission: standard permitting designs and scalability

C) Remediation
   8) Risk of third party liability with respect to the costs of remediation and recovery after an accident, *force majure*, or national security incident.
   9) Risk that costs for disposing of spent fuel and, to a lesser degree, low-level waste will be higher than anticipated (e.g., for alternatives to storage at Yucca Mountain).

1.0 INTRODUCTION

Cedar Bay Generating Company, L.P. (Cedar Bay), is seeking authorization from the Florida Department of Environmental Protection (FDEP) to co-fire up to 5 percent (by weight) of tire-derived fuel (TDF) with coal and change the coal sulfur limitation at the Cedar Bay Cogeneration Facility (Facility). Cedar Bay is also requesting an administrative change of the production limit for co-firing short fiber rejects (SFR) from a volume basis to a weight basis. Specifically, Cedar Bay requests that FDEP change the Prevention of Significant Deterioration (PSD) permit for the Facility [PSD-FL-137(A)] and the Title V permit for the facility (Permit No. 0310337-007-AV) to modify the Conditions of Certification that were issued for the Facility under the Florida Electrical Power Plant Siting Act [(PPSA); PA 88-24]. Although a change to the Facility's PSD permit is being requested to allow the co-firing of TDF and change the coal sulfur limit, there will not be any significant net emissions increase at the Facility, and thus the requirements of the PSD review process are not triggered.

Cedar Bay received authorization to conduct a test burn to co-fire 5 percent of TDF with coal (FDEP Letter Authorization dated December 7, 2004). The co-firing test was performed using Boiler C during a 30-day test burn period. The results of the test burn indicated that TDF could be successfully co-fired with coal without any changes in operation or emissions performance.

Cedar Bay received authorization to co-fire petroleum coke with coal [PSD-FL-137 (A); 12/20/02]. This authorization limited the sulfur content of the blended fuel to an equivalent sulfur dioxide (SO_2) content of 3.2 pounds per million British thermal units (lb/MMBtu) (Title V Final Permit Condition A.7.). The sulfur limit for coal is 1.7 percent, by weight, on a shipment (train load) basis and 1.2 percent, by weight, on an annual basis. Cedar Bay is requesting that these limits be changed to an equivalent SO_2 content of 3.2 lb/MMBtu.

The existing Cedar Bay Cogeneration Facility is located at 9640 Eastport Road, Jacksonville, Duval County, Florida (Figure 1). The cogeneration facility consists of three circulating fluidized bed (CFB) boilers and associated facilities. The CFB boilers, designated as Boilers A, B, and C, use coal as the primary fuel. No. 2 fuel oil is only used as a supplemental fuel, primarily for start-ups. SO_2 emissions are controlled using limestone injection into the CFB boilers and emissions of nitrogen oxides (NO_x) are controlled using selective non-catalytic reduction (SNCR). The reaction products of the limestone and SO_2, as well as particulate matter (PM) generated from combustion are controlled with baghouses.

Golder Associates Inc. (Golder) was contracted to prepare the necessary air permit application seeking authorization to co-fire up to 5 percent (by weight) of TDF with coal and change the coal sulfur content limitation. The air permit application consists of the appropriate application form [FDEP Form 62-210.900(1)], a technical description of the project (Part II Section 2.0), and rule applicability for the project (Part II Section 3.0).

2.0 PROJECT DESCRIPTION

2.1 CO-FIRING TDF

The disposal of used tires has been a significant environmental issue due to their resistance to degradation and poor compatibility with land filling. Indeed, in 1989, Florida implemented a waste tire management program resulting in the FDEP promulgating Chapter 62-711 to regulate the disposal of tires in Florida. Since 1990, significant progress has been made toward this environmental issue. However, Florida generates 19.5 million waste tires per year and disposal/recycling is still an on-going issue. This is summarized in FDEP's publication *Waste Tires in Florida*, State of the State Report, March 24, 2004 (see Attachment A). Although recycling opportunities are available, the market is currently insufficient to handle the large number of stockpiled tires. As such, the Bureau of Solid and Hazardous Waste of the FDEP identified Cedar Bay's boilers as being a suitable candidate to utilize processed tire chips as a supplementary fuel in the CFB boilers due to the inherent design to utilize various solid fuels.

TDF has useful energy and as shown in Table 1, with higher heat content and lower ash than coal, with only slightly higher sulfur content. Cedar Bay received authorization from FDEP and conducted a 30-day test burn of 5 percent TDF in Boiler C. The results of test burn are contained in Attachment B. The conclusions from this test burn are:

> "Based on the results of the emissions test at a 5% coal substitution, by weight, with TDF, the emissions of the existing permitted parameters in Cedar Bay's Title V and PSD permits are not different than when firing 100% bituminous coal.
>
> The operational results of the trial indicated essentially no changes to the operating characteristics of the boiler. No negative influences were noted due to the TDF substitution.
>
> These results indicate that Cedar Bay's Circulating Fluidized Bed Combustors can supplement their normal fuel (Bituminous Coal) with 5% TDF and achieve the environmental compliance emission limits. This substitution provides a viable supplemental fuel for Cedar Bay."

2.2 COAL SULFUR LIMITATION

Cedar Bay's Final Title V Permit (Permit No.:0310337-007-AV), Section A.7. (1) states:

> Sulfur Dioxide - Sulfur Content.
>
> 1. Coal. In order to ensure continuous compliance with the SO_2 limit stated in Specific Condition A.5, the coal sulfur content shall not exceed 1.7 percent, by weight, on a shipment (train load) basis and 1.2 percent, by weight, on an annual basis, as measured by applicable test methods (see Specific Condition A.36). When co-firing coal and petcoke, the blended fuel input to the CFBs shall not exceed 3.2 lb/MMBtu equivalent SO_2 content. Compliance shall be determined on a monthly basis via a composite of daily fuel samples.

Cedar Bay desires to remove the coal sulfur limitation of 1.7 percent, by weight, on a shipment (train load) basis and 1.2 percent, by weight, on an annual basis. Cedar Bay is requesting that these limits be changed to an equivalent SO_2 content of 3.2 lb/MMBtu, which is the same sulfur input limitation previously approved by FDEP for the co-firing of petroleum coke with coal. Cedar Bay was authorized to co-fire up to 35 percent petroleum coke with coal [PSD-FL-137(A)] in 2002 by supplying technical information that demonstrated that the CFB units could remove SO_2 in the blended fuel with an equivalent sulfur content of 3.2 lb/MMBtu. This demonstration included information from the manufacturer of the CFB units, Foster Wheeler Energy Services, Inc. (Foster Wheeler). A feasibility study was conducted by Foster Wheeler for co-firing petroleum coke with coal in the three Cedar Bay CFB boilers (see Attachment C).

Table 2 provides information on the sulfur removal required with a coal sulfur limit equivalent to 3.2 lb/MMBtu. As shown, the sulfur content based on the typical coal heat content of 12,000 British thermal units per pound (Btu/lb) is about 2 percent, resulting in a removal of about 94 percent to achieve an SO_2 emission limit of 0.2 lb/MMBtu (Condition A.5, 12-month rolling average). Based on the Foster Wheeler report, an uncontrolled sulfur limit of 3.2 lb/MMBtu for coal is equivalent to co-firing 20 percent petroleum coke with coal (refer to Figure 3 of the Foster Wheeler report). On this basis, the amount of limestone required is 17,000 pounds per hour per unit (lb/hr/unit) (see Figure 4 of the Foster Wheeler Report). Note that the Foster Wheeler projections are based on an SO_2 emission limit of 0.16 lb/MMBtu. This provides a conservative basis for limestone use. As shown in Figure 3 of the Foster Wheeler report, at an input sulfur equivalent to 3.2 lb/MMBtu represents co-firing about 15-percent petroleum coke with coal, further demonstrating the conservative nature of the limestone use.

Table 2 also presents the calculations of the annual limestone and ash production. As shown, the projected limestone and ash production is within the limits in the Final Title V Permit (Condition B.1.b). The annual amounts were based on 90-percent heat input capacity factor, which is 90 percent of the maximum permitted heat input of 1,063 million British thermal units per hour (MMBtu/hr). The heat input capacity factors has averaged 81 percent based on the Annual Operating Report (AOR) data with a range of 78 to 83 percent. (Note: The heat input capacity in this calculation is different from electrical capacity.)

Table 3 was prepared based on the maximum heat input limit of 1,063 MMBtu/hr (Condition A.1) and the coal production limit 104,000 pounds per hour (lb/hr) [Condition A.3.(b)]. This results in a coal heat content of about 10,200 Btu/lb and a sulfur content of about 1.6 percent, for an equivalent uncontrolled SO_2 emission rate of 3.2 lb/MMBtu. Table 3 demonstrates that the limestone and ash will be within the limits.

Table 4 shows the effect of co-firing TDF with higher percent sulfur coal. As previously shown in Table 1, TDF co-fired at 5 percent by weight, will only change the SO_2 emission rate by 0.1 lb/MMBtu. TDF has an equivalent uncontrolled SO_2 emission rate of about 2.5 lb/MMBtu, which is less than that requested for coal and thus there will be no increase in the uncontrolled emission rate of the blend.

2.3 <u>SHORT FIBER REJECTS (SFR)</u>

The current condition for short fiber rejects states (Condition A.3):

> (c) <u>Short Fiber Rejects</u>. The maximum charging rate to CFB Boilers B & C of short fiber recycle rejects from the SCC recycling process shall not exceed 210 yd^3/day (wet) and 69,588 yd^3/yr (wet). This reflects a combined total of 420 yd^3/day (wet) and 139,176 yd^3/yr (wet) for the two CFB boilers that fire recycle rejects. CFB Boiler A will not utilize recycle rejects, nor will it be equipped with handling and firing equipment for recycle rejects.

Cedar Bay requests an administrative change in the limitation from a volume basis to a mass basis. While the material is provided in 30 cubic yard boxes, accounting for the amount on a volume basis is not practical for determining operational and environmental parameters.

SFR is a by-product of the Smurfit Stone recycling process. Bales of corrugated cardboard are shredded, mixed with water and reduced to a pulp. Heavy trash material such as staples, glass, metal and stones sink to the bottom of the pulp slurry and are removed. The slurry is then spun in a centrifuge to remove any additional heavy material. From the centrifuge, the slurry passes through a coarse screen, which removes additional contaminants such as wax or plastic. The slurry passes on to another centrifuge and then short and long fibers are separated using two fine mesh screens and a reverse cleaner. The short fibers are pressed to remove liquids and the SFR is transferred to roll-off containers for disposal.

The Cedar Bay facility was constructed to support combustion of the SFR in two boilers (Boilers B and C) with a dedicated material handling and conveyance system to transport the SFR to the boilers. A detailed description of the process and equipment is found in the facility's operating procedures.

SFR is collected from Smurfit Stone's process in dedicated 30 cubic yard capacity roll-off boxes for disposal. The roll-off boxes will be transported within Smurfit Stone's property to the location of Cedar Bay's fiber waste handling system. The SFR is unloaded into a receiving hopper. The receiving hopper is equipped with a live bottom via drag chain feeder and interfaces with Cedar Bay's distributed control system (DCS). The DCS system allows this system, as well as most of the Cedar Bay plant, to be controlled and monitored from Cedar Bay's Control Room.

SFR is discharged from the receiving hopper by a variable speed drag conveyor to a 24-inch wide conveyor belt (SFR conveyor). This conveyor is rated at 16 tons per hour at a belt speed of 75 feet per minute. The conveyor is equipped with skirt boards; hood covers, automatic vertical gravity take-up with grab safety devices, speed switch, and pull cord switches and belt alignment switches. Additionally, the conveyor is equipped with a Thermo Ramsey Belt Scale/Integrator System that measures the fiber reject materials in tons and communicates the tonnage to the boiler DCS and CEM systems.

SFR is discharged from the SFR conveyor into the SFR surge hopper. The surge hopper is sized for a minimum capacity of 20 cubic yards and is equipped with four variable speed screw conveyors, each with their own speed switch. The surge hopper also has three capacitance-type level switches. One switch monitors low level, one switch to monitor high level, and one switch for emergency high level. Upon actuation of the high level switch, the DCS system automatically run the drag chain feeder in the receiving hopper in low speed to prevent overfill of the surge hopper. The feeder returns to high speed when the high level switch is no longer actuated. The emergency high-level switch stops both conveyor and feeder immediately after actuation.

The feed system feeds the SFR to the loop seal feed points of Boiler C and discharges through air locks (rotary valves) to the coal drag chain conveyors feeding the loop seals. The coal conveyors introduce the coal/fiber waste mix into the loop seal fuel feed port.

The fiber waste provides less than 5 percent of the heat input to C boiler when the feed rate is 150 tons/day and the boiler is at full load.

2.4 HISTORICAL EMISSIONS FOR CEDAR BAY COGENERATION FACILITY

The production information and actual emissions reported in the Annual Operating Reports submitted to FDEP for the years 2000 through 2004 are summarized in Table 5. The reported emissions are for carbon monoxide (CO), nitrogen oxides (NO_x), SO_2, particulate matter (PM), volatile organic compounds (VOC), and sulfuric acid mist (SAM). These reported emissions are based on continuous emission monitoring (CEM) systems for CO, NO_x, and SO_2. Testing is conducted annually for the other pollutants.

As shown in the table, the emissions have been relatively constant over the last 4 years.

Cedar Bay is proposing that the last two years (2003-2004) be used as the emissions for future comparisons.

3.0 RULE APPLICABILITY AND PROPOSED CHANGES

Under Federal and State of Florida PSD review requirements, all major new or modified sources of air pollutants regulated under the Clean Air Act (CAA) must be reviewed and a pre-construction permit issued. EPA has approved Florida's State Implementation Plan (SIP), which contains PSD regulations, therefore, PSD approval authority has been granted to the FDEP. For projects approved under the Florida PPSA, the PSD program is delegated.

A "major facility" is defined as any 1 of 28 named source categories that have the potential to emit 100 tons per year (TPY) or more, or any other stationary facility that has the potential to emit 250 TPY or more of any pollutant regulated under CAA. "Potential to emit" means the capability, at maximum design capacity, to emit a pollutant after the application of control equipment. Once a new source is determined to be a "major facility" for a particular pollutant, any pollutant emitted in amounts greater than the PSD significant emission rates is subject to PSD review. For an existing source for which a modification is proposed, the modification is subject to PSD review if the net increase in emissions due to the modification is greater than the PSD significant emission rates.

PSD review is used to determine whether significant air quality deterioration will result from the new or modified facility. Federal PSD requirements are contained in 40 Code of Federal Regulations (CFR) 52.21, *Prevention of Significant Deterioration of Air Quality*. The State of Florida has adopted the federal PSD regulations by reference [Rule 62-212.400, Federal Administrative Code (F.A.C.)]. Major facilities and major modifications are required to undergo the following analysis related to PSD for each pollutant emitted in significant amounts:

- Control technology review,
- Source impact analysis,
- Air quality analysis (monitoring),
- Source information, and
- Additional impact analyses.

The Cedar Bay Cogeneration Facility is a major source. Co-firing of TDF and changing the uncontrolled sulfur limit is an operational change based on past FDEP determinations. Therefore, the project is a modification as defined in the FDEP rules in 62-210.200, F.A.C., and under the PSD rules in 62-212.400, F.A.C. PSD review would be required for the project if there were a significant net increase in emissions. For the proposed requested changes, there will be no significant net increase in actual emissions based on the requested conditions.

Determining the amount of the change, if any, in the Facility's emission should be performed by following the requirements in 40 CFR Parts 52.21(b)(21)(v) and 52.21(b)(33). These applicable rules are stated below:

> **52.21(b)(21)(v)** For an electric utility steam generating unit (other than a new unit or the replacement of an existing unit) actual emissions of the unit following the physical or operational change shall equal the representative actual annual emissions of the unit, provided the source owner or operator maintains and submits to the Administrator on an annual basis for a period of 5 years from the date the unit resumes regular operation, information demonstrating that the physical or operational change did not result in an emissions increase. A longer period, not to exceed 10 years, may be required by the Administrator if he determines such a period to be more representative of normal source post-change operations.
>
> **52.21(b)(33)** Representative actual annual emissions means the average rate, in tons per year, at which the source is projected to emit a pollutant for the two-year period after a physical change or change in the method of operation of a unit, (or a different consecutive two-year period within 10 years after that change, where the Administrator determines that such period is more representative of normal source operations), considering the effect any such change will have on increasing or decreasing the hourly emissions rate and on projected capacity utilization. In projecting future emissions the Administrator shall:
>
> **(i)** Consider all relevant information, including but not limited to, historical operational data, the company's own representations, filings with the State or Federal regulatory authorities, and compliance plans under title IV of the Clean Air Act; and
>
> **(ii)** Exclude, in calculating any increase in emissions that results from the particular physical change or change in the method of operation at an electric utility steam generating unit, that portion of the unit's emissions following the change that could have been accommodated during the representative baseline period and is attributable to an increase in projected capacity utilization at the unit that is unrelated to the particular change, including any increased utilization due to the rate of electricity demand growth for the utility system as a whole.

These requirements have been included in many permits authorized by FDEP for operational changes. Cedar Bay requests that these requirements be included in a federally enforceable modification to the existing PSD and Title V permits for the Facility, and included in the PPSA Conditions of Certification for the Facility. The Facility has CEM systems for SO_2, NO_x, and CO that would demonstrate compliance with the requested condition. Individual stack tests, pursuant to the existing permit conditions, would be conducted for PM, particulate matter with aerodynamic size of

10 micrometers or less (PM_{10}), VOCs, and SAM when co-firing TDF. This mixture would not exceed 5 percent (by weight) TDF with coal.

The conditions requested are proposed as follows:

TDF Co-firing (Condition A.3 Method of Operation):

(b) Fuels.

1. Coal. 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. Petroleum coke (pet coke) may be utilized as a co-firing fuel, and shall not exceed 35 % fuel input by weight on a daily basis. Tire derived fuel (TDF) may be utilized as a co-firing fuel, and shall not exceed 5% fuel input by weight on a daily basis. {Permitting Note: The limitations on the coal charging rate include both coal, TDF and pet coke.}

Sulfur Coal Content (Condition A.7):

Sulfur Dioxide - Sulfur Content.

1. ~~Coal~~ Fuel. ~~In order to ensure continuous compliance with the SO_2 limit stated in Specific Condition A.5, the coal sulfur content shall not exceed 1.7 percent, by weight, on a shipment (train load) basis and 1.2 percent, by weight, on an annual basis, as measured by applicable test methods (see Specific Condition A.36). When co-firing coal and petcoke, the blended~~ The fuel input to the CFBs shall not exceed 3.2 lb/MMBtu equivalent SO_2 content. Compliance shall be determined on a monthly basis via a composite of daily fuel samples.

PSD Applicability: The proposed permit condition for demonstrating no significant increase is listed as follows:

Condition A.66. Upon co-firing TDF or implementing the 3.2 lb SO_2/MMBtu coal sulfur limit, the applicant shall maintain and submit to the Department on an annual basis for a period of five years from the date the units are initially co-fired with petroleum coke with coal greater than a 20 to 80 percent blend, information demonstrating in accordance with 40 CFR 52.21(b)(21)(v) and 40 CFR 52.21(b)(33) that operational changes did not result in emission increases of particulate matter, nitrogen oxides, carbon monoxide and sulfuric acid mist.

To provide guidance for this condition, Cedar Bay proposes that the following table be added to the technical evaluation. The annual emissions are based on actual emissions from 2003 and 2004 plus the PSD significant emission rate. For VOC and SAM, the annual emissions are based on the permit limits as the actual emissions plus significant emission rates are higher than the FDEP-authorized emission limits for these pollutants.

Pollutant	Compliance Procedures
NO_x	Five years of annual reporting by CEMS demonstrating annual emissions do not exceed 1,792.0 TPY
CO	Five years of annual reporting by stack test demonstrating annual emissions do not exceed 541.3TPY
VOC	Five years of annual reporting by stack test demonstrating annual emissions do not exceed 65 TPY
SO_2	Five years of annual reporting by CEMS demonstrating annual emissions do not exceed 2,012.5 TPY
SAM	Five years of annual reporting by stack test demonstrating annual emissions do not exceed 2 TPY
PM	Five years of annual reporting by stack test demonstrating annual facility emissions do not exceed 126.9 TPY

Short Fiber Rejects:

Condition A.3.(c) Short Fiber Rejects. The maximum charging rate to CFB Boilers B & C of short fiber recycle rejects from the SCC recycling process shall not exceed 420,000 lb/day and 69,600 tons/yr ~~210 yd³/day (wet) and 69,588 yd³/yr (wet)~~. This reflects a combined total of 840,000 lb/day and 139,200 tons/year~~420 yd³/day (wet) and 139,176 yd³/yr (wet)~~ for the two CFB boilers that fire recycle rejects. CFB Boiler A will not utilize recycle rejects, nor will it be equipped with handling and firing equipment for recycle rejects.

Note: The tonnage of SFR was based on a conservative density of 1 ton per cubic yard due to the potential range of moisture that can be included. Actual density was determined for several loads to be 0.6 tons per cubic yard. Thus, the 1-ton-per-cubic-yard density provides a worst-case estimate for SFR.

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September 19, 2005 0537586

Florida Department of Environmental Protection
Title V Section; Bureau of Air Regulation
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Fl 32399-2400

Attention: Mr. Michael P. Halpin, P.E., Permitting North

RE: Cedar Bay Cogeneration facility
Title V Permit # 0310337-009-AC; PSD-FL-137A
Conditions of Certification PA 88-24
Request for Additional Information (RAI)

Dear Mr. Halpin:

This correspondence is being submitted on behalf of Cedar Bay Generating Company, L.P. (Cedar Bay) to provide the information requested in the Florida Department of Environmental Protection (FDEP) August 19, 2005 correspondence related to the co-firing 5 percent Tire Derived Fuel (TDF), increasing the coal sulfur content and clarifying the input limit for short-fiber rejects (SFR). The information is being provided in the same order as requested.

1. **RAI:** Please provide the FDEP with estimates for the change in emissions of any non-criteria pollutants which might be expected to increase as a result of the 5% TDF co-firing. The estimates should include polynuclear aromatic hydrocarbons (PAHs), dioxins, furans, hydrogen chloride, benzene, PCB's and any other pollutants for which Cedar Bay or its consultants might reasonably expect a change. Additionally, the analysis should estimate (where practical) related impacts to ambient air quality and corresponding health impacts.

Additional Information: The results of the TDF test burn submitted as Appendix B of the application indicated that the only potential changes in emissions from the facility would be associated with the sulfur and zinc contents of TDF. The sulfur content is only slightly higher than coal and since the heat content for TDF is about 25% higher than coal the uncontrolled sulfur dioxide (SO_2) emission rate is well within the requested equivalent uncontrolled SO_2 limit of 3.2 lb/MMBtu. Actual uncontrolled TDF SO_2 emission rate ranged from 2.1 to 2.8 lb/MMBtu. For trace metals, zinc oxide is an ingredient in tires and the emission rate was determined to be 0.0468 lb/hr. The concentrations of other trace metals in the co-fired fuel (i.e., 5%TDF co-fired with coal) were determined to be either less than that in coal or no difference. Indeed, the emission rates for lead, mercury and beryllium were either lower than previous tests or well within the emission rates for previous tests.

Emissions of PAHs, dioxins, furans, benzene and PCBs are primarily products of the combustion process. As part of the TDF test burn, total volatile organic compounds (VOCs) were measured. Compounds such as PAHs, benzene and other organics would be included in the general category of VOCs. The test data indicted that the total VOCs when co-firing 5% TDF with coal were generally less than previous tests. The higher heat content for TDF suggests that when co-firing 5% TDF the combustion process in the circulating fluidized bed boiler is not affected and indeed may be enhanced. The formation of dioxins and furans is again combustion related. The attached description of the combustion process and the formation of dioxins and furans indicate that co-firing 5% TDF will have no effect on dioxin and furan emissions. Similarly, PCBs (polychlorinated biphenyls) is a chlorine based compound and formed in the combustion process. With the average chlorine content of bituminous coal at about 0.1%, the minor amounts of chlorine in TDF will not influence emissions of chlorinated compounds or hydrogen chloride (HCL). These results are similar to that found by the U.S. Environmental Protection Agency (EPA) which states:

> "Based on the results of the RKIS test program, it can be concluded that, with the exception of zinc emissions, potential emissions from TDF are not expected to be very much different than from other conventional fossil fuels, as long as combustion occurs in a well designed, well-operated and well-maintained combustion device." EPA. 2005. Air Emissions from Scrap Tire Combustion. EPA-600/R-97-115. October 1997. (Note: the RKIS is a test device used by EPA. Test data for a variety of combustion tests are found in the reference.)

To put into perspective the air quality impacts of the Cedar Bay facility, an air quality modeling evaluation was conducted and is attached. The results of the modeling, using worst-case emissions indicates that the air quality impacts for the facility are very low and will continue to be low when co-firing 5% TDF with coal.

2. The PSD regulations (under the provisions commonly known as the "WEPCO rule") allow a source undertaking a non-routine change that could affect emissions at an electric utility steam generating unit to lawfully avoid the major source permitting process by using the unit's representative actual annual emissions to calculate emissions following the change if the source submits information for 5 years following the change to confirm its pre-change projection. The FDEP wishes to confirm that Cedar Bay requests the application of the WEPCO provision, and commits to not exceeding PSD thresholds beyond the 2003-2004 emission levels for PM, PM_{10}, SO_2, NO_X, CO, VOC and SAM. Concerning the attendant application, should the FDEP gain reasonable assurance that the PSD thresholds will not be triggered, permit conditions will be crafted to ensure same.

<u>Additional Information</u>: As described in the application, Cedar Bay has proposed a permit condition that would meet the requirements of the WEPCO rule (please refer to Section 3.0, pages 10 and 11). The proposed condition was structured to be similar to recent FDEP permit authorizations that included the requirements codified in 40 CFR Parts 52.21(b)(21)(v) and 52.21(b)(33). In addition, Cedar Bay has proposed within the condition the means for complying with the WEPCO rule (i.e., CEMs and stack tests). Together, these provide the FDEP reasonable assurance that the PSD thresholds will not be exceeded.

3. The FDEP is appreciative of the analyses provided to help explain the requested permit change dealing with 3.2 lb/MMBtu as an equivalent SO_2 emission limit, in lieu of the existing coal sulfur limitations. Even so, the FDEP remains unclear as to the anticipated changes in scrubbing required. Please answer the following questions, based on coal-only combustion, except where otherwise specified:

   A. Utilizing actual historical scrubbing efficiencies and the historical (average) coal heat content, estimate the controlled and uncontrolled lb/MMBtu SO_2 emissions based upon the 1.7% sulfur "shipment limitation".

Additional Information: Table RAI-3 contains the requested information. Please note that Cedar Bay is proposing to increase SO_2 removal efficiency to limit annual SO_2 emissions to the proposed annual limitation that would not exceed the PSD threshold. The controlled SO_2 emissions will be similar to the existing emission rates regardless of the sulfur input, which would not exceed an equivalent uncontrolled emission rate of 3.2 lb/MMBtu. The SO_2 control system for each unit maintains the SO_2 emissions within compliance levels by controlling the limestone feed rate. The basic limestone feed rate set point is derived from the coal feeder demand signal, which generates a limestone-to-coal ratio. The ratio decreases with load and has been adjusted to observed steady state ratios. These ratios are then adjusted by the SO_2 controller to maintain SO_2 emissions to an operator-entered set point in lbs/mmBtu. Table RAI-3 contains the annual average SO_2 removal efficiencies for 1.7 percent sulfur coal (i.e., 93.8 percent). This is within the ability of the SO_2 control system as provided in the Foster Wheeler Report (Figure 3).

   B. Utilizing the same historical scrubbing efficiencies and heat content identified above, estimate the controlled and uncontrolled lb/MMBtu SO_2 emissions based upon the 1.2% sulfur "annual limitation".

Additional Information: Table RAI-3 contains the requested information.

   C. Utilizing the same historical scrubbing efficiencies and heat content identified above, estimate the maximum percent sulfur content of coal which could be combusted in order to yield an uncontrolled 3.2 lb/MMBtu emission level.

Additional Information: Table RAI-3 contains the requested information.

   D. Utilizing the same historical scrubbing efficiencies and heat content identified above, estimate the controlled and uncontrolled lb/MMBtu SO_2 emissions for coal plus 35% petcoke as compared to coal plus 5% TDF.

Additional Information: Table RAI-3 contains the requested information. The co-firing of TDF and Petroleum Coke (if implemented) would be limited to an uncontrolled SO_2 emission rate of 3.2 lb/MMBtu. Therefore the calculations would be the same as for RAI 3C above.

4. Please confirm that the purpose of the requested change in the short fiber rejects (SFR) condition is simply to make accounting easier and that 840,000 lb/day and 139,200 tons/yr are roughly equivalent to 420 yd^3/day (wet) and 139,176 yd^3/yr (wet).

Additional Information: The FDEP's comment is correct on the reason for the change in determining the amount of SRF fired. Using a mass basis for accounting for the amount of SFR co-fired is more accurate than the current volume based limit.

Please contact me if you have any questions on the information in the application. Your expeditious handling is appreciated.

Sincerely,

GOLDER ASSOCIATES

Kennard F. Kosky

SEAL

Kennard F. Kosky, P.E.
Professional Engineer No. 14996

Enclosures

cc: Martin Kreft, Cedar Bay Generating Company
Hamilton Oven, FDEP, Siting
Jeffery Walker, Cedar Bay Generating Company
Chris Kirts, P.E., FDEP Northeast District
Dot Mathias, Northside Civic Association

Table RAI-3. Information on Uncontrolled and Controlled SO_2 Emissions and Removal Efficiencies

Parameter	Units	RAI Response		
		3A	3B	3C&3D
Average Heating Value[a]	Btu/lb	12,121.4	12,121.4	12,121.4
Coal Sulfur Content	%	1.7	1.2	1.94
Historical SO_2 Removal[a]	%	88.84%	88.84%	88.84%
Uncontrolled SO_2 Emissions	lb/MMBtu	2.80	1.98	3.20
Controlled SO_2 Emissions with Historical SO_2 Removal	lb/MMBtu	0.31	0.22	0.36
Annual Emissons Cap	tons	2,012.5	2,012.5	2,012.5
Coal Usage	tons	940,000	940,000	940,000
Controlled SO_2 Emissions	lb/MMBtu	0.177	0.177	0.177
Required SO_2 Removal	%	93.70%	91.08%	94.48%

[a] Based on 2000-2004 data.

Dioxin Control in Coal-Fired Boilers

The control of dioxins in coal-fired boilers occurs from two mechanisms: the efficiency of combustion and a sulfur to chlorine ratio of greater than one.

Good combustion practices decrease the formation of dioxins by the complete oxidation of organic compounds and carbonaceous solids that are the precursors to dioxin formation. Good combustion practices include residence time, high temperature and turbulence. These are the three combustion parameters that are prevalent in a CFB boiler due to the nature of a fluidized bed providing excellent residence time and turbulence. A bed temperature of 1800 degrees Fahrenheit (°F) and a one to two second residence time will destroy most gas-phase compounds.

Dioxins are formed in the temperature range of 500 to 1100 (°F) and are destroyed at higher temperatures.

Another method for low dioxin emissions is a sulfur to chlorine (S/Cl) ratio of greater than one. The presence of sulfur will short-circuit the formation of dioxins by converting the chlorine gas released during fuel burning into hydrogen chloride (HCl) which is not effective in the formation of dioxins which requires free chlorine. Sulfur dioxide with chlorine and water gives sulfates and HCL. The HCl is then controlled with the limestone in the CFB.

Coal-fired plants have very low dioxin emissions due to good combustion efficiency and a S/Cl ratio of much greater than one (typically 35 to 500). A CFB will combust TDF with the same efficiency as coal and TDF has an S/Cl ratio of approximately 8. With the limitation of TDF to be burned in the Cedar Bay boilers being less than 20 percent of the heat input, the combined fuel has S/Cl that is much greater than one.

The reason that a municipal waste combustor (MWC) has inherently high dioxin emissions is that it does not meet the two criteria described above. Because of the inconsistency of the fuel, a boiler may have areas that do not meet high temperatures even though residence time and turbulence are present in the boiler. Temperatures may not reach greater than 1100 (°F). In addition, municipal waste has very little sulfur and potentially high chlorine content and therefore the S/Cl is much less than one.

Air Quality Evaluation

The Environmental Protection Agency (EPA) has issued Ambient Air Quality Standards (AAQS) for various air pollutants including sulfur dioxide (SO_2), particulate matter with an aerodynamic diameter of 10 microns (PM_{10}), nitrogen dioxide (NO_2) and carbon monoxide (CO). AAQS are designed to protect the public welfare of the general public, with an adequate margin of safety. The protection of public welfare includes the effects of air pollution on soils, vegetation and wildlife. Indeed, the foundation for the AAQS is the federal Clean Air Act (CAA), which clearly establishes the requirements of the AAQS as stated by the EPA (2005):

> "The Clean Air Act, which was last amended in 1990, requires EPA to set National Ambient Air Quality Standards (NAAQS) for wide-spread pollutants from numerous and diverse sources considered harmful to public health and the environment. The Clean Air Act established two types of national air quality standards. Primary standards set limits to protect public health, including the health of 'sensitive' populations such as asthmatics, children, and the elderly. Secondary standards set limits to protect public welfare, including protection against visibility impairment, damage to animals, crops, vegetation, and buildings. The Clean Air Act requires periodic review of the science upon which the standards are based and the standards themselves." http://www.epa.gov/ttn/naaqs/.

In areas where the air quality meets the AAQS, such as all of Florida, Prevention of Significant Deterioration (PSD) Increments have been established by EPA as incremental amounts of impacts that are allowed for new sources. The PSD Class II Increments are designed to protect the ambient air from being degraded and have been established for three air pollutants: SO_2, PM_{10}, and NO_2. These PSD Increments are more stringent than the AAQS and are less than 50 percent of the AAQS. The Florida Department of Environmental Protection (FDEP) has adopted AAQS and PSD Increments and requires new major sources to demonstrate compliance with these limits using air dispersion modeling.

To address the FDEP request, EPA and FDEP approved models were used to predict maximum air quality impacts for the facility. The air dispersion model used plant emissions and exhaust characteristics, five-years of meteorological data and receptor locations to determine the facility's impacts relative to the EPA and FDEP AAQS and PSD Class II Increments. The maximum permitted emissions were used in determining impacts.

The results of the air dispersion modeling analysis showing the maximum predicted concentrations for the Project is presented in Table 1. This table presents the maximum impacts for each averaging time for which there is an AAQS and PSD Increment. Concentrations are presented in micrograms of each pollutant per cubic meter of air (ug/m^3). As shown in the table, the maximum impacts range from 0.02 to 2.4 percent of the AAQS, which is designed to protect the health and welfare with an adequate margin of safety. The maximum impacts range from 0.1 to 6.9 percent of the PSD Class II Increments, which are designed to protect ambient air from degradation. The maximum predicted impacts shown in Table 1 are for a single location using five years of meteorological data. The impacts at other locations and times would be lower than the concentrations shown.

The maximum concentrations for certain trace elements were predicted. The trace elements evaluated included those with current emission limits (lead, mercury and beryllium) and zinc, for which there are higher concentrations in tire-derived fuel (TDF). With the exception of lead, there are no FDEP or EPA ambient air quality standards for the trace metals. For lead, the maximum impact of the facility will be over 5,000 times less than the air standard set to protect public health. While there are no air quality standards for the other trace elements, the EPA has reference air concentrations and there are occupational guidelines that can be compared to the maximum predicted concentrations for the Cedar Bay facility. This comparison is shown in Table 2, which shows a comparison with the EPA Reference Concentrations for Chronic Inhalation Exposure (RfC) and occupational Threshold Limit Values (TLV), Time Weighted Average (TWA). The EPA RfC is based on a lifetime of exposure and the comparison is shown against the maximum annual concentration predicted over a 5-year period. This comparison provides worst-case since predicted concentration for four of the five years will be lower that shown in the table. In addition, concentrations at other locations will be much less than the maximum predicted concentrations, which typically occur near the plant and in one discrete location. The TLV-TWA represents levels of 8-hour (hr) occupational exposure that are considered levels that workers can be exposed day after day without adverse health effects. The maximum 8-hr concentrations that occur over a 5-year period are also compared to the TLV-TWA in Table 2. Again, this comparison is extremely conservative since the predicted maximum 8-hr concentration from the facility will be much less than the average 8-hr exposure and levels at other locations will be less than the location of maximum impact.

As shown in Table 2, the maximum predicted annual concentrations are from about 1,800 to over 8,000 times lower than the EPA RfC for beryllium and mercury, respectively. When comparing the maximum predicted impacts to the TLV-TWA, the maximum impacts range from about 3,000 times lower than the TLV-TWA for beryllium to over 3 million times lower for zinc. For beryllium, the modeled emissions reflect the maximum permitted emission rate, which is over 40 times higher than the maximum emission rate observed during historical stack tests. The modeled emissions for lead and mercury also reflect the maximum permitted emission rate, which is over 6 and 20 times higher, respectively, than actual emission rates observed in previous stack test data. Therefore, the comparison of the maximum predicted impacts from the Cedar Bay facility to the EPA RfC and TLV-TWA are extremely conservative.

Table 1. Maximum Pollutant Concentrations Predicted for the Cedar Bay Generating Station

Pollutant	Averaging Time	Maximum Concentration (ug/m^3)	AAQS (ug/m^3)	AAQS (%)	PSD Class II Increment (ug/m^3)	PSD Class II Increment (%)
Criteria Air Pollutants						
SO2	Annual	0.36	60	0.6%	20	1.8%
	24-Hour	6.3	260	2.4%	91	6.9%
	3-Hour	29.2	1300	2.2%	512	5.7%
PM10	Annual	0.02	50	0.04%	17	0.1%
	24-Hour	0.4	150	0.25%	30	1.3%
NO2	Annual	0.20	100	0.20%	25	0.8%
CO	8-Hour	9.5	10,000	0.09%	NA	NA
	1-Hour	17	40,000	0.04%	NA	NA
Pb	Quarterly	0.00027	1.5	0.02%	NA	NA

Note: PSD = Prevention of Significant Deterioration
AAQS = Ambient Air Quality Standard
NA = Not applicable

Table 2. Comparison of Maximum Impacts of SWSLPP Trace Metals with EPA Reference Concentrations and Occupational Threshold Limit Values

Trace Metal	Maximum Concentration (ug/m^3)	Averaging Time	EPA RfC (ug/m^3)	Occupational TLV-TWA (ug/m^3)
Beryllium	0.000011	Annual	0.02	
	0.000643	8-hour		2
Lead	0.000068	Annual	No RfC[a]	
	0.003856	8-hour		50
Mercury	0.000034	Annual	0.3	
	0.001928	8-hour		25
Zinc[b]	0.000053	Annual	No RfC	
	0.003007	8-hour		10,000

RfC = Reference Concentration for Chronic Inhalation Exposure
The RfC is an estimate of the continuous inhalation exposure to the human population (including
TLV = Threshold Limit Values, TWA = Time Weighted Average
TLV-TWA based on American Conference of Governmental Industrial Hygienists (ACGIH)
[a] Lead has an ambient air standard of 1.5 ug/m^3 on an averaging time of a calendar quarter
[b] provided as zinc oxide based on February 2005 stack tests

Halpin, Mike

From: Gibson, Mark

Sent: Monday, September 26, 2005 10:47 AM

To: Halpin, Mike

Subject: RE: RIMS request

The presentation is loaded onto the desktop of the pc.
You will need to log as : Local User
The password is : Password1
The domain is : Arm-checkout3

It's ready when you are. You can pick it up at any time.

Mark W. Gibson
Computer Support Staff
FDEP-DARM
(850)921-9542

From: Halpin, Mike
Sent: Monday, September 26, 2005 9:34 AM
To: Gibson, Mark
Cc: Morris, Will; Vielhauer, Trina
Subject: RIMS request

Mark/Will -
I made a request this AM for a laptop and Boxlight, as I need to make a presentation to an organization in Jacksonville tonight. I'll be leaving the office about noon and do not expect to be back into town until after midnight (and I will probably be out of the office tomorrow).
If you guys can put this PowerPoint presentation on it, I would be appreciative.
Mike

DEPARTMENT OF ENVIRONMENTAL PROTECTION
FLORIDA

ST. JOHN'S SEAFOOD

I-10 east head N. on 295

'65 off Dunn Ave exit head east

1403 Dunn Ave

Before I-95

5:45 pm

Richard Robinson cell

904-616-6756

MTG @ 7:30

Department of Environmental Protection

Jeb Bush
Governor

Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Colleen M. Castille
Secretary

August 19, 2005

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. Martin Kreft
Cedar Bay Generating Company
9640 Eastport Road
Jacksonville, FL 32218-2260

Re: Request for Additional Information
5% TDF Co-firing
File No. 0310337-009-AC, PA 88-24, PSD-FL-137A
Cedar Bay Cogeneration Facility

Dear Mr. Kreft:

The Department is in receipt of your application dated August 1, 2005 and received August 2, 2005. The application is incomplete. In order to continue processing your application, the Department will need the additional information below. Should your response to any of the below items require new calculations, please submit the new calculations, assumptions, reference material and appropriate revised pages of the application form.

1. Please provide the Department with estimates for the change in emissions of any non-criteria pollutants which might be expected to increase as a result of the 5% TDF co-firing. The estimates should include polynuclear aromatic hydrocarbons (PAHs), dioxins, furans, hydrogen chloride, benzene, PCB's and any other pollutants for which Cedar Bay or its consultants might reasonably expect a change. Additionally, the analysis should estimate (where practical) related impacts to ambient air quality and corresponding health impacts.

2. The PSD regulations (under the provisions commonly known as the "WEPCO rule") allow a source undertaking a non-routine change that could affect emissions at an electric utility steam generating unit to lawfully avoid the major source permitting process by using the unit's representative actual annual emissions to calculate emissions following the change if the source submits information for 5 years following the change to confirm its pre-change projection. The Department wishes to confirm that Cedar Bay requests the application of the WEPCO provision, and commits to not exceeding PSD thresholds beyond the 2003-2004 emission levels for PM, PM_{10}, SO_2, NO_X, CO, VOC and SAM. Concerning the attendant application, should the Department gain reasonable assurance that the PSD thresholds will not be triggered, permit conditions will be crafted to ensure same.

3. The Department is appreciative of the analyses provided to help explain the requested permit change dealing with 3.2 lb/MMBtu as an equivalent SO_2 emission limit, in lieu of the existing coal sulfur limitations. Even so, the Department remains unclear as to the anticipated changes in scrubbing required. Please answer the following questions, based on coal-only combustion, except where otherwise specified:

    A. Utilizing actual historical scrubbing efficiencies and the historical (average) coal heat content, estimate the controlled and uncontrolled lb/MMBtu SO_2 emissions based upon the 1.7% sulfur "shipment limitation".

    B. Utilizing the same historical scrubbing efficiencies and heat content identified above, estimate the controlled and uncontrolled lb/MMBtu SO_2 emissions based upon the 1.2% sulfur "annual limitation".

C. Utilizing the same historical scrubbing efficiencies and heat content identified above, estimate the maximum percent sulfur content of coal which could be combusted in order to yield an uncontrolled 3.2 lb/MMBtu emission level.

D. Utilizing the same historical scrubbing efficiencies and heat content identified above, estimate the controlled and uncontrolled lb/MMBtu SO_2 emissions for coal plus 35% petcoke as compared to coal plus 5% TDF.

4. Please confirm that the purpose of the requested change in the short fiber rejects (SFR) condition is simply to make accounting easier and that 840,000 lb/day and 139,200 tons/yr are roughly equivalent to 420 yd^3/day (wet) and 139,176 yd^3/yr (wet).

The Department will forward any EPA comments as well as comments from our Waste Management Section once we have received them. Additionally, the applicant is advised that the Department intends to meet with representatives from the Northside Civic Association during the month of September and will forward any additional questions which arise as a result of that discussion.

Rule 62-4.050(3), F.A.C. requires that all applications for a Department permit must be certified by a professional engineer registered in the State of Florida. This requirement also applies to responses to Department requests for additional information of an engineering nature. Please note that per Rule 62-4.055(1): *"The applicant shall have ninety days after the Department mails a timely request for additional information to submit that information to the Department......... Failure of an applicant to provide the timely requested information by the applicable date shall result in denial of the application."*

If you have any questions, please call Michael P. Halpin, P.E. at 850/921-9519.

Sincerely,

Michael P. Halpin, P.E. FDEP/DARM
Permitting North

Jeff Walker, Cedar Bay
Ken Kosky, P.E. Golder Associates
Hamilton Oven, P.E. PPSO
Richard Robinson, P.E. City of Jacksonville EQD
Chris Kirts, P.E. DEP-NED
Dot Mathias, Northside Civic Association

Northside Civic Association, Inc.
341 Baisden Road, Jacksonville, Fl., 32218

August 24, 2005

Mr. Michael Halpin, P.E. FDEP/DARM
Permitting North
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Dear ~~Mr. Halpin~~ Mike

The Northside Civic Association, a.k.a. NCA, is an umbrella organization over 16 home owner and civic organizations in North Jacksonville. As you know, the NCA membership has been extremely concerned about Cedar Bay Cogeneration's plan to burn a 5% blend of tire derived fuel (TDF) as a supplement to coal.

During the course of our research, we discovered that in addition to the dioxin and furan emissions - tires contain about 20 different metals none of which can be destroyed by burning. Metals known to be in tires include aluminum, antimony, arsenic, barium, beryllium, chromium, cobalt, copper, iron, lead, magnesium, manganese, mercury, nickel, selenium, titanium, and zinc. Most of them, including arsenic, lead, mercury, and chromium, are quite toxic to humans and can also wreak ecological havoc on aquatic wildlife if even a small quantity finds its way into a body of water. This causes NCA additional concern as the Timucuan Preserve is located only four miles away from the facility.

According to the conclusions by Cedar Bay Cogeneration, results from the emissions test at a 5% coal substitution are no different than when firing 1200% bituminous coal. However, there are many problems with this – First of all the test data is not an accurate measure of actual day-to-day emissions of a given plant. Trial burns may be considered a poor indicator of operations on a daily basis - during trial burns when regulatory authorization is at stake and government officials are at the site, variables such as temperature, oxygen flow, and pollution control device efficiency are carefully maintained to optimum performance. On a day-to-day basis, emissions may be considerably higher. Another major concern about Tire Derived Fuel is the enormous lack of information in regards to burning tires and there are very few facilities to obtain information from.

The main problem with burning tires is the toxic emissions they generate. No matter how new and improved the technology , burning tires is going to generate toxic emissions. Emissions cannot be avoided because: (1) 100% destruction cannot be achieved by incineration ; 2) combustion efficiency is very hard to maintain because chlorine and metal content can vary widely from tire to tire; 3) pollution control devices are not 100% effective no matter how new and improved. Like any machine incinerators wear out and break down with use. Very little is known about these events except you can expect them to occur and that emissions increase sometimes by as much as 100%.

TDF's pose another problem – where do you store the shredded tires until they are burned? Will they be in a covered building or stockpiled in the open? Also, truck traffic and rail traffic will increase twofold.

NCA was told that the state Solid Waste Department contacted Cedar Bay regarding the burning of tires because of Cedar Bays circulating flouidized boilers. I find it hard to believe that a governmental agency, suppose to be protecting the health, safety, and welfare of its citizens, would promote burning shredded tires as a solution to the problem of waste tires. Especially when there are so many other alternatives to burning tires i.e., shredding and using tires as raw materials for road beds, combines with asphalt as a new road top material or in cement, remanufacturing into retread tires and other rubber products such as floor mats, gaskets, sandals, shoe soles sound barriers and etc. The Rubber Manufacturers Associations report on scrap tire markets is a great source of information other than TDF burning!!!!

The tread wire from passenger car tires is small and only an inch or two long , these wires can cause problems by becoming entangled with each other and forming balls in the discharge piping according to Cedar Bay Cogeneration's own report.

Mike, we are very concerned about our ambient air quality. There are three coal fired plants within a three mile radius – St. Johns Power Plant – Northside Generating Plant – and Cedar Bay. The San Mateo Elementary School , with an enrollment of over 700 students is located approximately ½ mile as the crow flies Northwest of the Cedar Bay facility and Louis Sheffield Elementary school is located approximately 2 miles Northeast of the Cedar Bay facility with an enrollment of over 800 students..There is a Little League ball park and a residential community located within a mile of this facility. NCA is worried about the effects of pollutants from all three of these plants but, with the addition of TDF's to the mixture it becomes a greater concern.

Jacksonville has more inversions than any other city in the state of Florida. These inversions occur from approximately 6:00 a.m. to 10:00 a.m. the very time our children are walking to school – waiting on the school buses – or playing in the school yards. Children's airways are narrower than those of adults, thus enhancing the inflammatory effect of air pollution. Children do not have a fully developed immune system to help protect them from the damaging effects of many chemicals. Jacksonville also has the highest rate of lung cancer of any city in the state- it is imperative that we protect the health, safety and welfare of all our citizens.

Cedar Bay has been a good neighbor in the past, Marty Kreft, Jeff Walker, and Steven Busbin have been very gracious in supplying information to us and attending meetings we have scheduled and we are certainly appreciative of this. Unfortunately, the cost of coal has gone up 60% since last year. NCA understands this could pose a financial burden to a coal fired plant, however, there is absolutely no comparison between the cost of coal and the health, safety, and welfare of our community.

I'm looking forward to seeing you on September 26th and will drop you a note with direction to the school as we draw closer to the date. Thank you so much….

Sincerely,

Dot Mathias, President
Northside Civic Association
341 Baisden Rd.
Jacksonville, Fl. 32218

cc: Richard Robinson, P.E. City of Jacksonville EQD
Marty Kreft, Cedar Bay Cogeneration Co. LP

DM/jw

Department of Environmental Protection

Jeb Bush
Governor

Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Colleen M. Castille
Secretary

April 30, 2004

Mr. Martin Kreft
General Manager
Cedar Bay Generating Company, L.P.
Cedar Bay Generating Plant
9640 Eastport Road
Jacksonville, Florida 32226

Re: Title V Air Operation Permit Renewal
DRAFT Permit Project No.: 0310337-007-AV
Cedar Bay Cogeneration Facility

Dear Mr. Kreft:

One copy of the DRAFT Permit for the renewal of a Title V Air Operation Permit for the Cedar Bay Cogeneration Facility located at 9640 Eastport Road, Jacksonville, Duval County, is enclosed. The permitting authority's "INTENT TO ISSUE TITLE V AIR OPERATION PERMIT RENEWAL" and the "PUBLIC NOTICE OF INTENT TO ISSUE TITLE V AIR OPERATION PERMIT RENEWAL" are also included.

An electronic version of the DRAFT Permit has been posted on the Division of Air Resources Management's world wide web site for the United States Environmental Protection Agency (USEPA) Region 4 office's review. The web site address is:

"http://www.dep.state.fl.us/air/permitting/airpermits/AirSearch_ltd.asp"

The "PUBLIC NOTICE OF INTENT TO ISSUE TITLE V AIR OPERATION PERMIT RENEWAL" must be published as soon as possible. Proof of publication, i.e., newspaper affidavit, must be provided to the permitting authority's office within 7 (seven) days of publication pursuant to Rule 62-110.106(5), F.A.C. Failure to publish the notice and provide proof of publication within the allotted time may result in the denial of the permit pursuant to Rule 62-110.106(11), F.A.C.

Please submit any written comments you wish to have considered concerning the permitting authority's proposed action to Michael P. Halpin, P.E., at the above letterhead address or 850/921-9519.

Sincerely,

Tri L Vielhauer

Trina Vielhauer, Chief
Bureau of Air Regulation

jkp/mph

Enclosures

In the Matter of an
Application for Permit Renewal by:

Cedar Bay Generating Company, L.P.
9640 Eastport Road
Jacksonville, FL 32226

DRAFT Permit Project No.: 0310337-007-AV
Cedar Bay Cogeneration Company
Duval County

INTENT TO ISSUE TITLE V AIR OPERATION PERMIT RENEWAL

The Florida Department of Environmental Protection (permitting authority) gives notice of its intent to issue a Title V Air Operation Permit Renewal (copy of DRAFT Permit attached) for the Title V source detailed in the application specified above, for the reasons stated below.

The applicant, Cedar Bay Generating Company, L.P., applied on January 12, 2004, to the permitting authority for a Title V Air Operation Permit Renewal for Cedar Bay Cogenration Facility located at 9640 Eastport Road, Jacksonville, Duval County.

The permitting authority has permitting jurisdiction under the provisions of Chapter 403, Florida Statutes (F.S.), and Florida Administrative Code (F.A.C.) Chapters 62-4, 62-210 and 62-213. This source is not exempt from Title V permitting procedures. The permitting authority has determined that a Title V Air Operation Permit Renewal is required to commence or continue operations at the described facility.

The permitting authority intends to issue this Title V Air Operation Permit Renewal based on the belief that reasonable assurances have been provided to indicate that operation of the source will not adversely impact air quality, and the source will comply with all appropriate provisions of Chapters 62-4, 62-204, 62-210, 62-212, 62-213, 62-256, 62-257, 62-281, 62-296, and 62-297, F.A.C.

Pursuant to Sections 403.815 and 403.087, F.S., and Rules 62-110.106 and 62-210.350(3), F.A.C., you (the applicant) are required to publish at your own expense the enclosed "PUBLIC NOTICE OF INTENT TO ISSUE TITLE V AIR OPERATION PERMIT RENEWAL." The notice shall be published one time only as soon as possible in the legal advertisement section of a newspaper of general circulation in the area affected. For the purpose of these rules, "publication in a newspaper of general circulation in the area affected" means publication in a newspaper meeting the requirements of Sections 50.011 and 50.031, F.S., in the county where the activity is to take place. If you are uncertain that a newspaper meets these requirements, please contact the permitting authority at the address or telephone number listed below. The applicant shall provide proof of publication to the Department's Bureau of Air Regulation, at 2600 Blair Stone Road, Mail Station #5505, Tallahassee, Florida 32399-2400 (Telephone: 850/488-0114; Fax 850/ 922-6979), within 7 (seven) days of publication pursuant to Rule 62-110.106(5), F.A.C. Failure to publish the notice and provide proof of publication may result in the denial of the permit pursuant to Rule 62-110.106(11), F.A.C.

The permitting authority will issue the PROPOSED Permit, and subsequent FINAL Permit, in accordance with the conditions of the attached DRAFT Permit unless a response received in accordance with the following procedures results in a different decision or significant change of terms or conditions.

The permitting authority will accept written comments concerning the proposed permit issuance action for a period of 30 (thirty) days from the date of publication of the "PUBLIC NOTICE OF INTENT TO ISSUE TITLE V AIR OPERATION PERMIT RENEWAL." Written comments should be provided to the permitting authority office. Any written comments filed shall be made available for public inspection. If written comments received result in a significant change in this DRAFT Permit, the permitting authority shall issue a Revised DRAFT Permit and require, if applicable, another Public Notice.

A person whose substantial interests are affected by the proposed permitting decision may petition for an administrative hearing in accordance with Sections 120.569 and 120.57, F.S. The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department at 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida, 32399-3000. Petitions filed by the permit applicant or any of the parties listed below must be filed within fourteen days of receipt of this notice of intent. Petitions filed by any persons other than those entitled to written notice under Section 120.60(3), F.S., must be filed within fourteen days of publication of the public notice or within fourteen days of receipt of this notice of intent, whichever occurs first. Under Section 120.60(3), F.S., however, any person who asked the permitting authority for notice of agency action may file a petition within fourteen days of receipt of that notice, regardless of the date of publication. A petitioner shall mail a copy of the petition to the applicant at the address indicated above, at the time of filing. The failure of any person to file a petition within the appropriate time period shall constitute a waiver of that person's right to request an administrative determination (hearing) under Sections 120.569 and 120.57, F.S., or to intervene in this proceeding and participate as a party to it. Any subsequent intervention will be only at the approval of the presiding officer upon the filing of a motion in compliance with Rule 28-106.205, F.A.C.

A petition that disputes the material facts on which the permitting authority's action is based must contain the following information:

(a) The name and address of each agency affected and each agency's file or identification number, if known;

(b) The name, address, and telephone number of the petitioner; the name, address and telephone number of the petitioner's representative, if any, which shall be the address for service purposes during the course of the proceeding; and an explanation of how the petitioner's substantial interests will be affected by the agency determination;

(c) A statement of how and when each petitioner received notice of the agency action or proposed action;

(d) A statement of all disputed issues of material fact. If there are none, the petition must so indicate;

(e) A concise statement of the ultimate facts alleged, as well as the rules and statutes which entitle the petitioner to relief;

(f) A statement of the specific rules or statutes the petitioner contends require reversal or modification of the agency's proposed action; and,

(g) A statement of the relief sought by the petitioner, stating precisely the action petitioner wishes the agency to take with respect to the agency's proposed action.

A petition that does not dispute the material facts upon which the permitting authority's action is based shall state that no such facts are in dispute and otherwise shall contain the same information as set forth above, as required by Rule 28-106.301, F.A.C.

Because the administrative hearing process is designed to formulate final agency action, the filing of a petition means that the permitting authority's final action may be different from the position taken by it in this notice of intent. Persons whose substantial interests will be affected by any such final decision of the permitting authority on the application have the right to petition to become a party to the proceeding, in accordance with the requirements set forth above.

Mediation will not be available in this proceeding.

In addition to the above, a person subject to regulation has a right to apply to the Department of Environmental Protection for a variance from or waiver of the requirements of particular rules, on certain conditions, under Section 120.542, F.S. The relief provided by this state statute applies only to state rules, not statutes, and not to any federal regulatory requirements. Applying for a variance or waiver does not substitute or extend the time for filing a petition for an administrative hearing or exercising any other right that a person may have in relation to the action proposed in this notice of intent.

The application for a variance or waiver is made by filing a petition with the Office of General Counsel of the Department of Environmental Protection, 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida 32399-3000. The petition must specify the following information:

(a) The name, address, and telephone number of the petitioner;

(b) The name, address, and telephone number of the attorney or qualified representative of the petitioner, if any;

(c) Each rule or portion of a rule from which a variance or waiver is requested;

(d) The citation to the statute underlying (implemented by) the rule identified in (c) above;

(e) The type of action requested;

(f) The specific facts that would justify a variance or waiver for the petitioner;

(g) The reason why the variance or waiver would serve the purposes of the underlying statute (implemented by the rule); and,

(h) A statement whether the variance or waiver is permanent or temporary and, if temporary, a statement of the dates showing the duration of the variance or waiver requested.

The Department will grant a variance or waiver when the petition demonstrates both that the application of the rule would create a substantial hardship or violate principles of fairness, as each of those terms is defined in Section 120.542(2), F.S., and that the purpose of the underlying statute will be or has been achieved by other means by the petitioner.

Persons subject to regulation pursuant to any federally delegated or approved air program should be aware that Florida is specifically not authorized to issue variances or waivers from any requirements of any such federally delegated or approved program. The requirements of the program remain fully enforceable by the Administrator of the United States Environmental Protection Agency and by any person under the Clean Air Act unless and until the Administrator separately approves any variance or waiver in accordance with the procedures of the federal program.

Finally, pursuant to 42 United States Code (U.S.C.) Section 7661d(b)(2), any person may petition the Administrator of the EPA within 60 (sixty) days of the expiration of the Administrator's 45 (forty-five) day review period as established at 42 U.S.C. Section 7661d(b)(1), to object to issuance of any permit. Any petition shall be based only on objections to the permit that were raised with reasonable specificity during the 30 (thirty) day public comment period provided in this notice, unless the petitioner demonstrates to the Administrator of the EPA that it was impracticable to raise such objections within the comment period or unless the grounds for such objection arose after the comment period. Filing of a petition with the Administrator of the EPA does not stay the effective date of any permit properly issued pursuant to the provisions of Chapter 62-213, F.A.C. Petitions filed with the Administrator of EPA must meet the requirements of 42 U.S.C. Section 7661d(b)(2) and must be filed with the Administrator of the EPA at: U.S. EPA, 401 M Street, S.W., Washington, D.C. 20460.

Executed in Tallahassee, Florida.

Trina L Vielhauer

Trina Vielhauer, Chief
Bureau of Air Regulation

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this INTENT TO ISSUE TITLE V AIR OPERATION PERMIT RENEWAL (including the PUBLIC NOTICE and the DRAFT Permit) and all copies were sent by certified mail before the close of business on 5/13/04 to the person(s) listed:

Martin Kreft, General Manager

In addition, the undersigned duly designated deputy agency clerk hereby certifies that copies of this INTENT TO ISSUE TITLE V AIR OPERATION PERMIT RENEWAL (including the PUBLIC NOTICE and Statement of Basis) were sent by U.S. mail on the same date to the person(s) listed or as otherwise noted:

George Lipka, P.E., Earth Tech
Jeff Walker, Environmental Manager

In addition, the undersigned duly designated deputy agency clerk hereby certifies that copies of this INTENT TO ISSUE TITLE V AIR OPERATION PERMIT RENEWAL (including the DRAFT Permit package) were sent by INTERNET E-mail on the same date to the person(s) listed:

Hamilton S. Oven, P.E.
James L. Manning, P.E., RESD
Chris Kirts, DEP-NED
EPA Region 4

Clerk Stamp

FILING AND ACKNOWLEDGMENT FILED, on this date, pursuant to Section 120.52(7), Florida Statutes, with the designated agency Clerk, receipt of which is hereby acknowledged.

Barbara J. Friday 5/13/04
(Clerk) (Date)

PUBLIC NOTICE OF INTENT TO ISSUE TITLE V AIR OPERATION PERMIT RENEWAL

Florida Department of Environmental Protection
DRAFT Permit Project No.: 0310337-007-AV
Cedar Bay Cogeneration Facility
Duval County

The Florida Department of Environmental Protection (permitting authority) gives notice of its intent to issue a Title V Air Operation Permit Renewal to Cedar Bay Generating Company, L.P. for their Cedar Bay Cogeneration Facility located at 9640 Eastport Road, Jacksonville, Duval County. The applicant's name and address are: Cedar Bay Generating Company, L.P., Martin Kreft, General Manager; 9640 Eastport Road, Jacksonville Florida 32226.

The permitting authority will issue the PROPOSED Permit, and subsequent FINAL Permit, in accordance with the conditions of the DRAFT Permit unless a response received in accordance with the following procedures results in a different decision or significant change of terms or conditions.

The permitting authority will accept written comments concerning the proposed DRAFT Permit issuance action for a period of 30 (thirty) days from the date of publication of this Notice. Written comments should be provided to the Department. Any written comments filed shall be made available for public inspection. If written comments received result in a significant change in this DRAFT Permit, the permitting authority shall issue a Revised DRAFT Permit and require, if applicable, another Public Notice.

A person whose substantial interests are affected by the proposed permitting decision may petition for an administrative hearing in accordance with Sections 120.569 and 120.57 of the Florida Statutes (F.S.). The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department at 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida, 32399-3000. Petitions filed by any persons other than those entitled to written notice under Section 120.60(3), F.S., must be filed within fourteen days of publication of the public notice or within fourteen days of receipt of the notice of intent, whichever occurs first. Under Section 120.60(3), F.S., however, any person who asked the permitting authority for notice of agency action may file a petition within fourteen days of receipt of that notice, regardless of the date of publication. A petitioner shall mail a copy of the petition to the applicant at the address indicated above, at the time of filing. The failure of any person to file a petition within the applicable time period shall constitute a waiver of that person's right to request an administrative determination (hearing) under Sections 120.569 and 120.57, F.S., or to intervene in this proceeding and participate as a party to it. Any subsequent intervention will be only at the approval of the presiding officer upon the filing of a motion in compliance with Rule 28-106.205 of the Florida Administrative Code (F.A.C.).

A petition that disputes the material facts on which the permitting authority's action is based must contain the following information:

(a) The name and address of each agency affected and each agency's file or identification number, if known;

(b) The name, address and telephone number of the petitioner; name address and telephone number of the petitioner's representative, if any, which shall be the address for service purposes during the course of the proceeding; and an explanation of how petitioner's substantial rights will be affected by the agency determination;

(c) A statement of how and when the petitioner received notice of the agency action or proposed action;

(d) A statement of all disputed issues of material fact. If there are none, the petition must so state;

(e) A concise statement of the ultimate facts alleged, as well as the rules and statutes which entitle petitioner to relief;

(f) A statement of the specific rules or statutes the petitioner contends require reversal or modification of the agency's proposed action; and,

(g) A statement of the relief sought by the petitioner, stating precisely the action petitioner wishes the agency to take with respect to the agency's proposed action.

A petition that does not dispute the material facts upon which the permitting authority's action is based shall state that no such facts are in dispute and otherwise shall contain the same information as set forth above, as required by Rule 28-106.301, F.A.C.

Because the administrative hearing process is designed to formulate final agency action, the filing of a petition means that the permitting authority's final action may be different from the position taken by it in this notice of intent. Persons whose substantial interests will be affected by any such final decision of the permitting authority on the application have the right to petition to become a party to the proceeding, in accordance with the requirements set forth above.

Mediation is not available for this proceeding.

In addition to the above, pursuant to 42 United States Code (U.S.C.) Section 7661d(b)(2), any person may petition the Administrator of the EPA within 60 (sixty) days of the expiration of the Administrator's 45 (forty-five) day review period as established at 42 U.S.C. Section 7661d(b)(1), to object to issuance of any permit. Any petition shall be based only on objections to the permit that were raised with reasonable specificity during the 30 (thirty) day public comment period provided in this notice, unless the petitioner demonstrates to the Administrator of the EPA that it was impracticable to raise such objections within the comment period or unless the grounds for such objection arose after the comment period. Filing of a petition with the Administrator of the EPA does not stay the effective date of any permit properly issued pursuant to the provisions of Chapter 62-213, F.A.C. Petitions filed with the Administrator of EPA must meet the requirements of 42 U.S.C. Section 7661d(b)(2) and must be filed with the Administrator of the EPA at: U.S. EPA, 401 M Street, S.W., Washington, D.C. 20460.

A complete project file is available for public inspection during normal business hours, 8:00 a.m. to 5:00 p.m., Monday through Friday, except legal holidays, at:

Permitting Authority:
Florida Department of Environmental Protection
2600 Blairstone Rd., Mail Station 5505
Tallahassee, FL 32399
Telephone: 850/488-0114
Fax: 850/922-6979

Affected District Program:
Florida Department of Environmental Protection
7825 Baymeadows Way
Jacksonville, FL 32256
Telephone: 904/807-3300
Fax: 904/448-4319

The complete project file includes the DRAFT Permit, the application for renewal, and the information submitted by the responsible official, exclusive of confidential records under Section 403.111, F.S. Interested persons may contact Michael P. Halpin, P.E., at the above address, or call 850/488-0114, for additional information.

National Energy & Gas Transmission
National Energy Power Company, LLC

Cedar Bay Generating Co., L.P.
9640 Eastport Road
Jacksonville, FL 32218

904.751.4000
Fax: 904.751.7320
www.negt.com

June 1, 2004

Mr. Michael Halpin, P.E.
Florida Department of Environmental Protection
Division of Air Resource Management
Bureau of Air Regulation
Mail Station #5505
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

RECEIVED
JUN 02 2004
BUREAU OF AIR REGULATION

Re: Title V Air Operation Permit Renewal
Draft Permit Project No.: 0310337-007-AV
Cedar Bay Cogeneration Facility

Dear Mr. Halpin:

Pursuant to the instructions in the Department's letter dated April 30, 2004, Cedar Bay submits the Affidavit of Publication for the "PUBLIC NOTICE OF INTENT TO ISSUE TITLE V AIR OPERATION PERMIT RENEWAL". The notice was published in the legal ad section of the Florida Times Union on May 22, 2004.

If there are any questions or if any additional information is needed, please do not hesitate to contact me via phone or e-mail.

Sincerely,

Jeffrey A. Walker

Jeffrey A. Walker
Environmental Manager, Cedar Bay Plant

Martin Kreft, Cedar Bay
AJ Jablonowski, Earthtech
Tom Fromm, Bethesda

Best Available Copy

THE FLORIDIA TIMES-UNION Jacksonville, Fl
Affidavit of Publication

Florida Times-Union

CEDAR BAY GENERATING CO.
PO BOX 26324
JACKSONVILLE FL 32236

REFERENCE: 0181153
R041145 Public Notice

State of Florida
County of Duval

Before the undersigned authority personally appeared Kimalete Frazier who on oath says she is a Legal Advertising Representative of The Florida Times-Union, a daily newspaper published in Jacksonville in Duval County, Florida; that the attached copy of advertisement is a legal ad published in The Florida Times-Union. Affiant further says that The Florida Times-Union is a newspaper published in Jacksonville, in Duval County, Florida, and that the newspaper has heretofore been continuously published in Duval County, Florida each day, has been entered as second class mail matter at the post office in Jacksonville, in Duval County, Florida for a period of one year preceeding the first publication of the attached copy of advertisement; and affiant further says that he/she has neither paid nor promised any person, firm or corporation any discount, rebate, commission, or refund for the purpose of securing this advertisement for publication in said newspaper.

PUBLISHED ON: 05/22

FILED ON: 05/25/04

Name: Kimalete Frazier Title: Legal Advertising Representativ
In testimony whereof, I have hereunto set my hand and affixed my of seal, the day and year aforesaid.

NOTARY: Twilla Shipp

TWILLA SHIPP
Notary Public, State of Florida
My comm. expires May 13, 2006
Comm. No. DD 117248

PUBLIC NOTICE OF INTENT TO ISSUE TITLE V AIR OPERATION PERMIT RENEWAL
Florida Department of Environmental Protection
DRAFT Permit Project No.: 0310337-007-AV
Cedar Bay Cogeneration Facility
Duval County

The Florida Department of Environmental Protection (permitting authority) gives notice of its intent to issue a Title V Air Operation Permit Renewal to Cedar Bay Generating Company, L.P. for their Cedar Bay Cogeneration Facility located at 9640 Eastport Road, Jacksonville, Duval County. The applicant's name and address are: Cedar Bay Generating Company, L.P., Martin Kreft, General Manager, 9640 Eastport Road, Jacksonville, Florida 32226.

The permitting authority will issue the PROPOSED Permit, and subsequent FINAL Permit, in accordance with the conditions of the DRAFT Permit unless a response received in accordance with the following procedures results in a different decision or significant change of terms or conditions.

The permitting authority will accept written comments concerning the proposed DRAFT Permit issuance action for a period of 30 (thirty) days from the date of publication of this Notice. Written comments should be provided to the Department. Any written comments filed shall be made available for public inspection. If written comments received result in a significant change in this DRAFT Permit, the permitting authority shall issue a Revised DRAFT Permit and require, if applicable, another Public Notice.

A person whose substantial interests are affected by the proposed permitting decision may petition for an administrative hearing in accordance with Sections 120.569 and 120.57 of the Florida Statutes (F.S.). The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department at 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida 32399-3000. Petitions filed by any persons other than those entitled to written notice under Section 120.60(3), F.S., must be filed within fourteen days of publication of the public notice or within fourteen days of receipt of the notice of intent, whichever occurs first. Under Section 120.60(3), F.S., however, any person who asked the permitting authority for notice of agency action may file a petition within fourteen days of receipt of that notice, regardless of the date of publication. A petitioner shall mail a copy of the petition to the applicant at the address indicated above, at the time of filing. The failure of any person to file a petition within the applicable time period shall constitute a waiver of that person's right to request an administrative determination (hearing) under Sections 120.569 and 120.57, F.S., or to intervene in this proceeding and participate as a party to it. Any subsequent intervention will be only at the approval of the presiding officer upon the filing of a motion in compliance with Rule 28-106.205 of the Florida Administrative Code (F.A.C.).

A petition that disputes the material facts on which the permitting authority's action is based must contain the following information:
(a) The name and address of each agency affected and each agency's file or identification number, if known;
(b) The name, address and telephone number of the petitioner; name, address and telephone number of the petitioner's representative, if any, which shall be the address for service purposes during the course of the proceeding; and an explanation of how petitioner's substantial rights will be affected by the agency determination;
(c) A statement of how and when the petitioner received notice of the agency action or proposed action;
(d) A statement of all disputed issues of material fact. If there are none, the petition must so state;
(e) A concise statement of the ultimate facts alleged, as well as the rules and statutes which entitle petitioner to relief;
(f) A statement of the specific rules or statutes the petitioner contends require reversal or modification of the agency's proposed action; and,
(g) A statement of the relief sought by the petitioner, stating precisely the action petitioner wishes the agency to take with respect to the agency's proposed action.

A petition that does not dispute the material facts upon which the permitting authority's action is based shall state that no such facts are in dispute and otherwise shall contain the same information as set forth above, as required by Rule 28-106.301, F.A.C.

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Mediation is not available for this proceeding.

In addition to the above, pursuant to 42 United States Code (U.S.C.) Section 7661d(b)(2), any person may petition the Administrator of the EPA within 60 (sixty) days of the expiration of the Administrator's 45 (forty-five) day review period as established at 42 U.S.C. Section 7661d(b)(1), to object to issuance of any permit. Any petition shall be based only on objections to the permit that were raised with reasonable specificity during the 30 (thirty) day public comment period provided in this notice, unless the petitioner demonstrates to the Administrator of the EPA that it was impracticable to raise such objections within the comment period or unless the grounds for such objection arose after the comment period. Filing of a petition with the Administrator of the EPA does not stay the effective date of any permit properly issued pursuant to the provisions of Chapter 62-213, F.A.C. Petitions filed with the Administrator of EPA must meet the requirements of 42 U.S.C. Section 7661d(b)(2) and must be filed with the Administrator of the EPA at: U.S. EPA, 401 M Street, S.W., Washington, D.C., 20460.

A complete project file is available for public inspection during normal business hours, 8:00 a.m. to 5:00 p.m., Monday through Friday, except legal holidays, at:

Permitting Authority:
Florida Department of Environmental Protection
2600 Blairstone Rd., Mail Station 5505
Tallahassee, FL 32399
Telephone: 850/488-0114
Fax: 850/922-6979

Affected District Program:
Florida Department of Environmental Protection
7825 Baymeadows Way
Jacksonville, FL 32256
Telephone: 904/807-3300
Fax: 904/448-4319

STATEMENT OF BASIS

Cedar Bay Generating Company, L.P.
Cedar Bay Cogeneration Facility
Facility ID No.: 0310337
Duval County

Title V Air Operation Permit Renewal
DRAFT Permit Project No.: 0310337-007-AV

This Title V Air Operation Permit Renewal is issued under the provisions of Chapter 403, Florida Statutes (F.S.), and Florida Administrative Code (F.A.C.) Chapters 62-4, 62-210 and 62-213. The above named permittee is hereby authorized to operate the facility shown on the application and approved drawing(s), plans, and other documents, attached hereto or on file with the permitting authority, in accordance with the terms and conditions of this permit.

The subject of this permit is for the renewal of Title V Air Operation Permit.

This facility consists of three circulating fluidized bed steam generators (boilers) designated as Boilers A, B, and C, a coal handling area, a limestone handling area, and an ash handling area. Crushed coal is the primary fuel for Boilers A, B and C with approval for limited co-firing of petroleum coke. The fuel for Boilers B and C can also be supplemented with short fiber recycle rejects received from Stone Container Corporation. No. 2 fuel oil is used as supplemental fuel in all three boilers normally only for start-ups. CAM does apply.

All three boilers began commercial operation January 25, 1994. Particulate matter emissions from each boiler are controlled by separate baghouses. NO_X emissions from all units are controlled by selective non-catalytic reduction (SNCR). SO_2 emissions are controlled by limestone injection on the fluidized bed of each boiler. The three boilers share a common stack.

In 2002, Cedar Bay received approval to co-fire petroleum coke (pet coke) in each CFB boiler via permit number 0310337-005-AC. The conditions of the approval have been added to this Title V permit as follows:

1) Pet coke may be utilized as a co-firing fuel, and shall not exceed 35 % fuel input by weight on a daily basis.
2) When co-firing coal and petcoke, the blended fuel input to the CFBs shall not exceed 3.2 lb/MMBtu equivalent SO2 content (determined on a monthly basis via a composite of daily fuel samples).

The permit additionally includes updates and corrections to material handling process descriptions plant-wide, including:

1) Addition of a pug mill for ash conditioning.
2) Clarification that dry ash is not loaded out by truck and that Wet Ash Truck Loadout will use a pug mill to condition the ash with a water source to allow the loading of wet ash into open top trailers.
3) Updates to limestone/aragonite and ash handling requirements to reflect co-firing of pet coke.
4) Removal of an insignificant activity (49. Recycle surge hopper baghouse was related to the removed pelletizer).
5) Corrections to typographical errors.

Note that the January 2002 revision to the Title V permit addressed the removal of several pieces of equipment related to the old ash pelletizer system.

Also included in this permit are miscellaneous unregulated/insignificant emissions units and/or activities.

Based on the Title V Air Operation Permit Renewal application received January 12, 2004, this facility is a major source of hazardous air pollutants (HAPs).

Halpin, Mike

From: Walker, Jeff [Jeff.Walker@negt.com]

Sent: Wednesday, March 17, 2004 2:33 PM

To: Halpin, Mike

Cc: ajjablonowski@earthtech.com; Fromm, Thomas; Kreft, Martin; Holm, Chuck; Busbin, Steven

Subject: Cedar Bay Title V Permit Renewal - Facility ID No.: 0310337

To: Mike Halpin, P.E.
Division of Air Resources - North Permitting Section
Florida Department of Environmental Protection

Mike

Cedar Bay is in receipt of your letter dated March 2, 2004. In accordance with the directives in the letter and in order to facilitate the processing of Cedar Bay's Title V permit renewal, Cedar Bay hereby provides the following responses to the items identified in the letter. In addition, Cedar Bay wishes to take this opportunity to request a change involving an annual compliance requirement during the Title V permit renewal process. Specifically, Cedar Bay will address

1. Boilers A,B &C CAM
2. Material Handling Units with Baghouses
3. Annual Visible Emission Monitoring of Boilers A, B, & C

Boilers A B & C CAM Plan

Cedar Bay is in agreement with the Department that there is not always a consistent correlation between opacity and actual PM emissions, however, based on actual operating experience and due to the plant's inherent baghouse design, we believe that the Continuous Opacity Monitoring (COM) system would be a more reliable indicator of PM emissions than using baghouse pressure drop indications.

Cedar Bay's A, B & C boilers are each equipped with an eight-compartment baghouse. There are 264 bags per compartment. With a flue gas volume approximately 297,700 ACFM, the baghouse is considered to have a high Air-to-Cloth ratio. With exit flue gas temps greater than 300 degrees F, the bags are manufactured with a fiberglass finish and are considered acid resistant with a high particulate retention ability. The differential pressure/pressure drop in inches of water is determined by a Rosemount transmitter across the inlet and outlet of the entire baghouse. The transmitter provides a 4-20 mA analog output for continuous monitoring and trending of differential pressure of the baghouse. While each of the eight compartments has a dedicated magnehelic gauge, they do not interface with the plant's distributed control system as does the Rosemont transmitter. The baghouse cleaning cycle logic is a function of the pressure drop as recorded by the Rosemount transmitter. Based on recommendations from our baghouse consultant, the cleaning cycle is initiated from the previous compartment being cleaned at 5 inches wc.and will cease when the pressure drop goes below 4 inches wc.

As part of the Title V permit renewal process/CAM plan development, Cedar Bay compared particulate data as determined quantitatively during annual compliance testing and compared that to the recorded COM data during the concurrent periods of the Method 5/Method 17 test runs. Due to the relatively young age of the boilers (commercial operation began in 1994), there are a limited number of data points for analysis. In addition, the COM data during early operating years was not readily available for comparison. The PM/PM10 data used for analyses was all derived from compliance testing data when the boilers were operating at greater than 90% heat input. Please find the opacity/PM/PM10 data below.

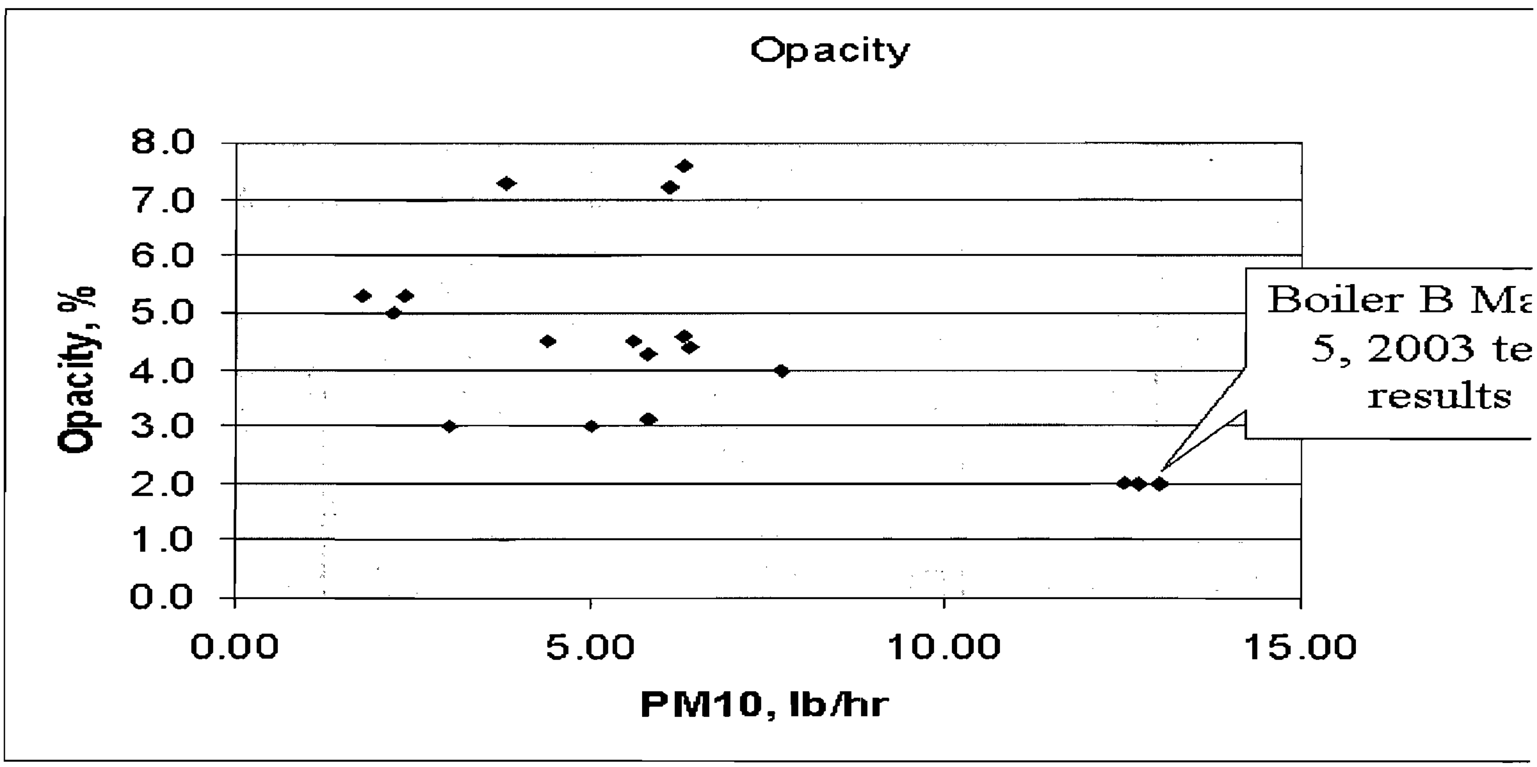
Cedar Bay Opacity - PM/PM Data

	Date		PM (lbs/MMBtu)	PM (lbs/hr)	Opacity	PM10 (lbs/MMBtu)	PM10 (Lbs/hr)
Boiler A	March 17/99	Run 1	0.015	15.24	2.7		
		Run 2	0.018	18.52	2.0		
		Run 3	0.015	16.26	2.0		
	March 7/00	Run 1	0.014	15.66	5.7	0.011	11.9
		Run 2	0.013	14.51	4.0	0.011	13.1

		Run 3	0.014	15.87	4.0	0.011	12.7
	March 19/01	Run 1	0.014	16.28	7.2	0.007	8.5
		Run 2	0.014	17.57	7.0	0.004	5.2
		Run 3	0.015	17.89	7.0	0.003	3.5
	March 12/02	Run 1	0.006	7.41	4.0	0.005	6.30
		Run 2	0.006	6.80	4.4	0.005	5.60
		Run 3	0.004	4.61	4.4	0.005	5.80
	March 4/03	Run 1	0.003	3.95	5.1	0.002	2.20
		Run 2	0.003	3.55	5.1	0.002	2.40
		Run 3	0.002	2.73	5.3	0.002	1.80
Boiler B	March 16/99	Run 1	0.009	10.67	5.8		
		Run 2	0.017	18.47	NA/maintenance		
		Run 3	0.015	17.04	5.1		
	March 8/00	Run 1	0.015	17.26	5.2	0.013	15.60
		Run 2	0.013	16.81	5.8	0.011	14.40
		Run 3	0.015	17.21	5.4	0.014	16.70
	March 22/01	Run 1	0.016	19.64	7.2	0.016	20.60
		Run 2	0.016	18.93	6.2	0.001	1.40
		Run 3	0.015	17.64	6.2	0.004	4.30
	March 13/02	Run 1	0.005	6.20	4.7	0.004	4.40
		Run 2	0.007	7.65	4.3	0.006	6.40
		Run 3	0.008	8.93	4.1	0.007	7.70
	March 5/03	Run 1	0.010	12.51	2.1	0.011	12.50
		Run 2	0.012	14.06	2.0	0.011	12.70
		Run 3	0.011	13.27	2.1	0.011	13.00
Boiler C	March 18/99	Run 1	0.014	15.11	Not available		
		Run 2	0.016	17.37	Not available		
		Run 3	0.015	17.05	Not available		
	March 9/00	Run 1	0.019	17.12	4.0	0.017	15.40
		Run 2	0.016	15.73	4.1	0.014	14.30
		Run 3	0.017	16.58	4.0	0.014	14.70

March 20/01	Run 1	0.019	18.22	3.1	0.006	5.90
	Run 2	0.015	17.36	3.0	0.012	14.20
	Run 3	0.017	19.17	3.0	0.009	10.40
March 14/02	Run 1	0.005	6.54	7.3	0.005	6.10
	Run 2	0.005	6.48	7.3	0.006	6.30
	Run 3	0.004	4.44	7.0	0.003	3.80
March 6/03	Run 1	0.005	5.69	3.0	0.004	5.00
	Run 2	0.007	8.20	3.0	0.003	3.00
	Run 3	0.007	8.23	3.0	0.005	5.80

Cedar Bay's consultant, Earthtech, attempted line-fitting the stack test and opacity data (Least-squares method, y=mx, b=0 to force 0 lbs=0% opacity. Boiler B's 2003 data points were outliers that throws off the line as that particular test had high PM/PM10 and low opacity.



Defining a direct relationship between opacity and PM values is difficult for many reasons, i.e. variability in the processes, calibration/span allowances of the opacity monitor, timeliness of opacity audits and subsequent adjustments, Method 5/17 testing variables, bag integrity at the time of mass emission testing, baghouse cleaning cycles and combustion parameters to name a few. However, operational experience indicates that COM data can be a solid and reliable indicator of a leaking/broken bag. Customarily, a sudden breach of a bag can be detected by the control room operator by a step change in the COM output. In fact, an alarm will annunciate on both the CEMDAS screen and the control room alarm summary screen if the opacity reaches a specified per cent value. Should this scenario develop, the control room operators will begin isolating each compartment manually and observe any resultant change in opacity output. This has been a successful method as reflected in the plant's opacity compliance history. Once the particular compartment with the broken bag is located, the compartment is isolated and allowed to cool to allow the defective bag(s) to be replaced. Cedar Bay's boilers can operate with up to two of the eight compartments isolated. As the plant measures pressure drop across the entire baghouse, a broken bag(s) in an individual compartment is not commonly detected by changes in the differential pressure data.

A review of Cedar Bay's 2004 COM data indicates a median value between 5 and 6 for each boiler. The highest and lowest values in the 2004 data set are 8% and 1% respectively. Please note that there were some COM values with a high of 13% that were not considered normal operating values as they were either attributed to a defective bag in a compartment or faulty COM hardware output. Cedar Bay's COM system is installed on the horizontal duct work downstream from the outlet of the baghouse.The normal induced fan inlet pressure of Cedar Bay's boilers is a negative 25-26 inches water column. The extreme negative atmosphere in the ductwork actually benefits the cleanliness of the COM system's transceiver/reflector assembly by providing clean optical boundaries. However, a boiler trip can suddenly expose the COM hardware to a positive environment. While the COM system has automatic dust compensation in the optical head, there is none for the reflector. Operating experience indicates that the COM output can be biased up to 5% if both the reflector and the lens of the optical head are dirty and/or not aligned. Thus, it is customary for Instrument & Control personnel at Cedar Bay to verify alignment and the cleanliness of the COM system after start-ups and/or boiler trips. In addition, quarterly preventative maintenance of the entire COM system is performed by a qualified contractor. This pm includes a formal audit that validates the accuracy of the system. The quarterly audit report of the COM is submitted to the Environmental Resource Management Department of the City of Jacksonville along with the plant's Excess Emission Report.

Cedar Bay's initial submittal of the CAM plan provided for the initiation of corrective action procedures with the discovery of 5 consecutive 6-minute averages of opacity greater than 15%. In light of the Department's initial feedback and after a review of the 2004 COM data, Cedar Bay proposes a new excursion level of 11%.

Material Handling Units with Baghouses
As the Department will not accept the initial CAM non-applicability determination of the plant's Material Handling Unit baghouses, Cedar Bay's consultant, Earthtech, will recalculate tons per year before control devices utilizing AP-42 emission factors with application of process knowledge where applicable. Cedar Bay acknowledges the dilemma with the methodology to calculate pre-control emission in tons per year. In addition, utilizing stoichiometric relationship based on assumed baghouse efficiencies is even more questionable as the inlet grain loading is not known and the fact that outlet emission rates are constant even with varying inlet particulate loads.

Annual Visible Emissions Monitoring of Boilers A, B & C
As you will read from previous correspondence between the Department, the Environmental Resource Management Department of the City of Jacksonville and Cedar Bay, we would like to improve the current compliance testing scenario for the Boiler's A,B & C visible emissions. Section 111, A.30, referring to Cedar Bay's boilers, stipulates that annual compliance tests shall be performed for PM, PM10, CO, SO2, NOx, and visible emissions. Additionally, A.33 defines Method 9 as the test method for the Visible Emission test. As you will read in the attached material, Cedar Bay, due to the flue gas ductwork configuration exiting one common stack, would like to submit COM data in lieu of conducting 1 hour Visible Emission data for each boiler pursuant to Cedar Bay's Title V permit, Appendix 40 CFR 60, #13. Specifically, if the Department is in agreement and as part of the Title V permit renewal, Cedar Bay requests that the language in A30 and A33 be modified as to allow COM data concurrent with the mass emission performance testing be used as an annual opacity compliance provision.

-----Original Message-----
From: Wayne Walker [mailto:WLW@coj.net]
Sent: Thursday, February 05, 2004 9:38 AM
To: Walker, Jeff
Cc: Wayne Tutt
Subject: Re: Cedar Bay Compliance Testing Notice/Request for Opacity Alternative

Mr. Walker,

Annual compliance testing notification for 3/1-4/04 @ Cedar Bay Generating Company (CBGC) has been received. Environmental Quality Division (EQD) personnel will most likely be present during the week to observe a portion of the testing. Regarding CBGC's request to submit Continuous Opacity Monitoring (COM) data in lieu of the annual 1-hour Reference Method 9 VE required by permit Specific Condition (SC) numbers A.30. and A.33. of Section III, please be advised EQD does not have the authority to grant approval for an alternate compliance method. SC A.33. states an equivalent method can only be used after obtaining prior written approval from the Department (FDEP). As you know, CBGC's Title V permit is due for renewal later this year. If CBGC wishes to pursue this matter, I would suggest conducting the required RM 9 VE as usual and submitting the COM data as supporting documentation. Assuming a passing test, CBGC could then cite the correlating data in its request to FDEP to modify the Title V permit to allow the submission of COM data in lieu of the annual RM 9 VE test.

If there are any further questions concerning this issue, please let me know.

Thanks,
Wayne Walker

>>> "Walker, Jeff" <Jeff.Walker@negt.com> 02/04/04 11:02AM >>>

Mr. Wayne L Walker, Data Quality Analyst
Environmental Resource Management Department
Environmental Quality Division
117 West Duval Street, Suite 225
Jacksonville, Fl. 32202

Re: Cedar Bay Compliance Testing, Site Certification PA 88-24A, PSD-FL-137, Title V Permit 0310337-002-AV

Dear Mr. Walker:

Pursuant to Title V Permit 0310337, Section III, Subsection A, A45(9) and in accordance with your letter dated January 7, 2004, Cedar Bay Generating Plant provides notice of the planned annual emissions testing for Boilers A, B, and C, Absorber Dryer Systems A and B and the Material Handling Sources as referenced in the above mentioned permits. The testing is scheduled for March 1-4, 2004. The air testing firm, Coastal Air Consulting, will set up source testing equipment on February 29, 2004. Concurrent with the testing of the boilers, the Relative Accuracy Test Audit (RATA) on Cedar Bay Generating Plant's Continuous Emissions Monitoring System will be conducted. Please find the testing schedule below.

February 29 - Mobilize and set-up
March 1 - RATA Boiler A, PM/PM10/SO2/NOX/CO/Lead, Mercury, Beryllium, VE's
March 2 - RATA Boiler B, PM/PM10/SO2/NOX/CO/Lead, Mercury, Beryllium, VE's
March 3 - RATA Boiler C, PM/PM10/SO2/NOX/CO/Lead, Mercury, Beryllium, VE's
March 4 - VE's/Make-up day if necessary

The sources for which testing will be conducted and testing methodology are identified on the attached file.

Historically, during annual compliance testing, Cedar Bay has had a Method 9-Visible Emission Test performed for each boiler as dictated in the facility's air permits. As you maybe aware, Cedar Bay's boiler configuration is somewhat unique in that each of the three boiler's flue gas systems discharge to one common stack. As such, during the annual 1-hour compliance VE for each boiler, the other two boilers are also in operation and are contributing to the total opacity output from the stack. As such, the individual compliance VE is impacted by the opacity emission from two other operating boilers. Please note, however, that Cedar Bay has never failed an annual opacity compliance VE, even with this testing scenario. As identified in Cedar Bay's Title V permit, Appendix 40, CFR 60, Subpart A, (40 CFR 60.11,13), due to the interferences from the other operating boilers and in order to improve the methodology for determining opacity compliance, Cedar Bay requests approval to submit the continuous opacity monitoring system (COM) data in lieu of the 1-hour VE for the annual opacity compliance testing documentation.

Cedar Bay's continuous opacity monitoring system is integrated with the facility's continuous emission monitoring system along with the boiler's distributed control system. In accordance with the plant's CEM QA/QC plan and in order to meet the requirements of 40 CFR 60.13, on a quarterly basis, a contractor conducts a performance evaluation of the COMs to ensure the systems are operating as specified in Performance Specification 1, Part 60, Appendix B. Recently, Cedar Bay has been submitting the quarterly Opacity Performance Report along with the submittal of the Excess Emission Report.

With the Environmental Resource Management's Department approval, Cedar Bay would submit the entire testing day's 6-minute opacity output in lieu of the 1-hour VE in the testing report.

If there are any questions or if any other information is needed on this matter, please do not hesitate to reach me via phone or e-mail.

Sincerely,

Jeff Walker
Environmental Manager, Cedar Bay Generating Plant
Tel: 751-4000 ext.147
Fax: 751-7320

Cedar Bay's consultant, Earthtech, will revise pages 3-2 and 3-3 of the Title V permit application that pertain to the potential emission calculations of the plant's material handling emission units. In addition, upon the Department' approval of Cedar Bay's revised COM indicator range of 11% for Boiler's A, B, & C CAM, the boilers CAM plan will also be re-submitted by the engineer of record pursuant to 62-4.050(3) F.A.C.

If there are any questions of if any other information is needed, please do not hesitate to reach me via phone or e-mail.

Sincerely,

Jeff Walker
Environmental Manager, Cedar Bay Generating Plant
Tel: 751-4000 ext. 147
Fax: 751-7320

National Energy & Gas Transmission.
National Energy Power Company, LLC

Cedar Bay Generating Co., L.P.
9640 Eastport Road
Jacksonville, FL 32218

904.751.4000
Fax: 904.751.7320
www.negt.com

RECEIVED
MAR 09 2004
BUREAU OF AIR REGULATION

March 8, 2004

Bureau of Air Regulation
Department of Environmental Protection
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Attention: Mr. Jim Pennington. P.E., Program Administrator

RE: Water Treatment Byproduct Use
DEP File No. PA 88-24; PSD-FP-137; Title V Permit 0310337-002-AV

Dear Mr. Pennington:

Cedar Bay Generating Company, L.P. is seeking authorization from the Department to use the solid byproduct from the water treatment process as a reactant in the circulating fluidized bed boilers. The authorization is being sought under Condition A.3(b)3. of the Title V Permit (Final Permit No. 0310337-002-AV). The solid byproduct is the filter cake from the lime-softening portion of the water treatment system. The byproduct is very similar in reactivity to the limestone used to control sulfur dioxide emissions. The amount of byproduct would not exceed 12,000 tons/year. This amount would displace up to 10 percent of the total amount of limestone currently used in the three CFB boilers. About 120,000 tons/year of limestone is currently used.

Please find attached an application and evaluation from Mr. Kennard F, Kosky, P.E. of Golder Associates on the use of the byproduct. Based on analyses of the filter cake and limestone, the use of filter cake will not increase emissions from the facility and the constituents within the filter cake are similar to those currently seen in trace amounts in our coal and limestone.

The Department's expeditious review will be appreciated. Please note that Mr. Mike Halpin of your staff is familiar with the Cedar Bay facility since he processed the permit modification that would allow the co-firing of petroleum coke with coal. Mr. Kosky briefly discussed the proposed use of the filter cake with Mr. Halpin earlier this week. Please contact me (904-751-4000 ext. 147) or Mr. Kosky (352-336-5600) if there are any questions.

Sincerely,

Jeffrey Walker

Jeffrey Walker, Environmental Manager

Enclosures

cc: Air and Water Division, Environmental Resource Management Department, City of Jacksonville
Kennard Kosky, P.E., Golder Associates
Hamilton S. Oven, P.E., FDEP Siting Coordination Office

Mike Halpin

Department of Environmental Protection

Jeb Bush
Governor

Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

David B. Struhs
Secretary

March 2, 2004

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. Jeffrey Walker
Cedar Bay Cogenerating Company, L.P.
9640 Eastport Road
Jacksonville, FL 32226

Re: Request for Additional Information
Title-V Renewal Application
File No. 0310337-007-AV
Cedar Bay Cogenerating Project

Dear Mr. Walker:

The Department is in receipt of your Title V Renewal application, however in order to continue processing the application, we will need the additional information below. Should your response to any of the below items require new calculations, please submit the new calculations, assumptions, reference material and appropriate revised pages of the application form.

Boilers A, B & C (EU 001, 002 & 003)

1. CAM is applicable for monitoring the control of particulate matter (PM) emissions from the baghouses. The proposal to use the COMS and recorded opacity as an indicator of compliance with the PM emissions limit is not the best choice. Experience has shown that there is not always a consistent and reliable correlation between opacity and actual PM emissions; however, it can be considered for use if a demonstration is presented that verifies a direct relationship between the COMS readings and the PM emission rates. To do so, please provide a table of data that documents the tested PM emission rate, the simultaneous opacity reading from the COMS, the test date, the operational rate during the test, and the allowable capacity of the unit. It should be noted that with normal opacity readings in the range of 3 – 7%, the choice of 15% opacity as an excursion level is not likely to be approved.

2. If a direct correlation can not be demonstrated between the opacity and PM readings, consider the possibility of using the pressure drop across the baghouse as an indicator range instead of opacity. If this appears to be more reliable, please identify an indicator range for the pressure drop across the baghouses (maximum and minimum) and provide a table of data that documents the tested PM emission rate, the simultaneous pressure drop across the baghouse, the test date, the operational rate during the test, and the allowable capacity of the units.

Material Handling Units with Baghouses

3. The non-applicability determination for the baghouses, with respect to CAM, is somewhat questionable due to the use of a baghouse efficiency factor of only 99%. The efficiency of a

baghouse is generally accepted to be closer to 99.9%. Using the permitted emission rates and applying an efficiency factor of 99.9% provides results that implies all of the material handling baghouses are subject to CAM due to pre-control potential emissions being greater than 100 tpy. However, this is not the only acceptable method of determining pre-control potential emissions for CAM purposes. AP-42 emission factors (or similar) combined with operator knowledge of the process may be used if justified, as well as vendor guarantees. Please re-evaluate the applicability determinations for these units and either supply the rationale and justification of the baghouse efficiencies or explore other methods of determining pre-control potential emissions. If the pre-control emissions can not be adequately justified, CAM plans will need to be submitted.

Please make the appropriate changes resulting from the above comments and resubmit the required CAM plans. Also include and electronic copy of the CAM plans as a Word (.doc) file.

Rule 62-4.050(3), F.A.C. requires that all applications for a Department permit must be certified by a professional engineer registered in the State of Florida. This requirement also applies to responses to Department requests for additional information of an engineering nature. Please note that per Rule 62-4.055(1): *"The applicant shall have ninety days after the Department mails a timely request for additional information to submit that information to the Department.......... Failure of an applicant to provide the timely requested information by the applicable date shall result in denial of the application."*

If you have any questions, please call Michael P. Halpin, P.E. at 850/921-9519.

Sincerely,

Michael P. Halpin

Michael P. Halpin, P.E.
DARM/BAR
North Permitting Section

Martin Kreft, Cedar Bay
George Lipka, P.E. EarthTech
James L. Manning, P.E. RESD
Chris Kirts, DEP-NED

Compliance Assurance Monitoring Plan for CFB Boilers at the Cedar Bay Generating Plant FDEP Facility ID 0310337

Prepared for:

Cedar Bay Generating Co., L.P.
P.O. Box 26324
Jacksonville Florida 32226

Facility Location:
9640 Eastport Road
Jacksonville Florida 32226

Prepared By:

Earth Tech
196 Baker Avenue
Concord, Massachusetts 01742

January 2004
Earth Tech Project No. 66645

COMPLIANCE ASSURANCE MONITORING REQUIREMENTS

This CAM Plan addresses the Compliance Assurance Monitoring (CAM) requirements of 40 CFR 64, as they apply to the Circulating Fluidized Bed (CFB) boilers at the Cedar Bay Generating Plant. The Title V Renewal Application Text (separate document, *Cedar Bay Title V.doc*) addresses a source-by-source CAM applicability review, and documentation of potential emissions calculations. .

1 CAM Submittal Guidance and Approach

For the CFB boilers, the existing Continuous Opacity Monitoring System (COMS) will be used to demonstrate compliance. Cedar Bay has prepared a review of available data under normal operation to determine the representative stack opacity of each unit. The results of this review indicate that 10% opacity during non-startup or shutdown periods is atypical and may indicate a potential problem with the baghouse.

3.□ Documentation of Regulatory Compliance

This CAM Plan meets the requirements of 40 CFR 64.4. Each regulatory requirement is repeated below, along with a description of how the CAM Plan meets the requirement.

Table CAM-1: Compliance with 40 CFR 64.4

Requirement	Compliance Description
64.4 (a) The owner or operator shall submit to the permitting authority monitoring that satisfies the design requirements in § 64.3. The submission shall include the following information: **3.**□ The indicators to be monitored to satisfy §§ 64.3(a)(1)-(2); (2) The ranges or designated conditions for such indicators, or the process by which such indicator ranges or designated conditions shall be established; (3) The performance criteria for the monitoring to satisfy § 64.3(b); and (4) If applicable, the indicator ranges and performance criteria for a CEMS, COMS or PEMS pursuant to § 64.3(d).	*Indicators for the CFB Boilers are: opacity. Ranges and performance criteria are listed in Section 3. The CFB Boilers have an associated COMS; the indicator range and performance criteria are listed in Section 3..*
64.4 (b) As part of the information submitted, the owner or operator shall submit a justification for the proposed elements of the monitoring. If the performance specifications proposed to satisfy § 64.3(b)(2) or (3) include differences from manufacturer recommendations, the owner or operator shall explain the reasons for the differences between the requirements proposed by the owner or operator and the manufacturer's recommendations or requirements.	*The proposed elements of monitoring are justified because they use the COMS. There are no differences between the requirements proposed and the manufacturers' recommendations and/or requirements.*

Requirement	Compliance Description
64.4 (b) (cont'd) The owner or operator also shall submit any data supporting the justification, and may refer to generally available sources of information used to support the justification (such as generally available air pollution engineering manuals, or EPA or permitting authority publications on appropriate monitoring for various types of control devices or capture systems).	*Cedar Bay supplies summaries of opacity readings as part of the quarterly COMS/Emission reporting, and has provided annual particulate matter stack test reports.*
64.4 (b) (cont'd) To justify the appropriateness of the monitoring elements proposed, the owner or operator may rely in part on existing applicable requirements that establish the monitoring for the applicable pollutant-specific emissions unit or a similar unit.	*The CAM Plan relies in part on the approved CAM plan for JEA Northside &St. Johns River Power Park (0310045.011AV.Appendix.CAM. SJRPP.NGS.doc) and Lakeland McIntosh (1050004.016.AV.F.zip), available through www.dep.state.fl.us/air/permitting/ airpermits/AirSearch_ltd.asp.*
64.4 (b) (cont'd) If an owner or operator relies on presumptively acceptable monitoring, no further justification for the appropriateness of that monitoring should be necessary other than an explanation of the applicability of such monitoring to the unit in question, unless data or information is brought forward to rebut the assumption. Presumptively acceptable monitoring includes: **3.** Presumptively acceptable or required monitoring approaches, established by the permitting authority in a rule that constitutes part of the applicable implementation plan required pursuant to title I of the Act, that are designed to achieve compliance with this part for particular pollutant-specific emissions units; (2) Continuous emission, opacity or predictive emission monitoring systems that satisfy applicable monitoring requirements and performance specifications as specified in § 64.3(d); (3) Excepted or alternative monitoring methods allowed or approved pursuant to Part 75 of this chapter; (4) Monitoring included for standards exempt from this part pursuant to § 64.2(b)(1)(i) or (vi) to the extent such monitoring is applicable to the performance of the control device (and associated capture system) for the pollutant-specific emissions unit; and (5) Presumptively acceptable monitoring identified in guidance by EPA. Such guidance will address the requirements under § 64.4(a), (b), and (c) to the extent practicable.	*To be conservative, the CAM plan includes justification that the monitoring is acceptable.*
64.4 (c) (1) Except as provided in paragraph (d) of this section, the owner or operator shall submit control	*The most recent compliance test results for the CFB Boilers were submitted to the Department*

Requirement	Compliance Description
device (and process and capture system, if applicable) operating parameter data obtained during the conduct of the applicable compliance or performance test conducted under conditions specified by the applicable rule. If the applicable rule does not specify testing conditions or only partially specifies test conditions, the performance test generally shall be conducted under conditions representative of maximum emissions potential under anticipated operating conditions at the pollutant-specific emissions unit. Such data may be supplemented, if desired, by engineering assessments and manufacturer's recommendations to justify the indicator ranges (or, if applicable, the procedures for establishing such indicator ranges). Emission testing is not required to be conducted over the entire indicator range or range of potential emissions.	*on April 17, 2003.*
(2) The owner or operator must document that no changes to the pollutant specific emissions unit, including the control device and capture system, have taken place that could result in a significant change in the control system performance or the selected ranges or designated conditions for the indicators to be monitored since the performance or compliance tests were conducted.	*Cedar Bay hereby documents that no changes to the CFB Boilers, have taken place that could result in a significant change in the control system performance or the selected ranges or designated conditions for the indicators to be monitored since the performance or compliance tests were conducted.*
64.4 (d) If existing data from unit-specific compliance or performance testing specified in paragraph (c) of this section are not available, the owner or operator: **3.** Shall submit a test plan and schedule for obtaining such data in accordance with paragraph (e) of this section; or (2) May submit indicator ranges (or procedures for establishing indicator ranges) that rely on engineering assessments and other data, provided that the owner or operator demonstrates that factors specific to the type of monitoring, control device, or pollutant-specific emissions unit make compliance or performance testing unnecessary to establish indicator ranges at levels that satisfy the criteria in § 64.3(a).	*Not applicable.*
64.4 (e) If the monitoring submitted by the owner or operator requires installation, testing, or other necessary activities prior to use of the monitoring for purposes of this part, the owner or operator shall include an implementation plan and schedule for installing, testing and performing any other appropriate activities prior to use of the monitoring. The implementation plan and schedule shall provide for use of the monitoring as expeditiously as practicable after approval of the	*The COM systems are functional and in use. Initial COM Certifications submitted.*

Requirement	Compliance Description
monitoring in the part 70 or 71 permit pursuant to § 64.6, but in no case shall the schedule for completing installation and beginning operation of the monitoring exceed 180 days after approval of the permit.	
64.4 (f) If a control device is common to more than one pollutant-specific emissions unit, the owner or operator may submit monitoring for the control device and identify the pollutant-specific emissions units affected and any process or associated capture device conditions that must be maintained or monitored in accordance with § 64.3(a) rather than submit separate monitoring for each pollutant-specific emissions unit.	*The affected control devices are not common to more than one pollutant-specific emissions unit. Therefore, this paragraph does not apply.*
64.4 (g) If a single pollutant-specific emissions unit is controlled by more than one control device similar in design and operation, the owner or operator may submit monitoring that applies to all the control devices and identify the control devices affected and any process or associated capture device conditions that must be maintained or monitored in accordance with § 64.3(a) rather than submit a separate description of monitoring for each control device.	*The affected pollutant-specific emissions units do not have multiple control devices. Therefore, this paragraph does not apply.*

3. Proposed CAM Text

The following tables include proposed language for inclusion into the renewed Title V permit.

Table CAM-2. Monitoring Approach – CFB Boilers

	Compliance Indicator
I. Indicator	Duct opacity.
Measurement Approach	Continuous opacity monitoring system (COMS).
II. Indicator Range	An excursion is defined as 5 consecutive 6-minute averages of opacity greater than 10.0%. (other than startup and shutdown periods).
III. Performance Criteria	

	Compliance Indicator
A. Data Representativeness	Based on available data under normal operation, the representative stack opacity of each unit is in the range of 3 to 7%. A 50% average opacity above 7% during non-startup or shutdown periods is atypical and may indicate a potential problem with the baghouse.
B. Verification of Operational Status	Annual testing during normal operation is used to verify particulate mass loading. The COM system is audited quarterly.
C. QA/QC Practices and Criteria	Install and operate COMS according to 40 CFR Part 60 Appendix B, Performance Specification 1 and general provisions 60.13.
D. Monitoring Frequency	Continuous.
E. Data Collection Procedures	The COMS collects data that are reduced to 6-minute averages. Consecutive 6-minute averages are tracked through the Distributed Control System (DCS) and CEM software.
F. Averaging Period	Five consecutive 6-minute averages.

Table CAM-3. Corrective Action Procedures Summary – CFB Boilers

	Description
I. Initiation of Corrective	Corrective action shall be initiated with the discovery of 5

	Action Procedures	consecutive 6-minute averages of opacity greater than 10% and that defines an excursion (as defined in Table CAM-2). The plant staff that made the discovery shall immediately notify the shift supervisor or responsible official. This action describes a corrective action trigger.
II.	Time of Completion of Corrective Action Procedures	As soon as practically possible.
III.	Corrective Action	The shift supervisor or responsible official will implement the following as a corrective action. Procedures, as presented in the O&M Plan, include the following alternatives that will be initiated as necessary. • Perform operational diagnostics to identify cause of the excursion. • If operational diagnostics indicate a malfunction of the baghouse, the reason for failure will be identified. • If isolation of the compartment can be accomplished to reduce opacity below the excursion level, such measures will be undertaken. • In the event of the need for the unit shutdown to bring opacity to below excursion levels, the task will be undertaken based on procedures described in the O&M Plan for the facility. Regardless of the failure mechanism, baghouse operation will be restored such that the cause of excursion is identified and appropriate actions taken to ensure opacity below excursion levels.

4. CAM Justification

1. Background

The pollutant-specific emission units are the Circulating Fluidized Bed (CFB) boilers, which fires coal (and oil and pet coke) to generate electricity and steam. It is controlled by a fabric filter baghouse, which filters approximately 300,000 dscfm of air from each CFB Boiler.

There are three CFB boilers. This CAM submission applies to all three boilers.

2. Rationale for Selection of Performance Indicators

The COMS was selected as the performance indicator because it is indicative of particulate emission rate. Although not a direct measurement of particulate emissions, opacity monitors have been used for some time to provide continuous assurance of good operation of particulate emission control systems. When the baghouse is operating properly, the opacity from the exhaust will be within the current permit limits. Any increase in visible emissions indicates reduced performance of a particulate control device, therefore, the presence of visible emissions is used as a performance indicator.

The COMS was also selected to provide consistency with the existing monitoring program as implemented through the PSD permit and the Title V permit.

3. Rationale for Selection of Indicator Ranges

The selected indicator range is an opacity reading greater than 10%, for five consecutive 6-minute averages. When an excursion occurs, corrective action will be initiated, beginning with an evaluation of the occurrence to determine the action required to correct the situation. All excursions will be documented and reported. This indicator range was selected based on an excursion level 50% above the representative stack opacity based on available data under normal operation.

The plant environmental manager conducted a review of the opacity readings during January-December 2003, and checked representative data against operation and maintenance logs. The customary range of opacity for all three boilers is 3-7% opacity, with occasional 9% & 10% (and 11%) opacity values. These most likely happened after a compartment was returned to service after having been isolated and cleaned. The overall typical opacity range of 3-10% covers all methods of operation, including boiler load change, base loaded operation and periods of soot blow. As Cedar Bay normally operates base-loaded, this is the vast majority of the operational data.

Cedar Bay
CAM Rule Applicability
Earth Tech March 2004

From 40 CFR 64, a facility is subject to Compliance Assurance monitoring conditions if the following two conditions are met:

1. Emissions unit uses a control device to achieve compliance
and
2. Potential precontrol emissions of applicable pollutant are at least 100 percent of the major source amount.

This spreadsheet documents which sources/pollutants are subject to the CAM rule at Cedar Bay. Calculations are performed two ways - based on EPA AP-42 factors for particulate generation, and based on airflow and permit limits for particulate emission rate.

Emission Source	Potential Emiss. pre-control	Calc. Type	Major Source Threshold, tpy	Subject to CAM?	Notes	EU No.
	tpy		tpy			
Coal Crusher Dust Collector	28.8	AP-42 Drop & Crush	100	No	Conservatively assume crushing emissions from both collectors	6
Coal Silo Area Dust Collector	28.8	AP-42 Drop & Crush	100	No		7
Pulverized Limestone Feeder 1A1	0.18	AP-42 Drop	100	No		31
Pulverized Limestone Feeder 1A2	0.18	AP-42 Drop	100	No		31
Pulverized Limestone Feeder 1B1	0.18	AP-42 Drop	100	No		31
Pulverized Limestone Feeder 1B2	0.18	AP-42 Drop	100	No		31
Pulverized Limestone Feeder 1C1	0.18	AP-42 Drop	100	No		31
Pulverized Limestone Feeder 1C2	0.18	AP-42 Drop	100	No		31
ADS Storage Bin - 1	0.71	AP-42 Drop	100	No	AP-42 calculated emissions (0.6 tpy) less than PTE after control	9
ADS Storage Bin - 2	0.75	AP-42 Drop	100	No	AP-42 calculated emissions (0.6 tpy) less than PTE after control	25
Bed Ash Hopper	0.14	AP-42 Drop	100	No		10
Dry Ash Rail Car Load Out	1.85	AP-42 Drop	100	No		30
Fly Ash Silo Bin Vent	1.85	AP-42 Drop	100	No		33
Bed Ash Silo Bin Vent	0.46	AP-42 Drop	100	No	AP-42 calculated emissions (0.41 tpy) less than PTE after control	32
Bed Ash Separator/Collector	0.14	AP-42 Drop	100	No		11
Fly Ash Separator/Collector-1	1.85	AP-42 Drop	100	No		12
Fly Ash Separator/Collector-2	1.85	AP-42 Drop	100	No		26

* for sources where the calculated potential emission rate before control is lower than the permit limit after control, the permit limit after control is used as the estimate for the potential emission rate before control.

CEDAR BAY
PARTICULATE EMISSIONS FROM DROP OPERATIONS

DROP OPERATION EMISSIONS						
Coal Crusher Dust Collector						
			PM-30	PM-10		
particle size multiplier	k		0.74	0.35		
mean wind speed	U	miles/hour	5	5	(indoors)	
material moisture content	M	%	7.26	7.26		
Emission factor	E	lb/ton/drop	0.0004	0.0002		
Amount dropped		ton/yr	1,135,600	1,135,600		
Number of times dropped			2	2		
Emissions		pounds/year	885	418		
		tons/year	0.44	0.21		
Coal Silo Area Dust Collector						
			PM-30	PM-10		
particle size multiplier	k		0.74	0.35		
mean wind speed	U	miles/hour	5	5	(indoors)	
material moisture content	M	%	7.26	7.26		
Emission factor	E	lb/ton/drop	0.0004	0.0002		
Amount dropped		ton/yr	1,135,600	1,135,600		
Number of times dropped			2	2		
Emissions		pounds/year	885	418		
		tons/year	0.44	0.21		
Pulverized Limestone Feeders, typical of 6						
			PM-30	PM-10		
particle size multiplier	k		0.74	0.35		
mean wind speed	U	miles/hour	12	12	(outdoors)	
material moisture content	M	%	2	2		
Emission factor	E	lb/ton/drop	0.0074	0.0035		
Amount dropped		ton/yr	24,605	24,605		
Number of times dropped			2	2		
Emissions		pounds/year	364	172		
		tons/year	0.18	0.09		
ADS Storage Bin, typical of 2						
			PM-30	PM-10		

particle size multiplier	k		0.74	0.35		
mean wind speed	U	miles/hour	12	12	(outdoors)	
material moisture content	M	%	2	2		
Emission factor	E	lb/ton/drop	0.0074	0.0035		
Amount dropped		ton/yr	73,814	73,814		
Number of times dropped			2	2		
Emissions		pounds/year	1091	516		
		tons/year	0.55	0.26		
Bed Ash Hopper						
			PM-30	PM-10		
particle size multiplier	k		0.74	0.35		
mean wind speed	U	miles/hour	12	12	(outdoors)	
material moisture content	M	%	3	3		
Emission factor	E	lb/ton/drop	0.0042	0.0020		
Amount dropped		ton/yr	34,068	34,068		
Number of times dropped			2	2		
Emissions		pounds/year	285	135		
		tons/year	0.14	0.07		
Dry Ash Rail Car Load Out						
			PM-30	PM-10		
particle size multiplier	k		0.74	0.35		
mean wind speed	U	miles/hour	12	12	(outdoors)	
material moisture content	M	%	2	2		
Emission factor	E	lb/ton/drop	0.0074	0.0035		
Amount dropped		ton/yr	249,832	249,832		
Number of times dropped			2	2		
Emissions		pounds/year	3693	1747		
		tons/year	1.85	0.87		
Fly Ash Silo Bin Vent						
			PM-30	PM-10		
particle size multiplier	k		0.74	0.35		
mean wind speed	U	miles/hour	12	12	(outdoors)	
material moisture content	M	%	2	2		
Emission factor	E	lb/ton/drop	0.0074	0.0035		
Amount dropped		ton/yr	249,832	249,832		
Number of times dropped			2	2		
Emissions		pounds/year	3693	1747		
		tons/year	1.85	0.87		
Bed Ash Silo Bin Vent						
			PM-30	PM-10		
particle size multiplier	k		0.74	0.35		
mean wind speed	U	miles/hour	12	12	(outdoors)	
material moisture content	M	%	3	3		
Emission factor	E	lb/ton/drop	0.0042	0.0020		
Amount dropped		ton/yr	34,068	34,068		
Number of times dropped			2	2		
Emissions		pounds/year	285	135		
		tons/year	0.14	0.07		

CEDAR BAY
PARTICULATE EMISSIONS FROM DROP OPERATIONS

Bed Ash Separator/Collector						
			PM-30	PM-10		
particle size multiplier	k		0.74	0.35		
mean wind speed	U	miles/hour	12	12	(outdoors)	
material moisture content	M	%	3	3		
Emission factor	E	lb/ton/drop	0.0042	0.0020		
Amount dropped		ton/yr	34,068	34,068		
Number of times dropped			2	2		
Emissions		pounds/year	285	135		
		tons/year	0.14	0.07		

CEDAR BAY
PARTICULATE EMISSIONS FROM DROP OPERATIONS

Fly Ash Separator/Collector (typical of 2)						
			PM-30	PM-10		
particle size multiplier	k		0.74	0.35		
mean wind speed	U	miles/hour	12	12	(outdoors)	
material moisture content	M	%	2	2		
Emission factor	E	lb/ton/drop	0.0074	0.0035		
Amount dropped		ton/yr	249,832	249,832		
Number of times dropped			2	2		
Emissions		pounds/year	3693	1747		
		tons/year	1.85	0.87		

CEDAR BAY
PARTICULATE EMISSIONS FROM CRUSHING OPERATIONS

MAXIMUM POTENTIAL MATERIAL QUANTITIES	
3189	MMBTU/HR MAXIMUM FIRING RATE
27,935,640	MMBTU/YR MAXIMUM FIRING RATE
12,300	BTU/LB average coal heat rate from 2003 as-fired coal analyses
1,135,595	TON/YR ESTIMATED MAXIMUM SOLID FUEL FIRING RATE
Round To:	
1,135,600	TON/YR TOTAL ESTIMATED MAXIMUM SOLID FUEL FIRING RATE
0.13	LB LIMESTONE/LB SOLID FUEL FIRED, ESTIMATED MAXIMUM
147,628	TON/YR TOTAL ESTIMATED MAXIMUM LIMESTONE USE RATE
12%	OF SOLID FUEL BECOMES ASH
100%	OF LIMESTONE BECOMES ASH
283,900	TONS/YEAR ESTIMATED MAXIMUM ASH
88%	OF ASH IS FLYASH
249,832	TONS/YEAR ESTIMATED MAXIMUM FLYASH
34,068	TONS/YEAR ESTIMATED MAXIMUM BED ASH

National Energy & Gas Transmission.
National Energy Power Company, LLC

RECEIVED
MAR 29 2004
BUREAU OF AIR REGULATION

Cedar Bay Generating Co., L.P.
9640 Eastport Road
Jacksonville, FL 32218

904.751.4000
Fax: 904.751.7320
www.negt.com

March 26, 2004

Mr. Michael Halpin, P.E.
Florida Department of Environmental Protection
Division of Air Resource Management
Bureau of Air Regulation
Mail Station #5505
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Re: Cedar Bay Title V Permit Renewal Request for Additional Information
File No. 0310337-007-AV

Dear Mr. Halpin:

Pursuant to your letter dated March 2, 2004 and in order to continue processing Cedar Bay's Title V permit renewal, Cedar Bay submits the following documents:

- A revised CAM Plan
- A revised CAM Non-Applicability Determination for Material Handling Units

CAM Plan for Boilers A, B, and C (EU 001, 002 & 003)
Cedar Bay's CAM plan has been revised after a review and additional analyses of COM data and after a review of other CAM plans. Specifically, Table CAM-2. Monitoring Approach Indicator Range and Data Representativeness and Table CAM-3. Corrective Action Procedures Summary, Corrective Action have been modified. The revised CAM plan was e-mailed to the Department on March 25, 2004.

Material Handling Units with Baghouses
Pursuant to the Department's request, the CAM non-applicability determination for Cedar Bay's Material Handling Emission Units were recalculated using applicable AP-42 emission factors. The revised non-applicability determination was e-mailed to the Department on March 24, 2004.

If there are any questions or if any additional information is needed, please do not hesitate to contact me via phone or e-mail.

Sincerely,

Jeffrey A. Walker

Jeffrey A. Walker
Environmental Manager, Cedar Bay Plant

Martin Kreft, Cedar Bay
AJ Jablonowski, Earthtech
Tom Fromm, Bethesda

FLORIDA DEPARTMENT OF ENVIRONMENTAL PROTECTION

Department of Environmental Protection

Jeb Bush
Governor

Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

David B. Struhs
Secretary

December 20, 2002

Mr. Bruce Smith
General Manager
Cedar Bay Generating Company, L.P.
P.O. Box 26324
Jacksonville, Florida 32226-6324

Re: DEP File No. PA 88-24; Modification of Permit No. PSD-FL-137
Cedar Bay Generating Plant / Duval County

The applicant, Cedar Bay Generating Company, L.P., applied on August 29, 2001, to the Department for a modification to PSD permit number PSD-FL-137 for its Cedar Bay Generating Plant located in Duval County. The modification is to allow the facility to co-fire petroleum coke (petcoke) in its three circulating fluidized bed boilers (A, B and C). The applicant has represented to the Department that the petcoke is to be delivered solely by rail.

The Department has reviewed the modification request. The referenced permit is hereby modified as follows:

II.A. Emission Limitations for 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. <u>Petroleum coke (petcoke) may be utilized as a co-firing fuel, and shall not exceed 35% fuel input by weight on a daily basis. {Permitting Note: The limitations on the coal charging rate include both coal and petcoke.}</u>

   d. The sulfur content of the coal shall not exceed 1.2%, by weight, on an annual basis. The sulfur content shall not exceed 1.7%, by weight, on a shipment (train load) basis. <u>When co-firing coal and petcoke, the blended fuel input to the CFBs shall not exceed 3.2 lb/MMBtu equivalent SO_2 content. Compliance shall be determined on a monthly basis via a composite of daily fuel samples.</u>

4. Ammonia (NH_3) slip from the exhaust gases shall not exceed 10 ppmvd when <u>co-firing petcoke or</u> burning coal at 100% capacity and 30 ppmvd when burning oil.

10. Operations Monitoring for each CFB

    b. All coal<u>, petcoke</u> 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 and recorded for each 24-hour period in which rejects are burned.

17. <u>The permittee shall submit annual reports to RESD and DEP/BAR summarizing emissions for each calendar year. The reports will commence during the first year in which petcoke is fired</u>

and continue for a total of five calendar years. Such reports are required in order to confirm Cedar Bay's projections of future actual emissions and to demonstrate to the Department's satisfaction that petcoke co-firing did not result in a significant emissions increase. Reporting shall be as follows:

Pollutant	**Compliance Procedures**
NO_X	Five years of annual reporting by CEMS proving annual facility emissions do not exceed 1799 TPY
CO	Five years of annual reporting by CEMS proving annual facility emissions do not exceed 648 TPY
VOC	Five years of annual reporting by stack test proving annual facility emissions do not exceed 74 TPY
SO_2	Five years of annual reporting by CEMS proving annual facility emissions do not exceed 1985 TPY
SAM	Five years of annual reporting by stack test proving annual facility emissions do not exceed 7.3 TPY
PM_{10}	Five years of annual reporting by stack test proving annual facility emissions do not exceed 198 TPY

II.B.CBCP - Material Handling and Treatment

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
Petcoke	40,950	409,500
Limestone	27,000	~~320,000~~ 275,000
Fly Ash	28,000	336,000
Bed Ash	8,000[1]	88,000[1]

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

[1] The Department will require a monitoring system to accurately measure Bed Ash throughput. The applicant will propose (to the Department's satisfaction) the system it recommends to utilize, prior to the initial receipt of petcoke. Actual in-service testing (while combusting coal) will be completed prior to the initial firing of petcoke, demonstrating its adequacy to the Department's satisfaction.

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

Coal Car Unloading
Ash Pellet Hydrator
Ash Pellet Curing Silo
Ash Pelletizing Pan

Petcoke Unloading/Handling Areas
Petcoke Transfer Areas
Petcoke Storage Areas

The above listed sources are subject to a VE and a PM emissions limitation requirement of 5% opacity and 0.01 gr/dscf (applicant requested limitation, which is more stringent than what is allowed by rule), respectively, in accordance with Rule 17-296.711, F.A.C. Initial and subsequent compliance tests shall be conducted for VE and PM emissions using EPA Methods 9 and 5, respectively, in accordance with Chapter 17-297, F.A.C., and 40 CFR 60, Appendix A (July, 1992 version).

A copy of this letter shall be filed with the referenced permit and shall become part of the permit. This permit modification is issued pursuant to Chapter 403, Florida Statutes.

Any party to this order (permit modification) has the right to seek judicial review of it under Section 120.68, F.S., by filing a notice of appeal under Rule 9.110 of the Florida Rules of Appellate Procedure with the clerk of the Department of Environmental Protection in the Office of General Counsel, Mail Station #35, 3900 Commonwealth Boulevard, Tallahassee, Florida, 32399-3000, and by filing a copy of the notice of appeal accompanied by the applicable filing fees with the appropriate District Court of Appeal. The notice must be filed within thirty days after this order is filed with the clerk of the Department.

Executed in Tallahassee, Florida.

Howard L. Rhodes

Howard L. Rhodes, Director
Division of Air Resources
Management

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this permit modification was sent by certified mail (*) and copies were mailed by U.S. Mail before the close of business on 12/20/02 to the person(s) listed:

Bruce Smith, Cedar Bay *
J. A. Walker, Cedar Bay
Ken Kosky, P.E. Golder Associates
Hamilton S. Oven, P.E.
James L. Manning, P.E., RESD
Doug Neeley, EPA
John Bunyak, NPS
Chris Kirts, DEP-NED
Stafford Campbell, Greater Arlington Civic Council

Clerk Stamp

FILING AND ACKNOWLEDGMENT FILED,
on this date, pursuant to §120.52, Florida Statutes, with the designated Department Clerk, receipt of which is hereby acknowledged.

Victoria Gibson / December 20, 2002
(Clerk) (Date)

PG&E National Energy Group™
Cedar Bay Generating Plant
Owner: Cedar Bay Generating Company, L.P.

RECEIVED
DEC 18 2002
BUREAU OF AIR REGULATION

POB 26324
Jacksonville, FL 32226-6324
904.751.4000
Fax 904.751.7320

December 17, 2002

A.A. Linero, P.E.
Bureau of Air Regulation
Department of Environmental Protection
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Re: DEP File No. PA 88-24; Modification of Permit No. PSD-FL-137
Cedar Bay Generating Plant / Duval County

Dear Mr. Linero:

On August 29, 2001, Cedar Bay Generating Company, L.P. (Cedar Bay), filed an application with the Department for a modification of the PSD permit (No. PSD-FL-137) for Cedar Bay's cogeneration facility (Facility) in Jacksonville, Florida. Specifically, Cedar Bay requested authorization to co-fire petroleum coke (pet coke) and coal in the Facility's three boilers. Cedar Bay's application included a description of a proposed truck unloading area that would be used for the delivery of petcoke. The new truck unloading area would supplement the Facility's existing rail unloading facility. Since the proposed truck unloading area would not be covered, unlike the existing rail unloading facility, the delivery of petcoke by truck could cause an increase in the fugitive emissions at the Facility. Accordingly, Cedar Bay's application included a calculation of the potential increase in fugitive emissions for PM and PM10, based on the assumption that petcoke would be delivered to the Facility by truck, rather than rail.

On July 31, 2002, the Department issued a Draft PSD Permit Modification concerning Cedar Bay's request. Thereafter, CSX Transportation (CSXT) filed a petition for a formal administrative hearing, challenging the Department's Draft PSD Permit Modification.

To resolve CSXT's objections, Cedar Bay has agreed that it will deliver petcoke to the Facility by rail. Accordingly, Cedar Bay hereby amends its application for a PSD permit modification by deleting all references in the application to the use of trucks or a truck unloading area for the delivery of petcoke. Cedar Bay is no longer seeking and no longer wishes to receive FDEP's approval for a truck unloading area or truck deliveries for petcoke. Further, Cedar Bay respectfully requests the Department to include the following sentence in its PSD Permit Modification, as a means of clarifying the basis for the Department's action in this case:

> The applicant has represented to the Department that the petcoke is to be delivered to the Facility solely by rail.

Cedar Bay greatly appreciates the Department's cooperation and assistance in resolving these matters. Please call Mr. Jeff Walker at (904) 751-4000 if you have any questions.

Sincerely,

Martin Kreft

Martin Kreft
General Manager
Cedar Bay Generating Company, L.P.

CC: Michael P. Halpin
David S. Dee
Jeff Walker
Kathleen Stallings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COKE EXPR
CSXT
29 62 43

ACCI ACTIONLINE

A NEWS BRIEF FROM THE AMERICAN COKE AND COAL CHEMICALS INSTITUTE / NUMBER I / 2002

PLAN TO ATTEND THE ACCCI 58TH ANNUAL MEETING

Plan now to join other top executives at the premier conference of the coke industry:

ACCCI 58th Annual Meeting
September 29-30, 2002

The Greenbrier
White Sulphur Springs, W.V.

James (Buddy) and Renee Wolfe, ABC Coke
Program Chairs

To help reduce ACCCI members' overall cost of attending the Annual Meeting, the program is shortened by one day. The ACCCI Annual Meeting remains the exclusive conference where the U.S. coke producers' decision makers and their suppliers can meet one-on-one in an intimate setting, without the distractions of competing seminars.

The committee meetings provide the latest updates on the coke market and its customer and supplier markets. The General Session features Dr. Mardy Grothe, a pioneer in the field of business therapy. For 20 years, Dr. Grothe has counseled top executives on applying therapeutic psychology to enhance business relationships.

The program also provides attendees with ample opportunities to enjoy the Greenbrier's unique activities, including its three championship golf courses and expanded spa. The Greenbrier was voted the "World's #1 Value Resort" by *Travel+Leisure* magazine.

Please register with ACCCI by August 30.

■ *Contact: David Saunders or Rebecca Page*

DUES REFUND WELCOMED BY ALL MEMBERS

Back in March, all ACCCI member companies received a much-welcomed 20% dues refund check for 2002. Due to the weak business climate, the ACCCI Board of Directors agreed that all member companies would benefit from this financial relief. After re-evaluating all of its programs, cutting some areas of the budget, and distributing the dues refunds, ACCCI remains in good financial standing.

ACCCI is committed to advancing the success of its member companies by providing valuable, quality programs. ACCCI's members continue to receive valuable services, such as quarterly statistical reports on the metallurgical coke and coal tar markets, including production, shipment, and injury/illness data; representation before the EPA and other federal agencies involved in regulatory rulemaking; updated capacity surveys on foundry and furnace coke plants; and, semi-annual meetings at which to discuss industry issues and network with customers and suppliers.

■ *Contact: David Saunders or Rebecca Page*

AK STEEL-MIDDLETOWN WINS ACCCI SAFETY AWARD

For the fourth time in five years, AK Steel Corp.'s Middletown, Ohio, coke plant is the recipient of the ACCCI Max Eward Safety Award. ACCCI Chairman Robert Bloom presented the 2001 award to Robert Weigel, manager of the Middletown coke plant, during the ACCCI 2002 Spring Meeting. Bloom remarked, "Another perfect record. In the history of the award, AK Steel-Middletown has been the only ACCCI-member coke plant to have absolutely no recordable injuries." The award, in its fourteenth year, is presented annually to the ACCCI-member coke plant which achieves the lowest incidence rate for worker injuries and illnesses.

■ *Contact: David Saunders*

CALL FOR SUPPLIER COMPANY PRESENTATIONS

Is your company effectively reaching the decision-makers for the coke plants? If not, then consider giving a face-to-face presentation before the executives and managers who count. This year opportunities to inform potential customers about your company's products or services are available at both the ACCCI Annual Meeting and the Fall Manufacturing, Environmental, Safety & Health (MESH) Committee Meeting. Depending on whom your company wishes to contact, top level executives attend the Annual Meeting, while operations managers, engineers, and environmental, safety, and health professionals attend the MESH Meeting. Call now to reserve a place on either meeting agenda. Further information on both meetings is available elsewhere in this newsletter.

■ *Contact: David Saunders, Dave Ailor, or Rebecca Page*

Industry Supplier Awards Presented at Spring Meeting

ACCCI members and spouses enjoyed an informative and enjoyable 2002 Spring Meeting, held May 8-10 in Monterey, Cal. During the banquet, supplier service awards were presented to two companies.

Awards were presented to CSX Transportation and Norfolk Southern Corporation for their innovation and dedication to the coke and metallurgical coal industries. CSXT was recognized for pioneering its Coke Express fleet, which includes high top rail cars designed specifically for the transport of coke. NS was recognized for implementing its Coal Transportation Management System, designed to custom track inbound coal deliveries. Ben Sheldon and Tony Wade, respectively, received the awards on behalf of CSXT and NS.

The Spring Meeting also featured the latest news on the metallurgical coke, coal chemicals, coal, steel, automotive, construction, and transportation markets. During the General Session, participants were entertained by humorist Jim Pelley, former contributing writer for the *Saturday Night Live* show.

Outside of the meetings, members were able to network with their colleagues during group dinners and cocktail receptions, and a golf tournament. The spouses enjoyed a visit to the National John Steinbeck Center in the Salinas Valley. The Monterey Peninsula, with its endless recreational choices, proved to be an ideal location for the meeting. ACCCI thanks Bob and Sandra Simons of Hickman, Williams & Company for serving as the program chairs.

■ *Contact: David Saunders or Rebecca Page*

MESH Committee Planning Its 2002 Meeting

The ACCCI Manufacturing, Environmental, Safety & Health (MESH) Committee will hold its 2002 Meeting on October 17-18. The meeting will focus on manufacturing practices, environmental issues, employee safety and health, coke quality, and human resource issues. Supplier member companies interested in being considered for presentation opportunities relative to their firms' products, services, and new technologies that may be of interest to coke producers should contact ACCCI as soon as possible.

■ *Contact: Dave Ailor or David Saunders*

ACCCI/COETF Continue Working with EPA on MACT Standards

ACCCI continues to coordinate the activities of the Coke Oven Environmental Task Force (COETF), which it and the American Iron and Steel Institute (AISI) formed in 1996 to address major environmental issues. The COETF continues to work with EPA in the Agency's development of "maximum achievable control technology" (MACT) standards for three coke plant emission points believed by the Agency to be sources of hazardous air pollutants (HAPs) — pushing operations, quenching operations, and battery stacks. EPA published its proposed rules for these three sources on July 3, 2001 (*66 Fed. Reg. 35326*). The COETF has provided EPA with comments on the proposed rules.

The standards, which will not be promulgated until late 2002 or early 2003, will be very stringent, because they must reflect the emissions performance of the best plants in the industry. The COETF has argued that it is infeasible for EPA to set numerical performance for pushing and battery stacks emissions, requesting that the Agency set "work practice" standards instead. EPA appears intent on rejecting this argument for battery stacks and intends to require coke plants to comply with these standards within three years of promulgation.

■ *Contact: Dave Ailor*

ACCCI/COETF Continue Working with EPA on Residual Risk Standards

The coke industry will be among the first industries subject to residual risk standard setting by EPA pursuant to Section 112(f) of the Clean Air Act Amendments of 1990. Section 112(f) requires that, when MACT standards are promulgated for a particular source category, EPA must then determine whether more stringent standards are required after application of MACT controls to protect public health with an "ample margin of safety."

In 1993 EPA issued a MACT standard, the Coke Oven NESHAP, for coke oven doors, lids, offtakes and charging. Under one of the two optional sets of standards, the "MACT Track" option, existing coke oven batteries first had to meet a stringent, technology-based MACT standard by the end of 1995. Many or all of the five "by-product recovery" batteries at four plants on this Track next may have to meet an "ample margin of safety" residual risk-based standard, depending on the outcome of an ongoing EPA residual risk analysis of these batteries.

In September 2001, EPA released the results of a "refined" residual risk analysis the Agency had completed for these plants. The COETF learned that:

(1) the estimated risks, while not unacceptable to the Agency, were still above EPA's long term goal and that the Agency had turned its attention to assessing whether it would be economically and technically feasible for these plants to reduce the risk further;

(2) EPA's preliminary analysis of the cost and technical feasibility of reducing the risk further indicated that the MACT Track batteries at all four plants could meet year 2010 limits proscribed in the 1993 Coke Oven NESHAP for doors, lids, offtakes and charging at zero cost because those batteries were already meeting those limits; and,

(3) in consideration of the above, EPA planned to move forward with proposing a residual risk standard for

all MACT Track by-product recovery coke batteries, that would require those batteries to meet the year 2010 limits proscribed in the 1993 Coke Oven NESHAP.

EPA expects to propose a rule by mid 2003, with a final rule expected about one year later.

■ *Contact: Dave Ailor*

ACCCI Leads Efforts in Commenting on EPA's Revised Draft AP-42

The COETF is working with EPA in the Agency's efforts to revise the Coke Production section of its "Compilation of Air Pollutant Emission Factors," otherwise known as AP-42. This will benefit U.S. coke plants in computing their annual Title V fees.

AP-42 is a compilation of emission factors for various air pollutants released by certain source categories [e.g., SO_2, NO_X, carbon monoxide (CO), ozone (VOCs), particulate matter (PM), and lead (Pb)]. The compilation is used by federal, state, and local regulatory agencies and industry in estimating emissions from these sources.

The emission factors in a revised draft Coke Production section released by EPA in August 2001 are badly out of date and grossly overstate emission factors for many coke plant sources (e.g., charging and door, topside and lid leaks). More accurate (and lower) emission factors in this section would benefit coke plants in lower annual permitting fees. Lower emission factors would also benefit plants in any residual risk standard setting.

The COETF has submitted its comments to EPA and is awaiting a draft final section from the Agency.

■ *Contact: Dave Ailor*

ACCCI/COETF Track EPA's National Air Toxics Assessment

The National Air Toxics Assessment (NATA), a primary component of EPA's national air toxics program, demonstrates the Agency's approach to characterizing air toxics risks nationwide.

Under the NATA, EPA is conducting an initial risk assessment to characterize the potential health risks associated with exposures to 33 hazardous air pollutants. "Coke oven emissions" is one of these pollutants. EPA is posting the results of its NATA activities on its Website (http://www.epa.gov/ttn/uatw/nata).

NATA could lead to increased scrutiny of coke plants nationwide by state and local regulatory agencies and the public. ACCCI has been addressing this issue on two fronts, via the COETF and via a Residual Risk Coalition (R2C), of which it is a member. The R2C has been successful in convincing EPA to include appropriate qualifiers on the meaning of the NATA data and results.

■ *Contact: Dave Ailor*

ACCCI Successfully Challenges CERCLA Reporting Requirements

ACCCI has completed a successful effort involving a coalition of about ten industry associations litigating against the EPA's Interim Guidance on Federally Permitted Release reporting requirements under the Comprehensive Environmental Response, Cleanup and Liability Act (CERCLA). EPA originally released the interim guidance on December 21, 1999, which stated that it was effective immediately. Subsequently, EPA suspended enforcement of the CERCLA reporting requirements and held a public meeting. The broad industry coalition submitted comments, and in June 2000, as result of the Coalition's lawsuit, EPA announced that it was revising the interim guidance and suspending the original guidance.

On April 17, 2002, EPA published its long awaited revised Federally Permitted Release Guidance for Air Emissions (*67 Fed. Reg. 18899*). This document provides guidance on what are "federally permitted releases" to the air and are, therefore, exempt from CERCLA and EPCRA release reporting requirements. It is a direct result of the industry's litigation, including ACCCI.

The guidance provides favorable interpretations of a selection of common release events, such as considering permit limits on "VOCs" to generally suffice as controls on specific hazardous substances. More importantly, the guidance does not purport to definitively outline what is considered a federally permitted release. Instead, it is intended to be used as a general guide and EPA recognizes that each situation must be addressed on a case-by-case basis due to the complexity of the Clean Air Act programs.

■ *Contact: Dave Ailor*

ACCCI a Signatory on Multi-Association NSR Letter to the Senate

On August 6, 2002, ACCCI and 26 other trade associations representing the manufacturing community sent a letter to the full U.S. Senate expressing support for new source review (NSR) reform. The multi-association letter was in response to a letter sent to EPA Administrator Whitman by 44 Senators, expressing concerns about the Administration's proposals to reform the NSR program.

■ *Contact: Dave Ailor*

ACCCI Considers Options on EPA's Final ELG Rule

Effluent Limitations Guidelines (ELGs) are industry-specific standards that instruct permit writers in limiting the amount of industrial wastewater pollutants being discharged into the nation's waters. EPA began reassessing the existing ELGs for the iron/steel industry category (which includes coke, iron, and steel manufacturing) in 1998. The Agency issued a proposed rule in late 2000 (*65 Fed. Reg. 81963*), and was under court order to issue a final rule by April 2002.

In 2001 ACCCI commented jointly with the American Iron and Steel Institute (AISI) and also independently on behalf of its nine merchant coke producer member companies. EPA Administrator Christine Todd Whitman signed the Agency's final ELG rule on April 30, 2002. Soon thereafter the Agency submitted the preamble and regulation for publication in the *Federal Register,* but as of early August the final rule had not appeared.

ACCCI's coke producer member companies have reviewed a prepublication copy of the rule as it would apply to byproduct cokemaking. Many question whether the rule is technically or economically justified, and ACCCI's MESH Environmental Subcommittee is weighing the companies options.

■ *Contact: Dave Ailor*

ACCCI Involved in the Great Lakes Binational Toxics Strategy

The Great Lakes Binational Toxics Strategy is a joint U.S./Canadian program focused on virtually eliminating the release of several persistent bioaccumulating toxic (PBT) substances into the Great Lakes basin. Coke oven emissions have been implicated under this program as a source of several PBT substances found in the basin, including benzo(a)pyrene, dioxins/furans, octochlorostyrene, and mercury. ACCCI is representing the COETF in an industry coalition, the Council of Great Lakes Industries (CGLI), that is addressing the program.

■ *Contact: Dave Ailor*

ACCCI ActionLine

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James Hansen, *Vice Chairman*
Steven Stark, *Treasurer/Secretary*
David Saunders, *President*

California EPA Rejects ACCCI Arguments on Naphthalene

In 2001, the California Environmental Protection Agency published a notice of intent to list naphthalene as a carcinogen under Proposition 65. Later that year, ACCCI submitted arguments to the Agency as to why naphthalene should not be on that list. Unfortunately, California EPA rejected ACCCI's arguments in April 2002.

■ *Contact: Dave Ailor*

ACCCI Comments on EPA's Naphthalene Determination

In June 2002, EPA's Office of Water published a preliminary regulatory determination not to regulate naphthalene in drinking water. In August, ACCCI joined several other interested parties in submitting comments to EPA supporting it.

■ *Contact: Dave Ailor*

ACCCI Dismisses Lawsuit Against EPA over PAI NESHAP

In 1999, four ACCCI tar refiner member companies, via ACCCI, addressed the applicability of EPA's Pesticide Active Ingredient (PAI) NESHAP rule to tar refining operations. During the next two years ACCCI filed suit against EPA to bring the Agency to the negotiating table and filed a request for an Applicability Determination about the extent to which the PAI NESHAP applied to tar refining plants.

On July 10, 2001, EPA issued an Applicability Determination stating that coal tar distillation processes were not subject to the PAI NESHAP. On November 21, 2001, EPA published a direct final rule revising the definition of "process vessel" (*66 Fed. Reg. 58396*). Both the Applicability Determination and the definition met the expectations of ACCCI and the participating companies, and in the spring of 2002, ACCCI voluntarily dismissed its lawsuit against EPA.

■ *Contact: Dave Ailor*

ACCCI Petitions DOT to Renew Solid Pitch Container Exemption

In 2002, ACCCI once again obtained a renewal of an exemption from the U.S. Department of Transportation (DOT-E 11263) for five tar refiner member companies from performance-oriented packaging requirements scheduled for mandatory implementation in 1996. Although the companies could have filed individually, they chose to file a consolidated renewal application with DOT via ACCCI. This latest renewal of the exemption does not expire until January 31, 2004.

■ *Contact: Dave Ailor*

Energy Argus

Petroleum Coke

MONTHLY www.energyargus.com/coke Monday September 3, 2001 Report No. 01S-001

ENERGY ARGUS PETROLEUM COKE	AUGUST COKE INDEX	See methodology below
FOB US GULF COAST $/t	40 HGI	70HGI
4.5% Sulphur	15.00 / 17.00	20.00 / 22.00
6.5% Sulphur	8.00 / 10.00	16.00 / 18.00
FOB US WEST COAST $/t	45 HGI	
3.0% Sulphur	25.00 / 28.00	
4.5% Sulphur	18.00 / 20.00	

IN THIS ISSUE...

ENERGY ARGUS COAL DAILY	COAL INDEX			
	Next Month Delivery		Next Quarter Delivery	
$/t	8/31/01	August Avg	8/31/01	August Avg
CAPP Nymex spec 12,000 Btu	41.50	46.00	39.25	43.08
Cif ARA 6,000 kcal	---	---	36.75	37.21
Fob Richard's Bay 6,000 kcal	---	---	32.00	32.35
Fob Newcastle 6,700 kcal	---	---	29.00	---

COKE PERCENT OF COAL	Nymex Spec	ARA	Richard's Bay
4.5% 40 HGI US Gulf Coast	37.14%	37.21%	49.45%
6.5% 40 HGI US Gulf Coast	20.89%	24.18%	27.82%

ENERGY ARGUS AIR DAILY	SO_2 INDEX	
$/t	August 31, 2001	August Average
SO_2 Allowance Index	218.00	206.75

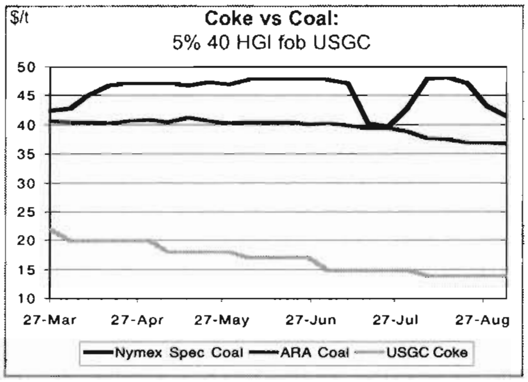
PETROLEUM ARGUS	CRUDE & PRODUCTS INDICES	
$/bl	August 31, 2001	August Average
Maya US Gulf Coast	19.82 / 19.87	19.09
ANS US West Coast	23.81 / 24.01	24.19
WTI/Maya spread	7.36	8.38
Brent/Dubai spread	2.25	1.36
1pc Fuel Oil New York	20.00 / 20.25	20.08
Asphalt, Western Gulf Coast, $/st	100 / 105	99.70

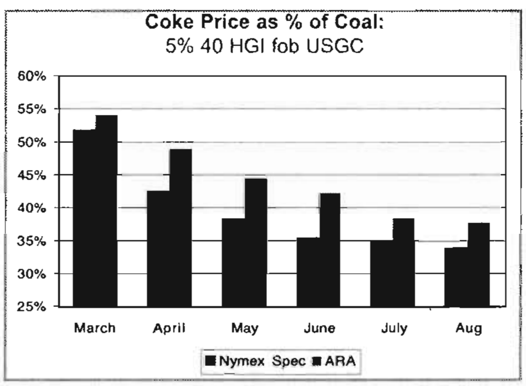
ARGUS INDEX METHODOLOGY:

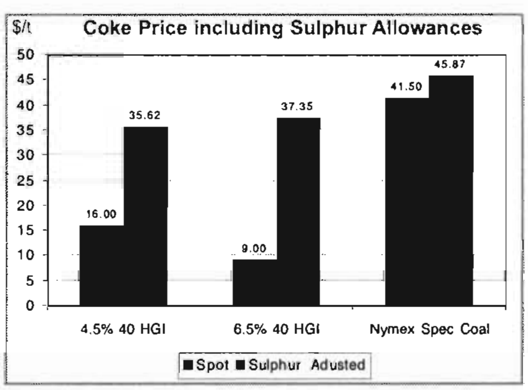
The Argus Petroleum Coke index is an assessment of spot market activity for the grades assessed. Spot activity is defined as transactions or negotiations during the month assessed for delivery within the next 90 days. We base our assessments on a market consensus of the commodity value.

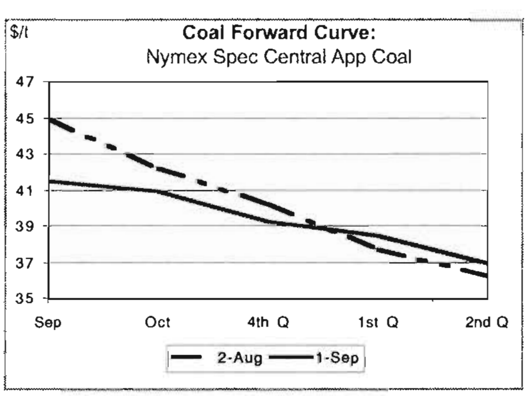
We consider spot transactions and negotiations at the market in question (as in fob US Gulf Coast and US West Coast), delivered prices netted back for freight, contract renegotiations, and estimates of market participants. Forward loading or delivery dates will be considered up to 90 days from the end of the month assessed. Prices for volumes loading or delivering in those 90 days that were negotiated prior to the month assessed will not be considered in the assessment, as they reflect historical not current market fundamentals. Prices for contracts negotiated in the month assessed but for delivery over a term that spans beyond the next 90 days will not be considered in the assessment.

We are reflecting intelligent index values for the grades assessed: where specifications of actual trades differ from the index, we will seek a market consensus as to how to adjust the traded value to properly inform the index specification. Where actual trades are not available, we will assess the value of the grade by seeking a consensus of participants and considering other connected markets. Where a range is assessed for a particular grade, it reflects the range of trade for that grade in the month assessed. If there is no trade, it reflects the range within which a willing buyer and seller could close a deal. Our survey includes producers, electricity generators, marketers/traders, heavy industry endusers, and other market participants.









High Sulphur Fuel Coke Comes Under Pressure In August

Fuel grade petroleum coke prices are under pressure on the US Gulf coast, especially for higher sulphur material. Good margins for refined products in the late spring and early summer pushed refinery runs to the maximum, and many plants fed with Mexican and Venezuelan crudes pushed out more high sulphur coke than the market could bear. Refinery turnarounds in the US could quickly reverse this trend but the supply effect will lag the market.

Prices eroding through the summer

Many **US Gulf coast** market participants are still quoting 6.5% 40 HGI material in the $10-14 range fob US Gulf coast, but most business done in that range appears to have been conducted in June and July – for delivery in August and September. Several large producers agree that spot deals done at the end of August, for delivery in the next 90 days, is in the $8-10 range fob US Gulf coast.

The same is true for the 4.5pc, 40 HGI material. Several market participants saw end August spot prices in the $17-19 range fob US Gulf coast – but again, these prices represent deals previously conducted for delivery through September. Spot prices that have just been concluded, for delivery in Q4 2001, have fallen to the $15-17 range fob US Gulf coast. And one large producer says he sees prices closer to $12-15 FOB Gulf coast, or a $4-5 premium over 6.5pc 40 HGI coke.

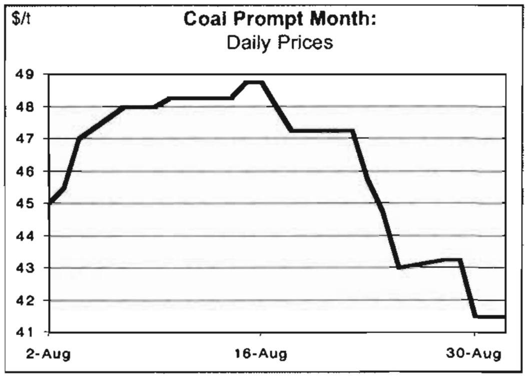
Market sources said end August spot prices for 4.5pc 70 HGI material ranged anywhere from $14-22 Gulf Coast. But the consensus held in the $20-22 range fob US Gulf coast. Talk was heard between $12-18.50 for 6.5pc 70 HGI spot coke, but there was more agreement in the $16-18 range.

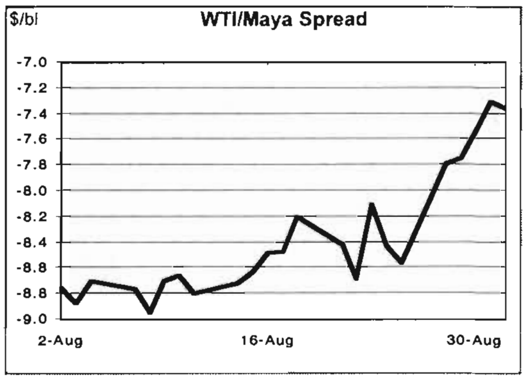
Even though US Gulf coast higher sulphur material is under pressure, the **US West coast** appears to be resisting. Operating problems at plants owned by Tosco and Equilon have reduced output and supported the market. On the whole the lower sulphur West coast coke appears to be in short supply, but pressure may be building on the higher sulphur. Coke under 3pc sulphur was talked around 24-29 fob US West coast and 4.5pc is at 18 fob US West coast. One refiner traded a volume of less than 3pc with 35-40 HGI at 28.50 fob US West coast, for delivery in 4th or 1st quarter at sellers option. At the same time, a volume of 4.5pc 70 HGI was offered at 20.00 fob but had trouble finding a buyer. The current freight from the US West coast to the Far East is between $13.50-15.50/mt.

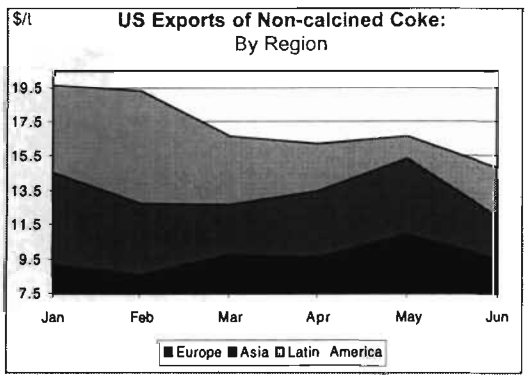
Coke prices in the **US midwest** are considerably stronger due to tighter availability and firmer coal prices. Spot prices at the end of August were heard in the low $20/ton range, fob refinery. Crude distillation at the Citgo refinery in Lemont, Illinois was suspended in August following a fire, and officials expect the plant to be down six months. Citgo produces in excess of 750,000 t/yr of coke at Lemont. The shortfall is now being pulled from the Gulf Coast region.

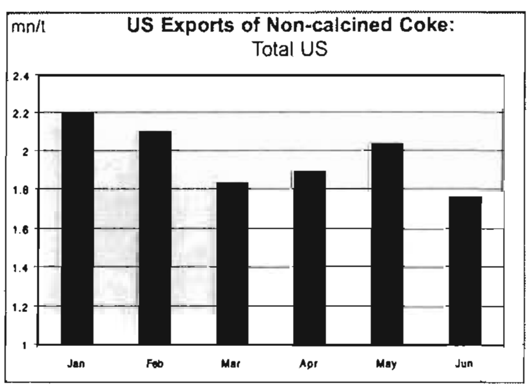
New supply looming

New capacity has more than offset new demand in the utility sector, and this has pushed the value of coke down sharply versus coal over the course of the summer. Between 4Q 2000 and 1Q 2001, over 1.8mn









t/yr of new capacity was brought online on the Gulf coast. And next month another 1.95mn t/yr of new capacity will be added, including ExxonMobil's 1mn t/yr delayed coker in Baytown, Texas, and Marathon Ashland Petroleum's 950,000 t/yr coker in Garyville, Louisiana. All of this production is high sulphur, which is depressing that market.

Market participants are quick to point out that the supply situation could be worse. Cokers in Venezuela, Mexico and St Croix that were originally scheduled to startup this year have been pushed back to between Q1 and Q3 of 2002. The three cokers total 4.3mn t/yr of new production. PdV/Mobil's new 1mn t/yr Cerro Negro unit in Jose, Venezuela will be brought online in Q4 2001. It was originally expected to startup in Q2 2001. Pemex also expects to start production at its new 1mn t/yr coker at Salina Cruz, Mexico, next year. So while there is some reprieve from the onslaught of new capacity, that will be quickly eradicated next year.

Adding to the downward pressure for high sulfur coke is the current sweet/sour crude differential. Sweet crudes are selling at a steep premium to sour crudes, which means refiners are running more sour crude and making more high sulfur coke. ExxonMobil is producing more fuel grade coke than anode grade at its Baton Rouge, Louisiana plant due to crude economics. The producer says it cannot afford to buy as many sweet crudes, and as a result will produce 1mn tons of fuel coke, and 700,000 tons of anode grade this year—the opposite from year earlier levels. Prices for anode grade are expected to continue firming in 4Q.

Where is the new demand?

The result of weakening prices is that most potential buyers are on the sidelines, not wanting to take long-term positions. If they have to buy, it is for the short-term, such as the next quarter. But in some cases, buyers like West Kentucky Energy (WKE) are reportedly putting out spot and long-term requests. WKE is receiving spot bids for a minimum of 10,000 t/month for Q4 delivery on September 12. Its long-term bid for 2002 and beyond will reportedly be due on October 5.

Among cement companies, Lafarge accepted bids on September 5 for 638,000 tons of coke, which represents the needs of its 12 domestic cement plants for 2002. Ten of the 12 plants will take soft coke, and all need less than 5.8pc sulfur. Domestic coke exports to Brazil have been cutback as much as 25pc due to the country's prolonged drought. Large industrial users, including cement maker Votorantim, have been ordered by the Brazilian government to cutback power usage up to 25pc due to the shortage of hydroelectric power.

The general consensus in the marketplace is that fuel grade coke will be oversupplied for the next 18 months or so. After that, demand will begin to catch up to the supply. Producers and suppliers are optimistic about new demand opportunities from utilities. One utility alone, JEA, is converting two oil and gas fired units at its Northside generating station to burn exclusively coke. The utility says the new units will be in full operation in the summer of 2002, and will consume 1.6mn mt/yr of coke. The same utility co-owns the St. John's River Power Park with Florida Power & Light. The coal-fired plant will burn 650,000mt of coke this year.

WHAT IS ENERGY ARGUS?

And why this new coke report?

Energy Argus is the publisher of ***Coal Daily***, the accepted benchmark for trade in the US and international markets for coal, and ***Air Daily***, the index for sulphur allowance trading. Energy Argus is part of the larger **Argus Media Group**, which has existed for over 30 years as **Petroleum Argus**. Petroleum Argus publishes numerous price reports and analytical newsletters, and is widely used as an index for trade in crude oil, refined products, and LPG.

We are launching ***Argus Petroleum Coke*** in order to bring our experience in market analysis and indexing to an important but often neglected corner of the industry. Our goal is to produce index-quality assessments of the coke market, and to analyze coke prices and their direction. Argus is uniquely able to provide market news and analysis from its global team of reporters covering related industries such as coal, crude, gas, power, and refining.

Our coke indices will assess spot market values for coke – which is a great challenge in an elusive and illiquid market. We are assessing the value that coke has traded at or would trade at during the most recent month, for delivery in the next 90 days. We are not assessing long term contracts, nor are we including prices that were transacted months ago and are now being delivered. The prompt value of a commodity is always the best index.

We are excited about this new venture, and welcome your comments and suggestions. Contact us at coke@energyargus.com.

Daniel Massey
President
Petroleum Argus Inc.

No help from Europe

The European petroleum coke market was bearish throughout August, with few signs emerging of the seasonal upturn that might normally be expected with the start of autumn. Traders assessed prices for 4.5pc sulphur petroleum coke moving from the US Gulf coast into the Mediterranean market at around $19-20/t cif Mediterranean. Levels for higher sulphur material were also weak at around $10/t cif Mediterranean for 6pc sulphur. Traders said that there were some offers of high sulphur material seen at levels of $12 and even $13/t cif Mediterranean, but that bids in excess of $10/t were scarce. Trading company Energy Coal Spa was rumored to have purchased at least one Panamax vessel of low sulphur material, but Italian utility Enel said that it had not been in the market at all in August or September.

Trans-Atlantic freight rates remain depressed

Freight rates for petroleum coke moving from the US into the Mediterranean and ARA markets remained severely depressed throughout August. Traders said that the cost of petroleum coke freight for a Panamax vessel moving from the US West coast into the Mediterranean market now stood at around $11/t, as much as $5/t cheaper than the same period last year. The normal downturn in market activity during the summer period is partially to blame for the slump in rates.

But shipping brokers also point to a more fundamental malaise caused by the US manufacturing downturn and fears of a global recession. This has limited trading activity and in turn put pressure on freight rates. A slide in the volume of petroleum coke exports from the Asia-Pacific region, specifically from Taiwan, Japan and Singapore, has also contributed to the downturn.

ARGUS BTU COMPARISONS

As of August 31, 2001	Heat Value in $/mmBtu	Spark Spread in $/MWH
New York Diesel	5.67	-27.61
New York 0.3% Fuel Oil*	3.84	-9.29
New York 1% Fuel Oil	3.15	-2.42
Transco Zone 6 Gas	2.75	1.60
Nymex spec Coal*	1.91	10.00
Gulf Coast 4.5% 40 HGI Coke*	1.27	16.40
Gulf Coast 6.5% 40 HGI Coke*	1.33	15.80

* New York .3% fuel oil is high pour and includes New York taxes. Coal and Coke values include cost of sulphur allowances. Spark spread assumes heat rate of 10.

Coke Market News - Americas

Marathon Ashland Petroleum (MAP) says production at the new 950,000 t/yr coker at its Garyville, Louisiana refinery will begin the first part of October. The Maya-fed, fuel-grade shot coke will be 7.5% sulfur, and 30 HGI. MAP will sell half the production to utilities up the Mississippi River, while the rest will be marketed by a trader. The producer was in the final stages of selecting a trader in the middle of August. A MAP spokesman says it is looking for a flexible relationship with a trader--one in which the producer can hold back spot tons from time to time. But Marathon stresses the desire not to compete with its own trader. As a result, selling spot material will be more isolated, and limited to circumstances when there is a particular value to doing it. The tons marketed by the trader are expected to be split between the domestic and the export market. MAP confirms that Applied Industrial Materials Corporation (AIMCOR) will provide operation and maintenance of petroleum coke handling equipment at the refinery, including operating the dock and the conveyor system.

Premcor Refining Group's Port Arthur, Texas, plant will produce 1.3mn mt of 6.5% sulfur, 30-35 HGI petroleum coke this year, or 9% below the nameplate capacity of 1.4mn mt. The plant, which came online in November 2000, will be conducting reliability testing of the heavy oil upgrade equipment through the end of September. A company official says petcoke output in 2002 will be over 1.5mn mt. Premcor has five, term sales contracts, in which all petcoke is moved through resellers. The balance of the coke is sold on the spot market. The largest buyer of Premcor's Port Arthur petcoke is Brazil's Votorantim. Premcor will also produce 325,000mt of 6.5% sulfur, 30-35 HGI petcoke at the Hartford, Illinois plant this year, and another 200,000mt of the same quality in Lima, Ohio. The Port Arthur plant conducted a planned, 10 day shutdown of the crude distillation unit in July to clean heaters fouled by a power outage from a lightning strike.

Ultramar Diamond Shamrock (UDS), Wilmington, California, is set to produce 550,000 tons of 4.2pc sulfur, 70 HGI petcoke at its delayed coker this year. UDS has an exclusive marketing arrangement with Oxbow, wherein Oxbow markets all the material and handles operation and maintenance activities. Oxbow moves 100pc of the coke in the export market, mostly to Japan. The producer is running a slate of crudes, as domestic crudes have been harder to come by the last few years. In addition to San Joaquin and Alaska North Slope (ANS) crude, UDS has run Maya, Venezuelan and other South American crudes.

Ultramar Diamond Shamrock's (UDS) output of fluid coke at the Golden Eagle, California refinery will hit 450,000 tons this year. The 2.2pc sulfur, 28 HGI coke is marketed by UDS, and 60pc is sold on the export market; most of the material moves to Europe and Japan. UDS splits the balance of its material among several domestic term customers. The primary buyers are utilities and power plants. Some sales are done on a spot basis, but very little spot deals have been concluded recently. The producer has the capability of storing large quantities of coke in an open pit area, and can load ships themselves at the Pittsburg Terminal. USD also moves dry lots of coke via rail car. As is the case at the Wilmington refinery, Golden Eagle optimizes crude slates by taking San Joaquin, ANS and foreign crudes.

Seminole Electric Cooperative says it began receiving 40,000st/month of 6% max sulphur, 45 min HGI petcoke in June, after taking no deliveries since the end of 1999. The spot tons will be supplied monthly by a trader through the end of this year. The utility purchased spot material in the past, some of which was cost effectively sourced from Coastal Aruba. But a company spoksman says it would consider other purchase options, such as a long-term contract. Seminole's coke is CSX rail delivered, while many refiners are limited to water delivery options for coke. As a result, Seminole's options are somewhat limited. The utility is set to burn 200,000st of coke this year and next, and is permitted to use coke in up to 30% of its fuel mix. With coal prices climbing and petcoke prices falling, the utility began reexamining the use of petcoke earlier this year. A company spokesman says it is aggressively looking at optimizing fuel pricing, and may begin to approach the 30% permitted level in the future. Seminole's power plant is located 50 miles south of Jacksonville, in Palatka, Florida, and the two generating units combine to produce 1240MW. The units have been fully scrubbed since going online in 1984.

Reliant Energy HL&P is building petcoke inventory at its Limestone I and II lignite fired generating station in Jewett, Texas, ahead of substantial burns the first half of 2002. The utility expects to burn 250,000mt of petcoke the first six months of next year, before switching from coke to Powder River Basin coal to supplement lignite usage. A company spokesman says a new rotary car dumper will be online on July 1, 2002, which will facilitate the use of PRB coal. Reliant Energy burned 75,000mt of coke the first five months of this year, but has not used coke since that time. And none will be consumed for the balance of this year. The Oxbow supplied coke was sourced from Frontier El Dorado Refining in El Dorado, Kansas. The utility says it will consider other sources of spot supply, which must be 38 minimum HGI. The Limestone units are scrubbed, so sulfur content is no problem.

Pennsylvania Power and Light (PPL Corp) As recently as 1999, PPL was the largest petcoke burning utility in the US, at 590,000mt/yr. But since that time, the utility closed one of its petcoke burning plants in Holtwood, Pennsylvania. And the other plant that burned coke, Sunbury station at Shamokin Dam, Pennsylvania, was sold to Wisconsin Public Service (WPS). But PPL says it has not abandoned the use of petcoke.

Tests were recently conducted at PPL's Colstrip, Montana plant, and in July, 2001, PPL received approval to burn petcoke on a full-time basis at the plant. The utility has contracted for supply with Conoco in Billings, Montana, which produces 272,000mt/yr of petcoke. At this time, PPL does not know exactly how much supply it will take from Conoco. The producer supplied up to 7000mt to PPL in December and January when tests were being conducted.

Owensboro Municipal Utilities, which stopped burning petcoke in June 2000, says coke prices would have to fall substantially below the price of coal for it to consider using it again. The Kentucky based utility received one order of coke from Koch Carbon, but says the two parties could not agree on the price of the second order. Koch Carbon offered to supply Owensboro up to 50,000 t/yr of 6-6.5pc sulfur material for a three-year term, beginning in March 2000. Koch Carbon's price was $12.85/ton for the first year, rising to $13.15 in the third. An Owensboro official says instead of coke, it is now co-firing chipped tires with coal. The tires are cheaper, higher in BTUs (15,000+ BTU/lb) and low in sulfur and ash.

Lakeland Electric open for spot/contract bids in 1Q – Lakeland Electric in Lakeland, Florida says it will try to lock up 2002 spot supplies in 1Q, but would like to work on turning spot purchases into a long-term supply contract. The utility believes prices are falling, and its current spot contract expires at the end of this year. Lakeland also has an existing three-year term supply contract in place, which extends to 2003. In November, the utility and supplier will negotiate a price for 2002. If no agreement is reached, the price will be set according to PACE assessments, with price ceilings and floors included. While Lakeland Electric is permitted to burn petcoke in up to 20% of its fuel mix, it is regularly consuming closer to 18%. But with coke prices in decline, Lakeland expects to bump right up against the 20% level and stay there. A company official says it will burn up to 125,000st of 5.5% max sulphur, 40 min HGI petcoke this year, and expects to consume closer to 150,000st next year. Material is currently supplied to the utility on a direct basis from offshore and domestic sources.

Brazil's drought hampering petcoke deliveries – Brazil's prolonged drought, which forced the government to initiate emergency power reduction measures in May, has resulted in lower petcoke consumption in the industrial sector. Large industrial users, including the aluminum and cement industries, have been ordered to cutback power usage by up to 25% due to the loss of hydro electric generated power. As a result, large users are cutting back petcoke commitments anywhere from 10 to 25%. A US trader says a large customer in Brazil was slated to take 1.6mn mt this year, but actual deliveries will be closer to 1.3mn mt. If the government mandate remains in place for the balance of this year, large industrial petcoke users are expected to be extremely cautious in terms of entering into supply contracts for next year. Brazil's rainfall is key regions, including the primary hydro electric producing states of Minas Gerais and Goias, has been the lowest in several decades, reports Energy Argus' Latin American Power Watch. A US coke producer notes that Brazilian customers have yet to cut back on lower priced coke purchases, but adds that the crisis is real. Brazil first opened its doors to petcoke in 1998, and is consuming 2.5mn mt/yr, an industry source says.

South Carolina Public Service Authority (Santee Cooper) is seeking approval to begin burning petcoke at its Winyah generating station in Georgetown, South Carolina. The utility has started the permitting process, which takes anywhere from 3-6 months. Upon receiving the permit, the utility will blend 20% petcoke with 80% coal. A utility spokesman says it will solicit a RFQ (request for quotations) when the market is advantageous, which could be as early as the end of August. Santee Cooper expects petcoke prices to weaken, so it will take only short term positions. The utility is permitted to burn up to 300,000mt of petcoke at the Cross generating station—the only unit that is permitted to burn petcoke at this time.

JEA says its Northside Generating Station Repowering Project, which is converting two old oil and gas units to coal and petcoke boilers using circulating fluidized bed (CFB) technology, will be in full commercial operation by the summer of 2002. But the units are expected to begin producing low cost energy during start start-up activities in December, 2001. The two units will operate at 300MW each, and consume 1.6mn mt/yr of petcoke, assuming petcoke is used exclusively, which is the plan. Upon completion of the repowering project , Northside's base load generating capacity will jump by over 30%. JEA believes that fuel costs for the new units will be substantially lower than all other units in the current generating system. JEA will purchase spot petcoke for the new units the first year, while performance guarantees and various tests are being conducted. After the first year, the utility will determine what type of supply arrangement it will make. JEA has not negotiated for any petcoke at this time.

St. Johns River Power Park, the coal fired electric power generating station jointly operated by JEA and Florida Power and Light (FP&L), consumes 650,000mt/yr of petcoke, and is the only user of petcoke in the JEA system, until Northside is up and running in June of 2002. A Power Park official says that half of the petcoke the plant consumes is purchased on the spot market, while none of its supply contracts are long-term. The Power Park is permitted to blend up to 20% of solid fuels with petcoke, and it does approach that percentage each month. Year ending March 2001, JEA's petcoke usage represented about 7% of its overall fuel mix. JEA and FP&L receive 50% of Power Park's capacity and energy output.

La Gloria Oil & Gas will produce up to 78,000 tons of green petroleum coke this year at the Tyler, Texas refinery. The producer markets all the 2.5pc sulfur coke itself to domestic buyers. The current crude slate consists of West and East Texas crudes. La Gloria's coker was taken down for a few days in July to clean out heaters, and came back online on July 28.

Conoco, Westlake, (Lake Charles) Louisiana, will produce 1.3mn tons of dry, 6pc sulfur, 40 HGI petcoke this year. Conoco sources its crude from Mexico and Venezuela. The producer will export 300,000 tons of coke in 2001.

Conoco is set to produce 272,000 tons of petcoke at its Billings, Montana refinery in 2001. The 5.5pc sulfur, 40 HGI petcoke is marketed in house, and none moves to the export market. The Billings refinery sources its crude from Canada. One buyer of Conoco's petcoke is PPL Montana, which received approval to burn coke at its Colstrip, Montana plant in July.

Imperial Oil in Sarnia, Ontario, Canada will produce slightly less coke than expected this year—270,000mt of 5pc, 40 HGI, 14,000 BTU/lb. ExxonMobil owns 69.6pc of Imperial.

Orion Refining--Good Hope, Louisiana says 2001 production will reach 1mn tons of 4.5pc sulfur, 45-55 HGI coke. It expects 2002 production to be slightly higher in volume.

Coastal Aruba Refining Co. – has no turnaround or upgrading plans the balance of this year or in 2002. Coke output this year will be right at 1.3mn mt of 5.5-6.5pc sulfur, 45-50 HGI. Coastal markets the coke itself and through traders. Half the output is sent to the US.

Coke Market News - Europe

India's Reliance refinery continues to attempt to move petroleum coke long distance into the European market, according to European buyers. The decision is an apparent attempt by Reliance to take advantage of current cheap freight rates and potentially more lucrative European prices. The company is reported to currently be offering material into the ARA region in a range of $24-26/tonne CIF ARA for a 30,000 tonne cargo.

Spanish utility Endessa has now started burning petroleum coke at its Compostilla facility, according to a source within the company's London office. There had been plans to use the fuel at Compostilla earlier in the year, but these were temporarily postponed by the company. The delay in the commissioning of the Compostilla unit will have a knock-on reduction in Spanish petroleum coke demand for the year as a whole.

Italian company Energy Coal Spa has said that it intends to buy as much as 1.5 million tonnes of petroleum coke in 2001. The company will rely mainly on US refiners to meet its requirements, including ExxonMobil, Conoco and Tosco.

Industry News

Phillips purchase of Tosco near completion

Phillips Petroleum expects the FTC to give final approval for its takeover of Tosco at any time. The acquisition is not expected to have any significant impact on the petroleum coke market, a company official says, but the producer could not comment on specific coke information prior to approval. A coke marketing position at Tosco has been left vacant and may be filled with a staff member from the Phillips team. Once the buyout is complete, Phillips' total coke production will jump to over 3.2mn t/yr. Tosco produces a total of 1.75mn t/yr of coke at its Los Angeles, Rodeo/Santa Maria, California, and Belle Chasse, Louisiana, refineries. Phillips will produce 1.46mn tons of 4.2-4.4pc sulfur, low 50's HGI petroleum coke at its Sweeny, Texas refinery this year. TCP markets the coke, up to 95pc of which is exported. Phillips sources its crude from Venezuela.

ExxonMobil coker to start up in October

ExxonMobil's new delayed coker at the Baytown, Texas, refinery in the US is scheduled to start up the end of October, producing 1mn t/yr of 6-7% sulfur, 35 HGI pet-coke. The new coker will push ExxonMobil's annual US fuel grade coke output to over 5.3mn t/yr. ExxonMobil has awarded contracts to TCP and Oxbow to market the new production, and has agreed with the parties that it can hold back up to 15% of the output to market itself. Initially, all the production will likely make its way to the export market. But the producer says the eventual goal is to split the coke 50/50, domestic and export.

ExxonMobil says its flexicoker at Baytown, which was built according to ExxonMobil patented technology, will produce approximately 188,000 tons of 1.8-4pc sulfur, 31 HGI coke this year. The breakdown of production is: 150,000 tons of bed coke, 20,000 tons of wet fines and 18,000 tons of dry fines.

Due to crude economics, ExxonMobil says petcoke output at its Baton Rouge refinery has swung in favor of fuel coke. The producer says it cannot afford to buy the volume of sweet crudes it takes to make as much anode grade. ExxonMobil will produce 1mn tons of fuel grade coke—5-7.5pc sulfur, 45-90 HGI, and 700,000 tons of anode grade (2.5-5.8pc sulfur, 70-90 HGI) this year, a complete reversal from a year earlier. A company official says production levels of fuel and anode grade coke is a constant debate, and daily decisions have to be made with regard to how much of each to produce.

ExxonMobil's fuel coke production/quality at its other refineries for this year:

Beaumont	950,000t	6pc sulfur
Billings	130,000t	6.3pc sulfur, 28 HGI fluid coke
Chalmette	720,000t	4.5pc sulfur, 45-50 HGI
Joliet	1.2mn/t	5-5.5pc sulfur, 45-50 HGI
Torrance	1.3mn/t	1.4pc sulfur, 45-50 HGI

Citgo Lemont refinery severely damaged

Damage to Citgo's 160,000 b/d refinery at Lemont, Illinois is more severe than originally thought, after a fire struck the plant earlier this month. Citgo first said operations at the plant would be curtailed for about a month. But the refinery's vacuum distillation unit has collapsed and getting the necessary permits to rebuild it could take months. News of the accident has undermined values for Canadian sour crudes, which made up nearly 100,000 b/d of the refinery's diet. The discount under WTI for heavy sour Lloyd Blend is hovering at $9.50/bl for injection at Hardisty, Alberta. Shortly before the accident the grade's discount to WTI was $5.25/bl.

Lafarge acquisition of Blue Circle finalized

Lafarge S.A., the French cement giant, received final approval from the Federal Trade Commission in July to acquire British cement manufacturer Blue Circle Industries. Blue Circle was one of the top five cement makers in North America. The takeover was subject to three divestitures, which the FTC and the Canadian Competition Bureau required to ensure competition in the cement and lime industries. Lafarge divested Blue Circle's cement business in the Great Lakes Region, which included all of parts of New York, Ohio, Michigan, Illinois and Wisconsin. Additionally, Lafarge divested Blue Circle's cement business in Syracuse, New York, and Blue Circle's lime business in the southeast US.

After receiving FTC approval for the takeover, Lafarge announced in August that it had closed the sale of certain Blue Circle's assets in North America to Brazil's Votorantim, one of the 10 largest cement producers in the world. The assets included two cement plants in the province of Ontario; a grinding station in Detroit, Michigan; seven cement terminals on the US side of the Great Lakes; 39 ready-mix concrete plants in the province of Ontario; and some of Blue Circle aggregates assets in Ontario.

The integration of Lafarge and Blue Circle is expected to be completed by the end of this year, a Lafarge spokesman says. Lafarge is the world leader in building materials, and is the largest cement producer in the world.

ITC confirms dumping of Chinese coke

The US Department of Commerce will be allowed to levy penalties on imports of Chinese foundry coke after the International Trade Commission ruled in late August that Chinese importers sold coke in the US market at less than fair value. The decision comes in contrast to a mid-August decision on blast furnace coke, in which the ITC ruled that Chinese and Japanese imports of that product didn't harm US businesses. Furnace coke is used to help produce pig iron, while foundry coke is defined by the ITC as "the carbonized product used as a fuel source of carbon in a cupola furnace for the production of molten iron."

ITC commissioners voted unanimously that the foundry coke industry is being materially injured by imports of Chinese coke, and cited a decision by the US International Trade Administration in early August stating that per-ton prices of imported Chinese foundry coke were at less than fair-value. "As a result of the Commission's affirmative decision," an ITC announcement read, "the [US Department of Commerce] will issue an antidumping order on imports of this product from China."

Complaints were brought against importers by three US foundry coke producers last October (**CD** 10/3/00). US producers claimed that foreign foundry coke was selling in the US for roughly $70/t less than comparable domestic coke. The plaintiffs, who were later joined by other companies and the **United Steelworkers of America**, cited an ITC report that attributed the lower price to government subsidies, low labor costs and lax environmental standards in China. Copies of the ITC's full decision will be available after September 26, 2001, by calling (202) 205-1809.

Cedar Bay plant may burn petroleum coke

PG&E National Energy Group's is preparing to seek permission to begin burning petroleum coke its Cedar Bay generating station in Jacksonville, Florida. Cedar Bay has three reheat circulating fluidized-bed boilers and also uses selective non-catalytic reduction technology to control NOX emissions. The plant provides electricity to Florida Power & Light and steam to a nearby recycled linerboard paper mill in Jacksonville.

The company had engineering firm Foster Wheeler Energy examine its options and the analysis concluded that the plant, with significant modifications, could burn up to 50 pct petcoke. Without a lot of capital investment, the plant could burn up to 35 pct petcoke, the review showed. As a result, PG&E expects to submit an application for a clean air permit, the first of two permits needed to burn petcoke at Cedar Bay. A site certification permit from the state is also needed. A little more work must be done to complete application requirements, including determining how the petcoke would be transported.

The 265-MW plant is several years into a 30-year agreement with Lodestar Energy for low-sulfur Kentucky coal.

Unfortunately, Lodestar entered Chapter 11 bankruptcy protection in the spring. Despite the bankruptcy, Lodestar has continued to deliver coal to the plant via CSX, the source said. However, the company is concerned that bankruptcy proceedings may terminate the contract. PG&E is also negotiating with Lodestar regarding the contract, but is looking at alternative fuel supplies as a back-up measure.

AIMCOR to market Hovensa coke

Applied Industrial Materials Corporation (AIMCOR) confirms it has been awarded the exclusive contract to market HOVENSA' S new petcoke output at the St. Croix, Virgin Islands refinery beginning in May 2002. The production has been rated at 1.2-1.3mn t/yr, and the contract will be in place at least three years. AIMCOR says it hopes to move 50pc of the new production to utilities along the US East Coast. Cheap freight to those destinations will make it easier to compete with coke from Venezuela. The rest will move to other global destinations, including Europe and South America. In Europe, the steel industry has been targeted. AIMCOR also has distribution capabilities in Rotterdam, and can blend the 4pc sulfur, 50 HGI material with lower sulfur coke to meet the requirements into various specialty markets. Other potential destinations include South America--primarily Brazil. HOVENSA has two 40,000 ton coke storage domes, and an AIMCOR official says scheduling will be the key to the new marketing contract. Movement of product is critical, and AIMCOR says it will tentatively schedule three vessels per month. Of all the Venezuelan cokers, the new HOVENSA production will be the best quality coke. HOVENSA is owned by subsidiaries of Amerada Hess and PDVSA, Venezuela's national oil company. With the new marketing contract, the coke AIMCOR moves will jump 20pc, from 6mn tons this year, to 7.5mn tons in 2002. HOVENSA also awarded a long-term contract to AIMCOR to provide operation and maintenance of petcoke handling equipment. Aimcor announced it signed similar long-term coke handling deals with ExxonMobil in Baytown, Texas, and Marathon Ashland Petroleum's new 950,000 t/yr coker in Garyville, Louisiana.

Two years ago, Middle East Oil Refining (MIDOR) awarded AIMCOR a 10 year contract to market the production at a new coker in Sidi Kerir, Egypt. AIMCOR says the coker started up three months ago, and is producing up to 400,000 t/yr of 4-5pc sulfur. When the refiner has its crude slate locked in, the coke will be consistently 4pc sulfur, with less than 40 HGI. The coke is being marketed exclusively in the Mediterranean.

With regard to new projects, AIMCOR is trying to get marketing rights for Maraven's new 2mn t/yr coker, which is due to come on line in Hamaca, Venezuela in 4Q 2003. The coke is expected to be 4.5pc sulfur with a 60 HGI. AIMCOR will also attempt to market the material at Pascagoula 2--Chevron's new 700,000 t/yr coker at Pascagoula, Mississippi, which will startup in 1Q 2003.

Chinese coal exports surge

Chinese coal exports continue to surge. Record export levels hit 51.6 mn t by 15 August of this year. This is 53% up on the same period last year when coal exports reached 33.8 mn t. The rise of 17.8 mn t has led to a new coal export record. These new coal exports have reversed the trend of the past few years when China was rationalising its coal production to limit pollution and save lives among the mining workforce. But the lucrative discovery of new markets for Chinese coal has led to mines reopening in China and an emphasis on hitting new export targets.

Chinese exports are going to rise still further as work progresses on Huanghua Port, which will be a large hub for shipping coal from north China. Work on the first phase is expected to be complete by the end of this year. The new port will be capable of handling 30 mn t of coal a year. Partly as a result of the new port developments Chinese exports could reach 80 mn t this year if the country's ambitious export targets are reached. The exports are a source of important foreign exchange and the coal is popular in Japan, Korea and among traders aiming at the European market.

Met coke production halted

Bethlehem Steel has decided to shutter its metallurgical coke production facility in Lackawanna, New York, primarily due to the competitive nature of the international steel industry. The Lackawanna Coke division bakes bituminous coal in 152 ovens to produce roughly 700,000 tons/year of met coke. The coke has been sold to other steel-making companies since Bethlehem closed its basic steel works in Lackawanna in 1983. The plant will stop producing coke at the end of September, but shipments will continue through the fourth quarter of 2001.

Petrobras upgrading refinery

A $900mn upgrade to the 242,000 b/d Reduc refinery in Rio de Janeiro will include new coker units to allow Reduc to process more domestic Marlim crude rather than imported lighter oil, such as Nigerian Bonny Light and Middle Eastern crudes. The upgrade is expected to be completed in 2005. Petrobras is looking for a private partner to finance 30pc of the upgrade.

Refining alliance with Ancap may include coker

At least seven oil companies have expressed interest in a tender to form a refining and trading association with Uruguay's state-owned oil company, Ancap. The alliance could involve the construction of a coker unit at Ancap's La Teja refinery. Companies wishing to associate with the state oil company must own net assets of at least $400mn, hold crude reserves of at least 400mn bl at the end of 2000, and have been producing a minimum of 25mn bl/yr between 1996 and 2000. Companies expressing interest include Repsol YPF, PDV, Petrobras, Shell, Texaco, Perez Companc, and Cepsa.

Sunoco considering coke JV with Brazilian firm

Sunoco is developing a joint venture with Brazilian firm Aco Minas Gerais SA in order to improve the profit margins for its coal and petroleum coke businesses. They are seeking to import Sunoco's coal into the Brazilian market and mix it with Brazilian petroleum coke in order to maximize potential profits on both commodities. Brazil has significant petroleum coke assets, but an almost complete absence of domestic coal production. A contract has not been signed yet, but senior executives from Sunoco have made over ten trips down to Brazil already this year, laying the groundwork for a possible deal. Sunoco will be seeking to take advantage of low Brazilian labor and production costs

Mexican maintenance cuts Maya output

Mexico confirmed that its crude production would dip by up to 90,000 b/d from August until November because of pipeline maintenance near the Ciudad Pemex complex in southeastern Mexico. Most, if not all, of the reduced output is presumed to be heavy sour Maya crude from the large Cantarell field. Rumors preceding the announcement had the cutback at closer to 200,000 b/d, and sent differentials for US domestic sour crudes soaring. North Sea players said the situation was spurring US Gulf coast interest in higher-sulphur grades like Alba and Flotta. Angolan Kuito and Syrian Souedie were also mentioned as possible Maya substitutes. But the return of Iraqi Basrah and a spate of unforeseen refinery cutbacks dulled any effect on prices.

Venezuela's Cerro Negro starts up

None of the upgraded crude from Venezuela's 108,000 b/d Cerro Negro project will be offered for sale, says operator ExxonMobil. Most of the stream, which began deliveries on 7 August, will move to the 182,000 b/d Chalmette, Louisiana refinery jointly owned by ExxonMobil and Venezuela's PdV. Each company owns a 42pc share of Cerro Negro, which draws 8.5°API crude from eastern Venezuela and con-verts it to 16°API synthetic crude.

Coal Markets

Central Appalachian coal prices in the US have been falling steadily since early May, but are maintaining levels at or above prices seen in the first quarter of this year. Other niche markets such as Pittsburgh Seam and Illinois Basin continue to be very strong. Powder River Basin coals are under severe pressure, moving from highs near $14/ton in May to $7.85/t at the end of August. US forward markets remain in backwardation through the second quarter, in contrast to Europe which is showing a contango through middle of next year.

The continued weakness in August is due in part to increased coal availability in both the US river and rail markets. While coal supply is not overwhelming, several buyers said it improved noticeably during late compared to earlier in the month. Regional flooding that hampered both coal production and coal transportation in the eastern US has ended, allowing for smoother operations. Another factor having an impact on Central Appalachian prices is the recent increase in international coal shipments into US utilities. Southern Co., American Electric Power, and Florida Progress have imported cargoes in recent months forcing US sellers to set a more realistic price ceiling. Several coke marketers indicated that these imports have caused concern and may be encouraging even deeper discounts for coke on the Gulf coast.

On the demand side, some utilities may be buying only the minimum for the fourth quarter. Those utilities may be holding off on some coal purchases and instead monitoring the prices of natural gas, which has been falling. Even with coal prices falling, the cost on a cents/mmBtu basis may be close enough for some utilities to cut back on coal-fired generation. Producers noted that many regular buyers are forgoing spot purchases and instead seeking to increase existing contracts or negotiate new long-term deals. Those companies are asking for more tons and longer terms in an effort to lock in a reliable supply, particularly in light of recent production problems at many mines.

European coal prices began a steep decline in June, moving from over $40/t to close August at $36.00. Both European and South African markets have reacted to heavy Chinese exports of coal while Australian exports have declined. Not all Chinese coal can meet western European requirements, but at the margin the incremental spot coal is establishing new price ideas. The European market was also inundated with material from Poland. This was particularly unusual, as the majority of Polish coal is either used in the domestic market or moved by road or rail car to elsewhere in central Europe. The arrival of significant quantities of sea-borne Polish coal into the ARA market is a strong symptom of the seriousness of the oversupply situation.

Crude Markets

The latest round of Opec production cuts is hitting the crude markets, promising a tightening in the spreads between light and heavy crudes in the coming weeks. In August, the price for deepwater Mars briefly dropped to around $4/bl below the lighter inland-based West Texas Sour (WTS). But by the start of September, when new Opec cuts took effect, the spread between the two US domestic sours had narrowed to half that. It now stands around just $1.80/bl, the tightest since mid July. Pricing from key crude producers indicates they think strength in heavy sours will continue. The discount that Mexico applies to the pricing formula for its heavy sour Maya is being tightened by 40c/bl in September. And Saudi Arabia just told US customers that the discount under WTI for Arab Heavy will be narrowed by 60c/bl in October compared to the $7.40/bl discount that they are currently paying. At the same time, weakness in European margins has been undercutting values for light sweet crudes in the North Sea.

Iraqi crude shipments to the US are being limited by coker expansions. The steady addition of coking capacity in the US is proving a challenge for sellers of Iraqi Basrah Light crude. New coking capacity means refiners need to run heavier crudes to use plant to the full. This has spurred a switch to grades such as Mexican Maya or Venezuelan Leona instead of the lighter Basrah. Premcor's imports of Iraqi crude fell to 58,000 b/d in the first five months of 2001 from nearly 130,000 b/d in the third quarter 2000, shortly before it brought online a new 80,000 b/d coker at its Port Arthur, Texas, refinery. Basrah Light prices have held firm versus WTI, but this in part reflects impending cuts by other producers. Venezuela has indicated it will have few spot availabilities in September, when lower Opec targets come into force. And Mexico's Maya output will be reduced by maintenance work later this year.

Fuel Oil Markets

Prices for 3pc sulphur fuel oil on the US Atlantic coast held firmed during August, supported by Caribbean exports to Asia and limited imports in New York. As a result, the spread between 1pc and 3pc sulphur fuel oil in New York narrowed to near its narrowest point this year, from $3.50/bl to $0.75/bl. The spread between low and high sulphur in Europe was less dramatic, narrowing from $15/t to $9.50/t. News of rapidly growing US natural gas stocks forced natural gas prices substantially lower, eliminating incremental utility demand for low sulphur fuel oil in the US northeast.

Special Supplement
Maintenance at US Coking Refineries

The customary autumn turnarounds season in the US began early this year and will involve over 1mn b/d of crude capacity each month from August to October. Catalytic cracking capacity was down by 308,000 b/d in August, and is expected to be down 285,000 b/d in September. The impact on cokers will be unmistakable with reduced feed coming from crude units and the catalytic crackers. Strong refining margins increased coke production at some plants in the second quarter. But it became apparent by mid-July that unseasonably low gasoline prices and unexpectedly weak refining margins was encouraging maintenance expected for late September or early October to be brought forward.

Unplanned maintenance is playing a larger role than usual in shaping turnaround schedules. This is especially true in the midcontinent where product prices have firmed, and may in fact delay turnarounds. A fire occurred on 14 August at the 165,000 b/d refinery in Lemont, Illinois owned by Citgo – the US subsidiary of Venezuela's state oil company PdV – resulting in structural damage to the main crude distillation unit (CDU). The refinery will be out of production for at least six weeks but crude and vacuum distillation units could be out of production for far longer. News of the fire initiated a steep climb in midcontinent gasoline and diesel prices. Traders speculated that the higher prices and expectations of continued output cuts could prompt other midcontinent refiners to delay turnarounds until next spring.

Current Maintenance at US Refineries with Coking Capacity

BP, Texas City 437,000 b/d

A 35,000 b/d FCC unit is scheduled for a three-week turnaround beginning in mid-October, according to traders. Market sources say a 15,000 b/d coker unit will undergo two weeks of planned maintenance beginning 8 October.

BP, Los Angeles 260,000 b/d

BP is refitting and upgrading several units to phase out use of MTBE. The CDU was reportedly brought out of operation for two weeks of maintenance on 17 July.

BP, Whiting 410,000 b/d

The refinery is expected to take down its 230,000 b/d crude unit for a month beginning in late September or early October. The crude unit involved is said to run primarily sweet crude. Market sources said a 115,000 b/d catalytic cracking unit was out of production for one week for unplanned maintenance in early July, but details could not be confirmed.

BP, Yorktown 59,500 b/d

A fire was reported on 27 July, causing the CDU to be brought out of production for one week of planned maintenance. The company could not confirm details but was seen buying additional naphtha and VGO to maintain gasoline and diesel output.

Chevron, El Segundo 260,000 b/d

The CDU returned to production on 22 August after several weeks of planned maintenance.

Chevron, Pascagoula 295,000 b/d

A 63,000 b/d catalytic cracking unit was taken out of production for unplanned maintenance in mid-July. Chevron sold up to 800,000 bl of VGO that could not be used by the plant. A 75,000 b/d coker unit was out of production for maintenance from 28 July to 5 August, according to market sources. Traders said the refinery's 63,000 b/d catalytic cracking unit will be in turnaround in October.

Citgo, Corpus Christi 156,000 b/d

The CDU is heard scheduled for a 30-day turnaround in October, but the company could not comment. Citgo denied reports of a fire at the refinery on 21 August.

Citgo, Lake Charles 317,000 b/d

The plant's coker unit is scheduled for turnaround in September, according to traders. Specific dates could not be confirmed.

Citgo, Lemont 165,000 b/d

A large fire occurred on 14 August, forcing the company to shut down all production for at least six weeks. The company said additional structural damage occurred on 17 August but did not specify the nature of the damage. Traders said the vacuum distillation unit had collapsed as a result of the fire, eliminating crude distillation for up to six months. The company was heard buying at least 35,000 b/d of VGO to allow for optimal gasoline and distillate output when the FCC unit returns to production in late September. News of the accident spurred a steep climb in midcontinent prices for gasoline and diesel.

Conoco, Billings 51,500 b/d

Conoco says the plant has been running above full capacity since 1999. The company does not plan to upgrade or add units to increase capacity. No turnarounds are planned through the end of the year.

Conoco, Ponca City 174,000 b/d

On 23 August a malfunction during routine maintenance forced the refinery to shut down one of two FCC units. The full extent of the damage was not available but Conoco says total motor fuel output will not be reduced. A 20,000 b/d catalytic cracking unit is scheduled for three weeks of planned maintenance in early October, according to market sources.

Cooperative Refining, McPherson 75,500 b/d

The plant is running at full capacity and will continue to do so through the end of the year. No turnarounds are planned for the balance of 2001. Market sources report that the plant may be sold or closed rather than updated to meet future reductions in sulphur emissions.

Crown, Pasadena 100,000 b/d
No significant maintenance is planned for the rest of the year. A large turnaround is tentatively scheduled for the second quarter of next year. Crown plans to sell the refinery in an effort to divest refining assets.

Equilon, Anacortes 142,000 b/d
The 55,000 b/d FCC unit was restarted on 23 August after several weeks of unplanned maintenance. A major turnaround was undertaken during the second quarter of last year, so no major maintenance projects are planned for the rest of 2001. A $70mn project to increase catalytic distillation capacity and to meet pending requirements to reduce diesel sulphur content is currently underway.

Equilon, Bakersfield 65,000 b/d
Traders said the CDU was operating below full capacity because of required unplanned maintenance. Equilon confirmed that the plant is operating below full capacity, but this is a response to relatively weak refining margins rather than maintenance projects.

Equilon, Martinez 156,000 b/d
The CDU was taken out of production for maintenance in early July but returned to full capacity by 3 August.

Equilon, Wilmington 96,000 b/d
No turnarounds are scheduled for the balance of this year. Several projects to meet more stringent emissions standards will be completed by the end of 2002.

Imperial, Sarnia 122,000 b/d
A 26,000 b/d FCC unit will be brought out of production in mid-October for a one-month turnaround.

Koch, St. Paul/Pine Bend 260,000 b/d
Koch is taking down its 120,000 b/d crude unit on 9 or 10 September for a turnaround expected to last through the end of the month. The refinery runs a slate dominated by heavy Canadian and light sour grades. Market sources say a 38,000 b/d coker unit was taken out of production for one week in early July, reducing crude distillation for the same period.

Lyondell Citgo, Houston 265,000 b/d
A large production stream is scheduled for turnaround in October. A one-month turnaround on a 136,000 b/d crude unit and the related 38,000 b/d coker will begin the second week of October. The associated 99,000 b/d FCC unit is scheduled for concurrent maintenance. A reformer unit is tentatively scheduled to be out of production for planned maintenance next February. In an effort to prevent full loss of output, maintenance for various units within the same stream is scheduled at intervals over the next two years.

Marathon Ashland, Garyville 232,000 b/d
No large maintenance projects are scheduled before the end of the year, following a large turnaround last January and February.

Motiva, Delaware City 157,000 b/d
The plant was brought out of operations after a fire on 17 July. Market sources reported that the plant was expected to return to full capacity by the end of July. Traders reported that the plant continued to operate below full capacity through the fourth week of August. The CDU was heard to be out of production for several more weeks.

Motiva, Port Arthur 238,000 b/d
Traders say no additional maintenance is planned for the balance of 2001, following extensive planned and unplanned projects early in the year.

Orion, Norco 155,000 b/d
A 50,000 b/d CDU is scheduled for a 40-day maintenance project beginning the last week of August. The plant's FCC unit was out of production for unplanned maintenance in late June and early July. The coker reportedly experienced intermittent production interruptions requiring unplanned maintenance from late June through mid-July, but specific dates could not be confirmed.

PetroCanada, Edmonton 120,000 b/d
The Edmonton refinery will undergo a planned turnaround in September to correspond to an expected dip in production of light sweet synthetic crude from Syncrude Canada. The September turnaround is expected to last 10 days.

Phillips, Sweeny 205,000 b/d
Market sources say the CDU is scheduled for turnaround beginning in early September but details could not be confirmed.

Premcor, Hartford 64,000 b/d
The company says no significant maintenance is scheduled through the end of the year.

Premcor, Lima 162,000 b/d
A 23,000 b/d hydrocracking unit and a 54,000 b/d reformer will be brought out of production for planned maintenance beginning the second week of September. The turnaround is scheduled for 10 days. No additional maintenance is scheduled before the end of the year.

Premcor, Port Arthur 212,000 b/d
Crude distillation was reduced during the first half of July because of unscheduled maintenance requirements. The company bought over 300,000 bl of VGO to maintain gasoline and distillate output at optimum levels. No turnarounds are planned this year.

Shell/Pemex, Deer Park 340,000 b/d
An expansion project completed in March increased crude distillation capacity by 65,000 b/d on one of two distillation units. The expansion project was designed to increase consumption of high sulphur Mexican crude oil, including

expanding coker capacity from 65,000 b/d to 85,000 b/d. The expansion project also included a 35,000 b/d vacuum flasher and a 270 t/d sulphur processing plant. A 67,000 b/d hydrocracking unit and a 67,000 b/d FCC unit were brought out of production for maintenance on 8 August and returned to operations on 20 August. Market sources said a 24,000 b/d platforming unit was in simultaneous turnaround.

Sunoco, Tulsa 85,000 b/d
No turnarounds are scheduled through the end of the year. Because the plant produces lubricants rather than motor fuels, the company could cut crude consumption later in the year if margins remain relatively weak.

Syncrude, Ft McMurray 480,000 b/d
Maintenance associated with the $6bn expansion will reduce September synthetic crude production to 207,000 b/d from an estimated August production of 232,200 b/d. Traders thought October output would return to between 232,200 b/d and 248,400 b/d, but recent speculation holds that the maintenance ould depress output well into October.

FOR FURTHER INFORMATION:

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Houston, TX 77056
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Fax: 713.622.2991
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Tosco, Wilmington 130,500 b/d
No turnarounds or significant maintenance projects are planned for the second half of 2001, largely because of a major turnaround completed in February.

Valero, Benicia 160,000 b/d
A major turnaround was completed during the first quarter of the year. As a result, no significant maintenance projects are planned for the rest of 2001.

Valero, Paulsboro 160,000 b/d
The CDU will undergo up to one month of planned maintenance beginning 6 September, according to market sources. The company said distillate output in September would be reduced by 40,000 b/d, in part because a hydrotreating unit will be brought out of production for planned maintenance.

Florida Department of Environmental Protection

Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Jeb Bush
Governor

David Struhs
Secretary

FAX TRANSMITTAL SHEET

DATE: 9-16-02

TO: ANNE SCHINDLER

PHONE: 904-260-9773 (FAX)

FAX:

FROM: 850/488-0114

PHONE:

Division of Air Resources Management

FAX: 850.922.6979

RE:

CC:

Total number of pages including cover sheet: 7

Message

As requested via Al Linero.

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"Protect, Conserve, and Manage Florida's Environmental and Natural Resources"

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To: Mike Halpin

CAS NO. 205719

Fax: 922-6979

7 pages

From: Linda Mason
Phone 921-9677

August 29, 2002

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

CSX TRANSPORTATION, INC.,

Petitioner,

FDEP File No.: PSD-FL-137(PA88-24)

vs.

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL
PROTECTION

Respondent.
_______________________________/

PETITION FOR FORMAL ADMINISTRATIVE HEARING

Petitioner, CSX Transportation, Inc. ("CSXT"), pursuant to Sections 120.569 and 120.57, Florida Statutes, hereby files this petition for formal administrative hearing. The subject of this petition is the proposed action by the State of Florida Department of Environmental Protection ("Department" or "FDEP") to issue a PSD permit modification to Cedar Bay Co-Generation facility located at 9640 East Port Road, Jacksonville, Florida. As grounds therefore, CSXT states as follows:

1. The name and address of the affected agency is the State of Florida Department of Environmental Protection with the principal address of 2600 Blair Stone Road, Tallahassee, Florida 32399-2400. The agency's file or identification number is PSD-FL-137(PA 88-24).

2. The name and address of the petitioner is CSX Transportation, Inc., 500 Water Street, Jacksonville, Florida 32202. For purposes of this proceeding, the telephone number for CSXT will be that of the undersigned counsel. For purposes of this proceeding, the name, address, and telephone number of petitioner's representative is the undersigned counsel.

3. Cedar Bay Generating Company, L.P. ("Cedar Bay") operates the Cedar Bay Co-Generation Facility ("Facility") at 9640 East Port Road, Jacksonville, Florida. The Facility sells steam to the Florida Power and Light Company and to an adjacent plant. The

Facility was initially permitted under Florida's Power Plant Siting Act (PPSA) (FDEP File No. PA88-24), issued a Prevention of Significant Deterioration (PSD) permit (FDEP Permit No. PSD-FL-137), and received a Title V permit (Final Permit No. 0310337-002-AV).

4. The Facility is considered a "major" source of hazardous air pollutants. The Facility consists of three circulating fluidized bed ("CFB") boilers, a coal handling area, a limestone handling area, and an ash handling area. The CFB boilers are fueled with bituminous coal with No. 2 fuel oil for start-up. The fuel is burnt in the existing CFB boilers which feed a common steam turbine with a nominal rating of 250 megawatts. The Facility emits carbon monoxide (CO), nitrogen oxide (NO_X), sulfuric dioxide (SO_2), particulate matter (PM/PM_{10}), volatile organic compounds (VOC), and sulfuric acid mist (SAM).

5. On August 29, 2001, Cedar Bay applied for a modification to the PSD permit and to the conditions of certification that were issued for the Facility under the PPSA. The modification application sought approval to co-fire up to 35% of petroleum coke ("petcoke") with coal at the Facility. Petcoke is a by-product from oil refineries and is composed mainly of carbon, but also contains high levels of sulfur and heavy metals. The co-firing of petcoke is an operational change and physical modifications are contemplated to receive, handle, burn, and dispose of petcoke and its associated pollutants. The change in the operation of the project and the associated construction is considered a modification under Rule 62-210.200 and 62-212.400, Florida Administrative Code. Based on a determination by the Department that the proposed modification would not cause a "significant net increase" in emissions at the Facility, the Department did not require PSD modification review.

6. Petitioner, CSXT, is a Florida corporation. For purposes of this proceeding, CSXT is a "person" as defined in Section 403.031(5), Florida Statutes. CSXT's substantial interest will be affected by the proposed permitting decision. CSXT's corporate headquarters is in Jacksonville and it conducts substantial operations in Duval County. CSXT's activities are directly and indirectly connected to and are dependent upon the operations at the Facility and the Facility's adherence to and compliance with applicable air emission standards and other

conditions of certification. In addition, more than 5,000 CSXT personnel live and/or work in the Duval County area and will be substantially and adversely affected by the proposed decision by the Department. The adverse impact of the Department's proposed action will be particularly immediate and acute with respect to those CSXT employees and other citizens of Duval County living near the Facility.

7. CSXT received notice of the agency's proposed action based on the publication of the "Public Notice of Intent to Issue PSD Permit Modification" in The Florida Times Union on August 12, 2002. Pursuant to Sections 120.596 and 120.57, Florida Statutes, CSXT timely filed this petition on the date set forth below.

8. The material facts which are disputed by CSXT are as follows:

a. Whether the Department correctly determined the PSD review under Rule 62-212.400, Florida Administrative Code, was not required;

b. Whether the Department acted in accordance with Florida law in granting the application for permit modification without PSD review;

c. Whether reasonable assurances have been provided that there will be no significant net increase in emissions for each of the pollutants as a result of the proposed modification;

d. Whether the Department correctly evaluated the future actual emissions given operational and pollutant variability;

e. Whether reasonable assurances have been provided that the proposed air pollution control systems will maintain the emissions at the current levels;

f. Whether there will be any significant increase in actual emissions of regulated air pollutants;

g. Whether the test methods and their required frequency to be used to measure future emissions of air toxins will effectively demonstrate future compliance;

h. Whether air toxins other than those present in coal have been adequately evaluated and addressed by the Department in conjunction with its review;

i. Whether all metals present in petcoke have been adequately evaluated and addressed by the Department in conjunction with its review;

j. Whether the fugitive emission standard of 5% is adequately verifiable, measurable, and reasonable;

k. Whether the operational controls to reduce fugitive dust emissions from petcoke storage and handling is adequate;

l. Whether the use of a higher sulfur fuel such as petcoke will interfere with maintaining the SO_2 air quality standards in the Jacksonville area;

m. Whether Cedar Bay has provided reasonable assurance that the immediate and long-term impacts of the modification will not result in a violation of air quality standards;

n. Whether the Department correctly determined that the proposed modification will not adversely affect the public interest, public health, safety, or welfare or the property of others;

o. Whether Cedar Bay has provided reasonable assurance that the direct, secondary, and cumulative effects of the modification are contrary to the public interest pursuant to Chapter 403, Florida Statutes and other applicable regulations.

9. A concise statement of the ultimate facts alleged, including the specific facts CSXT contends warrant reversal or modification of the agency's proposed action, is as follows: Petitioner asserts the negative of disputed facts 8(a) through 8(o) above as facts which Petitioner contends warrant reversal of the Department's proposed action to grant the application for permit modification.

10. A statement of the rules or statutes CSXT contends require reversal or modification of the agency's proposed actions is as follows:

a. 42 U.S.C. 7401, *et seq.*;

b. Chapter 403, Florida Statutes;

c. Chapters 62-4, 62-204, 62-210, 62-212, 62-296, and 62-297, Florida Administrative Code;

d. 40 CFR 52.21; and

e. 40 CFR 60.

WHEREFORE, petitioner, CSX Transportation, Inc., respectfully requests:

a. That this petition be referred to the Division of Administrative Hearings to conduct a formal hearing pursuant to Sections 120.569 and 120.57, Florida Statutes;

b. That upon the record of such hearing, the Administrative Law Judge so assigned issue a recommended order reversing the Department's Notice of Intent PSD Permit Modification;

c. That upon receipt of the recommended order, the Department issue a final order denying the application for permit modification; and

d. Such other relief be afforded as is just and lawful.

DATED this 26th day of August, 2002.

Respectfully Submitted,

ROBERT N. CLARKE, JR.
WILLIAM L. HYDE
Ausley & McMullen
Attorneys and Counselors at Law
227 South Calhoun Street
Post Office Box 391
Tallahassee, Florida 32302
(850)224-9115

Counsel for Petitioner

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that the original and one copy of the foregoing has been furnished by hand delivery to the Agency Clerk, State of Florida, Department of Environmental Protection, 3900 Commonwealth Boulevard, Tallahassee, Florida 32399 and to the Office of the General Counsel of the Florida Department of Environmental Protection, 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida 32399-3000 this 26th day of August, 2002.

ATTORNEY

Florida Department of Environmental Protection

Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Jeb Bush
Governor

David Struhs
Secretary

FAX TRANSMITTAL SHEET

DATE: 9-4-02

TO: LISA GLENN (DOUG BEASON)

PHONE: FAX: 921-3000

FROM: MIKE NACON PHONE: 921-9519

Division of Air Resources Management FAX: 850.922.6979

RE:

CC:

Total number of pages including cover sheet: 6

Message

As you requested.

If there are any problems with this fax transmittal, please call the above phone number.

"Protect, Conserve, and Manage Florida's Environmental and Natural Resources"

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In the Matter of an
Application for Permit by:

Bruce Smith, General Manager
Cedar Bay Cogeneration Facility
PO Box 26324
Jacksonville, Florida 32226-6324

DEP File No. PSD-FL-137 (PA 88-24)

INTENT TO ISSUE PSD PERMIT MODIFICATION

The Department of Environmental Protection (Department) gives notice of its intent to issue a PSD Permit Modification (copy of Draft permit attached) for the proposed project, detailed in the application specified above and for the reasons stated below.

The applicant, Bruce Smith, General Manager, U.S. Generating Company, applied on August 29, 2001, to the Department for a PSD Permit Modification for its Cedar Bay Cogeneration Facility, located at 9640 Eastport Road, Jacksonville, Duval County. The request is to revise the permit to allow for the limited co-firing of petroleum coke with coal in its three circulating fluidized bed boilers.

The Department has permitting jurisdiction under the provisions of Chapter 403, Florida Statutes (F.S.), and Florida Administrative Code (F.A.C.) Chapters 62-4, 62-210, 62-212 and 40 CFR 52.21. The above actions are not exempt from permitting procedures. The Department has determined that a PSD Permit Modification is required to revise the permit with respect to changes in fuel.

The Department intends to issue this PSD Permit Modification based on the belief that reasonable assurances have been provided to indicate that operation of these emission units will not adversely impact air quality, and the emission units will comply with all appropriate provisions of Chapters 62-4, 62-204, 62-210, 62-212, 62-296, and 62-297, F.A.C. and 40 CFR 52.21.

Pursuant to Section 403.815, F.S., and Rule 62-110.106(7)(a)1., F.A.C., you (the applicant) are required to publish at your own expense the enclosed Public Notice of Intent to Issue PSD Permit Modification. The notice shall be published one time only in the legal advertisement section of a newspaper of general circulation in the area affected. Rule 62-110.106(7)(b), F.A.C., requires that the applicant cause the notice to be published as soon as possible after notification by the Department of its intended action. For the purpose of these rules, "publication in a newspaper of general circulation in the area affected" means publication in a newspaper meeting the requirements of Sections 50.011 and 50.031, F.S., in the county where the activity is to take place. If you are uncertain that a newspaper meets these requirements, please contact the Department at the address or telephone number listed below. The applicant shall provide proof of publication to the Department's Bureau of Air Regulation, at 2600 Blair Stone Road, Mail Station #5505, Tallahassee, Florida 32399-2400 (Telephone: 850/488-0114; Fax 850/ 922-6979). You must provide proof of publication within seven days of publication, pursuant to Rule 62-110.106(5), F.A.C. No permitting action for which published notice is required shall be granted until proof of publication of notice is made by furnishing a uniform affidavit in substantially the form prescribed in section 50.051, F.S. to the office of the Department issuing the permit. Failure to publish the notice and provide proof of publication may result in the denial of the permit pursuant to Rules 62-110.106(9) & (11), F.A.C.

The Department will issue the final permit with the attached conditions unless a response received in accordance with the following procedures results in a different decision or significant change of terms or conditions.

The Department will accept written comments concerning the proposed permit issuance action for a period of 30 (thirty) days from the date of publication of Public Notice of Intent to Issue PSD Permit Modification. Written comments should be provided to the Department's Bureau of Air Regulation at 2600 Blair Stone Road, Mail Station #5505, Tallahassee, FL 32399-2400. Any written comments filed shall be made available for public inspection. If written comments received result in a significant change in the proposed agency action, the Department shall revise the proposed permit and require, if applicable, another Public Notice.

The Department will issue the permit with the attached conditions unless a timely petition for an administrative hearing is filed pursuant to sections 120.569 and 120.57 F.S., before the deadline for filing a petition. The procedures for petitioning for a hearing are set forth below.

A person whose substantial interests are affected by the proposed permitting decision may petition for an administrative proceeding (hearing) under sections 120.569 and 120.57 of the Florida Statutes. The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department at 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida, 32399-3000. Petitions filed by the permit applicant or any of the parties listed below must be filed within fourteen days of receipt of this notice of intent. Petitions filed by any persons other than those entitled to written notice under section 120.60(3) of the Florida Statutes must be filed within fourteen days of publication of the public notice or within fourteen days of receipt of this notice of intent, whichever occurs first. Under section 120.60(3), however, any person who asked the Department for notice of agency action may file a petition within fourteen days of receipt of that notice, regardless of the date of publication. A petitioner shall mail a copy of the petition to the applicant at the address indicated above at the time of filing. The failure of any person to file a petition within the appropriate time period shall constitute a waiver of that person's right to request an administrative determination (hearing) under sections 120.569 and 120.57 F.S., or to intervene in this proceeding and participate as a party to it. Any subsequent intervention will be only at the approval of the presiding officer upon the filing of a motion in compliance with Rule 28-106.205 of the Florida Administrative Code.

A petition that disputes the material facts on which the Department's action is based must contain the following information: (a) The name and address of each agency affected and each agency's file or identification number, if known; (b) The name, address, and telephone number of the petitioner, the name, address, and telephone number of the petitioner's representative, if any, which shall be the address for service purposes during the course of the proceeding; and an explanation of how the petitioner's substantial interests will be affected by the agency determination; (c) A statement of how and when petitioner received notice of the agency action or proposed action; (d) A statement of all disputed issues of material fact. If there are none, the petition must so indicate; (e) A concise statement of the ultimate facts alleged, including the specific facts the petitioner contends warrant reversal or modification of the agency's proposed action; (f) A statement of the specific rules or statutes the petitioner contends require reversal or modification of the agency's proposed action; and (g) A statement of the relief sought by the petitioner, stating precisely the action petitioner wishes the agency to take with respect to the agency's proposed action.

A petition that does not dispute the material facts upon which the Department's action is based shall state that no such facts are in dispute and otherwise shall contain the same information as set forth above, as required by Rule 28-106.301.

Because the administrative hearing process is designed to formulate final agency action, the filing of a petition means that the Department's final action may be different from the position taken by it in this notice. Persons whose substantial interests will be affected by any such final decision of the Department on the application have the right to petition to become a party to the proceeding, in accordance with the requirements set forth above.

Mediation is not available in this proceeding.

In addition to the above, a person subject to regulation has a right to apply for a variance from or waiver of the requirements of particular rules, on certain conditions, under Section 120.542 F.S. The relief provided by this state statute applies only to state rules, not statutes, and not to any federal regulatory requirements. Applying for a variance or waiver does not substitute or extend the time for filing a petition for an administrative hearing or exercising any other right that a person may have in relation to the action proposed in this notice of intent.

The application for a variance or waiver is made by filing a petition with the Office of General Counsel of the Department, 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida 32399-3000. The petition must specify the following information: (a) The name, address, and telephone number of the petitioner; (b) The name, address, and telephone number of the attorney or qualified representative of the petitioner, if any; (c) Each rule or portion of a rule from which a variance or waiver is requested; (d) The citation to the statute underlying (implemented by) the rule identified in (c) above; (e) The type of action requested; (f) The specific facts that would justify a variance or waiver for the petitioner; (g) The reason why the variance or waiver would serve the purposes of the underlying statute (implemented by the rule); and (h) A statement whether the variance or waiver is permanent or temporary and, if temporary, a statement of the dates showing the duration of the variance or waiver requested.

The Department will grant a variance or waiver when the petition demonstrates both that the application of the rule would create a substantial hardship or violate principles of fairness, as each of those terms is defined in Section 120.542(2) F.S., and that the purpose of the underlying statute will be or has been achieved by other means by the petitioner.

Persons subject to regulation pursuant to any federally delegated or approved air program should be aware that Florida is specifically not authorized to issue variances or waivers from any requirements of any such federally delegated or approved program. The requirements of the program remain fully enforceable by the Administrator of the EPA and by any person under the Clean Air Act unless and until the Administrator separately approves any variance or waiver in accordance with the procedures of the federal program.

Executed in Tallahassee, Florida.

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

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this Intent to Issue PSD Permit Modification (including the Public Notice of Intent to Issue PSD Permit Modification and the Draft PSD Permit) was sent by certified mail (*) and copies were mailed by U.S. Mail before the close of business on 8/1/02 to the person(s) listed:

Bruce Smith, Cedar Bay *
Jeff Walker, Cedar Bay
Ken Kosky, P.E. Golder Associates
Hamilton S. Oven, P.E. PPSO
James L. Manning, P.E. RESD
Chris Kirts, DEP-NED
Stafford Campbell, Greater Arlington Civic Council

Clerk Stamp

FILING AND ACKNOWLEDGMENT FILED, on this date, pursuant to §120.52, Florida Statutes, with the designated Department Clerk, receipt of which is hereby acknowledged.

Victoria Gibson — August 1, 2002
(Clerk) (Date)

PUBLIC NOTICE OF INTENT TO ISSUE PSD PERMIT MODIFICATION

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

DEP File No. PSD-FL-137 (PA 88-24)

U.S. Generating Company
Cedar Bay Cogeneration Facility
Duval County

The Department of Environmental Protection (Department) gives notice of its intent to issue a PSD Permit Modification to Cedar Bay Cogeneration Facility, located at 9640 Eastport Road, Jacksonville, Duval County. The permit is to revise the conditions so as to allow for limited co-firing of petroleum coke (petcoke) with coal. This is an existing facility, which currently combusts coal as its primary fuel. A new determination of Best Available Control Technology (BACT) was not required. The applicant's mailing address is: U. S. Generating Company, P.O. Box 26324, Jacksonville FL 32226-6324.

Typically petroleum coke has greater sulfur content than coal, but less ash. Accordingly, absent proper controls its usage presents the possibility of increased SO_2 emissions. The existing facility has adequate air pollution control equipment, consisting of a CFB (including limestone injection) for SO_2 control, in addition to a selective non-catalytic reduction system for control of nitrogen oxides and baghouses for control of particulate matter. This equipment is sufficient to provide reasonable assurance that no significant increases of the mentioned pollutants will occur.

This modification will revise the permit to allow for the co-firing of up to 35% petroleum coke (petcoke) by weight, with coal in the three circulating fluidized bed boilers. The Department has determined that co-firing can occur, provided that the equivalent SO_2 inlet loading to the boilers is less than 3.2 lb/MMBtu, yielding an emission rate of 0.16 lb/MMBtu. Additionally, the Department will require improved measurements of bed ash throughput and require reporting of facility emissions for five (5) years. These measures are sufficient to ensure that only decreases, or less than significant increases of the emissions of PSD pollutants will occur as a result of this modification. The Significant Emission Rates for pollutants of interest (for which this project will not exceed) are defined by the Florida Administrative Code, Chapter 62-212, Table 212.400-2 as follows:

POLLUTANT	SIGNIFICANT EMISSION RATES
Sulfur dioxide	40 Tons Per Year
Nitrogen oxides	40 Tons Per Year
PM_{10}	15 Tons Per Year
Sulfuric acid mist	7 Tons Per Year
Ozone (Volatile Organic Compounds)	40 Tons Per Year
Carbon monoxide	100 Tons Per Year

An air quality impact analysis was not required. The Department will issue the Final Permit with the attached conditions unless a response received in accordance with the following procedures results in a different decision or significant change of terms or conditions.

The Department will accept written comments concerning the proposed permit issuance action for a period of 30 (thirty) days from the date of publication of this Public Notice of Intent to Issue PSD Permit Modification. Written comments should be provided to the Department's Bureau of Air Regulation at 2600 Blair Stone Road, Mail Station #5505, Tallahassee, FL 32399-2400. Any written comments filed shall be made available for public inspection. If written comments received result in a significant change in the proposed agency action, the Department shall revise the proposed permit and require, if applicable, another Public Notice.

The Department will issue the permit with the attached conditions unless a timely petition for an administrative hearing is filed pursuant to sections 120.569 and 120.57 F.S., before the deadline for filing a petition. The procedures for petitioning for a hearing are set forth below. Mediation is not available in this proceeding.

NOTICE TO BE PUBLISHED IN THE NEWSPAPER

A person whose substantial interests are affected by the proposed permitting decision may petition for an administrative proceeding (hearing) under sections 120.569 and 120.57 of the Florida Statutes. The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department at 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida, 32399-3000. Petitions filed by the permit applicant or any of the parties listed below must be filed within fourteen days of receipt of this notice of intent. Petitions filed by any persons other than those entitled to written notice under section 120.60(3) of the Florida Statutes must be filed within fourteen days of publication of the public notice or within fourteen days of receipt of this notice of intent, whichever occurs first. Under section 120.60(3), however, any person who asked the Department for notice of agency action may file a petition within fourteen days of receipt of that notice, regardless of the date of publication. A petitioner shall mail a copy of the petition to the applicant at the address indicated above at the time of filing. The failure of any person to file a petition within the appropriate time period shall constitute a waiver of that person's right to request an administrative determination (hearing) under sections 120.569 and 120.57 F.S., or to intervene in this proceeding and participate as a party to it. Any subsequent intervention will be only at the approval of the presiding officer upon the filing of a motion in compliance with Rule 28-106.205 of the Florida Administrative Code.

A petition that disputes the material facts on which the Department's action is based must contain the following information: (a) The name and address of each agency affected and each agency's file or identification number, if known; (b) The name, address, and telephone number of the petitioner, the name, address, and telephone number of the petitioner's representative, if any, which shall be the address for service purposes during the course of the proceeding; and an explanation of how the petitioner's substantial interests will be affected by the agency determination; (c) A statement of how and when petitioner received notice of the agency action or proposed action; (d) A statement of all disputed issues of material fact. If there are none, the petition must so indicate; (e) A concise statement of the ultimate facts alleged, including the specific facts the petitioner contends warrant reversal or modification of the agency's proposed action; (f) A statement of the specific rules or statutes the petitioner contends require reversal or modification of the agency's proposed action; and (g) A statement of the relief sought by the petitioner, stating precisely the action petitioner wishes the agency to take with respect to the agency's proposed action.

A petition that does not dispute the material facts upon which the Department's action is based shall state that no such facts are in dispute and otherwise shall contain the same information as set forth above, as required by rule 28-106.301

Because the administrative hearing process is designed to formulate final agency action, the filing of a petition means that the Department's final action may be different from the position taken by it in this notice. Persons whose substantial interests will be affected by any such final decision of the Department on the application have the right to petition to become a party to the proceeding, in accordance with the requirements set forth above.

A complete project file is available for public inspection during normal business hours, 8:00 a.m. to 5:00 p.m., Monday through Friday, except legal holidays, at:

Florida Department of
Environmental Protection
Bureau of Air Regulation
111 S. Magnolia Drive, Suite 4
Tallahassee, Florida, 32301
Telephone: (850) 488-1344
Fax: (850) 922-6979

Florida Department of
Environmental Protection
Northeast District
Suite 200B, 7825 Baymeadows Way
Jacksonville, Florida 32256
Telephone: (904) 448-4300

The complete project file includes the application, Draft permit, and the information submitted by the Responsible Official, exclusive of confidential records under Section 403.111, F.S. Interested persons may review specific details of this project at http://www.dep.state.fl.us/air/permitting/construct.htm or contact the Administrator, New Source Review Section, at 111 South Magnolia Drive, Suite 4, Tallahassee, Florida 32301, or call 850/488-0114, for additional information.

NOTICE TO BE PUBLISHED IN THE NEWSPAPER

PG&E National Energy Group
Cedar Bay Generating Plant
Owner: Cedar Bay Generating Company, L.P.

RECEIVED
AUG 19 2002
BUREAU OF AIR REGULATION

POB 26324
Jacksonville, FL 32226-6324
904.751.4000
Fax: 904.751.7320

Mike- 9/6
I found this - Hope it was an extra & you already had one - Apparently I updated ARMS
Patty

August 16, 2002

Mr. C.H. Fancy, P.E.
Florida Department of Environmental Protection
Bureau of Air Regulation
Mail Station #5505
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Re: Cedar Bay Air Construction/PSD Permit Modification

Dear Mr. Fancy

Pursuant to the instructions in your letter dated July 31, 2002, Cedar Bay submits the Affidavit of Publication for the "PUBLIC NOTICE OF INTENT TO ISSUE PSD PERMIT MODIFICATION". The notice was published in the Florida Times Union on August 12, 2002.

Sincerely,

Jeffrey A. Walker

Jeffrey A. Walker
Environmental Manager, Cedar Bay

cc: M. Krest, Cedar Bay
T. Fromm, Bethesda

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THE FLORIDA TIMES-UNION
Jacksonville, Fl
Affidavit of Publication

Florida Times-Union

CEDAR BAY GENERATING CO.
PO BOX 26324
JACKSONVILLE FL 32236

REFERENCE: 0181153 Jeff Walker
R77826 Public Notice

State of Florida
County of Duval

Before the undersigned authority personally appeared Valerie Vest who on oath says she is a Legal Advertising Representative of The Florida Times-Union, a daily newspaper published in Jacksonville in Duval County, Florida; that the attached copy of advertisement is a legal ad published in The Florida Times-Union. Affiant further says that The Florida Times-Union is a newspaper published in Jacksonville, in Duval County, Florida, and that the newspaper has heretofore been continuously published in Duval County, Florida each day, has been entered as second class mail matter at the post office in Jacksonville, in Duval County, Florida for a period of one year preceeding the first publication of the attached copy of advertisement; and affiant further says that he/she has neither paid nor promised any person, firm or corporation any discount, rebate, commission, or refund for the purpose of securing this advertisement for publication in said newspaper.

PUBLISHED ON: 08/12

FILED ON: 08/12/02 Valerie Vest

Name: Valerie Vest Title: Legal Advertising

In testimony whereof, I have hereunto set my hand and seal, the day and year aforesaid.

NOTARY: Twilla Shipp

TWILLA SHIPP
Notary Public, State of Florida
My comm. expires May 13, 2006
Comm. No. DD 117248

PUBLIC NOTICE OF INTENT TO ISSUE PSD PERMIT MODIFICATION
STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
DEP File No. PSD-FL-137 (PA 88-24)
U.S. Generating Company
Cedar Bay Cogeneration Facility
Duval County

The Department of Environment Protection (Department) gives notice of its intent to issue a PSD Permit Modification to Cedar Bay Cogeneration Facility, located at 9640 Eastport Road, Jacksonville, Duval County. The permit is to revise the conditions so as to allow for limited co-firing of petroleum coke (petcoke) with coal. This is an existing facility, which currently combusts coal as its primary fuel. A new determination of Best Available Control technology (BACT) was not required. The applicant's mailing address is: U.S. Generating Company, P.O. Box 26324, Jacksonville, FL 32226-6324.

Typically petroleum coke has greater sulfer content than coal, but less ash. Accordingly, absent proper controls its usage presents the possibility of increased SO_2 emissions. The existing facility has adequate air pollution control equipment, consisting of a CFB (including limestone injection) for SO_2 control, in addition to a selective non-catalytic reduction system for control of nitrogen oxides and baghouses for control of particulate matter. This equipment is sufficient to provide reasonable assurance that no significant increases of the mentioned pollutants will occur.

This modification will revise the permit to allow for the co-firing of up to 35% petroleum coke (petcoke) by weight, with coal in the three circulating fluidized bed boilers. The Department has determined that co-firing can occur, provided that the equivalent SO_2 inlet loading to the boilers is less than 3.2 lb/MMBtu, yielding an emission rate of 0.16 lb/MMBtu. Additionally, the Department will require improved measurements of bed ash throughout and require reporting of facility emissions for five (5) years. These measures are sufficient to ensure that only decreases, or less than significant increases of the emissions of PSD pollutants will occur as a result of this modification. The Significant Emission Rates for pollutants of interest (for which this project will not exceed) are defined by the Florida Administrative Code, Chapter 62-212, Table 212.400-2 as follows:

POLLUTANT	SIGNIFICANT EMISSION RATES
Sulfur dioxide	40 Tons Per Year
Nitrogen oxides	40 Tons Per Year
PM_{10}	15 Tons Per Year
Sulfuric acid mist	7 Tons Per Year
Ozone (Volatile Organic Compounds)	40 Tons Per Year
Carbon Monoxide	100 Tons Per Year

An air quality impact analysis was not required. The Department will issue the Final Permit with the attached conditions unless a response received in accordance with the following procedures results in a different decision or significant change of terms or conditions.

The Department will accept written comments concerning the proposed permit issuance action for a period of 30 (thirty) days from the date of publication of this Public Notice of Intent to Issue PSD Permit Modification. Written comments filed should be provided to the Department's Bureau of Air Regulation at 2600 Blair Stone Road, Mail Station #5505, Tallahassee, FL 32399-2400. Any written comments filed shall be made available for public inspection. If written comments received result in a significant change in the proposed agency action, the Department shall revise the proposed permit and require, if applicable, another Public Notice.

The Department will issue the permit with the attached conditions unless a timely petition for an administrative hearing is filed pursuant to sections 120.569 and 120.57 F.S., before the deadline for filing a petition. The procedures for petitioning for a hearing are set forth below. Mediation is not available in this proceeding.

A person whose substantial interests are affected by the proposed permitting decision may petition for an administrative proceeding (hearing) under sections 120.569 and 120.57 of the Florida Statutes. The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department at 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida, 32399-3000. Petitions filed by the permit applicant or any of the parties listed below must be filed within fourteen days of receipt of this notice of intent. Petitions filed by any persons other than those entitled to written notice under section 120.60(3) of the Florida Statutes must be filed within fourteen days of publication of the public notice or within fourteen days of receipt of this notice of intent, whichever occurs first. Under section 120.60(3), however, any person who asked the Department for notice of agency action may file a petition within fourteen days of receipt of that notice, regardless of the date of publication. A petitioner shall mail a copy of the petition to the applicant at the address indicated above at the time of filing. The failure of any person to file a petition within the appropriate time period shall constitute a waiver of that person's right to request an administrative determination (hearing) under sections 120.569 and 120.57 F.S., or to intervene in this proceeding and participate as a party to it. Any subsequent intervention will be only at the approval of the presiding officer upon the filing of a motion in compliance with Rule 28-106.205 of the Florida Administrative Code.

A petition that disputes the material facts on which the Department's action is based must contain the following information: (a) The name and address of each agency affected and each agency's file or identification number, if known; (b) The name, address, and telephone number of the petitioner, the name, address, and telephone number of the petitioner's representative, if any, which shall be the address for service purposes during the course of the proceeding; and an explanation of how the petitioner's substantial interests will be affected by the agency determination; (c) A [illegible]

State of Florida **BEST AVAILABLE COPY**

County of Duval

Before the undersigned authority personally appeared Valerie Vest who on oath says she is a Legal Advertising Representative of The Florida Times-Union, a daily newspaper published in Jacksonville in Duval County, Florida; that the attached copy of advertisement is a legal ad published in The Florida Times-Union. Affiant further says that The Florida Times-Union is a newspaper published in Jacksonville, in Duval County, Florida, and that the newspaper has heretofore been continuously published in Duval County, Florida each day, has been entered as second class mail matter at the post office in Jacksonville, in Duval County, Florida for a period of one year preceeding the first publication of the attached copy of advertisement; and affiant further says that he/she has neither paid nor promised any person, firm or corporation any discount, rebate, commission, or refund for the purpose of securing this advertisement for publication in said newspaper.

PUBLISHED ON: 08/12

FILED ON: 08/12/02 Valerie Vest

Name: Valerie Vest Title: Legal Advertising

In testimony whereof, I have hereunto set my hand and seal, the day and year aforesaid.

NOTARY: Twilla Shipp

TWILLA SHIPP
Notary Public, State of Florida
My comm. expires May 13, 2006
Comm. No. DD 117248

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A petition that disputes the material facts on which the Department's action is based must contain the following information: (a) The name and address of each agency affected and each agency's file or identification number, if known; (b) The name, address, and telephone number of the petitioner, the name, address, and telephone number of the petitioner's representative, if any, which shall be the address for service purposes during the course of the proceeding; and an explanation of how the petitioner's substantial interests will be affected by the agency determination; (c) A statement of how and when petitioner received notice of the agency action or proposed action; (d) A statement of all disputed issues of material fact. If there are none, the petition must so indicate; (e) A concise statement of the ultimate facts alleged, including the specific facts the petitioner contends warrant reversal or modification of the agency's proposed action; (f) A statement of the specific rules or statutes the petitioner contends require reversal or modification of the agency's proposed action; and (g) A statement of the relief sought by the petitioner, stating precisely the action petitioner wishes the agency to take with respect to the agency's proposed action.

A petition that does not dispute the material facts upon which the Department's action is based shall state that no such facts are in dispute and otherwise shall contain the same information as set forth above, as required by rule 28-106.301.

Because the administrative hearing process is designed to formulate final agency action, the filing of a petition means that the Department's final action may be different from the position taken by it in this notice. Persons whose substantial interests will be affected by any such final decision of the Department on the application have the right to petition to become a party to the proceeding, in accordance with the requirements set forth above.

A complete project file is available for public inspection during normal business hours, 8:00 a.m. to 5:00 p.m., Monday through Friday, except legal holidays, at:

Florida Department of Environmental Protection Bureau of Air regulation 111 S. Magnolia Drive, Suite 4 Tallahassee, Florida 32301 Telephone: (850) 488-1344 Fax: (850) 922-6979	Florida Department of Environmental Protection Northeast District Suite 200B, 7825 Baymeadows Way Jacksonville, Florida 32256 Telephone: (904) 448-4300

The complete project file includes the application, Draft permit, and the information submitted by the Responsible Official, exclusive of confidential records under Section 403.111, F.S. Interested persons may review specific details of this project at http://www.dep.state.fl.us/air/permitting/construct.htm or contact the Administrator, New Source Review Section, at 111 South Magnolia Drive, Suite 4, Tallahassee, Florida 32301, or call 850/488-0114 for additional information.

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 4
ATLANTA FEDERAL CENTER
61 FORSYTH STREET
ATLANTA, GEORGIA 30303-8960

FACSIMILE TRANSMITTAL SHEET

To	Mike Halpin - FDEP
Fax Number	(850) 922-6979
From	Jim Little Air Planning Branch, Air Permits Section Phone: (404) 562-9118 Fax: (404) 562-9019 E-mail: little.james@epa.gov
Subject	WEPCO
Date	August 29, 2002
Pages	2 (including this sheet)

I hope this is readable.

BEST AVAILABLE COPY

Mike

increases and decreases in 40 CFR 52.21(b)(3)(i)(b).[20]

Moreover, EPA is not reading "normal source operations" out of the regulation as charged. Rather, the presumption recognizes the nature of utility operations without compromising the existing regulatory language which requires that the pre-change 2-year period used in defining baseline emissions be representative of "normal" operations. For example, as a system a utility's "normal" operations means directly responding to a demand for electricity. A cold winter or hot summer will result in high levels of "normal" operations while a relatively mild year will produce lower "normal" operations. By presumably allowing a utility to use any 2 consecutive years within the past 5, the rule better takes into consideration that electricity demand and resultant utility operations fluctuate in response to various factors such as annual variability in climatic or economic conditions that affect demand, or changes at other plants in the utility system that affect the dispatch of a particular plant. By expanding a baseline for a utility to any consecutive 2 in the last 5 years, these types of fluctuations in operations can be more realistically considered, with the result being a presumptive baseline more closely representative of normal source operation.

The EPA disagrees with comments seeking to allow the use of any 2 consecutive years within the last 5 years of a unit's "operation" rather within than the 5 years directly preceding the proposed change. A shifting of the 5-year period would be difficult to harmonize with definitions of contemporaneous contained in the regulations (see, e.g., 40 CFR 52.21(b)(3)(iii)). This type of open-ended provision would even credit a unit which has been inoperative for 20 or 30 years or longer with a high level of emissions. The EPA notes, however, that as has always been the case under the prior regulations, any source owner or operator may request a determination that another baseline period is more representative of the unit's "normal" operations.

Several commenters opposing today's regulatory changes charged that without appropriate assurances utilities could deliberately underestimate future operations (and thus emissions) for the purpose of avoiding review or that even where a forthright estimate is made, the forecast may prove inaccurate. The EPA is concerned that without appropriate safeguards increases in future actual emissions that in fact resulted from the physical or operational change could go unnoticed and unreviewed. For this reason, EPA has added the safeguard explained below.

The EPA does not, however, agree with comments that post-change emissions estimates must always be made into permanent federally-enforceable permit conditions. To do so would permanently restrict a utility's legally allowable emission limits to its pre-change actual emissions level unless it subsequently underwent NSR, and would fail to account for the very real possibility that emissions might increase over baseline levels in the future for reasons unrelated to the physical or operational change in question. As discussed more fully in the following section, NSR applies only where the emissions increase is caused by the change. Thus the issue should be viewed more as one of tracking and monitoring post-change utilization and/or emissions levels at the unit to confirm that baseline emission levels are not exceeded as a result of the change.

To guard against the possibility that significant increases in actual emissions attributable to the change may occur under this methodology, EPA is clarifying in the final regulations that any utility which utilizes the "representative actual annual emissions" methodology to determine that it is not subject to NSR must submit for 5 years after the change sufficient records to determine if the change results in an increase in representative actual annual emissions.[21] Utilities may use continuous emissions monitoring data, operational levels, fuel usage data, source test results or any other readily available data of sufficient accuracy for the purpose of documenting a unit's post-change actual annual emissions.

Where the change does not increase the unit's emissions factor, i.e., the amount of pollution emitted by a source after control per unit of fuel combusted (such as pounds of SO_2 emitted per ton of coal burned), the utility may submit annual utilization data, rather than emissions data, as a method of tracking post-change emissions. If annual utilization data show that the unit increased utilization above baseline levels, the permitting authority should determine whether the increase resulted from the change. Where a causal link exists between the change and the increase in utilization, the permitting authority should then determine whether emissions have also increased as a result of the change.

Changes that could increase a unit's emissions factor typically involve changes to the boiler itself. (Such changes do not include activities that qualify as pollution control projects under today's rule.) Where these types of changes exist, the utility should submit annual emissions data to the permitting authority. If these data suggests that the utility has increased annual emissions over baseline levels, the permitting authority should inquire whether the increase resulted from the physical or operational change. The utility may demonstrate that any increase was caused by an independent factor, such as demand growth.

Appropriate records are to be submitted to the permitting agency on an annual basis for a period of 5 years from the date the unit begins operations (i.e., post-change operations after an initial shakedown period). A longer period, not to exceed 10 years, may be required by the permitting agency where it has determined that no period within the first 5 years following the change is representative of source operations.

Since it is expected that utilities will submit the same data normally used to report emissions or operational levels under existing Federal, State or local air pollution control agency requirements, EPA does not expect that documentation of post-change actual annual emissions will impose any additional data collection burden on the part of a utility.

The purpose of this provision is to provide a reasonable means of determining whether a significant increase in representative actual annual emissions resulting from a proposed change at an existing utility occurs within the 5 years following the change. Thus the intent is to confirm the utility's initial projections rather than annually revisiting the issue of NSR applicability. If, however, the reviewing authority determines that the source's emissions have in fact increased significantly over baseline levels as a result of the change, the source would become subject to NSR requirements at that time. The EPA has adopted this approach and this time period because it believes that, in most cases, any emissions increase resulting from a physical or operational change at a utility unit would occur within the first 5 years of normal operation of the unit

[20] As discussed, this presumption does not apply to past modifications at an emissions unit for the purpose of determining contemporaneous emission changes at a source and cannot be used to extend the 5-year period specified in that provision (see 40 CFR 52.21(b)(3)(i)(b)).

[21] This is the only substantive change from the regulations as proposed. However, EPA has also made minor changes to the wording of some of the regulations to address problems with clarity and syntax. Since these changes are not intended to alter the meaning of the regulations, they are not individually discussed in this preamble.

PORTION OF FINAL WEPCO Rule

physical changes.

An environmental group and several State agencies noted that the projected post-change emissions should become an enforceable permit condition in order to commit a source to limit its future emissions to a specific amount and to provide assurance that these projections are reasonable estimates of expected emissions. If a source will not accept such a permit condition, then the source should have to use potential post-change emissions.

4. Comments Suggesting Revisions to the Proposal.

Three commenters suggested a more flexible test for ascertaining SO2 increases for determining applicability of NSR and NSPS requirements, namely a measure of pollution per unit of electrical output.

a. Commenters made the following specific suggestions for changes surrounding the future actual calculation method:

(1) develop guidelines to assist States in making like-kind determinations;

(2) require like-kind replacements to use the representative actual annual emissions for calculation of actual emissions;

(3) define "like-kind replacement" to include complete replacement of an existing emissions unit;

(4) define "routine repair and replacement;"

(5) apply the actual-to-actual test to like-kind replacement of an entire emitting unit;

(6) allow new units or greenfield plants to rely on future actual emissions if they can reliably project future emissions; and

(7) consider an alternative way to make the NSR accounting system consistent, such as basing it on past allowable to future allowable emissions.

Other suggestions included the following:

(1) provide guidance on routine repair and replacement and maintenance activities to include placing units on cold reserve and bringing them back on line, and

(2) use a 2-year period other than immediately after the change only when the EPA cannot clearly demonstrate that the 2-year period immediately following the change is not representative.

5. The EPA Analysis.

The EPA has decided to promulgate the proposed "representative actual annual emissions" methodology for calculating emissions changes at electric utility steam generating units where the changes do not involve the construction of a new, "greenfield" unit or the replacement of an existing one. After a thorough review of the comments, EPA concludes that the comparison of "actual emissions before" to a projection of "actual emissions after" a physical or operational change at an existing utility steam generating unit is workable and, with the added safeguard discussed below, is the most suitable method for evaluating emissions changes at such sources.

Many commenters questioned EPA's proposed presumption that sources may use, as the baseline, emissions from any 2 consecutive years within the 5 years prior to the proposed change without regard to normal source operations. As discussed in the proposal, this presumption is consistent with EPA's decision in WEPCO and the 5-year period for "contemporaneous" emissions increases and decreases in 40 CFR 52.21(b)(3)(i)(b).

Moreover, EPA is not reading "normal source operations" out of the regulation as charged. Rather, the presumption recognizes the nature of utility operations without compromising the existing regulatory language which requires that the pre-change 2-year period used in defining baseline emissions be representative of "normal" operations. For example, as a system a utility's "normal" operations means directly responding to a demand for electricity. A cold winter or hot summer will result in high levels of "normal" operations while a relatively mild year will produce lower "normal" operations. By presumably allowing a utility to use any 2 consecutive years within the past 5, the rule better takes into consideration that electricity demand and resultant utility operations fluctuate in response to various factors such as annual variability in climatic or economic conditions that affect demand, or changes at other plants in the utility system that affect the dispatch of a particular plant. By expanding a baseline for a utility to any consecutive 2 in the last 5 years, these types of fluctuations in operations can be more realistically considered, with the result being a presumptive baseline more closely representative of normal source operation.

The EPA disagrees with comments seeking to allow the use of any 2 consecutive years within the last 5 years of a unit's "operation" rather within than the 5 years directly preceding the proposed change. A shifting of the 5-year period would be difficult to harmonize with definitions of contemporaneous contained in the regulations [see, e.g., 40 CFR § 52.21(b)(3)(iii)]. This type of open-ended provision would even credit a unit which has been inoperative for 20 or 30 years or longer with a high level of emissions. The EPA notes, however, that as has always been the case under the prior regulations, any source owner or operator may request a determination that another baseline period is more representative of the unit's "normal" operations.

Several commenters opposing today's regulatory changes charged that without appropriate assurances utilities could deliberately underestimate future operations (and thus emissions) for the purpose of avoiding review or that even where a forthright estimate is made, the forecast may prove inaccurate. The EPA is concerned that without appropriate safeguards increases in future actual emissions that in fact resulted from the physical or operational change could go unnoticed and unreviewed. For this reason, EPA has added the safeguard explained below.

The EPA does not, however, agree with comments that post-change emissions estimates must always be made into permanent federally-enforceable permit conditions. To do so would permanently restrict a utility's legally allowable emission limits to its pre-change actual emissions level unless it subsequently underwent NSR, and would fail to account for the very real possibility that emissions might increase over baseline levels in the future for reasons unrelated to the physical or operational change in question. As discussed more fully in the following section, NSR applies only where the emissions increase is caused by the change. Thus the issue should be viewed more as one of tracking and monitoring post-change utilization and/or emissions levels at the unit to confirm that baseline emission levels are not exceeded as a result of the change.

To guard against the possibility that significant increases in actual emissions attributable to the change may occur under this methodology, EPA is clarifying in the final regulations that any utility which utilizes the "representative actual annual emissions" methodology to determine that it is not subject to NSR must submit for 5 years after the change sufficient records to determine if the change results in an increase in representative actual annual emissions. Utilities may use continuous emissions monitoring data, operational levels, fuel usage data, source test results or any other readily available data of sufficient accuracy for the purpose of documenting a unit's post-change actual annual emissions.

Where the change does not increase the unit's emissions factor, i.e., the amount of pollution emitted by a source after control per unit of fuel combusted (such as pounds of SO_2 emitted per ton of coal burned), the utility may submit annual utilization data, rather than emissions data, as a method of tracking post-change emissions. If annual utilization data show that the unit increased utilization above baseline levels, the permitting authority should determine whether the increase resulted from the change. Where a causal link exists between the change and the increase in utilization, the permitting authority should then determine whether emissions have also increased as a result of the change.

Changes that could increase a unit's emissions factor typically involve changes to the boiler itself. (Such changes do not include activities that qualify as pollution control projects under today's rule.) Where these types of changes exist, the utility should submit annual emissions data to the permitting authority. If these data suggests that the utility has increased annual emissions over baseline levels, the permitting authority should inquire whether the increase resulted from the physical or operational change. The utility may demonstrate that any increase was caused by an independent factor, such as demand growth.

Appropriate records are to be submitted to the permitting agency on an annual basis for a period of 5 years from the date the unit begins operations (i.e., post-change operations after an initial shakedown period). A longer period, not to exceed 10 years, may be required by the permitting agency where it has determined that no period within the first 5 years following the change is representative of source operations.

Since it is expected that utilities will submit the same data normally used to report emissions or operational levels under existing Federal, State or local air pollution control agency requirements, EPA does not expect that documentation of post-change actual annual emissions will impose any additional data collection burden on the part of a utility.

The purpose of this provision is to provide a reasonable means of determining whether a significant increase in representative actual annual emissions resulting from a proposed change at an existing utility occurs within the 5 years following the change. Thus the intent is to confirm the utility's initial projections rather than annually revisiting the issue of NSR applicability. If, however, the reviewing authority determines that the source's emissions have in fact increased significantly over baseline levels as a result of the change, the source would become subject to NSR requirements at that time. The EPA has adopted this approach and the time period because it believes that, in most cases, any emissions increase resulting from a physical or operational change at a utility unit would occur within the first 5 years of normal operation of the unit after the change. Thus, EPA will presume that any increase in emissions levels more than 5 years after the change has occurred is not related to the physical or operational change.

In response to comments regarding "like-kind" replacements, EPA notes that today's regulations recognize no distinction between "like-kind" replacements and other nonroutine physical or operational changes at a utility steam generating unit. The "actual-to-future-actual" methodology promulgated today for calculating emissions changes applies to all types of changes at utility units, including the replacement of "like-kind" components at an existing unit. However, the "like-kind" replacement of a whole unit is for all practical purposes a replacement unit and, therefore, is treated as a new unit.

Although several commenters suggested that EPA should expand the representative actual emissions test to new and reconstructed units, EPA has decided not to do so. Since there is no relevant operating history for new or reconstructed units, it would not be possible to accurately project operations or emissions for these units. Consequently, the EPA has left unchanged the regulations which require that for any unit which has not begun normal operations, actual emissions are considered equal to the unit's potential-to-emit.

A few commenters requested that EPA define or provide guidance on "routine repair, replacement and maintenance" activities. The June 14 proposal did not deal with this aspect of the regulations, nor do the regulatory changes promulgated today. However, the issue has an important bearing on today's rule because a project that is determined to be routine is excluded by EPA regulations from the definition of major modification. For this reason, EPA plans to issue guidance on this subject as part of a NSR regulatory update package which EPA presently intends to propose by early summer. In the meantime, EPA is today clarifying that the determination of whether the repair or replacement of a particular item of equipment is "routine" under the NSR regulations, while made on a case-by-case basis, must be based on the evaluation of whether that type of equipment has been repaired or replaced by sources within the relevant industrial category.

C. The Causation Requirement.

1. Background.

The NSR regulatory provisions require that the physical or operational change "result in" an increase in actual emissions in order to consider that change to be a modification [see e.g., 40 CFR 52.21(2)(i)]. In other words, NSR will not apply unless EPA finds that there is a causal link between the proposed change and any post-change increase in emissions. The EPA proposed to amend its rules to clarify this provision in the context of modifications at electric utility steam generating units.

Under the proposed regulations, any emissions increase attributable to a physical or operational change, such as a physical or operational change that significantly alters the efficiency of the plant, (see, Puerto Rican Cement, 889 F.2d at 297-8), must continue to be included in the post-change emissions calculation. The proposal clarified that where increased operations are in response to independent factors, such as system-wide demand growth, which would have occurred and affected the unit's operations even in the absence of the physical or operational change, such increases do not result from the change and shall be excluded from the projection of future actual emissions. Thus, in assessing whether the proposed change will result in an increase in actual emissions, utilities need not include in their projection of post-change utilization that portion of the increased rate of utilization, if any, due to factors unrelated to the physical or operational change, such as an increase in projected capacity utilization due to the rate of electricity demand growth for the utility system (of which that source is a member) as a whole.

Under today's rule, during a representative baseline period (see supra), the plant must have been able to accommodate the projected demand growth physically and legally even absent the particular change. Increased operations (and resultant increases in actual emissions) that could not physically and legally be accommodated during the representative baseline period but for the proposed physical or operational change should be considered to result from the change.

2. Comments Generally Favoring the EPA Proposal.

Several utility representatives supported the proposed demand growth exclusion and the causation requirement. Many commenters requested clarification of certain points or expansion of certain provisions. One commenter noted that there should be a specific exclusion for emissions increases at a generating station resulting from generation shifts and decreased plant efficiencies caused by operation of pollution control systems. Another noted that the discussion of the criteria for recognizing "factors unrelated to the physical or operational change" should be improved upon because the proposed requirements that a facility must have been physically able to accommodate the projected growth during a "representative baseline period" could have a negative impact in utility capacity planning and investment decisions, depending upon how such a period is determined.

One commenter noted that EPA should specifically recognize an exception for units which have been inactive, because a unit should not have to include all of its emissions due to demand growth merely because it was in need of repair or maintenance while inactive. Commenters asked that EPA better define "independent factors" in the context of the demand growth exclusion. Lastly, one commenter stated that the final rule should reconcile the "demand growth exclusion" with the existing "hours of operation/rate of production" exclusion by confirming that increases attributable to system-wide demand growth are already excluded under the already-existing exclusion and, therefore, the "demand growth exclusion" only applies where there is a federally-enforceable permit term limiting hours of operation or production rate.

3. Comments Generally Opposing the EPA Proposal.

Opponents of the exclusion of emissions attributable to demand growth contended that there is no rational basis for ignoring such emissions. When increased capacity or utilization is the immediate goal of a project and an increase in emissions occurs, the project must be subject to NSR regardless of the underlying reasons for the increased capacity or utilization and corresponding emission increase. Contrary to the letter and purpose of the statute, the demand growth exclusion could result in major increases in actual emissions going unreviewed and unregulated, would create serious local pollution problems, and would discriminate against companies that were successful in implementing energy efficiency programs. One local agency pointed out that it is virtually impossible to determine with any degree of certainty what portion of a unit's emissions are attributable to an increase in projected capacity utilization.

In addition, commenters noted that the exclusion will have an adverse effect on local agencies' ability to control emissions and that the time of construction of a project is the most efficient and effective time to address such emissions. One commenter stated that the exclusion for demand growth may further bias competitive power markets toward existing units, and that EPA failed to consider the impact of the causation requirement on utility operations, emissions or competition in power markets.

4. The EPA Analysis.

After careful consideration of the comments received and further analysis of the issues involved, EPA has decided to promulgate the causation provision as proposed.

Commenters argued that any post-change emissions increase, regardless of its origin, should subject a source to NSR. However, these arguments ignore the relevant statutory and regulatory modification provisions. No commenters challenging the provision have suggested that the statute and implementing regulations do not contain a causation provision. Rather, they argue that in the proposed rule EPA has misconstrued this requirement.

In conjunction with developing the representative actual annual emissions methodology, EPA recognized that the analysis of the causation requirement may disclose that an emissions increase that follows a nonroutine physical or operational change is merely coincidental, and in fact results from independent factors such as demand growth. It is important to emphasize, however, that this does not amount to a per se exclusion of demand growth from the emissions increase calculation. Rather, demand growth can only be excluded to the extent it -- and not the physical or operational change -- is the cause of the emissions increase. The EPA believes that this is a reasonable interpretation of the statutory provision in question, of EPA's own regulations, and of judicial precedents.

Consequently, where projected increased operations are in response to an independent factor, such as demand growth, which could have occurred and affected the unit's operations during the representative baseline period even in the absence of the physical or operational change, the increased operations cannot be said to result from the change and therefore may be excluded from the projection of the unit's future actual emissions. Conversely, where the increase could not have occurred during the representative baseline period but for the physical or operational change, that change will be deemed to have resulted in the increase.

The EPA did receive numerous comments regarding the difficulty of applying this new interpretation. However, EPA believes it is possible to distinguish between emissions increases that are related to a physical or operational change from those that are not. This issue is a fact-dependent determination that must be resolved on a case-by-case basis. As discussed, EPA considers emissions increases due to increased operations that could not be physically or legally accommodated during the representative baseline period but for the proposed physical or operational change, to result from the change. The preamble to the proposal also made clear that any emissions increase attributable to a physical or operational change that significantly alters the efficiency of the plant, (see Puerto Rican Cement, 889 F.2d at 297-8), must continue to be included in the post-change emissions calculations. However, EPA in no way intends to discourage physical or operational changes that increase efficiency or reliability or lower operating costs, or improve other operational characteristics of the unit and does so by focusing on the effect of any nonroutine changes on the operating characteristics of the unit during the representative baseline period. The EPA recognizes that improvements such as these are desirable for economic reasons and to assure a reliable supply of electricity. Thus, physical or operational changes that improve operational characteristics will be treated in the same manner as any other changes. This means that where an improvement involves a routine change, it is excluded from the NSR definition of "major modification." Alternatively, where an improvement is not routine and an emissions increase results from the improvement, that portion of the emissions increase resulting from the improvement will be considered in determining whether the proposed change subjects the unit to NSR requirements.

Several commenters requested a clarification concerning a unit's ability to accommodate demand growth in its pre-change configuration. In EPA's view, such a clarification is not warranted. As discussed above, operational levels that a unit could not have achieved during the representative baseline period but for the physical or operational change are considered to result from the change. Post-change emissions increases associated with such operational levels must, therefore, be considered to result from the change and be taken into account for NSR applicability purposes.

Numerous commenters pointed out that it may be very difficult to determine when an increase is caused by independent factors and when it is caused by the physical change. Also, an environmental commenter argued that this causation question must always be resolved in favor of including all post-change emission increases that follow a change which improves a unit's efficiency, since in its view an efficiency gain will always be the primary determinant of the utility's use of a generating unit, notwithstanding the presence of other necessary -- but not of themselves sufficient -- factors such as demand growth. However, as so formulated, the comment answers itself. If efficiency improvements are the predominant cause of the change in emissions and demand growth is not, the exclusion does not apply. But this is a question of fact which must be resolved on a case-by-case basis and is dependent on the individual facts and circumstances of the change at issue. EPA declines to create a presumption that every emissions increase that follows a change in efficiency is inextricably linked to the efficiency change.

In calculating demand growth, utilities may consider the company's historical operational data, its own representations, filings with Federal, State or local regulatory authorities, and compliance plans developed under title IV of the 1990 Amendments.

The EPA disagrees with comments that this provision could result in major increases in actual emissions going unreviewed with the potential to create serious local air pollution problems. First, the NSR major modification provisions do not apply to all increases in emissions, just emission increases which result from a nonroutine physical or operational change at an existing major source. Second, as has already been observed, this provision does not amount to a per se exclusion of demand growth. Finally, this new provision does not diminish the scope of the coverage of EPA's NSR regulations. Rather, it merely incorporates into the actual-to-future-actual methodology a requirement of the pre-existing statutory and regulatory scheme.

Moreover, in response to those concerns that a demand growth exclusion could lead to serious local air pollution problems, EPA notes the restrictions it placed on the overall future projection in the proposal: the level of emissions the source claims that it will operate at should be consistent with current assumptions regarding the source's emissions that are used in the relevant SIP.

Finally the EPA does not agree with the commenter requesting that the final rule confirm that increases attributable to system-wide demand growth are already excluded under the existing exclusion for increases in hours of operation and, therefore, the "demand growth exclusion" only applies where there is a federally-enforceable permit term limiting hours of operation or production rate. The commenter's statement is not correct. Although a source may vary its hours of operation or production as part of its everyday operations, an increase in emissions attributable to an increase in hours of operation or production rate which is the result of a construction-related activity is not excluded from review (see WEPCO, 893 F.2d at 916 n.11; Puerto Rican Cement, 889 F.2d at 298).

D. Repowering.

1. Background.

As previously mentioned, title IV of the 1990 Amendments grants special treatment to utilities that seek to comply with the mandated acid rain reductions by repowering a unit with qualifying clean coal technology [see 1990 Amendments §§ 402(12), 409(a)]. Specifically, repowering projects that qualify for a Phase II compliance extension will also be exempt from NSPS requirements, so long as the repowering "does not increase actual hourly emissions for any pollutant regulated under the Act" [see § 409(d)]. The EPA interprets the requirement that the repowering not lead to an increase in "actual hourly emissions" as an expression of Congressional intent that with respect to repowering projects, EPA should use the same general approach to determining applicability as it has for other physical or operational changes, discussed above. Accordingly, EPA proposed rules provided that a repowering project which results in an increase over baseline in a unit's post-modification hourly emissions will not be eligible for this limited NSPS exemption.

The proposed NSPS exemption applied to repowering of

PG&E National Energy Group

Cedar Bay Generating Plant
Owner: Cedar Bay Generating Company, L.P.

RECEIVED

AUG 19 2002

BUREAU OF AIR REGULATION

POB 26324
Jacksonville, FL 32226-6324

904.751.4000
Fax: 904.751.7320

August 16, 2002

Mr. C.H. Fancy, P.E.
Florida Department of Environmental Protection
Bureau of Air Regulation
Mail Station #5505
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Re: Cedar Bay Air Construction/PSD Permit Modification

Dear Mr. Fancy

Pursuant to the instructions in your letter dated July 31, 2002, Cedar Bay submits the Affidavit of Publication for the "PUBLIC NOTICE OF INTENT TO ISSUE PSD PERMIT MODIFICATION". The notice was published in the Florida Times Union on August 12, 2002.

Sincerely,

Jeffrey A. Walker

Jeffrey A. Walker
Environmental Manager, Cedar Bay

cc: M. Krest, Cedar Bay
T. Fromm, Bethesda

BEST AVAILABLE COPY

THE FLORIDA TIMES-UNION
Jacksonville, Fl
Affidavit of Publication

Florida Times-Union

CEDAR BAY GENERATING CO.
PO BOX 26324
JACKSONVILLE FL 32236

REFERENCE: 0181153 Jeff Walker
R77826 Public Notice

State of Florida
County of Duval

Before the undersigned authority personally appeared Valerie Vest who on oath says she is a Legal Advertising Representative of The Florida Times-Union, a daily newspaper published in Jacksonville in Duval County, Florida; that the attached copy of advertisement is a legal ad published in The Florida Times-Union. Affiant further says that The Florida Times-Union is a newspaper published in Jacksonville, in Duval County, Florida, and that the newspaper has heretofore been continuously published in Duval County, Florida each day, has been entered as second class mail matter at the post office in Jacksonville, in Duval County, Florida for a period of one year preceeding the first publication of the attached copy of advertisement; and affiant further says that he/she has neither paid nor promised any person, firm or corporation any discount, rebate, commission, or refund for the purpose of securing this advertisement for publication in said newspaper.

PUBLISHED ON: 08/12

FILED ON: 08/12/02 Valerie Vest

Name: Valerie Vest Title: Legal Advertising

In testimony whereof, I have hereunto set my hand and seal, the day and year aforesaid.

NOTARY: Twilla Shipp

TWILLA SHIPP
Notary Public, State of Florida
My comm. expires May 13, 2006
Comm. No. DD 117248

PUBLIC NOTICE OF INTENT TO ISSUE PSD PERMIT MODIFICATION

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
DEP File No. PSD-FL-137 (PA 88-24)
U.S. Generating Company
Cedar Bay Cogeneration Facility
Duval County

The Department of Environment Protection (Department) gives notice of its intent to issue a PSD Permit Modification to Cedar Bay Cogeneration Facility, located at 9640 Eastport Road, Jacksonville, Duval County. The permit is to revise the conditions so as to allow for limited co-firing of petroleum coke (petcoke) with coal. This is an existing facility, which currently combusts coal as its primary fuel. A new determination of Best Available Control technology (BACT) was not required. The applicant's mailing address is: U.S. Generating Company, P.O. Box 26324, Jacksonville, FL 32226-6324.

Typically petroleum coke has greater sulfer content than coal, but less ash. Accordingly, absent proper controls its usage presents the possibility of increased SO_2 emissions. The existing facility has adequate air pollution control equipment, consisting of a CFB (including limestone injection) for SO_2 control, in addition to a selective non-catalytic reduction system for control of nitrogen oxides and baghouses for control of particulate matter. This equipment is sufficient to provide reasonable assurance that no significant increases of the mentioned pollutants will occur.

This modification will revise the permit to allow for the co-firing of up to 35% petroleum coke (petcoke) by weight, with coal in the three circulating fluidized bed boilers. The Department has determined that co-firing can occur, provided that the equivalent SO_2 inlet loading to the boilers is less than 3.2 lb/MMBtu, yielding an emission rate of 0.16 lb/MMBtu. Additionally, the Department will require improved measurements of bed ash throughout and require reporting of facility emissions for five (5) years. These measures are sufficient to ensure that only decreases, or less than significant increases of the emissions of PSD pollutants will occur as a result of this modification. The Significant Emission Rates for pollutants of interest (for which this project will not exceed) are defined by the Florida Administrative Code, Chapter 62-212, Table 212.400-2 as follows:

POLLUTANT	SIGNIFICANT EMISSION RATES
Sulfur dioxide	40 Tons Per Year
Nitrogen oxides	40 Tons Per Year
PM_{10}	15 Tons Per Year
Sulfuric acid mist	7 Tons Per Year
Ozone (Volatile Organic Compounds)	40 Tons Per Year
Carbon Monoxide	100 Tons Per Year

An air quality impact analysis was not required. The Department will issue the Final Permit with the attached conditions unless a response received in accordance with the following procedures results in a different decision or significant change of terms or conditions.

The Department will accept written comments concerning the proposed permit issuance action for a period of 30 (thirty) days from the date of publication of this Public Notice of Intent to Issue PSD Permit Modification. Written comments filed should be provided to the Department's Bureau of Air Regulation at 2600 Blair Stone Road, Mail Station #5505, Tallahassee, FL 32399-2400. Any written comments filed shall be made available for public inspection. If written comments received result in a significant change in the proposed agency action, the Department shall revise the proposed permit and require, if applicable, another Public Notice.

The Department will issue the permit with the attached conditions unless a timely petition for an administrative hearing is filed pursuant to sections 120.569 and 120.57 F.S., before the deadline for filing a petition. The procedures for petitioning for a hearing are set forth below. Mediation is not available in this proceeding.

A person whose substantial interests are affected by the proposed permitting decision may petition for an administrative proceeding (hearing) under sections 120.569 and 120.57 of the Florida Statutes. The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department at 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida, 32399-3000. Petitions filed by the permit applicant or any of the parties listed below must be filed within fourteen days of receipt of this notice of intent. Petitions filed by any persons other than those entitled to written notice under section 120.60(3) of the Florida Statutes must be filed within fourteen days of publication of the public notice or within fourteen days of receipt of this notice of intent, whichever occurs first. Under section 120.60(3), however, any person who asked the Department for notice of agency action may file a petition within fourteen days of receipt of that notice, regardless of the date of publication. A petitioner shall mail a copy of the petition to the applicant at the address indicated above at the time of filing. The failure of any person to file a petition within the appropriate time period shall constitute a waiver of that person's right to request an administrative determination (hearing) under sections 120.569 and 120.57 F.S., or to intervene in this proceeding and participate as a party to it. Any subsequent intervention will be only at the approval of the presiding officer upon the filing of a motion in compliance with Rule 28-106.205 of the Florida Administrative Code.

A petition that disputes the material facts on which the Department's action is based must contain the following information: (a) The name and address of each agency affected and each agency's file or identification number, if known; (b) The name, address, and telephone number of the petitioner, the name, address, and telephone number of the petitioner's representative, if any, which shall be the address for service purposes during the course of the proceeding; and an explanation of how the petitioner's substantial interests will be affected by the agency determination; (c) A statement of how and when petitioner received notice

State of Florida

County of Duval

Best Available Copy

Before the undersigned authority personally appeared Valerie Vest who on oath says she is a Legal Advertising Representative of The Florida Times-Union, a daily newspaper published in Jacksonville in Duval County, Florida; that the attached copy of advertisement is a legal ad published in The Florida Times-Union. Affiant further says that The Florida Times-Union is a newspaper published in Jacksonville, in Duval County, Florida, and that the newspaper has heretofore been continuously published in Duval County, Florida each day, has been entered as second class mail matter at the post office in Jacksonville, in Duval County, Florida for a period of one year preceeding the first publication of the attached copy of advertisement; and affiant further says that he/she has neither paid nor promised any person, firm or corporation any discount, rebate, commission, or refund for the purpose of securing this advertisement for publication in said newspaper.

PUBLISHED ON: 08/12

FILED ON: 08/12/02 Valerie Vest

Name: Valerie Vest Title: Legal Advertising

In testimony whereof, I have hereunto set my hand and seal, the day and year aforesaid.

NOTARY: Twilla Shipp

TWILLA SHIPP
Notary Public, State of Florida
My comm. expires May 13, 2006
Comm. No. DD 117248

This equipment is sufficient to provide reasonable assurance that no significant increases of the mentioned pollutants will occur.

This modification will revise the permit to allow for the co-firing of up to 35% petroleum coke (petcoke) by weight, with coal in the three circulating fluidized bed boilers. The Department has determined that co-firing can occur, provided that the equivalent SO_2 inlet loading to the boilers is less than 3.2 lb/MMBtu, yielding an emission rate of 0.16 lb/MMBtu. Additionally, the Department will require improved measurements of bed ash throughout and require reporting of facility emissions for five (5) years. These measures are sufficient to ensure that only decreases, or less than significant increases of the emissions of PSD pollutants will occur as a result of this modification. The Significant Emission Rates for pollutants of interest (for which this project will not exceed) are defined by the Florida Administrative Code, Chapter 62-212, Table 212.400-2 as follows:

POLLUTANT	SIGNIFICANT EMISSION RATES
Sulfur dioxide	40 Tons Per Year
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PM_{10}	15 Tons Per Year
Sulfuric acid mist	7 Tons Per Year
Ozone (Volatile Organic Compounds)	40 Tons Per Year
Carbon Monoxide	100 Tons Per Year

An air quality impact analysis was not required. The Department will issue the Final Permit with the attached conditions unless a response received in accordance with the following procedures results in a different decision or significant change of terms or conditions.

The Department will accept written comments concerning the proposed permit issuance action for a period of 30 (thirty) days from the date of publication of this Public Notice of Intent to Issue PSD Permit Modification. Written comments filed should be provided to the Department's Bureau of Air Regulation at 2600 Blair Stone Road, Mail Station #5505, Tallahassee, FL 32399-2400. Any written comments filed shall be made available for public inspection. If written comments received result in a significant change in the proposed agency action, the Department shall revise the proposed permit and require, if applicable, another Public Notice.

The Department will issue the permit with the attached conditions unless a timely petition for an administrative hearing is filed pursuant to sections 120.569 and 120.57 F.S., before the deadline for filing a petition. The procedures for petitioning for a hearing are set forth below. Mediation is not available in this proceeding.

A person whose substantial interests are affected by the proposed permitting decision may petition for an administrative proceeding (hearing) under sections 120.569 and 120.57 of the Florida Statutes. The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department at 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida, 32399-3000. Petitions filed by the permit applicant or any of the parties listed below must be filed within fourteen days of receipt of this notice of intent. Petitions filed by any persons other than those entitled to written notice under section 120.60(3) of the Florida Statutes must be filed within fourteen days of publication of the public notice or within fourteen days of receipt of this notice of intent, whichever occurs first. Under section 120.60(3), however, any person who asked the Department for notice of agency action may file a petition within fourteen days of receipt of that notice, regardless of the date of publication. A petitioner shall mail a copy of the petition to the applicant at the address indicated above at the time of filing. The failure of any person to file a petition within the appropriate time period shall constitute a waiver of that person's right to request an administrative determination (hearing) under sections 120.569 and 120.57 F.S., or to intervene in this proceeding and participate as a party to it. Any subsequent intervention will be only at the approval of the presiding officer upon the filing of a motion in compliance with Rule 28-106.205 of the Florida Administrative Code.

A petition that disputes the material facts on which the Department's action is based must contain the following information: (a) The name and address of each agency affected and each agency's file or identification number, if known; (b) The name, address, and telephone number of the petitioner, the name, address, and telephone number of the petitioner's representative, if any, which shall be the address for service purposes during the course of the proceeding; and an explanation of how the petitioner's substantial interests will be affected by the agency determination; (c) A statement of how and when petitioner received notice of the agency action or proposed action; (d) A statement of all disputed issues of material fact. If there are none, the petition must so indicate; (e) A concise statement of the ultimate facts alleged, including the specific facts the petitioner contends warrant reversal or modification of the agency's proposed action; (f) A statement of the specific rules or statutes the petitioner contends require reversal or modification of the agency's proposed action; and (g) A statement of the relief sought by the petitioner, stating precisely the action petitioner wishes the agency to take with respect to the agency's proposed action.

A petition that does not dispute the material facts upon which the Department's action is based shall state that no such facts are in dispute and otherwise shall contain the same information as set forth above, as required by rule 28-106.301.

Because the administrative hearing process is designed to formulate final agency action, the filing of a petition means that the Department's final action may be different from the position taken by it in this notice. Persons whose substantial interests will be affected by any such final decision of the Department on the application have the right to petition to become a party to the proceeding, in accordance with the requirements set forth above.

A complete project file is available for public inspection during normal business hours, 8:00 a.m. to 5:00 p.m., Monday through Friday, except legal holidays, at:

Florida Department of Environmental Protection
Bureau of Air regulation
111 S. Magnolia Drive, Suite 4
Tallahassee, Florida 32301
Telephone: (850) 488-1344
Fax: (850) 922-6979

Florida Department of Environmental Protection
Northeast District
Suite 200B, 7825 Baymeadows Way
Jacksonville, Florida 32256
Telephone: (904) 448-4300

The complete project file includes the application, Draft permit, and the information submitted by the Responsible Official, exclusive of confidential records under Section 403.111, F.S. Interested persons may review specific details of this project at http://www.dep.state.fl.us/air/permitting/construct.htm or contact the Administrator, New Source Review Section, at 111 South Magnolia Drive, Suite 4, Tallahassee, Florida 32301, or call 850/488-0114 for additional information.

Memorandum

Florida Department of Environmental Protection

TO: Clair Fancy

THRU: Al Linero *ALL*

FROM: Michael P. Halpin *MH*

DATE: July 16, 2002

SUBJECT: Cedar Bay Generating Company, L.P.
Petroleum Coke - PSD Permit Modification
DEP File No. PP 88-24 (PSD-FL-137)

Attached is the public notice package for Cedar Bay Generating Plant permit modifications. This is an existing facility consisting of three circulating fluidized bed steam generators (boilers) designated as Boilers A, B, and C, a coal handling area, a limestone handling area, and an ash handling area. Crushed coal is the primary fuel for Boilers A, B and C. The fuel for Boilers B and C can also be supplemented with short fiber recycle rejects received from Stone Container Corporation. No. 2 fuel oil is used as supplemental fuel in all three boilers normally only for start-ups. These units have a Title V permit (0310337-002-AV) issued by the State of Florida.

The applicant has requested permission to co-fire petroleum coke (petcoke) up to 35% by weight. The applicant's proposal is intended to ensure that the PSD thresholds are not triggered, i.e. that the "modification" is not major and does not cause the effect of necessitating a BACT review.

A preliminary review supports the applicant's contention that PSD is not triggered, eliminating the requirement for a BACT review and related modeling. PSD regulations (under the provisions commonly known as the "WEPCO rule") allow a source undertaking a non-routine change that could affect emissions at an electric utility steam generating unit to lawfully avoid the major source permitting process by using the unit's representative actual annual emissions to calculate emissions following the change, if the source submits information for 5 years following the change to confirm its pre-change projection. Under the WEPCO rule, Cedar Bay must compute baseline actual emissions and must project the future actual emissions from the modified units for a period after the physical change. In addition, Cedar Bay must maintain and submit to the Department on an annual basis for a period of at least 5 years from the date the units resume regular operation, information demonstrating that the change did not result in a significant emissions increase.

These requirements have been built into the permit, and accordingly I recommend your approval. This is day 46 of the clock.

AAL/mph

Attachments

P.E. Certification Statement

Cedar Bay Generating Company, L.P.
Cedar Bay Generating Plant
Duval County

DEP File No.: PA 88-24 (PSD-FL-137)
Facility ID No.: 0310337

Project: Petroleum Coke - PSD Permit Modification

I HEREBY CERTIFY that the engineering features described in the above referenced application and related additional information submittals, if any, and subject to the proposed permit conditions, provide reasonable assurance of compliance with applicable provisions of Chapter 403, Florida Statutes, and Florida Administrative Code Chapters 62-4 and 62-204 through 62-297. However, I have not evaluated and I do not certify aspects of the proposal outside of my area of expertise (including but not limited to the electrical, mechanical, structural, hydrological, and geological features).

(Seal)

Michael P. Halpin

Michael P. Halpin, P.E.
Registration Number: 31970

7-31-02

Date

Permitting Authority:
Florida Department of Environmental Protection
Division of Air Resources Management
Bureau of Air Regulation
New Source Review Section
Mail Station #5505
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Telephone: 850/488-0114
Fax: 850/922-6979

Department of Environmental Protection

Jeb Bush
Governor

Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

David B. Struhs
Secretary

July 31, 2002

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. Bruce Smith
General Manager
Cedar Bay Cogeneration Facility
P.O. Box 26324
Jacksonville, FL 32226

Re: Co-firing Petroleum Coke with Coal
File No. PA 88-24 (PSD-FL-137)

Dear Mr. Smith:

Enclosed is one copy of the Draft PSD Permit Modification relative to Cedar Bay's request to be permitted for the co-firing of limited amounts of petcoke with coal in the three circulating fluidized bed boilers. The facility is located at 9640 Eastport Road, Jacksonville, Duval County.

The Public Notice of Intent to Issue PSD Permit Modification must be published one time only, as soon as possible, in the legal advertisement section of a newspaper of general circulation in the area affected, pursuant to the requirements Chapter 50, Florida Statutes. Proof of publication, i.e., newspaper affidavit, must be provided to the Department's Bureau of Air Regulation office within seven days of publication. Failure to publish the notice and provide proof of publication may result in the denial of the permit.

Please submit any written comments you wish to have considered concerning the Department's proposed action to A. A. Linero, P.E., Administrator, New Source Review Section at the above letterhead address. If you have any other questions, please contact Michael P. Halpin at 850/921-9519.

Sincerely,

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

CHF/mph

Enclosures

In the Matter of an
Application for Permit by:

Bruce Smith, General Manager
Cedar Bay Cogeneration Facility
PO Box 26324
Jacksonville, Florida 32226-6324

DEP File No. PSD-FL-137 (PA 88-24)

INTENT TO ISSUE PSD PERMIT MODIFICATION

The Department of Environmental Protection (Department) gives notice of its intent to issue a PSD Permit Modification (copy of Draft permit attached) for the proposed project, detailed in the application specified above and for the reasons stated below.

The applicant, Bruce Smith, General Manager, U.S. Generating Company, applied on August 29, 2001, to the Department for a PSD Permit Modification for its Cedar Bay Cogeneration Facility, located at 9640 Eastport Road, Jacksonville, Duval County. The request is to revise the permit to allow for the limited co-firing of petroleum coke with coal in its three circulating fluidized bed boilers.

The Department has permitting jurisdiction under the provisions of Chapter 403, Florida Statutes (F.S.), and Florida Administrative Code (F.A.C.) Chapters 62-4, 62-210, 62-212 and 40 CFR 52.21. The above actions are not exempt from permitting procedures. The Department has determined that a PSD Permit Modification is required to revise the permit with respect to changes in fuel.

The Department intends to issue this PSD Permit Modification based on the belief that reasonable assurances have been provided to indicate that operation of these emission units will not adversely impact air quality, and the emission units will comply with all appropriate provisions of Chapters 62-4, 62-204, 62-210, 62-212, 62-296, and 62-297, F.A.C. and 40 CFR 52.21.

Pursuant to Section 403.815, F.S., and Rule 62-110.106(7)(a)1., F.A.C., you (the applicant) are required to publish at your own expense the enclosed Public Notice of Intent to Issue PSD Permit Modification. The notice shall be published one time only in the legal advertisement section of a newspaper of general circulation in the area affected. Rule 62-110.106(7)(b), F.A.C., requires that the applicant cause the notice to be published as soon as possible after notification by the Department of its intended action. For the purpose of these rules, "publication in a newspaper of general circulation in the area affected" means publication in a newspaper meeting the requirements of Sections 50.011 and 50.031, F.S., in the county where the activity is to take place. If you are uncertain that a newspaper meets these requirements, please contact the Department at the address or telephone number listed below. The applicant shall provide proof of publication to the Department's Bureau of Air Regulation, at 2600 Blair Stone Road, Mail Station #5505, Tallahassee, Florida 32399-2400 (Telephone: 850/488-0114; Fax 850/ 922-6979). You must provide proof of publication within seven days of publication, pursuant to Rule 62-110.106(5), F.A.C. No permitting action for which published notice is required shall be granted until proof of publication of notice is made by furnishing a uniform affidavit in substantially the form prescribed in section 50.051, F.S. to the office of the Department issuing the permit. Failure to publish the notice and provide proof of publication may result in the denial of the permit pursuant to Rules 62-110.106(9) & (11), F.A.C.

The Department will issue the final permit with the attached conditions unless a response received in accordance with the following procedures results in a different decision or significant change of terms or conditions.

The Department will accept written comments concerning the proposed permit issuance action for a period of 30 (thirty) days from the date of publication of Public Notice of Intent to Issue PSD Permit Modification. Written comments should be provided to the Department's Bureau of Air Regulation at 2600 Blair Stone Road, Mail Station #5505, Tallahassee, FL 32399-2400. Any written comments filed shall be made available for public inspection. If written comments received result in a significant change in the proposed agency action, the Department shall revise the proposed permit and require, if applicable, another Public Notice.

The Department will issue the permit with the attached conditions unless a timely petition for an administrative hearing is filed pursuant to sections 120.569 and 120.57 F.S., before the deadline for filing a petition. The procedures for petitioning for a hearing are set forth below.

A person whose substantial interests are affected by the proposed permitting decision may petition for an administrative proceeding (hearing) under sections 120.569 and 120.57 of the Florida Statutes. The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department at 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida, 32399-3000. Petitions filed by the permit applicant or any of the parties listed below must be filed within fourteen days of receipt of this notice of intent. Petitions filed by any persons other than those entitled to written notice under section 120.60(3) of the Florida Statutes must be filed within fourteen days of publication of the public notice or within fourteen days of receipt of this notice of intent, whichever occurs first. Under section 120.60(3), however, any person who asked the Department for notice of agency action may file a petition within fourteen days of receipt of that notice, regardless of the date of publication. A petitioner shall mail a copy of the petition to the applicant at the address indicated above at the time of filing. The failure of any person to file a petition within the appropriate time period shall constitute a waiver of that person's right to request an administrative determination (hearing) under sections 120.569 and 120.57 F.S., or to intervene in this proceeding and participate as a party to it. Any subsequent intervention will be only at the approval of the presiding officer upon the filing of a motion in compliance with Rule 28-106.205 of the Florida Administrative Code.

A petition that disputes the material facts on which the Department's action is based must contain the following information: (a) The name and address of each agency affected and each agency's file or identification number, if known; (b) The name, address, and telephone number of the petitioner, the name, address, and telephone number of the petitioner's representative, if any, which shall be the address for service purposes during the course of the proceeding; and an explanation of how the petitioner's substantial interests will be affected by the agency determination; (c) A statement of how and when petitioner received notice of the agency action or proposed action; (d) A statement of all disputed issues of material fact. If there are none, the petition must so indicate; (e) A concise statement of the ultimate facts alleged, including the specific facts the petitioner contends warrant reversal or modification of the agency's proposed action; (f) A statement of the specific rules or statutes the petitioner contends require reversal or modification of the agency's proposed action; and (g) A statement of the relief sought by the petitioner, stating precisely the action petitioner wishes the agency to take with respect to the agency's proposed action.

A petition that does not dispute the material facts upon which the Department's action is based shall state that no such facts are in dispute and otherwise shall contain the same information as set forth above, as required by Rule 28-106.301.

Because the administrative hearing process is designed to formulate final agency action, the filing of a petition means that the Department's final action may be different from the position taken by it in this notice. Persons whose substantial interests will be affected by any such final decision of the Department on the application have the right to petition to become a party to the proceeding, in accordance with the requirements set forth above.

Mediation is not available in this proceeding.

In addition to the above, a person subject to regulation has a right to apply for a variance from or waiver of the requirements of particular rules, on certain conditions, under Section 120.542 F.S. The relief provided by this state statute applies only to state rules, not statutes, and not to any federal regulatory requirements. Applying for a variance or waiver does not substitute or extend the time for filing a petition for an administrative hearing or exercising any other right that a person may have in relation to the action proposed in this notice of intent.

The application for a variance or waiver is made by filing a petition with the Office of General Counsel of the Department, 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida 32399-3000. The petition must specify the following information: (a) The name, address, and telephone number of the petitioner; (b) The name, address, and telephone number of the attorney or qualified representative of the petitioner, if any; (c) Each rule or portion of a rule from which a variance or waiver is requested; (d) The citation to the statute underlying (implemented by) the rule identified in (c) above; (e) The type of action requested; (f) The specific facts that would justify a variance or waiver for the petitioner; (g) The reason why the variance or waiver would serve the purposes of the underlying statute (implemented by the rule); and (h) A statement whether the variance or waiver is permanent or temporary and, if temporary, a statement of the dates showing the duration of the variance or waiver requested.

The Department will grant a variance or waiver when the petition demonstrates both that the application of the rule would create a substantial hardship or violate principles of fairness, as each of those terms is defined in Section 120.542(2) F.S., and that the purpose of the underlying statute will be or has been achieved by other means by the petitioner.

Persons subject to regulation pursuant to any federally delegated or approved air program should be aware that Florida is specifically not authorized to issue variances or waivers from any requirements of any such federally delegated or approved program. The requirements of the program remain fully enforceable by the Administrator of the EPA and by any person under the Clean Air Act unless and until the Administrator separately approves any variance or waiver in accordance with the procedures of the federal program.

Executed in Tallahassee, Florida.

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

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this Intent to Issue PSD Permit Modification (including the Public Notice of Intent to Issue PSD Permit Modification and the Draft PSD Permit) was sent by certified mail (*) and copies were mailed by U.S. Mail before the close of business on 8/1/02 to the person(s) listed:

Bruce Smith, Cedar Bay *
Jeff Walker, Cedar Bay
Ken Kosky, P.E. Golder Associates
Hamilton S. Oven, P.E. PPSO
James L. Manning, P.E. RESD
Chris Kirts, DEP-NED
Stafford Campbell, Greater Arlington Civic Council

Clerk Stamp

FILING AND ACKNOWLEDGMENT FILED, on this date, pursuant to §120.52, Florida Statutes, with the designated Department Clerk, receipt of which is hereby acknowledged.

Victoria Gibson August 1, 2002
(Clerk) (Date)

PUBLIC NOTICE OF INTENT TO ISSUE PSD PERMIT MODIFICATION

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

DEP File No. PSD-FL-137 (PA 88-24)

U.S. Generating Company
Cedar Bay Cogeneration Facility
Duval County

The Department of Environmental Protection (Department) gives notice of its intent to issue a PSD Permit Modification to Cedar Bay Cogeneration Facility, located at 9640 Eastport Road, Jacksonville, Duval County. The permit is to revise the conditions so as to allow for limited co-firing of petroleum coke (petcoke) with coal. This is an existing facility, which currently combusts coal as its primary fuel. A new determination of Best Available Control Technology (BACT) was not required. The applicant's mailing address is: U. S. Generating Company, P.O. Box 26324, Jacksonville FL 32226-6324.

Typically petroleum coke has greater sulfur content than coal, but less ash. Accordingly, absent proper controls its usage presents the possibility of increased SO_2 emissions. The existing facility has adequate air pollution control equipment, consisting of a CFB (including limestone injection) for SO_2 control, in addition to a selective non-catalytic reduction system for control of nitrogen oxides and baghouses for control of particulate matter. This equipment is sufficient to provide reasonable assurance that no significant increases of the mentioned pollutants will occur.

This modification will revise the permit to allow for the co-firing of up to 35% petroleum coke (petcoke) by weight, with coal in the three circulating fluidized bed boilers. The Department has determined that co-firing can occur, provided that the equivalent SO_2 inlet loading to the boilers is less than 3.2 lb/MMBtu, yielding an emission rate of 0.16 lb/MMBtu. Additionally, the Department will require improved measurements of bed ash throughput and require reporting of facility emissions for five (5) years. These measures are sufficient to ensure that only decreases, or less than significant increases of the emissions of PSD pollutants will occur as a result of this modification. The Significant Emission Rates for pollutants of interest (for which this project will not exceed) are defined by the Florida Administrative Code, Chapter 62-212, Table 212.400-2 as follows:

POLLUTANT	SIGNIFICANT EMISSION RATES
Sulfur dioxide	40 Tons Per Year
Nitrogen oxides	40 Tons Per Year
PM_{10}	15 Tons Per Year
Sulfuric acid mist	7 Tons Per Year
Ozone (Volatile Organic Compounds)	40 Tons Per Year
Carbon monoxide	100 Tons Per Year

An air quality impact analysis was not required. The Department will issue the Final Permit with the attached conditions unless a response received in accordance with the following procedures results in a different decision or significant change of terms or conditions.

The Department will accept written comments concerning the proposed permit issuance action for a period of 30 (thirty) days from the date of publication of this Public Notice of Intent to Issue PSD Permit Modification. Written comments should be provided to the Department's Bureau of Air Regulation at 2600 Blair Stone Road, Mail Station #5505, Tallahassee, FL 32399-2400. Any written comments filed shall be made available for public inspection. If written comments received result in a significant change in the proposed agency action, the Department shall revise the proposed permit and require, if applicable, another Public Notice.

The Department will issue the permit with the attached conditions unless a timely petition for an administrative hearing is filed pursuant to sections 120.569 and 120.57 F.S., before the deadline for filing a petition. The procedures for petitioning for a hearing are set forth below. Mediation is not available in this proceeding.

NOTICE TO BE PUBLISHED IN THE NEWSPAPER

A person whose substantial interests are affected by the proposed permitting decision may petition for an administrative proceeding (hearing) under sections 120.569 and 120.57 of the Florida Statutes. The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department at 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida, 32399-3000. Petitions filed by the permit applicant or any of the parties listed below must be filed within fourteen days of receipt of this notice of intent. Petitions filed by any persons other than those entitled to written notice under section 120.60(3) of the Florida Statutes must be filed within fourteen days of publication of the public notice or within fourteen days of receipt of this notice of intent, whichever occurs first. Under section 120.60(3), however, any person who asked the Department for notice of agency action may file a petition within fourteen days of receipt of that notice, regardless of the date of publication. A petitioner shall mail a copy of the petition to the applicant at the address indicated above at the time of filing. The failure of any person to file a petition within the appropriate time period shall constitute a waiver of that person's right to request an administrative determination (hearing) under sections 120.569 and 120.57 F.S., or to intervene in this proceeding and participate as a party to it. Any subsequent intervention will be only at the approval of the presiding officer upon the filing of a motion in compliance with Rule 28-106.205 of the Florida Administrative Code.

A petition that disputes the material facts on which the Department's action is based must contain the following information: (a) The name and address of each agency affected and each agency's file or identification number, if known; (b) The name, address, and telephone number of the petitioner, the name, address, and telephone number of the petitioner's representative, if any, which shall be the address for service purposes during the course of the proceeding; and an explanation of how the petitioner's substantial interests will be affected by the agency determination; (c) A statement of how and when petitioner received notice of the agency action or proposed action; (d) A statement of all disputed issues of material fact. If there are none, the petition must so indicate; (e) A concise statement of the ultimate facts alleged, including the specific facts the petitioner contends warrant reversal or modification of the agency's proposed action; (f) A statement of the specific rules or statutes the petitioner contends require reversal or modification of the agency's proposed action; and (g) A statement of the relief sought by the petitioner, stating precisely the action petitioner wishes the agency to take with respect to the agency's proposed action.

A petition that does not dispute the material facts upon which the Department's action is based shall state that no such facts are in dispute and otherwise shall contain the same information as set forth above, as required by rule 28-106.301

Because the administrative hearing process is designed to formulate final agency action, the filing of a petition means that the Department's final action may be different from the position taken by it in this notice. Persons whose substantial interests will be affected by any such final decision of the Department on the application have the right to petition to become a party to the proceeding, in accordance with the requirements set forth above.

A complete project file is available for public inspection during normal business hours, 8:00 a.m. to 5:00 p.m., Monday through Friday, except legal holidays, at:

Florida Department of
Environmental Protection
Bureau of Air Regulation
111 S. Magnolia Drive, Suite 4
Tallahassee, Florida, 32301
Telephone: (850) 488-1344
Fax: (850) 922-6979

Florida Department of
Environmental Protection
Northeast District
Suite 200B, 7825 Baymeadows Way
Jacksonville, Florida 32256
Telephone: (904) 448-4300

The complete project file includes the application, Draft permit, and the information submitted by the Responsible Official, exclusive of confidential records under Section 403.111, F.S. Interested persons may review specific details of this project at http://www.dep.state.fl.us/air/permitting/construct.htm or contact the Administrator, New Source Review Section, at 111 South Magnolia Drive, Suite 4, Tallahassee, Florida 32301, or call 850/488-0114, for additional information.

NOTICE TO BE PUBLISHED IN THE NEWSPAPER

TECHNICAL EVALUATION

AND

PRELIMINARY DETERMINATION

Cedar Bay Generating Company, LP

Co-Firing of Petroleum Coke

U.S. Generating Company / Cedar Bay Cogeneration Facility

Duval County

0310337-005-AC

Department of Environmental Protection
Division of Air Resources Management
Bureau of Air Regulation
New Source Review Section

July 15, 2002

1. GENERAL INFORMATION

1.1 APPLICANT NAME AND ADDRESS

Cedar Bay Generating Company, L.P.
Cedar Bay Cogeneration Facility
9640 Eastport Road
Jacksonville, Florida 32218

Authorized Representative: Bruce Smith, General Manager

1.2 REVIEWING AND PROCESS SCHEDULE

August 29, 2001	Received permit application and fee
September 28, 2001	Request For Additional Information
April 2, 2002	Second Request For Additional Information
July 1, 2002	Application complete

2. FACILITY INFORMATION

2.1 FACILITY LOCATION

The facility is located in Jacksonville, Duval County. The UTM coordinates are Zone 17; 441.61 km E; 3365.552 km N. This site is approximately 54 kilometers from the Okefenokee National Wildlife Refuge and 98 kilometers from the Wolf Island National Wildlife Refuge, both Class I PSD Areas.

2.2 STANDARD INDUSTRIAL CLASSIFICATION CODES (SIC)

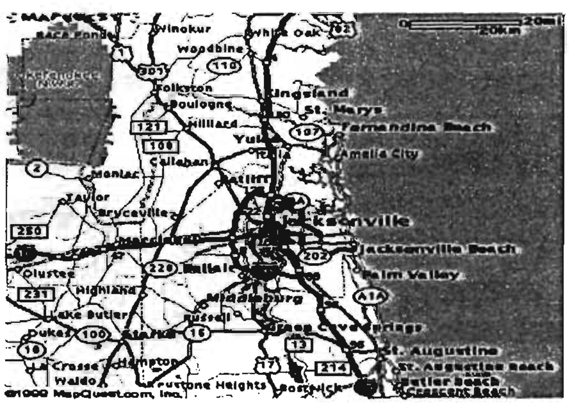
Industry Group No.	49	Electric, Gas and Sanitary Services
Industry No.	4911	Electric Services

2.3 FACILITY CATEGORY

This facility consists of three circulating fluidized bed (CFB) steam generators (boilers) designated as Boilers A, B, and C, a coal handling area, a limestone handling area, and an ash handling area. Crushed coal is the primary fuel for Boilers A, B and C. The fuel for Boilers B and C can also be supplemented with short fiber recycle rejects received from Stone Container Corporation. No. 2 fuel oil is used as supplemental fuel in all three boilers normally only for start-ups.

This facility is classified as a Major or Title V Source of air pollution because emissions of at least one regulated air pollutant, such as particulate matter (PM/PM_{10}), sulfur dioxide (SO_2), nitrogen oxides (NO_X), carbon monoxide (CO) or volatile organic compounds (VOC) exceeds 100 tons per year (TPY).

This facility is within an industry included in the list of the 28 Major Facility Categories per Table 62-212.400-1, F.A.C. Because emissions are greater than 100 TPY for at least one criteria pollutant, the facility is also a Major Facility with respect to Rule 62-212.400, Prevention of Significant Deterioration (PSD). Based upon the Title V permit, this facility is a major source of hazardous air pollutants (HAPs). See Figures 1 and 2 below.



3. PROJECT DESCRIPTION

This project primarily addresses the following emissions unit(s):

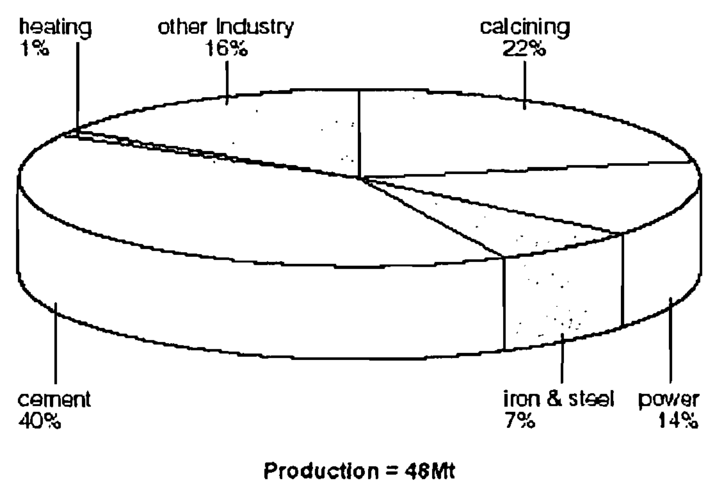
Emissions Unit No.	Emissions Unit Description
001	Pyroflow® Circulating Fluidized Bed (CFB) dry bottom boiler designated as "CFB Boiler A"
002	Pyroflow® Circulating Fluidized Bed (CFB) dry bottom boiler designated as "CFB Boiler B"
003	Pyroflow® Circulating Fluidized Bed (CFB) dry bottom boiler designated as "CFB Boiler C"

The applicant proposes to combust up to 35% of its fuel (on a weight basis) as petroleum coke (petcoke). The facility currently combusts coal as its primary fuel. The applicant indicates that this permit modification can be made in such a way that air emissions will not increase beyond historical levels, thus a PSD Review will not be triggered. The applicant further proposes to maintain and submit to the Department (FDEP) and the Regulatory and Environmental Services Department of Jacksonville (RESD) on an annual basis for a period of 5-years from the date each emission unit begins firing petroleum coke, data demonstrating in accordance with 40 CFR 52.21(b)(21)(v) and 40 CFR 52.21(b)(33) that the operational change associated with the use of petroleum coke did not result in significant emission increases for CO, NO_X, PM, SO_2, SAM and VOC. A general review of petcoke, CFB Boilers, a review of the future actual emissions and related emission analyses follow.

3.1 PETCOKE DISCUSSION

Much of this review was obtained from The Clean Coal Centre of the United Kingdom, in an article entitled "*The use of petroleum coke in a coal-fired plant*". Petroleum coke is a by-product from oil refineries and is composed mainly of carbon though it also contains high levels of sulfur and some heavy metals such as vanadium and nickel. There has been considerable interest in petcoke for several years, where it is available, as it is generally significantly cheaper than coal. The price does vary depending on the volumes produced and worldwide demand. The world production of petcoke grew by 50% from 1987 to 1998. It reached nearly 50 Million Tons (Mt) in 1999 and is expected to reach 100 Mt by 2010. The USA is the world's largest producer, producing three-quarters of world supplies. There are three types of petroleum coke, which can be produced depending on the process of production. The three processes are delayed, fluid and flexicoking with delayed coking producing over 90%. All three types of petcoke have higher calorific values than coal and contain less volatile matter and ash. The main uses of petcoke are as an energy source for power generation, in cement production and iron and steel production (which account for about two thirds of production) and the remainder is used mainly as a carbon source.

FIGURE 3 - 1999 WORLD PETROLEUM COKE MARKET PROFILE



The following additional information was compiled for the Year 2000. The source of this data is FERC Form 423, although the Energy Information Administration (EIA) summarized it in a report entitled "*Cost and Quality of Fuels for Electric Utility Plants 2000 Tables*", dated August 2001. This data was accumulated for electric generating plants with nameplate capacity of 50 megawatts or more. Tables 25 and 28 from that report are shown below:

Table 25. The Top 20 Electric Utilities, Ranked by Receipts of Coal, 2000

Electric Utility	Receipts (thousand short tons)	Average Delivered Cost		Total Coal Bill (million dollars)
		(cents per million Btu)	(dollars per short ton)	
1. Tennessee Valley Authority	41,092	110.2	25.44	1,068.1
2. Georgia Power Co.	34,743	154.5	35.65	1,238.7
3. TXU Electric Co	32,508	105.5	14.11	458.8
4. PacifiCorp	28,068	85.5	16.80	471.6
5. Alabama Power Co	25,634	147.0	31.37	804.2
6. Detroit Edison Co	19,582	129.6	26.90	526.8
7. Reliant HL&P	18,350	143.4	22.17	406.9
8. Basin Electric Power Coop	15,981	59.2	8.70	139.0
9. Ameren UE	15,675	93.6	16.46	258.0
10. Duke Power Co.	15,089	135.9	33.78	509.7
11. PSI Energy Inc	14,643	109.6	24.52	359.0
12. Ohio Power Co	14,618	213.1	50.70	741.1
13 Virginia Electric & Power	13,945	126.5	32.05	447.0
14. Northern States Power Co	13,147	108.6	19.22	252.7
15. Arkansas Power & Light Co.	12,383	142.9	24.88	308.1
16. Appalachian Power Co.	11,868	132.2	32.25	382.8
17. Southwestern Electric Power	11,705	140.5	22.40	262.1
18. Salt River Proj Ag I & P Dist	11,556	116.8	24.54	283.5
19. Wisconsin Electric Power	11,362	100.0	18.96	215.4
20. Cincinnati Gas & Electric Co.	11,210	105.9	25.66	287.7

Note: Data are for electric generating plants with a total steam-electric and combined-cycle nameplate capacity of 50 or more megawatts.
Source: Federal Energy Regulatory Commission, FERC Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants." .

Table 28. Receipts of Petroleum Coke by Electric Utility, 2000

Electric Utility	Receipts (thousand short tons)	Average Quality			Average Delivered Cost	
		Btu (per pound)	Sulfur (percent by weight)	Ash (percent by weight)	(cents per million Btu)	(dollars per short ton)
Central Illinois Pub Serv Co	26	14,419	3.44	0.32	90.8	26.18
Jacksonville Electric Authority	444	14,398	5.99	.32	60.8	17.51
Lakeland Dept of Water and Elec	2	14,068	6.43	.20	42.7	12.01
Manitowoc Public Utilities	36	14,405	5.88	.53	46.5	13.40
Michigan South Central Power	2	14,073	4.90	.40	106.9	30.08
Northern Indiana Pub Serv Co	174	14,106	4.11	.24	65.2	18.40
Northern States Power Co.	220	14,085	5.34	.54	33.4	9.40
Ohio Edison Co	8	13,729	3.71	.40	73.9	20.29
Owensboro City of	9	13,884	5.24	.86	53.7	14.91
Pennsylvania Power Co.	203	14,200	5.62	.42	74.3	21.09
San Antonio City of	9	14,500	4.00	.50	42.0	12.18
Tampa Electric Co	211	14,021	4.49	.40	51.2	14.35
Union Electric Co	124	14,306	3.74	.40	60.5	17.31
Wisconsin Electric Power Co	147	14,142	5.01	.34	70.3	19.89
Wisconsin Power & Light Co	60	14,213	5.62	.48	46.7	13.28
Total	**1,683**	**14,214**	**5.14**	**.39**	**58.5**	**16.62**

Notes: • Totals may not equal sum of components because of independent rounding. • Data are for electric generating plants with a total steam-electric and combined-cycle nameplate capacity of 50 or more megawatts.
Source: Federal Energy Regulatory Commission, FERC Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants."

Of interest, no Florida utilities show up in the top 20 listing of coal users, even though Florida is one of the most populous states. It is observed that the cost of petroleum coke in year 2000 was approximately ½ that of coal. According to Table 28, Florida had 3 users of petcoke out of 15 listed users. The tables also show that receipts of petcoke totaled 1683 thousand short tons, or less than 0.5% of the sum of coal receipts of the top 20 coal users. Only 3 utilities are listed on both tables: Northern States Power, Wisconsin Electric Power and Wisconsin Power & Light Company (Northern States Power is now known as XCEL Energy, headquartered in Minnesota). Jacksonville Electric Authority (JEA) is indicated as the largest utility user of petcoke during year 2000 for electrical generation.

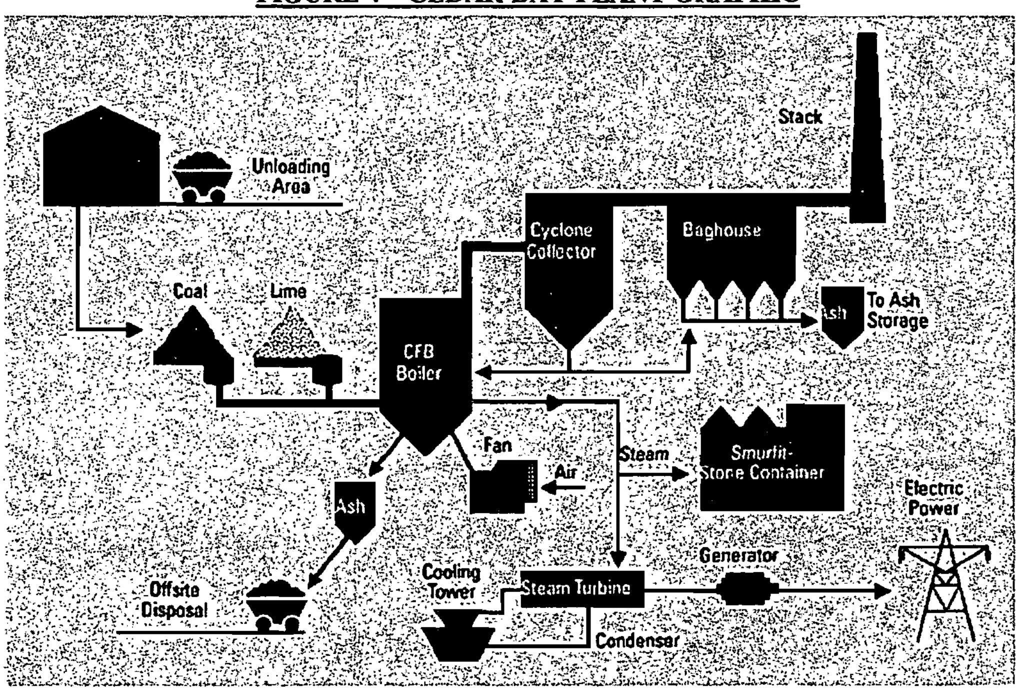
3.2 FLUIDIZED BED COMBUSTION

In a circulating fluidized-bed boiler, a portion of air is introduced through the bottom of the bed. The bed material normally consists of fuel, limestone and ash. Water-cooled membrane walls with specially designed air nozzles support the bottom of the bed, which distributes the air uniformly. The fuel and limestone (for sulfur capture) are fed into the lower bed. In the presence of fluidizing air, the fuel and limestone quickly and uniformly mix under the turbulent environment and behave like a fluid. Carbon particles in the fuel are exposed to the combustion air. The balance of combustion air is introduced at the top of the lower, dense bed. This staged combustion limits the formation of nitrogen oxides (NO_X). The captured solids, including any unburned carbon and unutilized calcium oxide (CaO), are re-injected directly back into the combustion chamber without passing through an external recirculation. This internal solids circulation provides longer residence time for fuel and limestone, resulting in good combustion and improved sulfur capture.

CFB plants are particularly suited for firing petcoke as the long residence times promote high burnout. The low combustion temperature allows SO_2 capture via limestone injection, while minimizing NO_X emissions. In fact, according to Foster Wheeler, CFB boilers are generally capable of removing over 98% of SO_2. The technology is flexible enough to handle a wide range of coals plus petroleum coke as well as blends of coal and coke. Furthermore, the low volatile content of the petcoke is compensated by the substantial amount of hot solids within the boiler providing a constant source of ignition. Petroleum coke has been fired successfully since the 1980s in a wide variety of CFB plants. In the early years, plants tended to be smaller, generating tens of MW whereas more recently plant generating hundreds of MW are common.

The 135 MW AES Deepwater cogeneration plant has been firing 100% petcoke in an arch-type furnace since 1986. The 1344 MW St Johns River Power Park in Florida has been co-firing coal and up to 20% petroleum coke in two wall-fired units and the plant has not experienced any significant problems with corrosion, slagging or fouling and the increased operational costs have been more than offset by the lower fuel costs. The U.S. Department of Energy (DOE) and JEA have entered into an agreement to repower the JEA Northside Generating Station with CFB technology from Foster Wheeler. When operational, the plant will demonstrate CFB technology for coal firing in large-scale applications while providing increased plant electric output, reduced emissions and broad fuel flexibility. The Mt. Poso cogeneration plant in Southern California is permitted to combust petcoke, various coals and tire-derived fuel (TDF) in the CFB unit owned by Millennium Energy Partners, LLC.

FIGURE 4 – CEDAR BAY PLANT GRAPHIC



4. PROJECT EMISSIONS

4.1 FUTURE ACTUAL EMISSION PROJECTIONS

The following table summarizes the future actual emissions increases/decreases at the facility, based upon the applicant's submittals:

Pollutant	1999 Actual Emissions (TPY)	2000 Actual Emissions (TPY)	1999–2000 Average (TPY)	Projected Emissions Co-firing Petcoke [1]	Projected Emissions Change	PSD Significant Emission Rates (TPY)	Subject To PSD Review?
NO_X	1741.5	1779.0	1760.2	1718.1	-42.1	40	NO
CO	582.3	516.0	549.1	400.9	-148.2	100	NO
VOC	17.89	17.25	17.57	34.65	17.08	40	NO
SO_2	1926.2	1965.1	1945.6	1941.3	-4.3	40	NO
SAM	0.359	0.346	0.35	0.61	0.26	7	NO
PM_{10}	193.7	165.2	179.4	169.9	-9.5	15	NO

[1] *Based upon heat inputs from years 1999 and 2000.*

4.2 BOTTLE-NECKING ISSUES

The existing permit provides certain limitations to the throughputs of raw and spent materials. As can be seen from Figure 4 above, there are two primary raw material inputs (coal and limestone) and two primary spent material streams (fly ash from the baghouse, and bed ash from the boiler bottom). A review of data reported to FDEP by Cedar Bay during years 1999 and 2000 shows the following actual annual throughputs along with their respective limits, each in tons per year (TPY).

	COAL	LIMESTONE	FLYASH	BED ASH
ANNUAL LIMIT	*1,170,000*	*320,000*	*336,000*	*88,000*
1999	962,569	122,835	138,306	69,153
2000	954,391	110,534	138,280	71,235

4.2.1 COAL (FUEL) THROUGHPUT

Co-firing of petcoke will result in a lower amount of coal being fired. Additionally, since petcoke has a higher BTU content per ton of fuel than does coal, the combined throughput of petcoke and coal should decrease. Therefore, it is improbable that the commencement of co-firing will cause the facility to approach the coal throughput limit.

4.2.2 LIMESTONE THROUGHPUT

Concerning limestone, the Department estimates that the facility will need to (approximately) double the throughput, in order to achieve the necessary SO_2 scrubbing required to ensure that the PSD significance level is not exceeded. As can be seen from the above table, limestone throughputs can nearly triple before the permitted limit is exceeded.

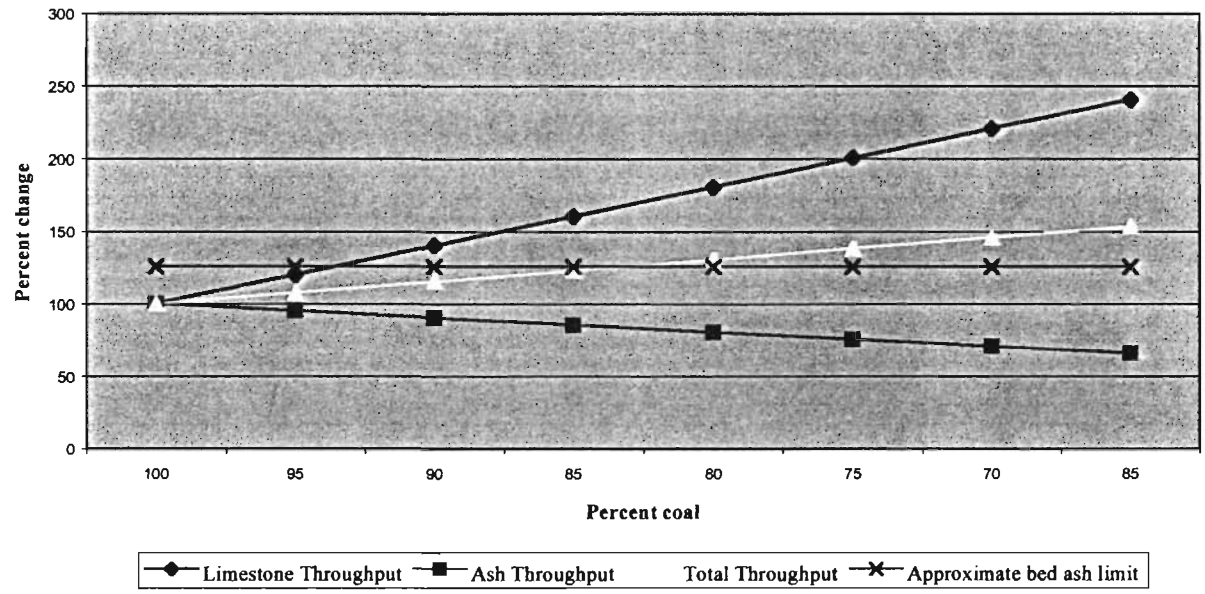
4.2.3 FLYASH THROUGHPUT

Like limestone, the past actual throughputs of flyash are well below permitted levels (approximately 40%). Since the ash content of petcoke is lower than that of coal, it is also unlikely that permitted throughputs of flyash will be exceeded, and Department calculations bear this out. However, the Department estimates that the throughput limit associated with bed ash could be problematic for the facility during the co-firing of petcoke, depending upon the amount and properties of the petcoke.

4.2.4 BED ASH THROUGHPUT

It can be observed from the above table that historically, the flyash to bed ash ratio has been approximately 2:1. Simply stated, for each 1,000 ton of combined limestone and ash entering the boilers, around 667 tons will end up as fly ash and 333 tons will become bed ash. Accordingly, at an increased (combined) limestone and ash throughput of approximately 54,000 TPY, the flyash would be expected to increase by about 36,000 TPY whereas the bed ash would increase by about 18,000 TPY (assuming unchanged fuel quality). This increased throughput of bed ash is roughly equivalent to the permit limit, as the historical average (of approximately 70,000 TPY) is 18,000 TPY less than the limit. In summary, the 88,000 TPY bed ash limit likely becomes an upper bound for the amount of co-firing, which the facility can accommodate. What follows is a Department approximation of the equivalent amount of high sulfur petcoke, which corresponds to the 88,000 TPY bed ash limit (125% of the past actual).

Cedar Bay petcoke co-firing



4.2.5 BOTTLE-NECKING SUMMARY

Based upon the graph above and a number of conservative assumptions (e.g. coal quality, petcoke quality, limestone utilization rate, etc.) a practical co-firing limit for the highest sulfur-laden petcoke is approximately 20% (80% coal), as this is about the point at which it is anticipated that the bed ash limit may be reached. Of course, as the sulfur content of the petcoke is reduced, this practical limit begins to disappear (e.g. as the sulfur level of the petcoke approaches that of the coal). For example, at a petcoke sulfur content of 4%, the practical co-firing limit (based upon bed ash throughput) is approximately 35%. Accordingly, in order for the Department to have reasonable assurance that this facility can be permitted for the co-firing of petcoke without exceeding the existing permit limits, a limit on the petcoke throughput as well as the equivalent coal/petcoke blended sulfur content will be established.

5. RULE APPLICABILITY

This facility is located in an area designated, in accordance with Rule 62-204.340, F.A.C., as attainment for all pollutants. Rule 62-4.030, F.A.C., prohibits modification of any existing emissions unit without first receiving a permit. It further specifies that a permitted installation may only be modified in a manner that is consistent with the terms of such a permit. Rule 62-210.200, F.A.C., defines "modification" to mean generally a physical change or change in the method of operation that results in an increase in actual emissions of regulated air pollutants. Rules 62-210.300(1) and 62-212.300(1)(a), F.A.C., also reiterate the requirement for construction permits. Additionally, Rule 62-210.300 requires an Air Construction permit for all new sources of air pollution unless specifically exempt.

FDEP deems that burning of petcoke is a change in the method of operation. Given that the source is major with regard to PSD, an analysis must be performed to verify that the burning of petcoke will not result in a significant net emissions increase and that, consequently, use of petcoke is not a major modification subject to PSD review. The emission units affected by this permit shall comply with all applicable provisions of the Florida Administrative Code (including applicable portions of the Code of Federal Regulations incorporated therein).

6. PSD POLLUTANT ANALYSIS

The following excerpt from a 1998 publication of *Heat Engineering*, entitled Firing Refinery By-products in Circulating Fluidized-Bed Steam Generators is used as a preface to the Department's analysis of each PSD pollutant. It is noted that the emissions at this facility have been relatively steady over the past several years with consistently high capacity factors. FDEP data for years 1999 and 2000 is utilized as the 2-year baseline period.

The largest petcoke-fired CFB steam generators in the world were designed and built by Foster Wheeler for Nelson Industrial Steam Company (NISCO). They are located at the NISCO cogeneration facility in Lake Charles, La. The two 100 MWe CFB boilers at the facility have successfully burned petcoke since 1992 to repower existing turbine-generator equipment and to provide steam for an adjacent chemical plant. The project has been a financial success and the CFB plant has operated with high availability and capacity. Each of the NISCO boilers generates 825,000 pounds per hour of main steam at 1005°F and 1625 psig as well as 727,000 pounds per hour of reheat steam. The petcoke design fuel is characterized in Table 3. Boiler efficiency has been greater than 90 percent as measured by the ASME heat-loss method, and combustion efficiency has exceeded 99 percent. The boilers have also demonstrated excellent turndown capability, easily exceeding the guaranteed operating range of 40 to 100 percent maximum continuous rating (MCR) without having to fire auxiliary fuel for combustion stability. Since commissioning, plant availability has consistently been greater than 95 percent. As expected, levels of potential pollutants in the flue gas leaving the furnace have been very low. Sulfur removal has consistently been greater than 90 percent. Nitrogen-oxide emissions have typically been less than 0.15 lb. per Million Btu's (MMBtu) and often less than 0.07 lb/MMBtu. Carbon-monoxide emissions have been less than 0.06 lb/MMBtu at 100 percent boiler load. Managers of the NISCO project have aggressively pursued beneficial uses of the ash-waste streams to further enhance cost-effectiveness. Virtually all of the environmentally inert ash produced by the two CFB boilers is sold for purposes such as soil conditioning.

TABLE 3

Composition of Petcoke for NISCO Project

Carbon	75–86% (by wt)
Hydrogen	3.0–3.6%
Nitrogen	1.3–1.9%
Sulfur	3.4–5.3%
Ash	0.0–0.6%
Oxygen	0.0–0.1%
Moisture	5.5–15.0%
Vanadium	500–2800 ppm
Nickel	250–450 ppm
Iron	50–250 ppm
HHV	12,600–14,500 Btu/lb

6.1 CARBON MONOXIDE (CO) AND VOLATIVE ORGANIC COMPOUNDS (VOC)

The applicant contends that there will be a net emission decrease in CO from the co-firing of petcoke and coal, and no change in VOC emissions. Annual CO emissions averaged 549 TPY and 0.05 lb/MMBtu, while annual VOC emissions averaged 34.7 TPY. The Significant Emission Rate for CO is 100 TPY, and for VOC is 40 TPY. The Department finds it unlikely that the co-firing of petcoke will cause CO emissions to exceed 648 TPY (549 + 99) or VOC emissions to exceed 74 TPY (35 + 39). Accordingly, a BACT review is not required for these pollutants.

6.2 NITROGEN OXIDE (NO_X)

The applicant indicates that NO_X emissions are likely to decrease, as uncontrolled NO_X will reduce by as much as 25%. Annual NO_X emissions averaged 1760 TPY and 0.15 lb/MMBtu. The Significant Emission Rate for NO_X is 40 TPY. The Department accepts the applicant's assessment and finds it unlikely that co-firing petcoke will cause NO_X emissions to exceed 1799 TPY (1760 + 39). Accordingly, a BACT review is not required.

6.3 SULFUR DIOXIDE (SO_2) AND SULFURIC ACID MIST (SAM)

The applicant recognizes that additional scrubbing will be required in order to maintain SO_2 and SAM emissions at historical levels. The past actual average emissions of SO_2 and SAM were 1945.6 and 0.35 TPY respectively. The average annual emission rate for SO_2 was 0.17 lb/MMBtu. The Significant Emission Rates (SER) are 40 TPY (SO_2) and 7 TPY (SAM). The Department accepts the applicant's proposal that SO_2 and SAM emissions can be maintained below the respective SER by additional scrubbing within the CFB's. However, the Department estimates that the practical limit of scrubbing within a CFB is approximately 95%. Accordingly, the Department will place a limit on the inlet SO_2 loading to the CFB's, which limits the maximum emission rate at the historical 0.17 lb/MMBtu via reasonable scrubbing efficiencies. The applicant proposes to limit the inlet SO_2 loading to 3.2 lb/MMBtu, which at 95% scrubbing results in an emission rate of 0.16 lb/MMBtu. This is acceptable to the Department and should ensure that the annual emission levels of SO_2 and SAM exceed neither 1985 (1945.6 + 39.9) TPY nor 7.34 (0.35 + 6.99) TPY respectively. In addition to this, the Department will place a limit on the throughput of petcoke at 35% input on a weight basis. Accordingly, the SO_2 and SAM emission increases are considered insignificant for PSD purposes and BACT reviews are not required.

6.4 PARTICULATE MATTER (PM_{10})

According to FDEP data, the historical level of PM_{10} for the CFB's averaged 180.06 TPY and the PSD Significant Emission Rate is 15 TPY. Given that the ash content of petcoke is significantly less than that of coal, the prime concern for potential increases in PM_{10} is related to the increased lime throughput required for SO_2 scrubbing. As shown above, the Department estimates that this additional scrubbing can be achieved at removal efficiencies as high as 95%. This additional scrubbing is anticipated to result in total lime throughputs at twice historical levels. As reviewed in Section 4.2, and in order to ensure that the bed ash permitted throughput is not exceeded, the Department will require a monitoring system to accurately measure such throughput. The applicant will propose (to the Department's satisfaction) the system it recommends to utilize, prior to the initial receipt of petcoke. Actual in-service testing (while combusting coal) will be completed prior to the initial firing of petcoke, demonstrating its adequacy to the Department's satisfaction. As an additional means of ensuring compliance, the limestone throughput limit will be reduced to further ensure that the bed ash limit cannot be exceeded. Since no applicant estimate, including those of Foster Wheeler, indicates that the limestone throughput is required to exceed 275,000 TPY (in order to maintain SO_2 emissions at historical levels while co-firing petcoke), this will additionally be established as a reduced permit limit.

Concerning the stack emissions of PM_{10}, the facility uses baghouses. The applicant maintains that the emission rate from the baghouse for each CFB can be maintained because PM removal is not a function of loading, particularly given the low loading rates to the baghouse. This information is provided in the ABB Emissions Control System Operations and Maintenance Manual, a portion of which the applicant has provided to the Department. According to the manual, the particulate emission rate can be maintained over a range of grain loading and flow rates. The baghouses are designed for an inlet grain loading of 19.5 grains/acf at 297,700 acfm. The grain loading for coal is provided as 4.5 - 4.7 grains/acf for the baseline years of 1999 - 2000. A calculation of the total loading during co-firing reveals loadings at 5.1 - 5.5 grains/acf, still well below the design of 19.5 grains/acf. Additionally, the maximum grain loading projected in the Foster Wheeler report is 6.7 grains/acf, which is also less than the design condition. Unlike particulate removal devices such as ESP's, it is unlikely that PM emissions will increase through a baghouse, while the inlet loading is well below the design. This conclusion is supported by information available from EPA regarding fabric filters. In the Air Pollution Technology Fact Sheets for fabric filters EPA states that: "the effluent particle concentration from a fabric filter is nearly constant"... and "fabric filters can be considered constant outlet devices rather than constant efficiency devices." Accordingly, the annual PM/PM_{10} emissions from the stack are likely to be maintained with no increase above the PSD significant emission rate of 25/15 tons/year.

With regard to ancillary (or fugitive) emissions resulting from the increased lime throughput, the applicant estimates an annual PM_{10} increase of 0.59 TPY. The historical PM_{10} emission level for the balance of the plant (as reported to the Department) averaged 2.97 TPY. For the facility, total average annual PM_{10} emissions were 183.03 TPY (180.06 + 2.97). In summary, all PM_{10} emissions from the facility must remain less than 198 TPY (183 + 15) in order to be underneath the Significant Emission Rates. The applicant maintains that this can be accomplished and the Department accepts the applicant's claim.

6.5 SUMMARY

A preliminary review supports the applicant's contention that PSD is not triggered, eliminating the requirement for a BACT review and related modeling. PSD regulations (under the provisions commonly known as the "WEPCO rule") allow a source undertaking a non-routine change that could affect emissions at an electric utility steam generating unit to lawfully avoid the major source permitting process by using the unit's representative actual annual emissions to calculate emissions following the change, if the source submits information for 5 years following the change to confirm its pre-change projection. Under the WEPCO rule, Cedar Bay must compute baseline actual emissions and must project the future actual emissions from the modified units for a period after the physical change. In addition, Cedar Bay must maintain and submit to the Department on an annual basis for a period of at least 5 years from the date the units resume regular operation, information demonstrating that the change did not result in a significant emissions increase. If Cedar Bay fails to comply with the reporting requirements of the WEPCO rule or if the submitted information indicates that emissions have increased above PSD thresholds as a consequence of the change, it will be required to obtain a PSD permit for petcoke co-firing (meaning that a BACT Review would then be applicable). Finally, even though a PSD review is not triggered due to the co-firing project, Cedar Bay must meet all other applicable federal, state, and local air pollution requirements.

7. ADDITIONAL COMPLIANCE PROCEDURES

Pollutant	Compliance Procedures
NO_X emission limit	Five years of annual reporting by CEMS proving annual emissions do not exceed 1799 TPY
CO emission limit	Five years of annual reporting by CEMS proving annual emissions do not exceed 648 TPY
VOC emission limit	Five years of annual reporting by stack test proving annual emissions do not exceed 74 TPY
SO_2 emission limit	Five years of annual reporting by CEMS proving annual emissions do not exceed 1985 TPY
SAM emission limit	Five years of annual reporting by stack test proving annual emissions do not exceed 7.3 TPY
PM_{10} emission limit	Five years of annual reporting by stack test proving annual facility emissions do not exceed 198 TPY

Specific permit conditions shall further describe these limitations. The reporting procedures are to begin during the first calendar year in which petcoke is fired.

8. CONCLUSION

Based on the foregoing technical evaluation of the application, additional information submitted by the applicant and other available information, the Department has made a preliminary determination that the proposed project will comply with all applicable state and federal air pollution regulations.

Michael P. Halpin, P.E. Review Engineer
Department of Environmental Protection, Bureau of Air Regulation
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

August xx, 2002

Mr. Bruce Smith
General Manager
Cedar Bay Generating Company, L.P.
P.O. Box 26324
Jacksonville, Florida 32226-6324

Re: DEP File No. PA 88-24; Modification of Permit No. PSD-FL-137
Cedar Bay Generating Plant / Duval County

The applicant, Cedar Bay Generating Company, L.P., applied on August 29, 2001, to the Department for a modification to PSD permit number PSD-FL-137 for its Cedar Bay Generating Plant located in Duval County. The modification is to allow the facility to co-fire petroleum coke (petcoke) in its three circulating fluidized bed boilers (A, B and C). The Department has reviewed the modification request. The referenced permit is hereby modified as follows:

II.A. Emission Limitations for 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. Petroleum coke (petcoke) may be utilized as a co-firing fuel, and shall not exceed 35% fuel input by weight on a daily basis. {Permitting Note: The limitations on the coal charging rate include both coal and petcoke.}

   d. The sulfur content of the coal shall not exceed 1.2%, by weight, on an annual basis. The sulfur content shall not exceed 1.7%, by weight, on a shipment (train load) basis. When co-firing coal and petcoke, the blended fuel input to the CFBs shall not exceed 3.2 lb/MMBtu equivalent SO_2 content. Compliance shall be determined on a monthly basis via a composite of daily fuel samples.

4. Ammonia (NH_3) slip from the exhaust gases shall not exceed 10 ppmvd when co-firing petcoke or burning coal at 100% capacity and 30 ppmvd when burning oil.

10. Operations Monitoring for each CFB

    b. All coal, petcoke 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 and recorded for each 24-hour period in which rejects are burned.

17. The permittee shall submit annual reports to RESD and DEP/BAR summarizing emissions for each calendar year. The reports will commence during the first year in which petcoke is fired and continue for a total of five calendar years. Such reports are required in order to confirm Cedar Bay's projections of future actual emissions and to demonstrate to the Department's

satisfaction that petcoke co-firing did not result in a significant emissions increase. Reporting shall be as follows:

Pollutant	**Compliance Procedures**
NO_X	Five years of annual reporting by CEMS proving annual facility emissions do not exceed 1799 TPY
CO	Five years of annual reporting by CEMS proving annual facility emissions do not exceed 648 TPY
VOC	Five years of annual reporting by stack test proving annual facility emissions do not exceed 74 TPY
SO_2	Five years of annual reporting by CEMS proving annual facility emissions do not exceed 1985 TPY
SAM	Five years of annual reporting by stack test proving annual facility emissions do not exceed 7.3 TPY
PM_{10}	Five years of annual reporting by stack test proving annual facility emissions do not exceed 198 TPY

II.B. CBCP - Material Handling and Treatment

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	
Petcoke	40,950	409,500	
Limestone	27,000	~~320,000~~	275,000
Fly Ash	28,000	336,000	
Bed Ash	8,000[1]	88,000[1]	

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

[1] The Department will require a monitoring system to accurately measure Bed Ash throughput. The applicant will propose (to the Department's satisfaction) the system it recommends to utilize, prior to the initial receipt of petcoke. Actual in-service testing (while combusting coal) will be completed prior to the initial firing of petcoke, demonstrating its adequacy to the Department's satisfaction.

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

Coal Car Unloading
Ash Pellet Hydrator
Ash Pellet Curing Silo
Ash Pelletizing Pan

Petcoke Unloading/Handling Areas
Petcoke Transfer Areas
Petcoke Storage Areas

The above listed sources are subject to a VE and a PM emissions limitation requirement of 5% opacity and 0.01 gr/dscf (applicant requested limitation, which is more stringent than what is allowed by rule), respectively, in accordance with Rule 17-296.711, F.A.C. Initial and subsequent compliance tests shall be conducted for VE and PM emissions using EPA Methods 9 and 5, respectively, in accordance with Chapter 17-297, F.A.C., and 40 CFR 60, Appendix A (July, 1992 version).

A copy of this letter shall be filed with the referenced permit and shall become part of the permit. This permit modification is issued pursuant to Chapter 403, Florida Statutes.

Any party to this order (permit modification) has the right to seek judicial review of it under Section 120.68, F.S., by filing a notice of appeal under Rule 9.110 of the Florida Rules of Appellate Procedure with the clerk of the Department of Environmental Protection in the Office of General Counsel, Mail Station #35, 3900 Commonwealth Boulevard, Tallahassee, Florida, 32399-3000, and by filing a copy of the notice of appeal accompanied by the applicable filing fees with the appropriate District Court of Appeal. The notice must be filed within thirty days after this order is filed with the clerk of the Department.

Executed in Tallahassee, Florida.

____

Howard L. Rhodes, Director
Division of Air Resources
Management

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this permit modification was sent by certified mail (*) and copies were mailed by U.S. Mail before the close of business on ______________ to the person(s) listed:

Bruce Smith, Cedar Bay *
J. A. Walker, Cedar Bay
Ken Kosky, P.E. Golder Associates
Hamilton S. Oven, P.E.
James L. Manning, P.E., RESD
Doug Neeley, EPA
John Bunyak, NPS
Chris Kirts, DEP-NED
Stafford Campbell, Greater Arlington Civic Council

Clerk Stamp

FILING AND ACKNOWLEDGMENT FILED, on this date, pursuant to §120.52, Florida Statutes, with the designated Department Clerk, receipt of which is hereby acknowledged.

____________________ ________________
(Clerk) (Date)

PG&E National Energy Group
Cedar Bay Generating Plant
Owner: Cedar Bay Generating Company, L.P.

RECEIVED
JUL 24 2002
BUREAU OF AIR REGULATION

POB 26324
Jacksonville, FL 32226-6324

904.751.4000
Fax: 904.751.7320

Mike ~~F.Y.I.~~
~~Then~~ send to
Cedar Bay
File. AL

July 23, 2002

Mr. C.H. Fancy, P.E.
Florida Department of Environmental Protection
Bureau of Air Regulation
Mail Station #5505
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Re: Cedar Bay Generating Plant Fiber Reject Test Burn
Permit Nos. PSD-FL-137 & Title V 0310337-003-AV
Site Certification PA 88-24

Dear Mr. Fancy

Pursuant to the above referenced permits, Cedar Bay Generating Company, L.P. (Cedar Bay), is providing the required 30–day notification for the short fiber reject test burn to the Department and the City of Jacksonville's Regulatory and Environmental Services Department (RESD). Specifically, in accordance with the Prevention and Significant Deterioration and Site Certification Permits, Specific Condition II.A.1.h and Title V Permit, Subsection A.64, Cedar Bay is providing notice to the Department and RESD of the test burn at least 30 days prior to initiation of the test burn.

In accordance with the specific conditions in the referenced permits, Cedar Bay has previously submitted the fiber reject test burn protocol on May 24th, 2002 to comply with the ninety (90) day time frame notification. In addition, emission testing, as identified in the test burn protocol, is planned for September 3, 2002.

If there are any questions or if any additional information is needed, please contact me at (904) 751-4000 ext. 147.

Sincerely,

Jeffrey A. Walker

Jeffrey A. Walker
Environmental Manager, Cedar Bay

Cc: A.A. Linero, FDEP
Ernest Frye, FDEP NE Distict

Steven Pace, Jacksonville RESD
Hamilton S. Oven, FDEP- Siting Board

Golder Associates Inc.

6241 NW 23rd Street, Suite 500
Gainesville, FL 32653-1500
Telephone (352) 336-5600
Fax (352) 336-6603

Golder Associates

June 28, 2002

Mr. Michael P. Halpin, P.E.
New Source Review Section
Bureau of Air Regulation
Florida Department of Environmental Protection
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

RECEIVED

JUL 01 2002

BUREAU OF AIR REGULATION

RE: REQUEST FOR ADDITIONAL INFORMATION
CEDAR BAY COGENERATION FACILITY
CO-FIRING PETROLEUM COKE WITH COAL
FILE NO. PA 88-24 (PSD-FL-137)

Dear Mr. Halpin:

This correspondence is being submitted on behalf of Cedar Bay Cogenerating Company, L.P. in reference to the Department's letter dated April 2, 2002 requesting additional information related to co-firing petroleum coke with coal at the facility. The additional information, along with calculations, is attached and follows the format of the Department's request. I am providing as part of this letter a professional engineer certification of the calculations contained with the additional information.

The Department's expeditious review of the application is appreciated. Please contact me if there are question on the information submitted with this correspondence.

Sincerely,

GOLDER ASSOCIATES INC.

Kennard F. Kosky

Kennard F. Kosky, P.E.
Principal
Professional Engineer Registration No. 14996

SEAL

cc: Bruce Smith, General Manager Cedar Bay Generating Company, L.P. (with enclosures)
Jeff Walker, Cedar Bay Generating Company, L.P. (with enclosures)
Michelle Golden, PG&E National Energy Group (with enclosures)
David Dee, Landers and Parsons (with enclosures)
Hamilton S. Oven, P.E., PPSO (with enclosures)
James L. Manning, Jacksonville RESD (with enclosures)
Chris Kirts, DEP NE District (with enclosures)

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ADDITIONAL INFORMATION FOR CO-FIRING PETROLEUM COKE WITH COAL

File No. PA 88-24 (PSD-FL-137)
Cedar Bay Cogenerating Project

This document provides additional information requested by the Department in the letter dated April 2, 2002 related to co-firing petroleum coke with coal at the Cedar Bay Cogeneration facility. The information is presented in the same format as requested.

1. **FDEP Request/Comment:** The technical basis for the development of the "Representative Future Actual Emissions" in Table B is unclear. Rather, in each case, the "Representative Future Actual Emissions" appear to simply represent values that are slightly less than the past actual emissions plus the PSD Significant Emission Rates. Please provide the basis for the emission calculations, which Cedar Bay utilized in the development of this table. The Department notes that the basis for the original BACT emission calculation was a 93% capacity factor.

Additional Information: The "representative future actual emissions" were based on the average 1999/2000 actual emissions with an incremental addition for each pollutant to keep the emissions less than the PSD significant emission rates. The increment was added due to the potential variability of operations in any given year as well as pollutant variability. As indicated by the operation over the last five years, the facility operates at a high capacity given the requirement to provide power under contract to FPL and to supply steam to the host facility. Therefore, it is intended that the facility would operate in the same manner as in previous years with slight variability in operations and emission rates. Based on this premise, information on past actual performance and emissions when firing coal, and calculations of expected performance and emissions during the same period when co-firing petroleum coke with coal, were developed. This information and the associated calculations are presented in attached Tables 1 through 5. Each table is discussed below.

Table 1 presents information on the actual fuel and material used during operation of the facility from 1997 through 2001. This information was provided to the Department in the Annual Operating Reports (AORs) and includes fuel and limestone usage and generation of bed and fly ash. Information on the heat, ash and sulfur content of the fuel is also provided as these are used in subsequent calculations.

Table 2 presents operations information for coal firing during 1997 through 2001. The purpose of this table is for comparison with calculations for co-firing petroleum coke with coal. The information presented in this table is from the AORs and calculated based on data from the AORs. The far right column provides the basis of the information or the calculation. The amount of potential ash can be calculated directly. The amount of limestone required for SO_2 removal can be calculated based on the reaction of SO_2 with limestone ($CaCO_3$). The amount of byproduct formed by this reaction is calculated by assuming the formation of $CaSO_4$. The excess limestone is based on the actual limestone used minus that calculated for SO_2 removal. The CFB technology utilizes a reactant (i.e., limestone) to obtain high removal efficiencies. The total bed and fly ash, which includes ash from the fuel, excess reactant and $CaSO_4$, was also calculated. In this calculation, the CO_2 formed in the high temperature process of heating limestone is subtracted from the calculated total bed and fly ash. The table also includes a calculation of the lb/hr values for coal, limestone, bed ash and fly ash. This information is used to calculate the differences in fuel and material handling with regard to past actual emissions and future actual emissions.

Tables 3a and 3b present calculations representing the co-firing of petroleum coke with coal based on the same operation conditions as experienced in 1997 through 2001. As discussed previously, the facility will operate in basically the same manner. Cedar Bay Generating Company is proposing to limit the sulfur content of the total co-firing fuel to 3.2 lb/MMBtu or less. This approach would provide Cedar Bay with greater flexibility and would allow Cedar Bay to use a range of petroleum cokes. Specifically, the fuel used at Cedar Bay could range from approximately 20 percent petroleum coke (approximately 6 percent sulfur content) to approximately 35 percent petroleum coke (approximately 4 percent sulfur content). This approach would limit the maximum SO_2 removal in the CFB to approximately 95 percent when meeting a target emission rate of approximately 0.16 lb/MMBtu. To determine compliance with a 3.2 lb SO_2/MMBtu fuel input to the CFBs, daily as fired analyses would be performed.

To demonstrate the ability of the CFB to operate within this range, calculations were preformed using the 4.1 and 5.5 percent sulfur petroleum cokes identified in the Foster Wheeler report. The calculations in Table 3a are based on a 5.5 percent sulfur petroleum coke with the same heat input for the given year with 80 percent by weight of coal and 20 percent by weight of petroleum coke. Table 3b presents calculations based on a 4.1 percent petroleum coke with 65 percent by weight of coal and 35 percent by weight of petroleum coke supplying the heat input for the year. The coal fuel parameters (i.e., heat, sulfur and ash contents) are based on those for each year while the petroleum coke parameters are those used in the Foster Wheeler report provided with the original calculation (Coke #4). The calculations provided are identical to those for Table 2 including historical limestone requirements. Projections by Foster Wheeler of the amount of limestone required as a function of the amount of fuel at 35 percent petroleum coke in the total fuel suggest better limestone utilization due to improved bed combustion. This information was summarized in Table 1 of the application (i.e., 22,500 lb limestone/hr / 78,000 lb fuel/hr = 0.29). Therefore the calculations presented in Tables 3a and 3b are conservative. The tables also include calculations of the lb/hr values for coal, limestone, bed ash and fly ash for co-firing petroleum coke and coal. The projected lb/hr values in the Foster Wheeler are also provided for comparison. As noted, the calculated values are similar to and less than those provided in the Foster Wheeler report. Also presented in the tables are differences between coal and co-firing for fuel, fuel ash, limestone, total ash and fly ash. As shown, there would be decreases in fuel and fuel ash and increases in limestone and total bed and fly ash when co-firing 20 to 35 percent petroleum coke. It should be noted that the amount of increase in total ash is a direct result of the additional limestone; there is not an increase in fuel ash. The high calcium content of the ash would continue to help make this by-product a marketable soil supplement.

Tables 4a and 4b present calculations for each pollutant when co-firing coal and petroleum coke, with the actual emissions and net emissions increase. Each pollutant is discussed below.

- CO – The calculated emissions are based on projections of Foster Wheeler. As shown there is a net emission decrease.
- NO_x – Each CFB is equipped with Selective Non-Catalytic Reduction (SNCR), which will be used to limit NO_x emission rates to levels that would not increase annual emissions above the PSD significant emission rate of 40 tons/year. As noted from the Foster Wheeler report the co-firing of petroleum coke with coal would reduce uncontrolled emissions by about 25 percent (Figure 5) with the benefit of lower ammonia usage (Figure 6).
- PM/PM_{10} – The calculated emission are based on the average particulate emissions for each year. The emission rate from the baghouse for each CFB can be maintained because PM removal is not a function of loading, given the low loading rates to the baghouse. This information is provided in the ABB Emissions Control System Operations and Maintenance Manual, which is attached. As provided in the manual, the particulate emission rate can be maintained over a range of grain loading and flow rates. The baghouses are designed for an inlet grain loading o 19.5 grains/acf at 297,700 acfm. The grain loading (in grains/acf) for

coal and co-firing are presented in Tables 5a and 5b. As shown in the table, the increase loading to the baghouses resulting from co-firing is less than 1 grain/acf. In addition, the maximum grain loading projected in the Foster Wheeler report is 6.7 grains/acf, which is much less than the design condition. This conclusion is supported by information available from EPA regarding fabric filters. In the Air Pollution Technology Fact Sheets for fabric filters EPA states that: "the effluent particle concentration from a fabric filter is nearly constant"... and "fabric filters can be considered constant outlet devices rather than constant efficiency devices." The annual PM/PM_{10} emissions would be maintained with no increase above the PSD significant emission rate of 40 tons/year.

- Sulfuric Acid Mist (SAM) – The emissions for sulfuric acid mist when co-firing were based on the actual emissions determined during initial testing when firing coal, and increased proportionally for the increased sulfur content of the fuel when co-firing. The test data determined a emission rate of <0.00003 lb/MMBtu for all units. This was increased based on the sulfur content of the fuel and was about 0.00006 lb/MMBtu. While there is an projected increase in SAM emissions, the amount is less than the PSD significant emission rate of 7 tons/year.
- SO_2 – The removal of SO_2 would be increased by increasing the efficiency of removal through the use of more limestone. The Foster Wheeler report indicated that an emission rate of 0.16 lb/MMBtu can be maintained by increasing the use of limestone. The calculations presented in Tables 4a and 4b were based on meeting the annual emissions by controlling the outlet SO_2 emission. For each year, the required emission rates to keep emissions at past actual emissions ranges from 0.165 to 0172 lb/MMBtu. This is within the emission reduction predicted in Foster Wheeler Report. Thus, the annual SO_2 emissions would be maintained with no increase above the PSD significant emission rate of 40 tons/year.
- VOC – For VOC emissions, the tests suggest an emission rate ranging from 0.0014 lb/MMBtu (1994) to 0.0047 lb/MMBtu (2001) when firing coal, with and average of 0.003 lb/MMBtu. For VOC emissions, the calculation in Tables 4a and 4b show a comparison of the reported AOR emissions using the 1994 emission rate with the average emission rate for co-firing. The increase presented is an artifact of the calculation and is not expected. Given that the combustion process is improved when co-firing petroleum coke with coal, and that petroleum coke has lower volatile matter and hydrocarbons, no increase in VOCs is expected. The annual VOC emissions would be maintained with no increase above the PSD significant emission rate of 40 tons/year.

2. **FDEP Request/Comment:** Notwithstanding Cedar Bay's reference to 40 CFR 52.21(b)(33), it does not appear that the original question posed in the Department's letter dated September 28, has been fully answered. Within that request, the Department is attempting to obtain reasonable assurance as to whether a PSD Review is required. The relevant statutes expressly contemplate that projections of the impact of a change must be made before construction. Before a permit is issued, among other things, the owner or operator of the source must, using projections of post-change emissions, demonstrate that emissions from the modified source will not violate air quality requirements.

   Specifically, section 165 states that "[n]o major emitting facility ... may be constructed unless a permit has been issued for such proposed facility" [CAA § 165, 42 U.S.C. § 7475]. Further, the owner or operator must demonstrate to the administrator's satisfaction that "emissions from construction or operation of such facility will not cause, or contribute to, air pollution in excess of" the NAAQS, among other things [CAA § 165(a)(3), 42 U.S.C. § 7475(a)(3)].

This statutory and regulatory structure has two important features relevant to this application:

(1) the permit must be obtained *before* the physical change is made, and

(2) whether a physical change requires a permit is determined in part by reference to anticipated results or consequences, which necessarily would occur *after* the physical change is made.

Thus, the only way for the owner or operator of the source to know whether a permit is required for any particular physical change is for the owner or operator to make a prediction as to whether the emissions increase will occur. This observation was described by EPA in the 1992 preamble to amendments to the NSR regulations as follows:

> Applicability of the CAA's NSR provisions must be determined in advance of construction and is pollutant specific. In cases involving existing sources, this requires a pollutant-by-pollutant projection of the emissions increases, if any, which will result from the physical or operational change. [57 Fed. Reg. 32,314, 32,316 n.8 (1992.)]

Any other construction of the statute would allow sources to make modifications or changes without a permit, while they wait to see if it would be proven that emissions would increase. Clearly Congress did not intend such an outcome, which would effectively allow avoidance of the *preconstruction* dimension of the program.

Concerning the attendant application, should the Department gain reasonable assurance that the PSD thresholds are not triggered, a permit condition (similar to the one referenced within your response) may be able to be implemented, with additional restrictions as deemed appropriate by the Department.

Additional Information: The comment is acknowledged. As requested, Cedar Bay Cogenerating Company, L.P. will demonstrate on a continuing basis for the next 5-years when co-firing that there is not a significant increase in any PSD air pollutant.

3. **FDEP Request/Comment:** According to prior data reported to FDEP by Cedar Bay, past actual SO_2 has been controlled at 90% with limestone throughputs averaging 120,000 TPY. The application has estimated past actual sulfur capture at over 93% and annual limestone throughput at 152,753 TPY. As indicated below, the Department intends to revise all related calculations.

Additional Information: Comment acknowledged. The actual usage of limestone is presented in Table 1. Table 6 presents a update of the material usage for the project based on 35 percent petroleum coke co-fired with coal. The information on the fugitive emissions calculation presented in Appendix B of the application were based on an increase using 35 percent of the coal utilization and the use of a truck dump. A truck dump is no longer planned. Petroleum coke will be received within the enclosed coal unloading building. Since this building is partially enclosed and has a water spray system for controlling fugitive dust, overall emissions will be lower than those presented in the application. The limestone usage was based on the projection of Foster Wheeler for 35 percent petroleum coke with coal. Using this approach, these fugitive emissions estimates are greater than those using the revised calculations (e.g., 22,500 lb/hr/unit compared to a calculated of 19,000 lb/hr/unit in Table 6). Figure 3 has been updated to reflect the change in the use of the coal unloading building.

4. **FDEP Request/Comment:** According to prior data reported to FDEP by Cedar Bay, past actual throughputs of bed (bottom) ash have averaged over 70,000 TPY during years 1998 through 2000. The application has provided a calculated past value of 51,325 TPY. The Department intends to revise all related calculations, and notes that the existing permit limits the throughput to 88,000 TPY.

Additional Information: Comment acknowledged. Table 6 presents an update of actual and potential bed and fly ash.

5. **FDEP Request/Comment:** Based upon a preliminary analysis by the Department, the co-firing of petcoke at 35% will necessitate an increase in limestone feed by over 100% in order to ensure that SO_2 emissions are not increased. The Department specifically requires additional information (beyond that which has been submitted) in order to ensure that annual PM_{10} emissions remain below a 15 TPY increase, while simultaneously maintaining SO_2 emissions below a 40 TPY increase. Please provide assumed collection efficiencies within submitted calculations.

Additional Information: As presented in the response to FDEP Request/Comment 1, the PM/PM_{10} emission rate will be maintained by the baghouses on each CFB boiler. This conclusion is based on the design data in the manufacturer's manual and the relatively low increase in grain loading resulting from co-firing (i.e., less than 1 grain/acf) compared to the baghouse design. In addition, the SO_2 emission rate can be maintained based on increasing the rate of limestone usage. The ability to increase the limestone usage and concomitantly increase efficiency is based on the calculations supplied herein and the manufacturer's report, which was supplied as Appendix A of the application.

Table 1. Fuel and Material Handling Information from Annual Operating reports for Cedar Bay Cogeneration Facility

Material	Source of Information	Units	Year				
			1997	1998	1999	2000	2001
Total Fuel Usage	Coal	tons/yr	970,331	972,999	962,569	954,391	920,356
Coal Sulfur Content	Coal Sulfur Content	%	0.94	1.06	1.11	1.06	0.95
Coal Ash Content	Coal Ash Content	%	11.40	12.10	11.82	10.53	11.90
Coal Heat Content	Coal Heat Content	MMBtu/ton	23.80	23.40	23.90	23.90	23.80
Coal Heat Content	Coal Heat Content	Btu/lb	11,900.00	11,700.00	11,950.00	11,950.00	11,899.93
Total Limestone Throughput	Limestone Storage Bin 1	tons/yr	85,596	85,050	82,325	74,765	--
Total Limestone Throughput	Limestone Storage Bin 2	tons/yr	42,798	41,890	40,141	35,769	--
Total Limestone Throughput	Limestone Vib Pan Conv	tons/yr	66,337	66,337	--	--	--
Total Limestone Throughput	Pulv Limestone Feeders (6)	tons/yr	--	--	122,835	110,534	110,201
Total Lime Manufactured	Abs Dryer System Train 1	tons/yr	--	--	60,874	68,823	--
Total Lime Manufactured	Abs Dryer System Train 2	tons/yr	--	--	66,135	56,660	--
Total Bed Ash Throughput	Bed Ash Hopper	tons/yr	64,997	69,400	69,153	71,235	69,550
Total Bed Ash Throughput	Bed Ash Silo (Sep+Col)	tons/yr	64,997	69,340	69,153	71,235	69,550
Total Fly Ash Throughput	Fly Ash Silo (Sep+Col) 1	tons/yr	65,982	70,452	69,153	69,140	67,504
Total Fly Ash Throughput	Fly Ash Silo (Sep+Col) 2	tons/yr	65,982	70,452	69,153	69,140	67,504
Total Fly Ash Throughput	Fly Ash Silos	tons/yr	131,964	140,904	138,306	138,280	135,008
Total Fly/Bed Ash Processed	Dry Ash Rail Car Loadout	tons/yr	196,960	210,303	209,556	209,515	204,558

Table 2. Data and Calculation for Coal Firing at Cedar Bay Cogeneration Facility

Parameter	Units	Year 1997	1998	1999	2000	2001	Basis
Operation	hours	8,052.3	8,088.3	7,978.7	7,692.7	7,482.7	AOR
Coal	tons	970,331	972,999	962,569	954,391	920,356	AOR
Coal	MMBtu	23,093,878	22,768,177	23,005,399	22,809,945	21,904,349	AOR
Ash	%	11.40	12.10	11.82	10.53	11.90	AOR
Ash	tons	110,618	117,733	113,776	100,497	109,522	Coal (tons) x Ash (%)
Limestone total	tons	128,394	126,940	122,466	110,534	110,201	AOR
Sulfur	%	0.94	1.06	1.11	1.06	0.95	AOR
SO_2 total	tons	18,242.2	20,627.6	21,369.0	20,233.1	17,486.8	Coal (tons) x Sulfur (%)/100 x 2
SO_2 emitted	tons	1,909.0	1,935.6	1,926.2	1,965.1	1,901.5	AOR
SO_2 removed	tons	16,333.2	18,692.0	19,442.8	18,268.0	15,585.3	SO_2 total - SO_2 emitted
SO_2 removed	%	89.5%	90.6%	91.0%	90.3%	89.1%	SO_2 removed/SO_2 total
Limestone required for SO_2 removal	tons	25,520.7	29,206.2	30,379.4	28,543.7	24,352.0	SO_2 removed x 100/64
Limestone excess	tons	102,873.3	97,733.8	92,086.6	81,990.2	85,849.0	Limestone total - Limestone for SO_2
$CaSO_4$ Formed	tons	34,708.1	39,720.5	41,316.0	38,819.4	33,118.7	SO_2 removed x 130/64
CO_2 emitted from SO_2 removal	tons	11,229.1	12,850.7	13,367.0	12,559.2	10,714.9	SO_2 removed x 44/64
Ash and $CaSO_4$	tons	145,325.8	157,453.3	155,091.7	139,316.8	142,641.0	Ash (tons) + $CaSO_4$ formed (tons)
Actual Total Bed and Fly Ash	tons	196,960.0	210,303.0	209,556.0	209,515.0	204,558.0	AOR
Calculated Total Bed and Fly Ash	tons	202,934.9	212,184.3	206,660.2	185,231.3	190,716.5	Ash and $CaSO_4$ + Limestone excess x 44/100
Ratio of Ash & $CaSO_4$ to Total		1.36	1.34	1.35	1.50	1.43	
Ratio of Fly Ash to Total Ash		0.67	0.67	0.66	0.66	0.66	
Fuel	lb/hr	241,006.17	240,593.20	241,285.68	248,130.08	245,995.67	tons x 2,000/hours
Limestone	lb/hr	31,889.89	31,388.42	30,698.36	28,737.47	29,454.88	tons x 2,000/hours
Fly Ash	lb/hr	32,776.59	34,841.29	34,668.95	35,951.12	36,085.47	tons x 2,000/hours
Bed Ash	lb/hr	16,143.64	17,145.68	17,334.48	18,520.24	168,472.53	tons x 2,000/hours

Table 3a. Data and Calculation for 20% Co-firing Pet Coke (5.5% S) with 80% Coal at Cedar Bay Cogeneration Facility Based on Utilization

Parameter	Units	Year 1997	1998	1999	2000	2001	Basis
Co-firing Fuel	MMBtu	23,093,877.8	22,768,176.6	23,005,399.1	22,809,944.9	21,904,349.0	Same as AOR
Co-firing Fuel	tons	938,424.6	937,378.6	931,800.1	923,883.5	890,091.6	Coal + Pet Coke (tons)
Coal (80% by weight)	tons	750,739.7	749,902.9	745,440.1	739,106.8	712,073.3	Co-firing Fuel x 0.80
Coal (80% by weight)	MMBtu	17,867,604	17,547,728	17,816,018	17,664,653	16,947,251	Coal (tons) x Coal heat content (MMBtu/ton)
Coal	**%**	**80%**	**80%**	**80%**	**80%**	**80%**	minimum
Pet Coke (20% by weight)	MMBtu	5,226,274	5,220,449	5,189,381	5,145,292	4,957,098	Pet Coke (tons) x 27.846 MMBtu/ton
Pet Coke (20% by weight)	tons	187,685	187,476	186,360	184,777	178,018	Co-firing Fuel x 0.20
Pet Coke	**%**	**20%**	**20%**	**20%**	**20%**	**20%**	maximum
Pet Coke - sulfur	%	5.45	5.45	5.45	5.45	5.45	Foster Wheeler
Pet Coke - ash	%	0.37	0.37	0.37	0.37	0.37	Foster Wheeler
Coal - ash	tons	85,584.3	90,738.2	88,111.0	77,827.9	84,736.7	Coal (tons) x Ash (%)
Pet Coke - ash	tons	694.4	693.7	689.5	683.7	658.7	Pet Coke (tons) x Ash (%)
Total Ash	tons	86,278.8	91,431.9	88,800.5	78,511.6	85,395.4	Coal ash + Pet Coke ash
SO_2 coal	tons	14,113.9	15,897.9	16,548.8	15,669.1	13,529.4	Coal (tons) x Sulfur (%)/100 x 2
SO_2 pet coke	tons	20,457.7	20,434.9	20,313.2	20,140.7	19,404.0	Pet Coke (tons) x Sulfur (%)/100 x 2
SO_2 total	tons	34,571.6	36,332.8	36,862.0	35,809.7	32,933.4	Coal SO
SO_2 emitted	tons	1,909.0	1,935.6	1,926.2	1,965.1	1,901.5	AOR
SO_2 removed	tons	32,662.6	34,397.2	34,935.8	33,844.6	31,031.9	SO_2 total - SO_2 emitted
SO_2 removed	%	94.5%	94.7%	94.8%	94.5%	94.2%	SO_2 removed/SO_2 total
$CaSO_4$ Formed	tons	69,407.9	73,094.0	74,238.6	71,919.8	65,942.8	SO_2 removed x 130/64
Ash and $CaSO_4$	tons	155,686.7	164,525.9	163,039.2	150,431.4	151,338.2	Ash (tons) + $CaSO_4$ formed (tons)
Total Bed and Fly Ash	tons	270,891.1	265,242.4	255,699.9	235,496.1	247,061.4	Ash and $CaSO_4$ + Limestone excess x 44/100
Fly Ash	tons	181,498.2	177,713.7	168,760.7	155,427.5	163,060.7	Total Bed and Fly Ash x Ratio Fly to Total Ash
Bed Ash	tons	89,393.0	87,528.7	86,939.1	80,068.6	84,000.8	Total Ash - Fly Ash
Limestone for SO_2 removal	tons	51,035.3	53,745.6	54,587.2	52,882.2	48,487.3	SO_2 removed x 100/64
Limestone Utilization		**19.9%**	**23.0%**	**24.8%**	**25.8%**	**22.1%**	
Limestone -total	**tons**	**256,757.5**	**233,596.5**	**220,052.7**	**204,783.4**	**219,421.7**	**Based on Percent utilization**
Limestone excess	tons	205,722.2	179,850.8	165,465.5	151,901.2	170,934.4	Limestone total - Limestone for SO_2
Fuel	lb/hr	233,081.4	231,785.4	233,572.9	240,198.5	237,906.5	tons x 2,000/hours
Limestone	lb/hr	63,772.2	57,761.3	55,160.3	53,241.2	58,647.7	tons x 2,000/hours
Fly Ash	lb/hr	45,079.6	43,943.2	42,303.0	40,409.3	43,583.4	tons x 2,000/hours
Bed Ash	lb/hr	22,203.0	21,643.2	21,792.9	20,816.9	22,452.0	tons x 2,000/hours
Difference in Fuel	tons	-31,906.4	-35,620.4	-30,768.9	-30,507.5	-30,264.3	Co-firing Fuel - Coal (tons)
Difference in Fuel Ash	tons	-24,339.0	-26,301.0	-24,975.1	-21,985.8	-24,127.0	Co-firing Fuel - Coal (tons)
Difference in Limestone	tons	128,363.5	106,656.5	97,586.7	94,249.5	109,220.7	Co-firing Fuel - Coal (tons)
Difference in Total Ash	tons	73,931.1	54,939.4	46,143.9	25,981.1	42,503.4	Co-firing Fuel - Coal (tons)
Difference in Fly Ash	tons	49,534.2	36,809.7	30,454.7	17,147.5	28,052.3	Co-firing Fuel - Coal (tons)
Difference in Fly Ash	tons	46,146.3	29,902.0	23,766.7	12,238.1	23,642.5	Co-firing Fuel - Coal (tons)

Bottom Ash to Total Ash	33.00%	33.00%	34.00%	34.00%	34.00%

Table 3b. Data and Calculation for 35% Co-firing Pet Coke (4% S) with 65% Coal at Cedar Bay Cogeneration Facility Based on Utilization

Parameter	Units	Year 1997	1998	1999	2000	2001	Basis
Co-firing Fuel	MMBtu	23,093,877.8	22,768,176.6	23,005,399.1	22,809,944.9	21,904,349.0	Same as AOR
Co-firing Fuel	tons	901,104.9	897,501.5	895,381.7	887,774.5	854,693.3	Coal + Pet Coke (tons)
Coal (65% by weight)	tons	585,718.2	583,376.0	581,998.1	577,053.4	555,550.7	Co-firing Fuel x 0.65
Coal (65% by weight)	MMBtu	13,940,093	13,650,998	13,909,754	13,791,577	13,222,032	Coal (tons) x Coal heat content (MMBtu/ton)
Coal	**%**	**65%**	**65%**	**65%**	**65%**	**65%**	**minimum**
Pet Coke (35% by weight)	MMBtu	9,153,784	9,117,179	9,095,645	9,018,368	8,682,317	Pet Coke (tons) x 27.846 MMBtu/ton
Pet Coke (35% by weight)	tons	315,387	314,126	313,384	310,721	299,143	Co-firing Fuel x 0.35
Pet Coke	**%**	**35%**	**35%**	**35%**	**35%**	**35%**	**maximum**
Pet Coke - sulfur	%	4.09	4.09	4.09	4.09	4.09	Foster Wheeler
Pet Coke - ash	%	0.6	0.6	0.6	0.6	0.6	Foster Wheeler
Coal - ash	tons	66,771.9	70,588.5	68,792.2	60,763.7	66,110.5	Coal (tons) x Ash (%)
Pet Coke - ash	tons	1,892.3	1,884.8	1,880.3	1,864.3	1,794.9	Pet Coke (tons) x Ash (%)
Total Ash	tons	68,664.2	72,473.2	70,672.5	62,628.1	67,905.4	Coal ash + Pet Coke ash
SO_2 coal	tons	11,011.5	12,367.6	12,920.4	12,233.5	10,555.5	Coal (tons) x Sulfur (%)/100 x 2
SO_2 pet coke	tons	25,798.6	25,695.5	25,634.8	25,417.0	24,469.9	Pet Coke (tons) x Sulfur (%)/100 x 2
SO_2 total	tons	36,810.1	38,063.0	38,555.1	37,650.5	35,025.3	Coal SO
SO_2 emitted	tons	1,909.0	1,935.6	1,926.2	1,965.1	1,901.5	AOR
SO_2 removed	tons	34,901.1	36,127.4	36,628.9	35,685.4	33,123.8	SO_2 total - SO_2 emitted
SO_2 removed	%	94.8%	94.9%	95.0%	94.8%	94.6%	SO_2 removed/SO_2 total
$CaSO_4$ Formed	tons	74,164.9	76,770.8	77,836.5	75,831.4	70,388.1	SO_2 removed x 130/64
Ash and $CaSO_4$	tons	142,829.1	149,244.1	148,509.0	138,459.5	138,293.5	Ash (tons) + $CaSO_4$ formed (tons)
Total Bed and Fly Ash	tons	265,929.3	255,026.7	245,660.4	228,150.8	240,469.8	Ash and $CaSO_4$ + Limestone excess x 44/100
Fly Ash	tons	178,173.7	170,869.1	162,134.7	150,579.6	158,710.2	Total Bed and Fly Ash x Ratio Fly to Total Ash
Bed Ash	tons	87,755.6	84,157.6	83,525.6	77,571.2	81,759.6	Total Ash - Fly Ash
Limestone for SO_2 removal	tons	54,533.0	56,449.1	57,232.7	55,758.4	51,756.0	SO_2 removed x 100/64
Limestone Utilization		**19.9%**	**23.0%**	**24.8%**	**25.8%**	**22.1%**	
Limestone -total	**tons**	**274,354.7**	**245,346.8**	**230,717.3**	**215,921.5**	**234,213.5**	**Based on Percent utilization**
Limestone excess	tons	219,821.7	188,897.7	173,484.6	160,163.1	182,457.6	Limestone Total - Limestone for SO_2 removal
Fuel	lb/hr	223,812.1	221,924.9	224,443.9	230,810.6	228,445.2	tons x 2,000/hours
Limestone	lb/hr	68,142.9	60,666.8	57,833.6	56,137.0	62,601.3	tons x 2,000/hours
Fly Ash	lb/hr	44,253.9	42,250.8	40,642.1	39,148.9	42,420.6	tons x 2,000/hours
Bed Ash	lb/hr	21,796.3	20,809.6	20,937.2	20,167.6	21,853.0	tons x 2,000/hours
Difference in Fuel	tons	-69,226.1	-75,497.5	-67,187.3	-66,616.5	-65,662.6	Co-firing Fuel - Coal (tons)
Difference in Fuel Ash	tons	-41,953.5	-45,259.6	-43,103.2	-37,869.3	-41,617.0	Co-firing Fuel - Coal (tons)
Difference in Limestone	tons	145,960.7	118,406.8	108,251.3	105,387.6	124,012.5	Co-firing Fuel - Coal (tons)
Difference in Total Ash	tons	68,969.3	44,723.7	36,104.4	18,635.8	35,911.8	Co-firing Fuel - Coal (tons)
Difference in Fly Ash	tons	46,209.7	29,965.1	23,828.7	12,299.6	23,701.8	Co-firing Fuel - Coal (tons)
Difference in Fly Ash	tons	46,562.2	30,458.3	24,280.9	12,634.0	24,060.5	Co-firing Fuel - Coal (tons)

Bottom Ash to Total Ash		33.00%	33.00%	34.00%	34.00%	34.00%

Table 4a. Data and Calculation for Co-firing 20% Pet Coke (5.5%S) with Coal at Cedar Bay Cogeneration Facility

Parameter	Units	Year					Basis
		1997	1998	1999	2000	2001	
CO emission rate with co-firing	lb/MMBtu	0.04	0.04	0.04	0.04	0.04	Foster Wheeler Report
CO emissions when co-firing	tons/year	461.9	455.4	460.1	456.2	438.1	MMBtu x lb/MMBtu (assumes same heat input)
CO emissions with coal	tons/year	496	549.6	582.26	516.01	485.1	AOR
Net CO Emissions	tons/year	-34.1	-94.2	-122.2	-59.8	-47.0	Cofiring - Actual Coal
NO_x emission rate with co-firing	lb/MMBtu	0.15	0.15	0.15	0.15	0.15	Foster Wheeler Report
NO_x emissions with co-firing	tons/year	1,732.0	1,707.6	1,725.4	1,710.7	1,642.8	MMBtu x lb/MMBtu (assumes same heat input)
NO_x emissions with coal	tons/year	1,726.0	1,716.4	1,741.5	1,779.0	1,656.9	AOR
Net NO_x emissions	tons/year	6.0	-8.8	-16.1	-68.3	-14.1	Cofiring - Actual Coal
PM_{10} emission rate with co-firing	lb/MMBtu	0.0129	0.0160	0.0150	0.0147	0.0157	average of actual test data
PM_{10} emissions with co-firing	tons/year	149.3	182.5	172.5	167.3	171.6	MMBtu x lb/MMBtu (assumes same heat input)
PM_{10} emissions with coal	tons/year	149.5	178.3	193.7	165.2	201.9	AOR
Net PM_{10} emissions	tons/year	-0.16	4.22	-21.20	2.05	-30.32	Cofiring - Actual Coal
SAM emission rate with co-firing	lb/MMBtu	5.69E-05	5.28E-05	5.18E-05	5.31E-05	5.65E-05	Test data increased for increased sulfur in fuel
SAM emissions with co-firing	tons/year	0.66	0.60	0.60	0.61	0.62	MMBtu x lb/MMBtu (assumes same heat input)
SAM emissions with coal	tons/year	0.35	0.35	0.35904	0.34617	0.3	AOR
Net SAM emissions	tons/year	0.31	0.25	0.24	0.26	0.32	Cofiring - Actual Coal
SO_2 emission rate with co-firing	lb/MMBtu	0.165	0.17	0.167	0.172	0.172	rate adjusted to meet past actuals
SO_2 emissions with co-firing	tons/year	1,905.2	1,935.3	1,921.0	1,961.7	1,883.8	MMBtu x lb/MMBtu (assumes same heat input)
SO_2 emissions with coal	tons/year	1909	1935.6	1926.19	1965.13	1901.5	AOR
Net SO_2 emissions	tons/year	-3.8	-0.3	-5.2	-3.5	-17.7	Cofiring - Actual Coal
VOC emission rate with co-firing	lb/MMBtu	0.0030	0.0030	0.0030	0.0030	0.0030	Test data from 1994 and 2001
VOC emissions when co-firing	tons/year	35.0	34.5	34.8	34.5	33.2	MMBtu x lb/MMBtu (assumes same heat input)
VOC emissions with coal	tons/year	14.8	14.7	17.89104	17.250215	48.7	AOR
Net VOC Emissions	tons/year	20.2	19.8	16.9	17.3	-15.5	Cofiring - Actual Coal

Table 4b. Data and Calculation for Co-firing 35% Pet Coke (4.1%S) with Coal at Cedar Bay Cogeneration Facility

Parameter	Units	Year 1997	1998	1999	2000	2001	Basis
CO emission rate with co-firing	lb/MMBtu	0.035	0.035	0.035	0.035	0.035	Foster Wheeler Report
CO emissions when co-firing	tons/year	404.1	398.4	402.6	399.2	383.3	MMBtu x lb/MMBtu (assumes same heat input)
CO emissions with coal	tons/year	496	549.6	582.26	516.01	485.1	AOR
Net CO Emissions	tons/year	-91.9	-151.2	-179.7	-116.8	-101.8	Cofiring - Actual Coal
NO_x emission rate with co-firing	lb/MMBtu	0.15	0.15	0.15	0.15	0.15	Foster Wheeler Report
NO_x emissions with co-firing	tons/year	1,732.0	1,707.6	1,725.4	1,710.7	1,642.8	MMBtu x lb/MMBtu (assumes same heat input)
NO_x emissions with coal	tons/year	1,726.0	1,716.4	1,741.5	1,779.0	1,656.9	AOR
Net NO_x emissions	tons/year	6.0	-8.8	-16.1	-68.3	-14.1	Cofiring - Actual Coal
PM_{10} emission rate with co-firing	lb/MMBtu	0.0129	0.0160	0.0150	0.0147	0.0157	average of actual test data
PM_{10} emissions with co-firing	tons/year	149.3	182.5	172.5	167.3	171.6	MMBtu x lb/MMBtu (assumes same heat input)
PM_{10} emissions with coal	tons/year	149.5	178.3	193.7	165.2	201.9	AOR
Net PM_{10} emissions	tons/year	-0.16	4.22	-21.20	2.05	-30.32	Cofiring - Actual Coal
SAM emission rate with co-firing	lb/MMBtu	6.05E-05	5.54E-05	5.41E-05	5.58E-05	6.01E-05	Test data increased for increased sulfur in fuel
SAM emissions with co-firing	tons/year	0.70	0.63	0.62	0.64	0.66	MMBtu x lb/MMBtu (assumes same heat input)
SAM emissions with coal	tons/year	0.35	0.35	0.35904	0.34617	0.3	AOR
Net SAM emissions	tons/year	0.35	0.28	0.26	0.29	0.36	Cofiring - Actual Coal
SO_2 emission rate with co-firing	lb/MMBtu	0.165	0.17	0.167	0.172	0.172	rate adjusted to meet past actuals
SO_2 emissions with co-firing	tons/year	1,905.2	1,935.3	1,921.0	1,961.7	1,883.8	MMBtu x lb/MMBtu (assumes same heat input)
SO_2 emissions with coal	tons/year	1909	1935.6	1926.19	1965.13	1901.5	AOR
Net SO_2 emissions	tons/year	-3.8	-0.3	-5.2	-3.5	-17.7	Cofiring - Actual Coal
VOC emission rate with co-firing	lb/MMBtu	0.0030	0.0030	0.0030	0.0030	0.0030	Test data from 1994 and 2001
VOC emissions when co-firing	tons/year	35.0	34.5	34.8	34.5	33.2	MMBtu x lb/MMBtu (assumes same heat input)
VOC emissions with coal	tons/year	14.8	14.7	17.89104	17.250215	48.7	AOR
Net VOC Emissions	tons/year	20.2	19.8	16.9	17.3	-15.5	Cofiring - Actual Coal

Table 5a. Data and Calculation for Inlet Loading to Baghouses when Co-firing 20% Pet Coke (5.5%S) with Coal at Cedar Bay Cogeneration Facility

Parameter	Units	Year 1997	1998	1999	2000	2001	Basis
Fly Ash - Coal Firing	lb/hr/facility	32,776.59	34,841.29	34,668.95	35,951.12	36,085.47	Table 2, based on actual fly ash
Fly Ash - Coal Firing	lb/hr/unit	10,925.53	11,613.76	11,556.32	11,983.71	12,028.49	divided by 3 CFBs
PM Emission Rate with coal	grains/acfm	4.28	4.55	4.53	4.70	4.71	lb/hr x 7,000 grains/lb x 1/acfm x 1/60
Fly Ash - Co-Firing	lb/hr/facility	45,079.64	43,943.21	42,302.99	40,409.27	43,583.38	Table 2, based on actual fly ash
Fly Ash - Co-Firing	lb/hr/unit	15,026.55	14,647.74	14,101.00	13,469.76	14,527.79	divided by 3 CFBs
PM Emission Rate with coal	grains/acfm	5.89	5.74	5.53	5.28	5.69	lb/hr x 7,000 grains/lb x 1/acfm x 1/60
PM Emission Rate Increase	grains/acfm	1.61	1.19	1.00	0.58	0.98	Co-firing - Coal (grains/acf)
Maximum Projected	lb/hr/unit	17,000.00					Foster Wheeler Report (Figure 12)
Maximum Projected	grains/acfm	6.66					lb/hr x 7,000 grains/lb x 1/acfm x 1/60
Flow Rate of Unit	acfm	297,700					

Table 5b. Data and Calculation for Inlet Loading to Baghouses when Co-firing 20% Pet Coke (5.5%S) with Coal at Cedar Bay Cogeneration Facility

Parameter	Units	Year 1997	1998	1999	2000	2001	Basis
Fly Ash - Coal Firing	lb/hr/facility	32,776.59	34,841.29	34,668.95	35,951.12	36,085.47	Table 2, based on actual fly ash
Fly Ash - Coal Firing	lb/hr/unit	10,925.53	11,613.76	11,556.32	11,983.71	12,028.49	divided by 3 CFBs
PM Emission Rate with coal	grains/acfm	4.28	4.55	4.53	4.70	4.71	lb/hr x 7,000 grains/lb x 1/acfm x 1/60
Fly Ash - Co-Firing	lb/hr/facility	44,253.93	42,250.76	40,642.06	39,148.88	42,420.56	Table 2, based on actual fly ash
Fly Ash - Co-Firing	lb/hr/unit	14,751.31	14,083.59	13,547.35	13,049.63	14,140.19	divided by 3 CFBs
PM Emission Rate with coal	grains/acfm	5.78	5.52	5.31	5.11	5.54	lb/hr x 7,000 grains/lb x 1/acfm x 1/60
PM Emission Rate Increase	grains/acfm	1.50	0.97	0.78	0.42	0.83	Co-firing - Coal (grains/acf)
Maximum Projected	lb/hr/unit	17,000.00					Foster Wheeler Report (Figure 12)
Maximum Projected	grains/acfm	6.66					lb/hr x 7,000 grains/lb x 1/acfm x 1/60
Flow Rate of Unit	acfm	297,700					

Table 6. Material Usage of Coal, Limestone, Bottom Ash and Fly Ash for Co-firing 35% Petroleum Coke with Coal at Cedar Bay Cogeneration Facility

	Units	1999-2000 Coal	1999-2000 Co-Firing	1999-2000 Difference	Co-Firing[d]	Permit Limits	Title V Permit Condition
Fuel	lb/hr/unit[a]	81,569	75,876	-5,694	78,000	104,000	Section III. A.3.
	lb/hr/plant[b]	244,708	227,627	-17,081	234,000	312,000	Section III. A.3.
	tons/month[c]	88,095	81,946	-6,149	84,240	117,000	Section III. A.3.
	tons/year[b]	958,480	891,579	-66,902	953,176	1,170,000	Section III. A.3.
Limestone	lb/hr/unit[a]	9,906	18,995	9,089	22,500	NA	
	lb/hr/plant[b]	29,718	56,985	27,267	67,500	NA	
	tons/month[c]	10,698	20,515	9,816	24,300	27,000	Section III. B.1.
	tons/year[b]	116,685	223,320	106,635	274,955	320,000	Section III. B.1.
Fly Ash	lb/hr/unit[a]	11,770	13,299	1,529	15,500	NA	
	lb/hr/plant[b]	35,310	39,896	4,586	46,500	NA	
	tons/month[c]	12,712	14,362	1,651	16,740	28,000	Section III. B.1.
	tons/year[b]	138,293	156,358	18,065	189,413	336,000	Section III. B.1.
Bottom Ash	lb/hr/unit[a]	5,976	6,851	875	7,000	NA	
	lb/hr/plant[b]	17,927	20,552	2,624	21,000	NA	
	tons/month[c]	6,454	7,399	945	7,560	8,000	Section III. B.1.
	tons/year[b]	70,194	80,549	10,355	85,541	88,000	Section III. B.1.

Footnotes: [a] average for three CFB units.
[b] Coal from Table 2 and Co-firing from Table 3.
[c] based on 24 hour/day and 30 days/month per permit condition.
[d] based on Foster Wheeler Report for a single CFB unit co-firing 35 percent petroleum coke.

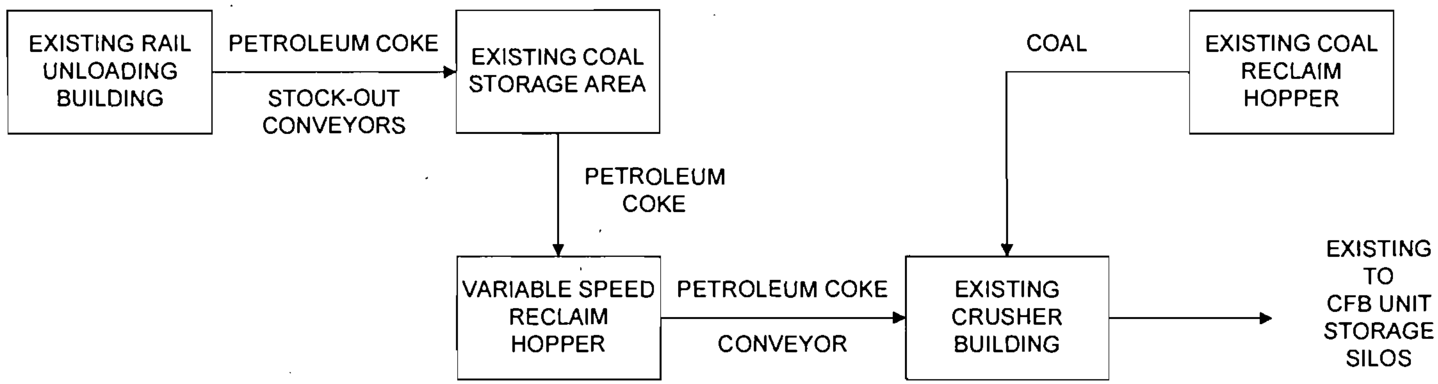


Figure 3
Process Flow Diagram for Petroleum Coke Unloading
Cedar Bay Cogeneration Facility
Jacksonville, Florida

Process Flow Legend:
Solid / Liquid
Gas
Steam

Golder Associates

3.0 EQUIPMENT DESCRIPTION/INSTALLATION

3.1 DESIGN CONDITIONS

3.1.1 Unit Operating Conditions

The Flakt baghouses are for a circulating fluidized bed (CFB) boiler cogeneration plant.

3.1.2 Induced Draft Fans

Owner furnished induced draft fans will be used by the owner to maintain the baghouse at below atmospheric pressure. Discharge from these fans will be into the Owner's stack.

3.1.3 Flue Gas Condition

1. Inlet dust load to collector system - 19.5 grains/ACF (including flyash re-injection).
2. Flue gas volume - 297,700 ACFM at 265°F per baghouse and -15" W.G.
3. Maximum flue gas temperature at baghouse inlet - 450°F.
4. Normal flue gas operating temperature - 265°F.
5. Raw material analysis - see Figure 1.

3.2 BAGHOUSE DESIGN DESCRIPTION

3.2.1 Basic Design:

Number of baghouses	3
Number of compartments/baghouse	8
Number of bags per compartment	264
Total number of bags/baghouse	2,112
Bag diameter, inches	12"
Bag length, ft-in.	33'-0" O.A.
Bag area, sq. ft.	99.01
Total area sq. ft./compartment	26,139
Total area sq. ft. for baghouse	209,112
Reverse air volume, ACFM	54,742

FIGURE 1

CEDAR BAY FUELS

COAL DATA PROXIMATE ANALYSIS	PERFORMANCE	RANGE/MAXIMUMS
MOISTURE, %		5.0 - 10.0
ASH, %		6.0 - 14.0
VOLATILE, %		33.0 - 37.0
FIXED CARBON, %		47.0 - 53.0
HEATING VALUE, BTU/LB	12,200	11,500 - 12,600
SULFUR, %		0.6 - 1.7

ULTIMATE ANALYSIS	PERFORMANCE	RANGE/MAXIMUMS
MOISTURE, %	7.51	5.0 - 9.0
CARBON, %	68.5	68.0 - 76.0
HYDROGEN, %	4.35	4.2 - 5.2
NITROGEN, %	1.14	1.0 - 1.7
CHLORINE, %	0.08	0.01 - 0.1
SULFUR, %	1.20	0.6 - 1.7
ASH, %	11.31	6.0 - 12.0
OXYGEN, %	5.91	3.5 - 7.0

MINERAL ANALYSIS OF ASH, %	PERFORMANCE	RANGE/MAXIMUMS
PHOSPHATE PENTOXIDE (P_2O_5		0.05 - 0.15
SILICA (SiO_2)		50.0 - 60.0
FERRIC OXIDE (Fe_2O_3)		3.5 - 7.5
ALUMINA (Al_2O_3)		25.0 - 32.0
TITANIA (TiO_2)		0.75 - 1.2
LIME (CaO)		1.5 - 3.0
MAGNESIA (MgO)		0.5 - 0.8
SULFUR TRIOXIDE (SO_3)		1.5 - 3.0
POTASSIUM OXIDE (K_2O) AND SODIUM OXIDE (Na_2O)		5.0 MAX COMBINED

CB SECONDARY FUEL

In addition to other fuels the steam generators will burn bark at a rate of up to 10 percent of the total heat input of the steam generators.

Typical bark analysis is as follows.

FUEL ANALYSIS	TYPICAL
Btu/lb (Dry Basis)	6,971
Carbon (Dry Basis)	50.11%
Hydrogen (Dry Basis)	6.08%
Nitrogen (Dry Basis)	0.26%
Sulfur (Dry Basis)	0.012%
Chloride (Dry Basis)	0.061%
Oxygen	41.67%
Ash (Dry Basis)	1.804%
Moisture (As required)	34.89%

CEDAR BAY LIMESTONE	PERFORMANCE	RANGE/MAXIMUMS
$CaCO_3$		90%
$MgCO_3$		3.0%
MOISTURE		1.0%

CEDAR BAY SUPPLEMENTAL FUEL

NO. 2 COMMERCIAL GRADE FUEL OIL IN ACCORDANCE WITH ASTM D396 OR SIMILAR FUEL.

FLYASH RE-INJECTION

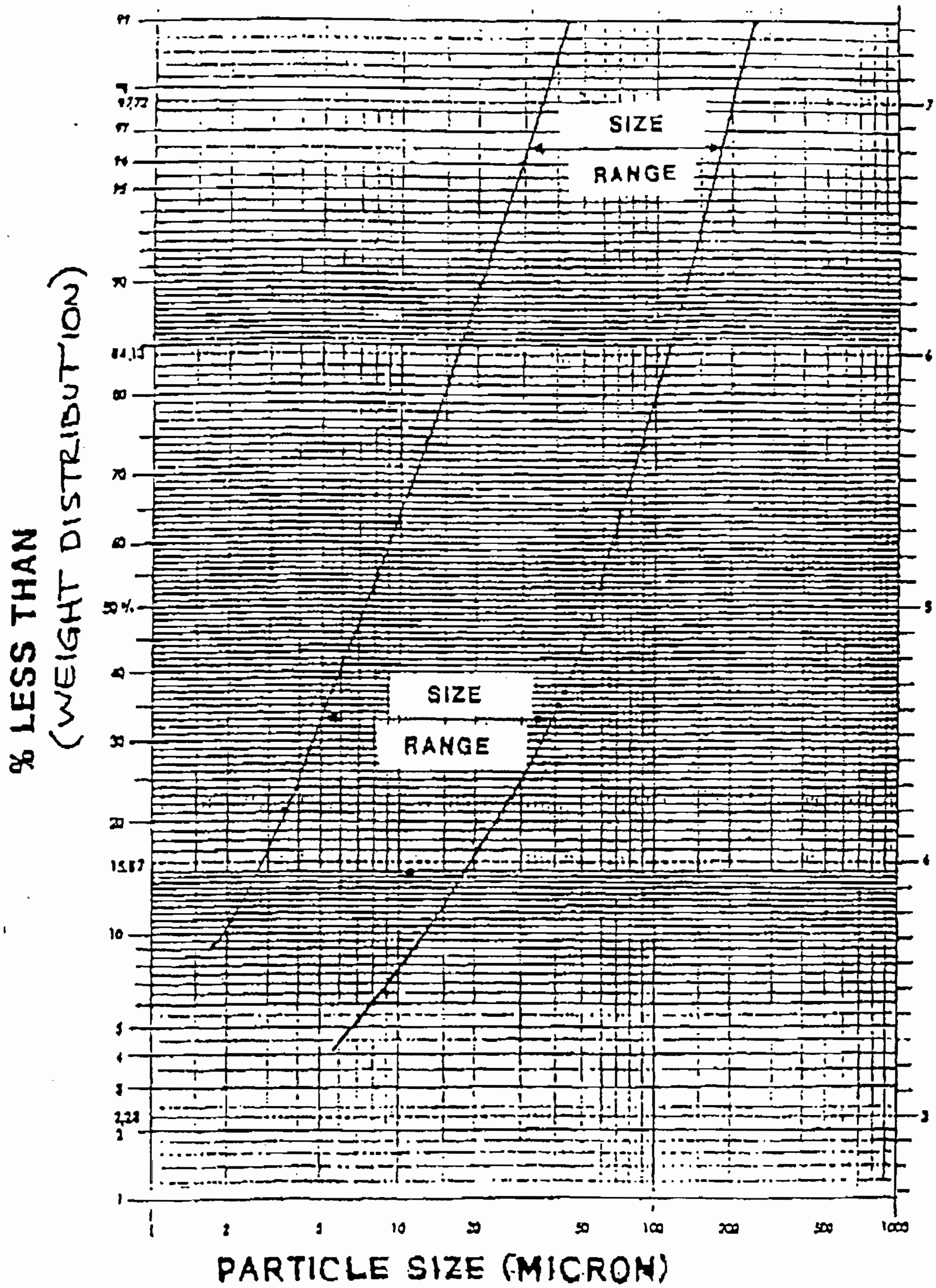
THE FLYASH RE-INJECTION SYSTEMS WILL BE PLACED IN SERVICE OR REMOVED FROM SERVICE AT THE OWNER'S DISCRETION AND BASED ON THE AVAILABILITY OF FLYASH FOR RE-INJECTION. THE UNITS MAY BE OPERATED FOR EXTENDED PERIODS OF TIME WITH OR WITHOUT FLYASH RE-INJECTION. AN ASH PARTICLE SIZE DISTRIBUTION CURVE IS ATTACHED. THIS CURVE IS REPRESENTATIVE OF OPERATION WITHOUT ASH RE-INJECTION. SMALLER PARTICLES MAY RESULT WHEN RE-INJECTION IS EMPLOYED.

ASH COMPOSITION (Estimated -- will vary depending on operations and fuel)

	LOW S COAL	HIGH S COAL
CaO %	15-24	21-30
CaSO4 %	10-17	22-31
Lmstn Inert %	2-7	3-5
Coal Ash %	44-65	28-48
Unburnt Fuel %	6-11	5-7

ABB ASEA BROWN BOVERI Environmental Systems Division	AES - CEDAR BAY EMISSION CONTROL SYSTEM OPERATIONS AND MAINTENANCE MANUAL EQUIPMENT DESCRIPTION/INSTALLATION	PROJECT NO. 326 JANUARY 10, 1992 SECTION 3 PAGE: 3 - 5 REV: 0

FLYASH PARTICLE SIZE RANGE (BAGHOUSE INLET)



3.2.2 Air-to-Cloth Ratios

Gross air-to-cloth ratio	1.4:1
Net air-to-cloth ratio, one compartment out for cleaning and one compartment out for maintenance.	2.2:1

3.2.3 Filter Fabric Bag Construction

Material	Woven fiberglass w/teflon finish.
Diameter	12 inches
Bag length	33.0 feet
Weight (oz/sq.yd.)	10.3 oz.
Weave	3 X 1 twill
Permeability, CFM/sq. ft.	1/2" W.G., 35-60 CFM sq. ft.
Top suspension method -----	"J" Hook, compression spring and cap. Compression band sewn into top of bag for retainment over cap.
Bottom Attachment ---------	Filter bag slip over thimble and is secured with stainless steel clamp.
Filter Tube Rings ---------	3/16" dia. cadmium plated steel are sewn into bag so that the bag does not collapse upon itself during reverse air cleaning, eight (8) rings per bag.
Installation, Tension and Adjustment -----------	Tension is shown by deflection of spring. 75# tension is initial setting. (See Drawing No. 325-11-00-E-01, Section 10).

3.3 INSTALLATION

3.3.1 Preliminary Inspection

3.3.1.1 Before installing or storing this equipment, inspect all items for shipping damage. Check the delivery list to determine that all parts are accounted for.

CAUTION: OBSERVE ALL APPLICABLE NATIONAL AND LOCAL CODES WHEN PERFORMING ELECTRICAL INSTALLATION.

3.3.1.2 Installation of Fabric Filter System must conform to the arrangement drawings (Section 10) and the instructions supplied with system components in Section 11.

3.3.2 Storage Requirements

3.3.2.1 In the event this Fabric Filter System or its components are not installed immediately, attention must be directed to proper methods of storage. The table below lists shelf life requirements under specific conditions for Flakt supplied equipment.

EQUIPMENT	0 - 6 MONTHS	7 - 18 MONTHS	19 - 36 MONTHS
ELECTRICAL COMPONENTS, CONTROL EQUIPMENT	3	4	4
GATES, MECHANICAL ASSEMBLY, MACHINE CASTINGS	2	3	4
CLOSED CRATES AND BOXES	2	3	
STRUCTURAL STEEL	1	1	3
BAGS (IN CARTONS)	5	5	

CODE:
1 - UNPROTECTED OUTDOOR STORAGE
2 - PROTECTED OUTDOOR STORAGE (ELEVATED AND COVERED)
3 - UNHEATED INDOOR STORAGE
4 - HEATED INDOOR STORAGE
5 - HEATED INDOOR STORAGE FOR NOT MORE THAN 12 MONTHS

3.3.1.1.1 Always store components and equipment in an upright position.

NOTE: INDOOR STORAGE IS PREFERABLE

3.3.1.1.2 Remove all fan belts and store in a heated enclosed area.

3.3.1.1.3 Rotate fans and motors once a month.

3.3.1.1.4 Filter bags are shipped in cartons. DO NOT remove filter bags from their protective carton until ready to install.

CAUTION: DO NOT STACK PALLETS OF BAG CARTONS.

3.3.3 Filter Bags

CAUTION: SHARP CREASES IN A BAG ARE POTENTIAL LEAKS. DO NOT STEP ON BAGS OR DRAPE THEM OVER STEEL MEMBERS OR PLANKS. DO NOT REMOVE BAGS FROM THEIR PROTECTIVE CARTONS UNTIL READY TO HANG.

3.3.3.1 Transport bags in protective cartons to bag tube sheet elevation of compartment.

3.3.3.2 Installation should proceed from the far corners os each compartment. Maintenance crews must avoid standing on bags during installing.

3.3.3.3 Apply a great deal of caution in handling of bags to ensure long life.

3.3.3.4 Remove bag carefully from cartons.

3.3.3.5 When removing bag, visually inspect for holes, heavy creases, abrasion damages, etc. Do not install the bag in less than perfect condition!

3.3.3.6 Attach hoisting line from bag cap and raise per Step 2, Drawing 326-11-00-E-01.

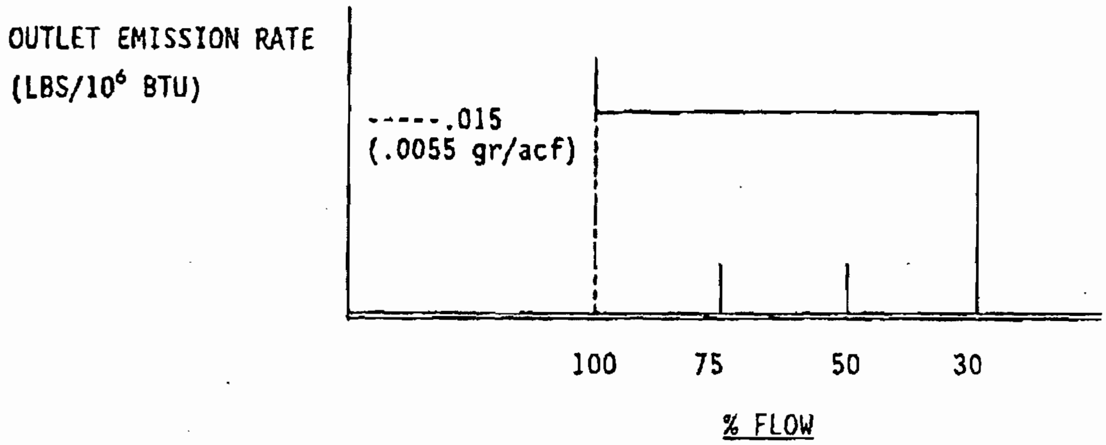
3.3.3.7 After raising bag, attach to bag support steel per Step 3, Drawing 326-11-00-E-01.

CAUTION: THE BAG SEAM MUST ALWAYS BE FACING THE CENTER AISLE OF THE COMPARTMENT (SEE DRAWING 326-11-00-E-01 FOR CORRECT ORIENTATION). DO NOT POSITION CLAMP SCREW HOLDER DIRECTLY OVER BAG SEAM. PERMANENT BAG DAMAGE MAY RESULT IF THE CLAMP SCREW HOLDER IS INSTALLED ON THE BAG SEAM.

3.3.3.8 Adjust bag to remove any noticeable slack.

3.4 PERFORMANCE CURVES

OUTLET EMISSION RATE VS. FLUE GAS FLOW RATE



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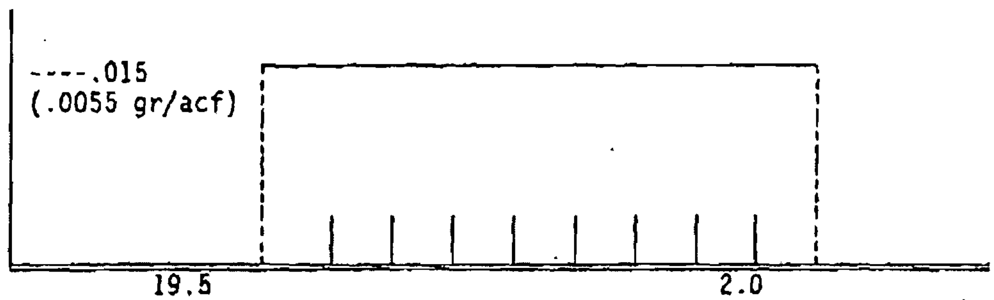
PERFORMANCE CURVE

OUTLET EMISSION RATE VS. INLET PARTICULATE LOAD



PARTICULATE LOAD (GRAINS/ACF)

TECHNICAL EVALUATION

AND

PRELIMINARY DETERMINATION

Cedar Bay Generating Company, LP

Co-Firing of Petroleum Coke

U.S. Generating Company / Cedar Bay Cogeneration Facility

Duval County

0310337-005-AC

Department of Environmental Protection
Division of Air Resources Management
Bureau of Air Regulation
New Source Review Section

July 12, 2002

Mike, I thought it read much better. 7-2-02

Only a few comments, which I highlighted for you.

Jeff

TECHNICAL EVALUATION AND PRELIMINARY DETERMINATION

1. GENERAL INFORMATION

1.1 APPLICANT NAME AND ADDRESS

Cedar Bay Generating Company, L.P.
Cedar Bay Cogeneration Facility
9640 Eastport Road
Jacksonville, Florida 32218

Authorized Representative: Bruce Smith, General Manager

1.2 REVIEWING AND PROCESS SCHEDULE

August 29, 2001	Received permit application and fee
September 28, 2001	Request For Additional Information
April 2, 2002	Second Request For Additional Information
July 2, 2002	Application complete

2. FACILITY INFORMATION

2.1 FACILITY LOCATION

The facility is located in Jacksonville, Duval County. The UTM coordinates are Zone 17; 441.61 km E; 3365.552 km N. This site is approximately 54 kilometers from the Okefenokee National Wildlife Refuge and 98 kilometers from the Wolf Island National Wildlife Refuge, both Class I PSD Areas.

2.2 STANDARD INDUSTRIAL CLASSIFICATION CODES (SIC)

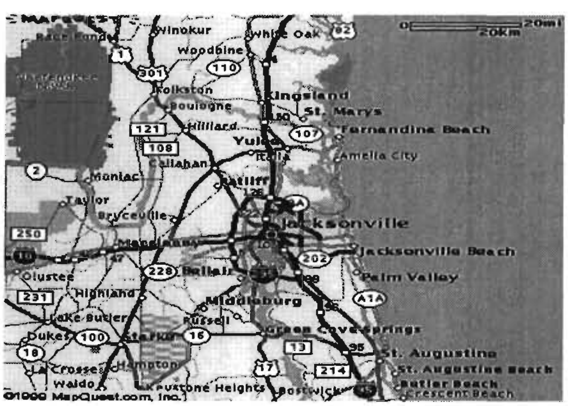
Industry Group No.	49	Electric, Gas and Sanitary Services
Industry No.	4911	Electric Services

2.3 FACILITY CATEGORY

This facility consists of three circulating fluidized bed (CFB) steam generators (boilers) designated as Boilers A, B, and C, a coal handling area, a limestone handling area, and an ash handling area. Crushed coal is the primary fuel for Boilers A, B and C. The fuel for Boilers B and C can also be supplemented with short fiber recycle rejects received from Stone Container Corporation. No. 2 fuel oil is used as supplemental fuel in all three boilers normally only for start-ups.

This facility is classified as a Major or Title V Source of air pollution because emissions of at least one regulated air pollutant, such as particulate matter (PM/PM_{10}), sulfur dioxide (SO_2), nitrogen oxides (NO_X), carbon monoxide (CO) or volatile organic compounds (VOC) exceeds 100 tons per year (TPY).

This facility is within an industry included in the list of the 28 Major Facility Categories per Table 62-212.400-1, F.A.C. Because emissions are greater than 100 TPY for at least one criteria pollutant, the facility is also a Major Facility with respect to Rule 62-212.400, Prevention of Significant Deterioration (PSD). Based upon the Title V permit, this facility is a major source of hazardous air pollutants (HAPs). See Figures 1 and 2 below.



3. PROJECT DESCRIPTION

This project primarily addresses the following emissions unit(s):

Emissions Unit No.	Emissions Unit Description
001	Pyroflow® Circulating Fluidized Bed (CFB) dry bottom boiler designated as "CFB Boiler A"
002	Pyroflow® Circulating Fluidized Bed (CFB) dry bottom boiler designated as "CFB Boiler B"
003	Pyroflow® Circulating Fluidized Bed (CFB) dry bottom boiler designated as "CFB Boiler C"

The applicant proposes to combust up to 35% of its fuel (on a weight basis) as petroleum coke (petcoke). The facility currently combusts coal as its primary fuel. The applicant indicates that this permit modification can be made in such a way that air emissions will not increase beyond historical levels, thus a PSD Review will not be triggered. The applicant further proposes to maintain and submit to the Department (FDEP) and the Regulatory and Environmental Services Department of Jacksonville (RESD) on an annual basis for a period of 5-years from the date each emission unit begins firing petroleum coke, data demonstrating in accordance with 40 CFR 52.21(b)(21)(v) and 40 CFR 52.21(b)(33) that the operational change associated with the use of petroleum coke did not result in significant emission increases for CO, NO_X, PM, SO_2 and SAM. A general review of petcoke, CFB Boilers, a review of the future actual emissions and related emission analyses follow.

and VOC

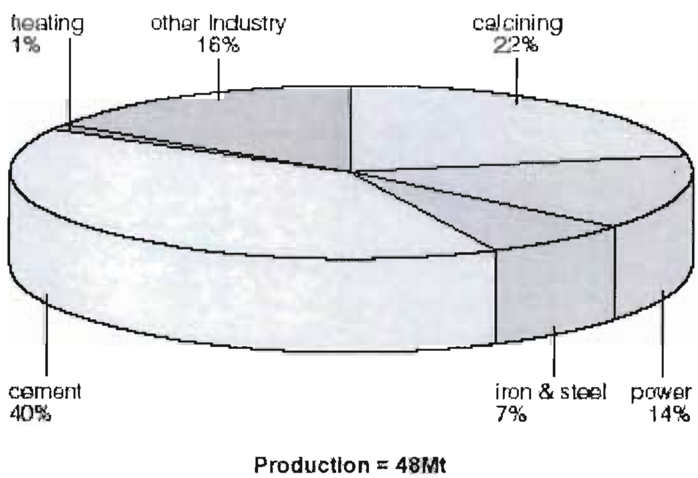
3.1 PETCOKE DISCUSSION

Much of this review was obtained from The Clean Coal Centre of the United Kingdom, in an article entitled "*The use of petroleum coke in a coal-fired plant*". Petroleum coke is a by-product from oil refineries and is composed mainly of carbon though it also contains high levels of sulfur and some heavy metals such as vanadium and nickel. There has been considerable interest in petcoke for several years, where it is available, as it is generally significantly cheaper than coal. The price does vary depending on the volumes produced and worldwide demand. The world production of petcoke grew by 50% from 1987 to 1998. It reached nearly 50 Mt in 1999 and is expected to reach 100 Mt by 2010. The USA is the world's largest producer, producing three-quarters of world supplies. There are three types of petroleum coke, which can be produced depending on the process of production. The three processes are delayed, fluid and flexicoking with delayed coking producing over 90%. All three types of petcoke have higher calorific values than coal and contain less volatile matter and ash. The main uses of petcoke are as an energy source for power generation, in cement production and iron and steel production (which account for about two thirds of production) and the remainder is used mainly as a carbon source.

Million years

Million tons

FIGURE 3 - 1999 WORLD PETROLEUM COKE MARKET PROFILE



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The following additional information was compiled for the Year 2000. The source of this data is FERC Form 423, although the EIA summarized it in a report entitled "*Cost and Quality of Fuels for Electric Utility Plants 2000 Tables*", dated August 2001. This data was accumulated for electric generating plants with nameplate capacity of 50 megawatts or more. Tables 25 and 28 from that report are shown below:

Table 25. The Top 20 Electric Utilities, Ranked by Receipts of Coal, 2000

Electric Utility	Receipts (thousand short tons)	Average Delivered Cost		Total Coal Bill (million dollars)
		(cents per million Btu)	(dollars per short ton)	
1. Tennessee Valley Authority	41,992	110.2	25.44	1,068.1
2. Georgia Power Co.	34,743	154.5	35.65	1,238.7
3. TXU Electric Co	32,508	105.5	14.11	458.8
4. PacifiCorp	28,068	85.5	16.80	471.6
5. Alabama Power Co	25,634	147.0	31.37	804.2
6. Detroit Edison Co	19,582	129.6	26.90	526.8
7. Reliant HL&P	18,350	143.4	22.17	406.9
8. Basin Electric Power Coop	15,981	59.2	8.70	139.0
9. Ameren UE	15,675	93.6	16.46	258.0
10. Duke Power Co	15,089	135.9	33.78	509.7
11. PSI Energy Inc	14,643	109.6	24.52	359.0
12. Ohio Power Co	14,618	213.1	50.70	741.1
13 Virginia Electric & Power	13,945	126.5	32.05	447.0
14. Northern States Power Co	13,147	108.6	19.22	252.7
15. Arkansas Power & Light Co	12,383	142.9	24.88	308.1
16. Appalachian Power Co	11,868	132.2	32.25	382.8
17. Southwestern Electric Power	11,705	140.5	22.40	262.1
18. Salt River Proj Ag I & P Dist	11,556	116.8	24.54	283.5
19. Wisconsin Electric Power	11,362	100.0	18.96	215.4
20. Cincinnati Gas & Electric Co.	11,210	105.9	25.66	287.7

Note: Data are for electric generating plants with a total steam-electric and combined-cycle nameplate capacity of 50 or more megawatts.
Source: Federal Energy Regulatory Commission, FERC Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants."

Table 28. Receipts of Petroleum Coke by Electric Utility, 2000

Electric Utility	Receipts (thousand short tons)	Average Quality			Average Delivered Cost	
		Btu (per pound)	Sulfur (percent by weight)	Ash (percent by weight)	(cents per million Btu)	(dollars per short ton)
Central Illinois Pub Serv Co	26	14,419	3.14	0.32	90.8	26.18
Jacksonville Electric Authority	444	14,398	5.99	.32	60.8	17.51
Lakeland Dept of Water and Elec	2	14,068	6.43	.20	42.7	12.01
Manitowoc Public Utilities	36	14,405	5.88	.53	46.5	13.40
Michigan South Central Power	2	14,073	4.90	.40	106.9	30.08
Northern Indiana Pub Serv Co	174	14,106	4.11	.24	65.2	18.40
Northern States Power Co.	220	14,085	5.34	.54	33.4	9.40
Ohio Edison Co	8	13,729	3.71	.40	73.9	20.29
Owensboro City of	9	13,884	5.24	.86	53.7	14.91
Pennsylvania Power Co	203	14,200	5.62	.42	74.3	21.09
San Antonio City of	9	14,500	4.00	.50	42.0	12.18
Tampa Electric Co	211	14,021	4.49	.40	51.2	14.35
Union Electric Co	124	14,306	3.74	.40	60.5	17.31
Wisconsin Electric Power Co	147	14,142	5.01	.34	70.3	19.89
Wisconsin Power & Light Co	69	14,213	5.62	.48	46.7	13.28
Total	**1,683**	**14,214**	**5.14**	**.39**	**58.5**	**16.62**

Notes: • Totals may not equal sum of components because of independent rounding. • Data are for electric generating plants with a total steam-electric and combined-cycle nameplate capacity of 50 or more megawatts.
Source: Federal Energy Regulatory Commission, FERC Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants."

Of interest, no Florida utilities show up in the top 20 listing of coal users, even though Florida is one of the most populous states. It is observed that the cost of petroleum coke in year 2000 was approximately ½ that of coal. According to Table 28, Florida had 3 users of petcoke out of 15 listed users. The tables also show that receipts of petcoke totaled 1683 thousand short tons, or less than 0.5% of the sum of coal receipts of the top 20 coal users. Only 3 utilities are listed on both tables: Northern States Power, Wisconsin Electric Power and Wisconsin Power & Light Company (Northern States Power is now known as XCEL Energy, headquartered in Minnesota). Jacksonville Electric Authority (JEA) is indicated as the largest utility user of petcoke during year 2000 for electrical generation.

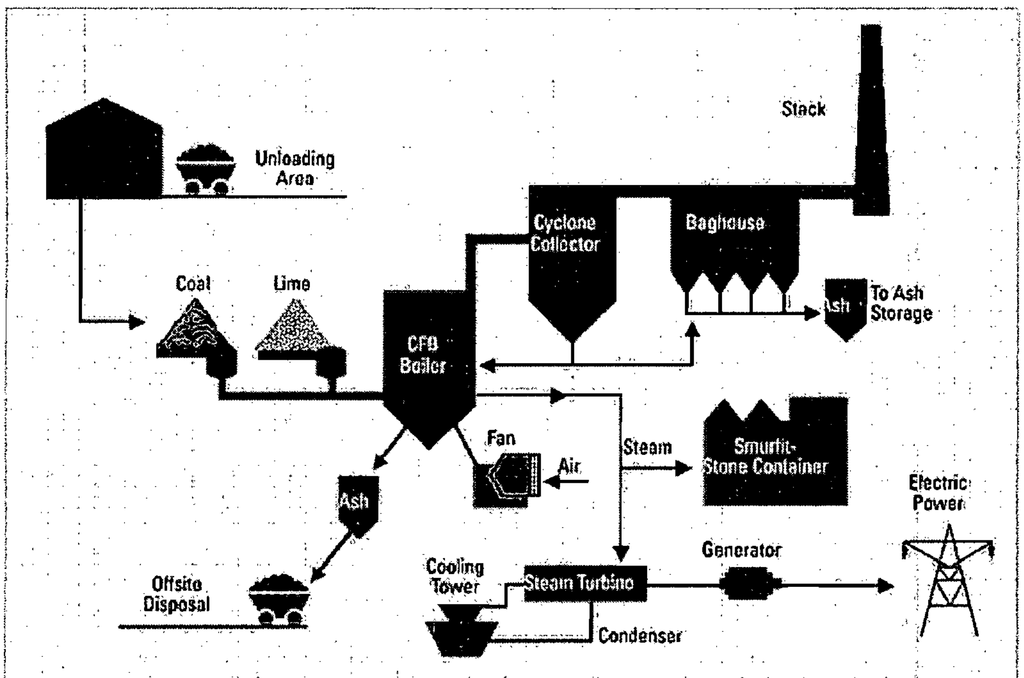
3.2 FLUIDIZED BED COMBUSTION

In a circulating fluidized-bed boiler, a portion of air is introduced through the bottom of the bed. The bed material normally consists of fuel, limestone and ash. Water-cooled membrane walls with specially designed air nozzles support the bottom of the bed, which distributes the air uniformly. The fuel and limestone (for sulfur capture) are fed into the lower bed. In the presence of fluidizing air, the fuel and limestone quickly and uniformly mix under the turbulent environment and behave like a fluid. Carbon particles in the fuel are exposed to the combustion air. The balance of combustion air is introduced at the top of the lower, dense bed. This staged combustion limits the formation of nitrogen oxides (NO_X). The captured solids, including any unburned carbon and unutilized calcium oxide (CaO), are re-injected directly back into the combustion chamber without passing through an external recirculation. This internal solids circulation provides longer residence time for fuel and limestone, resulting in good combustion and improved sulfur capture.

CFB plants are particularly suited for firing petcoke as the long residence times promote high burnout. The low combustion temperature allows SO_2 capture via limestone injection, while minimizing NO_X emissions. In fact, according to Foster Wheeler, CFB boilers are generally capable of removing over 98% of SO_2. The technology is flexible enough to handle a wide range of coals plus petroleum coke as well as blends of coal and coke. Furthermore, the low volatile content of the petcoke is compensated by the substantial amount of hot solids within the boiler providing a constant source of ignition. Petroleum coke has been fired successfully since the 1980s in a wide variety of CFB plants. In the early years, plants tended to be smaller, generating tens of MW whereas more recently plant generating hundreds of MW are common.

The 135 MW AES Deepwater cogeneration plant has been firing 100% petcoke in an arch-type furnace since 1986. The 1344 MW St Johns River Power Park in Florida has been co-firing coal and up to 20% petroleum coke in two wall-fired units and the plant has not experienced any significant problems with corrosion, slagging or fouling and the increased operational costs have been more than offset by the lower fuel costs. The U.S. Department of Energy (DOE) and JEA have entered into an agreement to repower the JEA Northside Generating Station with CFB technology from Foster Wheeler. When operational, the plant will demonstrate CFB technology for coal firing in large-scale applications while providing increased plant electric output, reduced emissions and broad fuel flexibility. The Mt. Poso cogeneration plant in Southern California is permitted to combust petcoke, various coals and tire-derived fuel (TDF) in the CFB unit owned by Millennium Energy Partners, LLC.

FIGURE 4 – CEDAR BAY PLANT GRAPHIC



4. PROJECT EMISSIONS

4.1 FUTURE ACTUAL EMISSION PROJECTIONS

The following table summarizes the future actual emissions increases/decreases at the facility, based upon the applicant's submittals:

Pollutant	1999 Actual Emissions (TPY)	2000 Actual Emissions (TPY)	1999–2000 Average (TPY)	Projected Emissions Co-firing Petcoke [1]	Projected Emissions Change	PSD Significant Emission Rates (TPY)	Subject To PSD Review?
NO_X	1741.5	1779.0	1760.2	1718.1	-42.1	40	NO
CO	582.3	516.0	549.1	400.9	-148.2	100	NO
VOC	17.89	17.25	17.57	34.65	17.08	40	NO
SO_2	1926.2	1965.1	1945.6	1941.3	-4.3	40	NO
PM_{10}	193.7	165.2	179.4	169.9	-9.5	15	NO

[1] Based upon heat inputs from years 1999 and 2000.

SAM

4.2 BOTTLE-NECKING ISSUES

The existing permit provides certain limitations to the throughputs of raw and spent materials. As can be seen from Figure 4 above, there are two primary raw material inputs (coal and limestone) and two primary spent material streams (fly ash from the baghouse, and bed ash from the boiler bottom). A review of data reported to FDEP by Cedar Bay during years 1999 and 2000 shows the following actual annual throughputs along with their respective limits, each in tons per year (TPY).

	COAL	LIMESTONE	FLYASH	BED ASH
ANNUAL LIMIT	*1,170,000*	*320,000*	*336,000*	*88,000*
1999	962,569	122,835	138,306	69,153
2000	954,391	110,534	138,280	71,235

4.2.1 COAL (FUEL) THROUGHPUT

Co-firing of petcoke will result in a lower amount of coal being fired. Additionally, since petcoke has a higher BTU content per ton of fuel than does coal, the combined throughput of petcoke and coal should decrease. Therefore, it is improbable that the commencement of co-firing will cause the facility to approach the coal throughput limit.

4.2.2 LIMESTONE THROUGHPUT

Concerning limestone, the Department estimates that the facility will need to (approximately) double the throughput, in order to achieve the necessary SO_2 scrubbing required to ensure that the PSD significance level is not exceeded. As can be seen from the above table, limestone throughputs can nearly triple before the permitted limit is exceeded, indicating that it is unlikely that limestone throughput limits will be exceeded while co-firing petcoke.

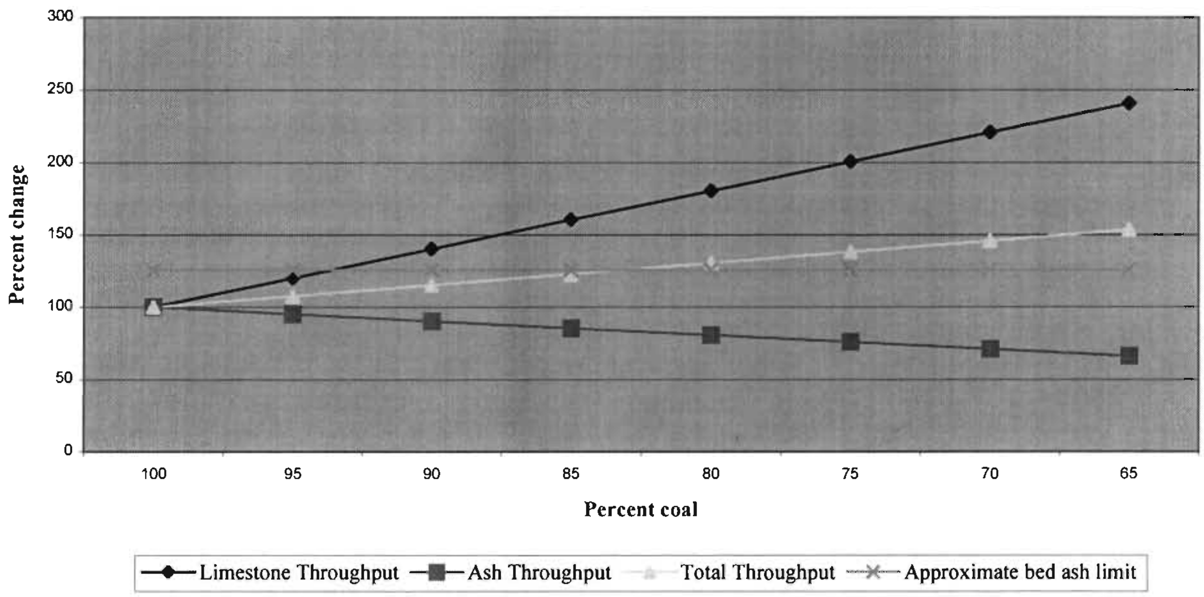
4.2.3 FLYASH THROUGHPUT

Like limestone, the past actual throughputs of flyash are well below permitted levels (approximately 40%). Since the ash content of petcoke is lower than that of coal, it is also unlikely that permitted throughputs of flyash will be exceeded, and Department calculations bear this out. However, the Department estimates that the throughput limit associated with bed ash could be problematic for the facility during the co-firing of petcoke, depending upon the amount and properties of the petcoke.

4.2.4 BED ASH THROUGHPUT

It can be observed from the above table that historically, the flyash to bed ash ratio has been approximately 2:1. Simply stated, for each 1,000 ton of combined limestone and ash entering the boilers, around 667 tons will end up as fly ash and 333 tons will become bed ash. Accordingly, at an increased (combined) limestone and ash throughput of approximately 54,000 TPY, the flyash would be expected to increase by about 36,000 TPY whereas the bed ash would increase by about 18,000 TPY (assuming unchanged fuel quality). This increased throughput of bed ash is roughly equivalent to the permit limit, as the historical average (of approximately 70,000 TPY) is 18,000 TPY less than the limit. In summary, the 88,000 TPY bed ash limit likely becomes an upper bound for the amount of co-firing, which the facility can accommodate. What follows is a Department approximation of the equivalent amount of high sulfur petcoke, which corresponds to the 88,000 TPY bed ash limit (125% of the past actual).

Cedar Bay petcoke co-firing



4.2.5 BOTTLE-NECKING SUMMARY

Based upon the graph above and a number of conservative assumptions (e.g. coal quality, petcoke quality, limestone utilization rate, etc.) a practical co-firing limit for the highest sulfur-laden petcoke is approximately 20% (80% coal), as this is about the point at which it is anticipated that the bed ash limit may be reached. Of course, as the sulfur content of the petcoke is reduced, this practical limit begins to disappear (e.g. as the sulfur level of the petcoke approaches that of the coal). For example, at a petcoke sulfur content of 4%, the practical co-firing limit (based upon bed ash throughput) is approximately 35%. Accordingly, in order for the Department to have reasonable assurance that this facility can be permitted for the co-firing of petcoke without exceeding the PSD thresholds, a limit on the petcoke throughput as well as the equivalent coal/petcoke blended sulfur content will be established.

existing permit limits

5. RULE APPLICABILITY

This facility is located in an area designated, in accordance with Rule 62-204.340, F.A.C., as attainment for all pollutants. Rule 62-4.030, F.A.C., prohibits modification of any existing emissions unit without first receiving a permit. It further specifies that a permitted installation may only be modified in a manner that is consistent with the terms of such a permit. Rule 62-210.200, F.A.C., defines "modification" to mean generally a physical change or change in the method of operation that results in an increase in actual emissions of regulated air pollutants. Rules 62-210.300(1) and 62-212.300(1)(a), F.A.C., also reiterate the requirement for construction permits. Additionally, Rule 62-210.300 requires an Air Construction permit for all new sources of air pollution unless specifically exempt.

FDEP deems that burning of petcoke is a change in the method of operation. Given that the source is major with regard to PSD, an analysis must be performed to verify that the burning of petcoke will not result in a significant net emissions increase and that, consequently, use of petcoke is not a major modification subject to PSD review. The emission units affected by this permit shall comply with all applicable provisions of the Florida Administrative Code (including applicable portions of the Code of Federal Regulations incorporated therein).

6. PSD POLLUTANT ANALYSIS

The following excerpt from a 1998 publication of *Heat Engineering*, entitled Firing Refinery By-products in Circulating Fluidized-Bed Steam Generators is used as a preface to the Department's analysis of each PSD pollutant. It is noted that the emissions at this facility have been relatively steady over the past several years with consistently high capacity factors. FDEP data for years 1999 and 2000 is utilized as the 2-year baseline period.

The largest petcoke-fired CFB steam generators in the world were designed and built by Foster Wheeler for Nelson Industrial Steam Company (NISCO). They are located at the NISCO cogeneration facility in Lake Charles, La. The two 100 MWe CFB boilers at the facility have successfully burned petcoke since 1992 to repower existing turbine-generator equipment and to provide steam for an adjacent chemical plant. The project has been a financial success and the CFB plant has operated with high availability and capacity. Each of the NISCO boilers generates 825,000 pounds per hour of main steam at 1005°F and 1625 psig as well as 727,000 pounds per hour of reheat steam. The petcoke design fuel is characterized in Table 3. Boiler efficiency has been greater than 90 percent as measured by the ASME heat-loss method, and combustion efficiency has exceeded 99 percent. The boilers have also demonstrated excellent turndown capability, easily exceeding the guaranteed operating range of 40 to 100 percent maximum continuous rating (MCR) without having to fire auxiliary fuel for combustion stability. Since commissioning, plant availability has consistently been greater than 95 percent. As expected, levels of potential pollutants in the flue gas leaving the furnace have been very low. Sulfur removal has consistently been greater than 90 percent. Nitrogen-oxide emissions have typically been less than 0.15 lb. per Million Btu's (MMBtu) and often less than 0.07 lb/MMBtu. Carbon-monoxide emissions have been less than 0.06 lb/MMBtu at 100 percent boiler load. Managers of the NISCO project have aggressively pursued beneficial uses of the ash-waste streams to further enhance cost-effectiveness. Virtually all of the environmentally inert ash produced by the two CFB boilers is sold for purposes such as soil conditioning.

TABLE 3

Composition of Petcoke for NISCO Project

Carbon	75–86% (by wt)
Hydrogen	3.0–3.6%
Nitrogen	1.3–1.9%
Sulfur	3.4–5.3%
Ash	0.0–0.6%
Oxygen	0.0–0.1%
Moisture	5.5–15.0%
Vanadium	500–2900 ppm
Nickel	250–450 ppm
Iron	50–250 ppm
HHV	12,600–14,500 Btu/lb

6.1 CARBON MONOXIDE (CO) AND VOLATIVE ORGANIC COMPOUNDS (VOC)

The applicant contends that there will be a net emission decrease in CO from the co-firing of petcoke and coal, and no change in VOC emissions. Annual CO emissions averaged 549 TPY and 0.05 lb/MMBtu, while annual VOC emissions averaged 34.7 TPY. The Significant Emission Rate for CO is 100 TPY, and for VOC is 40 TPY. The Department finds it unlikely that the co-firing of petcoke will cause CO emissions to exceed 648 TPY (549 + 99) or VOC emissions to exceed 74 TPY (35 + 39). Accordingly, a BACT review is not required for these pollutants. ?

6.2 NITROGEN OXIDE (NO_X)

If CO is going down, how is NOx also going down.

The applicant indicates that NO_X emissions are likely to decrease, as uncontrolled NO_X will reduce by as much as 25%. Annual NO_X emissions averaged 1760 TPY and 0.15 lb/MMBtu. The Significant Emission Rate for NO_X is

? (If they have SCR, they can just control more.)

40 TPY. The Department accepts the applicant's assessment and finds it unlikely that co-firing petcoke will cause NO_X emissions to exceed 1799 TPY (1760 + 39). Accordingly, a BACT review is not required.

6.3 SULFUR DIOXIDE (SO_2) AND SULFURIC ACID MIST (SAM)

The applicant recognizes that additional scrubbing will be required in order to maintain SO_2 and SAM emissions at historical levels. The past actual average emissions of SO_2 and SAM were 1945.6 and 0.43 TPY respectively. The average annual emission rate for SO_2 was 0.17 lb/MMBtu. The Significant Emission Rates (SER) are 40 TPY (SO_2) and 7 TPY (SAM). The Department accepts the applicant's proposal that SO_2 and SAM emissions can be maintained below the respective SER by additional scrubbing within the CFB's. However, as indicated above the Department estimates that the practical limit of scrubbing is approximately 95%. Accordingly, the Department will place a limit on the inlet SO_2 loading to the CFB's, which results in a maximum emission rate of 0.17 lb/MMBtu at reasonable scrubbing efficiencies. The applicant proposes to limit the inlet SO_2 loading to 3.2 lb/MMBtu, which at 95% scrubbing results in an emission rate of 0.16 lb/MMBtu. This is acceptable to the Department and should ensure that the annual emission levels of SO_2 and SAM exceed neither 1985 (1945.6 + 39.9) TPY nor 7.42 (0.43 + 6.99) TPY respectively. In addition to this, the Department will place a limit on the throughput of petcoke at 35% input on a weight basis. Accordingly, the SO_2 and SAM emission increases are considered insignificant for PSD purposes and BACT reviews are not required.

6.4 PARTICULATE MATTER (PM_{10})

According to FDEP data, the historical level of PM_{10} for the CFB's averaged 180.06 TPY and the PSD Significant Emission Rate is 15 TPY. Given that the ash content of petcoke is significantly less than that of coal, the prime concern for potential increases in PM_{10} is related to the increased lime throughput required for SO_2 scrubbing. As shown above, the Department estimates that this additional scrubbing can be achieved at removal efficiencies as high as 95% before the bed ash throughput limit is potentially reached. This additional scrubbing is anticipated to result in total lime throughputs at twice historical levels. As reviewed in Section 4.2, and in order to ensure that the bed ash permitted throughput is not exceeded, the Department will require a monitoring system to accurately measure such throughput. The applicant will propose (to the Department's satisfaction) the system it recommends to utilize, prior to the initial receipt of petcoke. Actual in-service testing (while combusting coal) will be completed prior to the initial firing of petcoke, demonstrating its adequacy to the Department's satisfaction. As an additional means of ensuring compliance, the limestone throughput limit will be reduced to further ensure that the bed ash limit cannot be exceeded. Since no applicant estimate, including those of Foster Wheeler, indicates that the limestone throughput is required to exceed 275,000 TPY (in order to maintain SO_2 emissions at historical levels while co-firing petcoke), this will additionally be established as a reduced permit limit.

space

Concerning the stack emissions of PM_{10}, the facility uses baghouses. The applicant maintains that the emission rate from the baghouse for each CFB can be maintained because PM removal is not a function of loading, particularly given the low loading rates to the baghouse. This information is provided in the ABB Emissions Control System Operations and Maintenance Manual, a portion of which the applicant has provided to the Department. According to the manual, the particulate emission rate can be maintained over a range of grain loading and flow rates. The baghouses are designed for an inlet grain loading of 19.5 grains/acf at 297,700 acfm. The grain loading for coal is provided as 4.5 - 4.7 grains/acf for the baseline years of 1999 - 2000. A calculation of the total loading during co-firing reveals loadings at 5.1 - 5.5 grains/acf, still well below the design of 19.5 grains/acf. Additionally, the maximum grain loading projected in the Foster Wheeler report is 6.7 grains/acf, which is also less than the design condition. Unlike particulate removal devices such as ESP's, it is unlikely that PM emissions will increase through a baghouse, while the inlet loading is well below the design. This conclusion is supported by information available from EPA regarding fabric filters. In the Air Pollution Technology Fact Sheets for fabric filters EPA states that: "the effluent particle concentration from a fabric filter is nearly constant"... and "fabric filters can be considered constant outlet devices rather than constant efficiency devices." Accordingly, the annual PM/PM_{10} emissions from the stack are likely to be maintained with no increase above the PSD significant emission rate of 25/15 tons/year.

With regard to ancillary (or fugitive) emissions resulting from the increased lime throughput, the applicant estimates an annual PM_{10} increase of 0.59 TPY. The historical PM_{10} emission level for the balance of the plant (as reported to the Department) averaged 2.97 TPY. For the facility, total average annual PM_{10} emissions were 183.03 TPY

(180.06 + 2.97). In summary, all PM_{10} emissions from the facility must remain less than 198 TPY (183 + 15) in order to be underneath the Significant Emission Rates. The applicant maintains that this can be accomplished and the Department accepts the applicant's claim.

6.5 SUMMARY

A preliminary review supports the applicant's contention that PSD is not triggered, eliminating the requirement for a BACT review and related modeling. PSD regulations (under the provisions commonly known as the "WEPCO rule") allow a source undertaking a non-routine change that could affect emissions at an electric utility steam generating unit to lawfully avoid the major source permitting process by using the unit's representative actual annual emissions to calculate emissions following the change, if the source submits information for 5 years following the change to confirm its pre-change projection. Under the WEPCO rule, Cedar Bay must compute baseline actual emissions and must project the future actual emissions from the modified units for a period after the physical change. In addition, Cedar Bay must maintain and submit to the Department on an annual basis for a period of at least 5 years from the date the units resume regular operation, information demonstrating that the change did not result in a significant emissions increase. If Cedar Bay fails to comply with the reporting requirements of the WEPCO rule or if the submitted information indicates that emissions have increased above PSD thresholds as a consequence of the change, it will be required to obtain a PSD permit for petcoke co-firing (meaning that a BACT Review would then be applicable). Finally, even though a PSD review is not triggered due to the co-firing project, Cedar Bay must meet all other applicable federal, state, and local air pollution requirements.

7. ADDITIONAL COMPLIANCE PROCEDURES

Pollutant	Compliance Procedures
NO_X emission limit	Five years of annual reporting by CEMS proving annual emissions do not exceed 1799 TPY
CO emission limit	Five years of annual reporting by CEMS proving annual emissions do not exceed 648 TPY
VOC emission limit	Five years of annual reporting by stack test proving annual emissions do not exceed 74 TPY
SO_2 emission limit	Five years of annual reporting by CEMS proving annual emissions do not exceed 1985 TPY
SAM PM_{10} emission limit	Five years of annual reporting by stack test proving annual facility emissions do not exceed 198 TPY

Specific permit conditions shall further describe these limitations. The reporting procedures are to begin during the first calendar year in which petcoke is fired.

7. HAZARDOUS AIR POLLUTANT ANALYSIS

This review is not applicable, as the applicant does not intend to construct or reconstruct a major source of Hazardous Air Pollutants based upon the definitions of 40CFR 63, Subpart B.

8. CONCLUSION

Based on the foregoing technical evaluation of the application, additional information submitted by the applicant and other available information, the Department has made a preliminary determination that the proposed project will comply with all applicable state and federal air pollution regulations.

Michael P. Halpin, P.E. Review Engineer
Department of Environmental Protection, Bureau of Air Regulation
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

August xx, 2002

Mr. Bruce Smith
General Manager
Cedar Bay Generating Company, L.P.
P.O. Box 26324
Jacksonville, Florida 32226-6324

Re: DEP File No. PA 88-24; Modification of Permit No. PSD-FL-137
Cedar Bay Generating Plant / Duval County

The applicant, Cedar Bay Generating Company, L.P., applied on August 29, 2002, to the Department for a modification to PSD permit number PSD-FL-137 for its Cedar Bay Generating Plant located in Duval County. The modification is to allow the facility to co-fire petroleum coke (petcoke) in its three circulating fluidized bed boilers (A, B and C). The Department has reviewed the modification request. The referenced permit is hereby modified as follows:

II.A. Emission Limitations for 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. Petroleum coke (petcoke) may be utilized as a co-firing fuel, and shall not exceed 35% fuel input by weight on a daily basis. {Permitting Note: The limitations on the coal charging rate includes both coal and petcoke.}

   d. The sulfur content of the coal shall not exceed 1.2%, by weight, on an annual basis. The sulfur content shall not exceed 1.7%, by weight, on a shipment (train load) basis. When co-firing coal and petcoke, the blended fuel input to the CFBs shall not exceed 3.2 lb/MMBtu equivalent SO_2 content. Compliance shall be determined on a monthly basis via a composite of daily fuel samples. (There's no maximum sulfur content for petcoke ?)

4. Ammonia (NH_3) slip from the exhaust gases shall not exceed 10 ppmvd when co-firing petcoke or burning coal at 100% capacity and 30 ppmvd when burning oil.

10. Operations Monitoring for each CFB

    b. All coal, petcoke 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 and recorded for each 24-hour period in which rejects are burned.

17. The permittee shall submit annual reports to RESD and DEP/BAR summarizing emissions for each calendar year. The reports will commence during the first year in which petcoke is fired and continue for a total of five calendar years. Such reports are required in order to confirm Cedar Bay's projections of future actual emissions and to demonstrate to the Department's

satisfaction that petcoke co-firing did not result in a significant emissions increase. Reporting shall be as follows:

Pollutant	**Compliance Procedures**
NO_X	Five years of annual reporting by CEMS proving annual facility emissions do not exceed 1799 TPY
CO	Five years of annual reporting by CEMS proving annual facility emissions do not exceed 648 TPY
VOC	Five years of annual reporting by stack test proving annual facility emissions do not exceed 74 TPY
SO_2	Five years of annual reporting by CEMS proving annual facility emissions do not exceed 1985 TPY
PM_{10}	Five years of annual reporting by stack test proving annual facility emissions do not exceed 198 TPY

II.B. CBCP - Material Handling and Treatment

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
Petcoke	40,950	409,500
Limestone	27,000	~~320,000~~ 275,000
Fly Ash	28,000	336,000
Bed Ash	8,000[1]	88,000[1]

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

[1] The Department will require a monitoring system to accurately measure Bed Ash throughput. The applicant will propose (to the Department's satisfaction) the system it recommends to utilize, prior to the initial receipt of petcoke. Actual in-service testing (while combusting coal) will be completed prior to the initial firing of petcoke, demonstrating its adequacy to the Department's satisfaction.

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

Coal Car Unloading
Ash Pellet Hydrator
Ash Pellet Curing Silo
Ash Pelletizing Pan

Petcoke Unloading/Handling Areas
Petcoke Transfer Areas
Petcoke Storage Areas

The above listed sources are subject to a VE and a PM emissions limitation requirement of 5% opacity and 0.01 gr/dscf (applicant requested limitation, which is more stringent than what is allowed by rule), respectively, in accordance with Rule 17-296.711, F.A.C. Initial and subsequent compliance tests shall be conducted for VE and PM emissions using EPA Methods 9 and 5, respectively, in accordance with Chapter 17-297, F.A.C., and 40 CFR 60, Appendix A (July, 1992 version).

A copy of this letter shall be filed with the referenced permit and shall become part of the permit. This permit modification is issued pursuant to Chapter 403, Florida Statutes.

Any party to this order (permit modification) has the right to seek judicial review of it under Section 120.68, F.S., by filing a notice of appeal under Rule 9.110 of the Florida Rules of Appellate Procedure with the clerk of the Department of Environmental Protection in the Office of General Counsel, Mail Station #35, 3900 Commonwealth Boulevard, Tallahassee, Florida, 32399-3000, and by filing a copy of the notice of appeal accompanied by the applicable filing fees with the appropriate District Court of Appeal. The notice must be filed within thirty days after this order is filed with the clerk of the Department.

Executed in Tallahassee, Florida.

____

Howard L. Rhodes, Director
Division of Air Resources
Management

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this permit modification was sent by certified mail (*) and copies were mailed by U.S. Mail before the close of business on ______________ to the person(s) listed:

Bruce Smith, Cedar Bay *
J. A. Walker, Cedar Bay
Ken Kosky, P.E. Golder Associates
Hamilton S. Oven, P.E.
James L. Manning, P.E., RESD
Doug Neeley, EPA
John Bunyak, NPS
Chris Kirts, DEP-NED
Stafford Campbell, Greater Arlington Civic Council

Clerk Stamp

FILING AND ACKNOWLEDGMENT FILED, on this date, pursuant to §120.52, Florida Statutes, with the designated Department Clerk, receipt of which is hereby acknowledged.

____________________ ________________

(Clerk) (Date)

Department of Environmental Protection

Jeb Bush
Governor

Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

David B. Struhs
Secretary

July 2, 2002

Mr. Gregg Worley, Chief
Air, Radiation Technology Branch
Preconstruction/HAP Section
U.S. EPA, Region 4
61 Forsyth Street
Atlanta, Georgia 30303

RE: Cedar Bay Cogeneration Facility
Co-firing Petroleum Coke with Coal
PSD-FL-137A Revision
DEP File No. 0310337-005-AC

Dear Mr. Worley:

Enclosed for your review and comment is an application submitted by U.S. Generating Company to allow permit the co-firing of up to 35 percent petroleum coke with coal in the three existing circulating fluidized bed boilers at the Cedar Bay cogeneration facility in Duval County, Florida.

Your comments may be forwarded to my attention at the letterhead address or faxed to the Bureau of Air Regulation at 850/922-6979. If you have any questions, please contact Mike Halpin, review engineer, at 850/921-9519.

Sincerely,

Patty Adams

for Al Linero, P.E.
Administrator
New Source Review Section

AAL/pa

Enclosure

Cc: Mike Halpin

Department of Environmental Protection

Jeb Bush
Governor

Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

David B. Struhs
Secretary

July 2, 2002

Mr. John Bunyak, Chief
Policy, Planning & Permit Review Branch
NPS – Air Quality Division
Post Office Box 25287
Denver, Colorado 80225

RE: Cedar Bay Cogeneration Facility
Co-firing Petroleum Coke with Coal
PSD-FL-137A Revision
DEP File No. 0310337-005-AC

Dear Mr. Bunyak:

Enclosed for your review and comment is an application submitted by U.S. Generating Company to allow permit the co-firing of up to 35 percent petroleum coke with coal in the three existing circulating fluidized bed boilers at the Cedar Bay cogeneration facility in Duval County, Florida.

Your comments may be forwarded to my attention at the letterhead address or faxed to the Bureau of Air Regulation at 850/922-6979. If you have any questions, please contact Mike Halpin, review engineer, at 850/921-9519.

Sincerely,

Patty Adams
for Al Linero, P.E.
Administrator
New Source Review Section

AAL/pa

Enclosure

Cc: Mike Halpin

PG&E National
Energy Group

Cedar Bay
Generating Plant
Owner: Cedar Bay Generating Company, L.P.

POB 26324
Jacksonville, FL 32226-6324

904.751.4000
Fax: 904.751.7320

March 7, 2002

RECEIVED
MAR 0 8 2002
BUREAU OF AIR REGULATION

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

RE: Cedar Bay Cogeneration Facility
Co-firing Petroleum Coke with Coal
Revision of PSD-FL-137A

Dear Mr. Fancy:

In a letter dated September 28, 2001, the Department requested additional information related to the request to co-fire petroleum coke with coal at the Cedar Bay Cogeneration Facility. The Department subsequently granted an extension to Cedar Bay on January 14, 2002. The information requested was an analysis of the facility's past actual emissions, future emissions and a comparison with the Prevention of Significant Deterioration (PSD) significant emission rates in Table 62-212.400(5).

The applicable FDEP rule for determining actual emissions is 62-210.200(11), FAC, and is attached to this letter for reference. The Cedar Bay Cogeneration Facility consists of three boilers and associated electric generator, which is an electric utility steam generating unit as defined in 62-210.200(11)(d). Therefore, the use of representative actual annual emissions is appropriate when making annual emission comparisons. The definition of "representative actual annual emissions" in 40 CFR 52.21(b)(33) is also attached for reference.

EPA has provided guidance for electric utility units on what it considers "representative" operation. The current PSD regulation promulgated in 1992 and adopted by FDEP clearly recognized the use of any consecutive two years within the 5-year period preceding a change for utility units. This is clearly stated in the preamble to the EPA regulations as follows:

> *Under the proposed action, the administrator would presume that any 2 consecutive years within the 5 years prior to a proposed change is representative of normal source operation for a utility. This presumption is consistent with the 5-year period for "contemporaneous" emission increases and decreases in 40 CFR 52.21(b)(3)(i)(b). [57 FR 32,314]*

The historical emissions from the Cedar Bay Cogeneration Facility were provided in Table 2 of the application and summarized in the attached Table A. Table A also contains an emissions summary for 2001 because this is the last full year of available data. This table also provides information related to Equivalent Forced Outage Rate (EFOR) for the facility for the last 5-years, i.e., 1997 through 2001. The EFOR is based on outages that are unplanned and occur as a result of unforeseen mechanical and electrical failures, and other causes. As shown in Table A, the EFOR in 2001 was considerably higher than previous years and significantly different than the average EFOR over the 5-year period.

The average emissions for 1999 and 2000 are the most appropriate as the "actual emissions" because these years represent two consecutive years out of the last 5 years and are representative of the operation of the facility. The "representative actual annual emissions" were based on emission increases slightly less than the PSD significant emission rates for CO, NOx, PM/PM_{10}, H_2SO_4, SO_2, VOC, Fl, Pb and Hg and are essentially the upper bound on emissions proposed by Cedar Bay. However, any future comparison would exclude any emissions due to increased utilization as a result of increased electricity demand growth for the utility system.

Table B presents the past actual emissions, representative actual annual emissions proposed for the co-firing of petroleum coke with coal and the PSD significant emission rates. This table shows that the project emission increase of all pollutants is less than the applicable PSD significant emission rate.

To ensure that the co-firing of petroleum coke with coal is restricted in a manner that is consistent with PSD regulations, the following permit condition is requested, which is nearly identical to the condition authorizing four other facilities to co-fire petroleum coke with coal (i.e., Tampa Electric Company' Big Bend Generating Station, St. Johns River Power Park, City of Lakeland McIntosh Unit 3 and Seminole Electric Cooperative, Inc. Seminole Plant

> CO, NOx, PM/PM_{10}, H_2SO_4, and SO_2. The permittee shall maintain and submit to the Department and RESD, on an annual basis for a period of 5-years from the date each emission unit begins co-firing petroleum coke, data demonstrating in accordance with 40 CFR 52.21(b)(21)(v) and 40 CFR 52.21(b)(33) that the operational change associated with the use of petroleum coke did not result in a significant emission increases for CO, NOx, PM/PM_{10}, H_2SO_4, and SO_2.

Table B also presents the current permit emission limits and the representative actual annua emissions. As shown, the representative future actual emissions are less than maximum potential emissions for each pollutant authorized in the PSD and PPSA approvals for firing coal. As a result, there will be no emissions increase over that currently authorized by FDE for the facility. ?

The Department's expeditious review of the application is appreciated. Please contact me i there is any further information needed.

Sincerely,

Bruce Smith, General Manager
Cedar Bay Generating Company, LP

Cc: A.A Linero, DEP
Scott Gorland, DEP
Jonathan Holtom, DEP
Ernest Frye, DEP NE District
Steve Pace, Jacksonville RESD
Hamilton S. Oven, Jr.
Ken Kosky
David Dee

Definitions of Actual Emissions and Representative Actual Annual Emissions

<u>62-210.200(11) F.A.C. "Actual Emissions"</u> *- The actual rate of emission of a pollutant from an emissions unit as determined in accordance with the following provisions:*

(a) In general, actual emissions as of a particular date shall equal the average rate, in tons per year, at which the emissions unit actually emitted the pollutant during a two year period which precedes the particular date and which is representative of the normal operation of the emissions unit. The Department may allow the use of a different time period upon a determination that it is more representative of the normal operation of the emissions unit. Actual emissions shall be calculated using the emissions unit's actual operating hours, production rates and types of materials processed, stored, or combusted during the selected time period.

(b) The Department may presume that unit-specific allowable emissions for an emissions unit are equivalent to the actual emissions of the emissions unit provided that, for any regulated air pollutant, such unit-specific allowable emissions limits are federally enforceable.

(c) For any emissions unit (other than an electric utility steam generating unit specified in subparagraph (d) of this definition) which has not begun normal operations on a particular date, actual emissions shall equal the potential emissions of the emissions unit on that date.

(d) For an electric utility steam generating unit (other than a new unit or the replacement of an existing unit) actual emissions of the unit following a physical or operational change shall equal the representative actual annual emissions of the unit following the physical or operational change, provided the owner or operator maintains and submits to the Department on an annual basis, for a period of 5 years representative of normal post-change operations of the unit, within the period not longer than 10 years following the change, information demonstrating that the physical or operational change did not result in an emissions increase. The definition of "representative actual annual emissions" found in 40 CFR 52.21(b)(33) is adopted and incorporated by reference in Rule 62-204.800, F.A.C.

<u>40 CFR 52.21(b)(33) Representative actual annual emissions</u> *means the average rate, in tons per year, at which the source is projected to emit a pollutant for the two-year period after a physical change or change in the method of operation of a unit, (or a different consecutive two-year period within 10 years after that change, where the Administrator determines that such period is more representative of normal source operations), considering the effect any such change will have on increasing or decreasing the hourly emissions rate and on projected capacity utilization. In projecting future emissions the Administrator shall:*

(i) Consider all relevant information, including but not limited to, historical operational data, the company's own representations, filings with the State or Federal regulatory authorities, and compliance plans under title IV of the Clean Air Act; and

(ii) Exclude, in calculating any increase in emissions that results/from the particular physical change or change in the method of operation at an electric utility steam generating unit, that portion of the unit's emissions following the change that could have been accommodated during the representative baseline period and is attributable to an increase in projected capacity utilization at the unit that is

unrelated to the particular change, including any increased utilization due to the rate of electricity demand growth for the utility system as a whole.

Table A. Annual Emissions and Equivalent Forced Outage Rate (EFOR) 1997-2001
Cedar Bay Cogeneration Facility

		Year				
	Units	1997	1998	1999	2000	2001
CO emissions	tons/yr	496.0	549.6	582.3	516.0	485.1
NOx emissions	tons/yr	1,726.0	1,716.4	1,741.5	1,779.0	1,656.9
PM10 emissions	tons/yr	149.5	178.3	193.7	165.2	201.9
Sulfuric Acid Mist	tons/yr	0.4	0.4	0.4	0.3	0.3
SO2 emissions	tons/yr	1,909.0	1,935.6	1,926.2	1,965.1	1,901.5
VOC	tons/yr	14.8	14.7	17.9	17.3	48.7
EFOR		2.08%	1.74%	4.91%	6.87%	11.87%
EFOR Statistics:		Average	Std Dev	Upper CI	Lower CI	
		5.49%	0.041423339	9.44%	1.54%	

Std Dev = Standard Deviation; CI = Confidence Interval
Note: Upper and Lower CI based on Student's "t" statistic at the 95 percent confidence level.

Table B. Actual Emissions and Representative Actual Annual Emissions when Cofiring Petroleum Coke with Coal Compared to PSD Significant Emission Rate and Permitted Emission Limitations - Cedar Bay Cogeneration Facility

Pollutant	1999 & 2000 Annual Emissions (tons/year)	Representative Future Actual Emissions (tons/year)	Difference for Co-Firing Pet Coke w/Coal (tons/year)	PSD Significant Emission Rate (tons/year)	PPSA & PSD Emission Limitations (tons/year)	Difference from Emission Limitations (tons/year)
CO	549.1	648.1	99.0	100.0	2,273.0	-1,624.9
NOx	1,760.3	1,799.3	39.0	40.0	2,208.0	-408.7
PM10	179.5	193.5	14.0	15.0	234.0	-40.5
Sulfuric Acid Mist	0.4	6.0	5.6	6.0	6.1	-0.1
SO2	1,945.7	1,984.7	39.0	40.0	2,598.0	-613.3
VOC	17.6	56.7	39.1	40.0	195.0	-138.3
Fl	1.5	3.5	2.0	3.0	9.7	-6.2
Pb	0.006	0.5	0.5	0.6	0.8	-0.3

Table B. Actual Emissions and Representative Actual Annual Emissions when Cofiring Petroleum Coke with Coal Compared to PSD Significant Emission Rate and Permitted Emission Limitations - Cedar Bay Cogeneration Facility

Pollutant	1999 & 2000 Annual Emissions (tons/year)	Representative Future Actual Emissions (tons/year)	Difference for Co-Firing Pet Coke w/Coal (tons/year)	PSD Significant Emission Rate (tons/year)	PPSA & PSD Emission Limitations (tons/year)	Difference from Emission Limitations (tons/year)
CO	549.1	648.1	99.0	100.0	2,273.0	-1,624.9
NOx	1,760.3	1,799.3	39.0	40.0	2,208.0	-408.7
PM10*	179.5	193.5	14.0	15.0	234.0	-40.5
Sulfuric Acid Mist	0.4	6.0	5.6	6.0	6.1	-0.1
SO2	1,945.7	1,984.7	39.0	40.0	2,598.0	-613.3
VOC*	17.6	56.7	39.1	40.0	195.0	-138.3
Fl	1.5	3.5	2.0	3.0	9.7	-6.2
Pb	0.006	0.5	0.5	0.6	0.8	-0.3

* Data reflects use of most recent stack testing data

Limit potential increases
only from burning of petcoke.
Let Coal alone stay at current

increment ?
Modeling Required for Non PSD ? Some classes of Non-PSD require modeling

cause or contribute to an Increment violation

DVL Co. has demonstrated, modeled increment violation for SO_2

Looks at JEA a Seminole Pet Coke permits wp

[PRINTER TABLE command: MANUAL]

PERMITTEE: **Permit Number: PSD-FL-137A**
Cedar Bay Cogeneration, Inc. **County: Duval**
7475 Wisconsin Avenue **Latitude/Longitude: 30°25'21"N**
Bethesda, Maryland 20814-3422 **81°36'23"W**
Project: Cedar Bay Cogeneration Project

This air permit is issued for the Cedar Bay Cogeneration Project (CBCP) under the provisions of Chapter 403, Florida Statutes (F.S.), and Florida Administrative Code (F.A.C.) Chapters 17-210 through 297 and 17-4. The above named permittee is hereby authorized to perform the work or operate the facility shown on the application and approved drawings, plans, and other documents attached hereto or on file with the Department of Environmental Protection (Department) and specifically described as follows:

This air permit is for the installation of the CBCP, an integrated cogeneration power plant complex at the existing Seminole Kraft Corporation (SKC) facility located in Jacksonville, Florida. The power complex will be owned by Cedar Bay Cogeneration, Inc., and consist of: three circulating fluidized bed (CFB) boilers, whose principal fuel will be coal; the associated coal, ash, and other material handling equipment; a cooling tower; and, two limestone dryers.

The three CFB boilers, each rated at a maximum of 3,189 MMBtu/hr heat input, will fire fuel made up largely or exclusively of coal, with the possibly that two CFBs will fire some short fiber recycle rejects from the SKC facility. The boilers will generate steam to produce power from a turbine generator set. The cogeneration facility will generate electricity for sale to Florida Power & Light as well as process steam for the SKC facility.

Nitrogen oxides will be controlled by selective non-catalytic reduction and good combustion characteristics, which are an inherent part of the CFB technology. Sulfur dioxide will be controlled by limiting the average annual sulfur content of coal to 1.2%, by weight, and the inherent scrubbing provided by the CFB technology; also, the No. 2 fuel oil, which will be fired by the CFB auxiliary fuel burners (normally only for startup) and by other process equipment, will be limited to a maximum sulfur content of 0.05%, by weight. Particulate matter will be controlled with fabric filters.

The existing SKC facility is located at 9469 East Port Road, Jacksonville, Duval County, Florida. UTM coordinates of the site are: Zone 17, 441.8 km E and 3,365.6 km N.

The source shall be constructed in accordance with the permit application, plans, documents, amendments and drawings, except as otherwise noted in the General and Specific Conditions.

Attachments are listed below:

1. Power Plant Site Certification package PA 88-24 and its associated attachments dated January 19, 1990.
2. Letter from EPA dated March 27, 1991.
3. DER's Final Determination dated March 28, 1991.
4. Settlement Stipulation dated April 13, 1993, in re: Power Plant Site Certification of Cedar Bay Cogenerat
5. Final Order approving Modification of Certification dated May 11, 1993, in re: Power Plant Site Certifica
6. Mr. Patrick Tobin's letter dated October 26, 1993.
7. Ms. Jewell A. Harper's letter dated November 3, 1993.
8. DEP's Final Determination dated November 16, 1993.

I. GENERAL CONDITIONS:

1. The terms, conditions, requirements, limitations, and restrictions set forth in this permit are "Permit Conditions" and are binding and enforceable pursuant to Sections 403.161, 403.727, or 403.859 through 403.861, F.S. The permittee is placed on notice that the Department will review this permit periodically and may initiate enforcement action for any violation of these conditions.

2. This permit is valid only for the specific processes and operations applied for and indicated in the approved drawings or exhibits. Any unauthorized deviation from the approved drawings, exhibits, specifications, or conditions of this permit may constitute grounds for revocation and enforcement action by the Department.

3. As provided in Subsections 403.087(6) and 403.722(5), F.S., the issuance of this permit does not convey any vested rights or any exclusive privileges. Neither does it authorize any injury to public or private property or any invasion of personal rights, nor any infringement of federal, state or local laws or regulations. This permit is not a waiver of or approval of any other Department permit that may be required for other aspects of the total project which are not addressed in the permit.

4. This permit conveys no title to land or water, does not constitute State recognition or acknowledgement of title, and does not constitute authority for the use of submerged lands unless herein provided and the necessary title or leasehold interests have been obtained from the State. Only the Trustees of the Internal Improvement Trust Fund may express State opinion as to title.

GENERAL CONDITIONS cont.:

5. This permit does not relieve the permittee from liability for harm or injury to human health or welfare, animal, or plant life, or property caused by the construction or operation of this permitted source, or from penalties therefore; nor does it allow the permittee to cause pollution in contravention of F.S. and Department rules, unless specifically authorized by an order from the Department.

6. The permittee shall properly operate and maintain the facility and systems of treatment and control (and related appurtenances) that are installed or used by the permittee to achieve compliance with the conditions of this permit, as required by Department rules. This provision includes the operation of backup or auxiliary facilities or similar systems when necessary to achieve compliance with the conditions of the permit and when required by Department rules.

7. The permittee, by accepting this permit, specifically agrees to allow authorized Department personnel, upon presentation of credentials or other documents as may be required by law and at a reasonable time, access to the premises, where the permitted activity is located or conducted to:

a. Have access to and copy any records that must be kept under the conditions of the permit;

b. Inspect the facility, equipment, practices, or operations regulated or required under this permit; and,

c. Sample or monitor any substances or parameters at any location reasonably necessary to assure compliance with this permit or Department rules.

Reasonable time may depend on the nature of the concern being investigated.

8. If, for any reason, the permittee does not comply with or will be unable to comply with any condition or limitation specified in this permit, the permittee shall immediately provide the Department with the following information:

a. A description of and cause of non-compliance; and,

b. The period of noncompliance, including dates and times; or, if not corrected, the anticipated time the non-compliance is expected to continue, and steps being taken to reduce, eliminate, and prevent recurrence of the non-compliance.

The permittee shall be responsible for any and all damages which may result and may be subject to enforcement action by the Department for penalties or for revocation of this permit.

GENERAL CONDITIONS cont.:

9. In accepting this permit, the permittee understands and agrees that all records, notes, monitoring data and other information relating to the construction or operation of this permitted source which are submitted to the Department may be used by the Department as evidence in any enforcement case involving the permitted source arising under the F.S. or Department rules, except where such use is prescribed by Sections 403.73 and 403.111, F.S. Such evidence shall only be used to the extent it is consistent with the Florida Rules of Civil Procedure and appropriate evidentiary rules.

10. The permittee agrees to comply with changes in Department rules and F.S. after a reasonable time for compliance, provided, however, the permittee does not waive any other rights granted by F.S. or Department rules.

11. This permit is transferable only upon Department approval in accordance with Rules 17-4.120 and 17-730.300, F.A.C., as applicable. The permittee shall be liable for any non-compliance of the permitted activity until the transfer is approved by the Department.

12. This permit or a copy thereof shall be kept at the work site of the permitted activity.

13. This permit also constitutes:

(x) Determination of Best Available Control Technology (BACT)
(x) Determination of Prevention of Significant Deterioration and Nonattainment Areas NSR
(x) Compliance with New Source Performance Standards
(NSPS; Subpart Da)

14. The permittee shall comply with the following:

a. Upon request, the permittee shall furnish all records and plans required under Department rules. During enforcement actions, the retention period for all records will be extended automatically unless otherwise stipulated by the Department.

b. The permittee shall hold at the facility or other location designated by this permit records of all monitoring information (including all calibration and maintenance records and all original strip chart recordings for continuous monitoring instrumentation) required by the permit, copies of all reports required by this permit, and records of all data used to complete the application for this permit. These materials shall be retained at least three years from the date of the sample, measurement, report, or application unless otherwise specified by Department rule.

GENERAL CONDITIONS cont.:

c. Records of monitoring information shall include:

- The date, exact place, and time of sampling or measurements;
- The person responsible for performing the sampling or measurements;
- The dates analyses were performed;
- The person responsible for performing the analyses;
- The analytical techniques or methods used; and,
- The results of such analyses.

15. When requested by the Department, the permittee shall within a reasonable time furnish any information required by law which is needed to determine compliance with the permit. If the permittee becomes aware that relevant facts were not submitted or were incorrect in the permit application or in any report to the Department, such facts or information shall be corrected promptly.

II. SPECIFIC CONDITIONS:

General: The construction and operation of Cedar Bay Cogeneration Project (CBCP) shall be in accordance with all applicable provisions of Chapters 17-210 through 17-297, F.A.C. In addition to the foregoing, CBCP shall comply with the following conditions as indicated, which reflect the conditions of the Modification of Certification dated May 11, 1993:

A. Emission Limitations for 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 charging rate to each of two CFBs of short fiber recycle rejects from the Seminole Kraft Corporation (SKC) recycling process shall not exceed 210 yd^3/day wet and 69,588 yd^3/yr wet. This reflects a combined total of 420 yd^3/day wet and 139,176 yd^3/yr wet 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.

SPECIFIC CONDITIONS cont.:

d. The sulfur content of the coal shall not exceed 1.2%, by weight, on an annual basis. The sulfur content shall not exceed 1.7%, by weight, on a shipment (train load) basis.

e. Auxiliary fuel burners shall be fueled only with No. 2 fuel oil with a maximum sulfur content of 0.05%, by weight. The fuel oil shall normally only be used for startups. During the commercial operation, the maximum annual oil usage shall not exceed 1,900,000 gals./year. The maximum heat input from the fuel oil shall not exceed 380 MMBtu/hr. for each of the CFBs.

f. The CFBs shall be fueled only with the fuels permitted in Conditions Nos. II.A.1.a., 1.b. and 1.e. Other fuels or wastes shall not be burned without prior specific written approval of the Secretary of the Department of Environmental Protection pursuant to Specific Condition No. II.E., Modification of Conditions.

g. The CFBs may operate continuously, i.e., 8760 hrs/yr, but shall not exceed 25.98×10^6 MMBtu/yr total annual heat input.

h. To the extent that it is consistent with Specific Condition No. II.A.1.b. and the following, CBCP shall burn all of the short fiber rejects generated by SKC in processing recycled paper. No less than ninety (90) days prior to completion of construction, CBCP shall submit a plan to the Department 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 supplemental fuel without exceeding any of the limitations on emissions and fuel usage contained in Specific Condition No. 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 the Department 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 the Department and to the RESD within forty-five (45) days of completion of the test burn. The Department 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.

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.

SPECIFIC CONDITIONS cont.:

c. CBCP shall conduct a test to determine whether substantial additional removal of mercury can be obtained through a 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, CBCP shall conduct a test on one CFB to compare mercury emissions to the atmosphere with and without carbon injection. The test program will include the testing of carbon injection between the boiler and the fabric filter. Carbon forms to be tested may include activated carbon with or without additives and pulverized coal with or without additives. After consultation with the Department, RESD and EPRI, CBC shall submit a mercury control test protocol to the Department for approval by December 1, 1993. Results of the test shall be submitted to the Department within 90 days of completion.

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	0.175[1]	186[1]	758	2273
NOx	0.17[2]	180.7[2]	736.1	2208
SO_2	0.24[3]	255.1[3]	--	--
	0.20[4]	--	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	4.66×10^{-4}	0.50	2.0	6.1
Fluorides	7.44×10^{-4}	0.79	3.2	9.7
Lead	6.03×10^{-5}	0.06	0.26	0.78
Mercury	2.89×10^{-5}	0.03	0.13	0.38
Beryllium	8.70×10^{-6}	0.01	0.04	0.11

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

1 Eight-hour rolling average, except for initial and annual compliance tests and the CEM certification, when the 1-hour applies.
2 Thirty-day rolling average.
3 Three-hour rolling average.
4 Twelve-Month rolling average.

SPECIFIC CONDITIONS cont.:

4. Ammonia (NH_3) slip from exhaust gases shall not exceed 10 ppmvd when burning coal at 100% capacity and 30 ppmvd when burning oil.

5. Visible emissions (VE) shall not exceed 20% opacity (6 minute average), except for one 6 minute period per hour when VE shall not exceed 27% opacity pursuant to 40 CFR 60.42a.

6. Compliance with the emission limits shall be determined by EPA reference method tests included in the July 1, 1992 version of 40 CFR 60 and 61, Chapter 17-297, F.A.C., and listed in Specific Condition No. II.A.8. of this permit or by equivalent methods after obtaining prior written Department approval. In addition, compliance with the emission limitations in Specific Condition No. II.A.3. for CO, NOX and SO_2, and with the opacity requirements in Specific Condition No. II.A.5., shall be determined with the continuous emission monitoring systems (CEMS) identified in Specific Condition No. II.A.9.

7. The CFBs are subject to 40 CFR 60, Subparts A and Da; except that where requirements within this permit are more restrictive, the requirements of this permit shall apply.

8. Compliance Tests for each CFB

a. Initial and subsequent 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), (c), (d), (e) and (f).

b. Annual compliance tests shall be performed for PM, CO, 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 for each permitted fuel.

e. The following test methods and procedures pursuant to Chapter 17-297, F.A.C., and 40 CFR 60 and 61, or by equivalent methods after obtaining prior written Department 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.

SPECIFIC CONDITIONS cont.:

(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 and Appendix A.

(10) Method 10 for CO.

(11) Method 12 for lead.

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

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

(14) Method 18 or 25 for VOCs.

(15) Method 101A for mercury.

(16) Method 104 for beryllium.

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

(18) Ammonia (NH_3) method to be determined by the Department.

9. Continuous Emission Monitoring for each CFB

CBCP shall install, certify, calibrate, operate, and maintain CEMS for opacity, SO_2, NO_x, CO, and O_2 or CO_2, pursuant to all applicable requirements of Rule 17-296.800, F.A.C.; Chapter 17-297, F.A.C.; 40 CFR 60, Subpart A; 40 CFR 60, Subpart Da; 40 CFR 60, Appendix B; and, 40 CFR 60, Appendix F. These CEMS shall be used to determine compliance with the emission limitations in Specific Condition No. II.A.3. for CO, NOx, and SO_2, and with the opacity requirements in Specific Condition No. II.A.5. The permittee may elect to install, certify, calibrate, operate, and maintain multiple span CEMS for sulfur dioxide and nitrogen oxides providing certification tests and calibrations are performed for each span. Each of the CEMS for sulfur dioxide and nitrogen oxides shall continuously record data on a span that satisfies the requirements of 40 CFR 60.47a. Any exception to the above must be specifically authorized by the

SPECIFIC CONDITIONS cont.:
Department, in writing, and in accordance with state and federal regulations.

a. 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.

b. 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.

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

d. 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).

e. For purposes of reports required under this permit, excess emissions are defined as any calculated average emission concentration, as determined pursuant to Specific Condition No. II.A.11., herein, which exceeds the applicable emission limit in Specific Condition No. II.A.3.

f. The permittee is subject to all applicable provisions of Rule 17-4.130, F.A.C., Plant Operation-Problems.

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. All coal 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 and recorded for each 24-hour period in which rejects are burned.

11. Reporting for each CFB

a. A minimum of thirty (30) days prior written notification of compliance testing shall be given to the Department's N.E. District office and to the RESD office, in accordance with 40 CFR 60.8.

SPECIFIC CONDITIONS cont.:

b. In accordance with Rule 17-297.570, F.A.C., the results of the compliance test shall be submitted to the RESD office within 45 days after completion of the last test run.

c. The owner or operator shall submit excess emission reports to the RESD office, in accordance with Rule 17-210.700, F.A.C., and 40 CFR 60.7(c) and (d). The reports 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 measures 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, monitoring devices, and performance testing measurements; all continuous monitoring system performance evaluations; all continuous 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)(e)).

d. Annual and quarterly reports shall be submitted to the RESD office as per Rule 297.500, F.A.C.

12. Any change in the method of operation, fuels utilized, equipment, or operating hours or any other changes pursuant to Rule 17-212.200, F.A.C., defining modification, shall be submitted for approval to the Department's Bureau of Air Regulation (BAR).

13. All records of documentation shall be kept on file for a minimum of 3 years pursuant to Rule 17-4.160(4), F.A.C.

14. The permittee is subject to all applicable provisions of Rule 17-210.700, F.A.C., Excess Emissions.

SPECIFIC CONDITIONS cont.:

15. The permittee is subject to all applicable provisions of Rule 17-210.650, F.A.C., Circumvention.

16. The permittee is subject to all applicable provisions of Rule 17-4.160, F.A.C., Permit Conditions.

B. 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 dryers, 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 a maximum of 11 hours per day (maximum of 2920 hrs/yr) at maximum capacity.

2. The material handling/usage rates for coal, limestone, fly ash, and bed ash shall not exceed the following:

	Handling/Usage Rate	
Material	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; and, TPY is tons per year.

3. The VOC emissions, from the maximum No. 2 fuel oil utilization rate of 240 gals/hr. and 700,800 gals/year for the limestone dryers and 8000 gals/hr. and 1,900,000 gals/year for the three boilers, are not expected to be significant.

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 Silo
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 PM emission limitation requirement of 0.003 gr/dscf (applicant

SPECIFIC CONDITIONS cont.:
requested limitation which is more stringent than what is allowed by Rule 17.296.711, F.A.C.). Since these sources are RACT standard type, then a one-time verification test on each source shall be required for PM mass emissions to demonstrate that the baghouse control systems can achieve the 0.003 gr/dscf. The performance tests shall be conducted using EPA Method 5 pursuant to Rule 17-297, F.A.C., and 40 CFR 60, Appendix A (July, 1992 version).

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

Coal Car Unloading
Ash Pellet Hydrator
Ash Pellet Curing Silo
Ash Pelletizing Pan

The above listed sources are subject to a VE and a PM emissions limitation requirement of 5% opacity and 0.01 gr/dscf (applicant requested limitation, which is more stringent than what is allowed by rule), respectively, in accordance with Rule 17-296.711, F.A.C. Initial and subsequent compliance tests shall be conducted for VE and PM emissions using EPA Methods 9 and 5, respectively, in accordance with Chapter 17-297, F.A.C., and 40 CFR 60, Appendix A (July, 1992 version).

5. VE shall not exceed 5% opacity from any source in the material handling and treatment area listed in Specific Condition No. II.B.4., in accordance with Rule 17-296.711(2)(a), F.A.C. After the one-time PM mass emissions verification compliance tests have been performed, neither the Department nor the RESD will require a PM mass emissions test in accordance with EPA Method 5 unless the VE limit of 5% opacity is exceeded for a given source, or unless the Department or the RESD, based on other information, has reason to believe that the PM emission limits are being violated in accordance with Rule 17-297.620(4), F.A.C.

6. All sources subject to VE and PM mass emissions performance tests shall conduct them concurrently, except where inclement weather interferes.

SPECIFIC CONDITIONS cont.:

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

Pollutant	lbs/hr.	TPY	TPY for 2 dryers
PM/PM_{10}	0.24	0.32	0.64
SO_2	0.85	1.15	2.3
CO	0.60	0.81	1.62
NOx	2.40	3.25	6.5
VOC	0.05	0.06	0.12

VE from the dryers shall not exceed 5% opacity.

8. The maximum sulfur content of No. 2 fuel oil shall not exceed 0.05%, by weight. The maximum firing rate of No. 2 fuel oil for each limestone dryer shall not exceed 120 gals/hr., or 350,400 gals/year. This reflects a combined total fuel oil firing rate of 240 gals/hr., and 700,800 gals/year, for the two dryers.

9. Initial and annual PM emissions and VE 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, 1992 version of 40 CFR 60, Appendix A, using EPA Methods 5 and 9, respectively.

10. Compliance test reports shall be submitted to the RESD within 45 days of test completion in accordance with Rule 17-297.570, F.A.C.

11. Any changes in the method of operation, raw materials processed, equipment, or operating hours or any other changes pursuant to Rule 17-212.200, F.A.C., defining modification, shall be submitted for approval to the Department's BAR.

C. Requirements For the Permittees

1. Beginning one month after certification, CBCP shall submit to the RESD and the Department'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. CBCP shall report any delays in construction and completion of the project which would delay commercial operation by more than 90 days to the RESD office.

SPECIFIC CONDITIONS cont.:

3. Reasonable precautions to prevent fugitive PM 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 CBCP. CBCP is subject to all applicable provisions of Rule 17-296.310(3), F.A.C., Unconfined Emissions of Particulate Matter.

4. Fuel shall not be burned in any CBCP unit unless the control devices are operating properly, pursuant to 40 CFR 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 0.05%, 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 three years to be available for the Department and RESD inspection.

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

7. CBC 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. CBCP shall provide stack sampling facilities as required by Rule 17-297.345, F.A.C.

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

10. All CBCP records of documentation shall be kept on file for a minimum of three years pursuant to Rule 17-4.160(14), F.A.C.

D. Contemporaneous Emission Reductions

The following SKC sources shall be permanently shut down and made incapable of operation, and shall turn in their operation permits to the Department's BAR, within 30 days of written confirmation by the Department of the successful completion of the initial compliance tests on the 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. The RESD office 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

SPECIFIC CONDITIONS cont.:
requirement to assure common control for purpose of ensuring that all commitments relied on are in fact fulfilled.

E. Modification of Specific Conditions

The Specific Conditions of this permit may be modified in the following manner:

1. Through the May 11, 1993 Modification of Certification, the Board, which means the Governor and Cabinet, delegated to the Secretary of Department of Environmental Protection the authority to modify, after notice and opportunity for hearing, any conditions pertaining to consumptive use of water, reclaimed water, monitoring, sampling, ground water, surface water, mixing zones, or variances to water quality standards, zones of discharge, leachate control programs, effluent limitations, air emission limitations, fuel, or solid waste disposal, right of entry, railroad spur transmission line, access road, pipelines, or designation of agents for the purpose of enforcing the conditions of this permit.

2. All other modifications shall be made in accordance with Section 403.516, F.S.

Issued this______________day

of____________________,1993

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL REGULATION

____
Virginia B. Wetherell, Secretary

Table 3. Data and Calculation for Co-firing Pet Coke with Coal at Cedar Bay Cogeneration Facility -Mike's Calculations for Percent Utilization

Parameter	Units	Year 1997	1998	1999	2000	2001	Basis
Co-firing Fuel	MMBtu	23,093,877.8	22,768,176.6	23,005,399.1	22,809,944.9	21,904,349.0	Same as AOR
Co-firing Fuel	tons	915,838.6	912,329.1	909,984.1	902,252.9	868,668.2	Coal + Pet Coke (tons)
Coal (65% by weight)	tons	595,295.1	593,013.9	591,489.7	586,464.4	564,634.3	Co-firing Fuel x 0.65
Coal (65% by weight)	MMBtu	14,168,023	13,876,526	14,136,603	14,016,498	13,438,222	Coal (tons) x Coal heat content (MMBtu/ton)
Coal	%	65%	65%	65%	65%	65%	minimum
Pet Coke (35% by weight)	MMBtu	8,925,855	8,891,651	8,868,796	8,793,447	8,466,127	Pet Coke (tons) x 27.846 MMBtu/ton
Pet Coke (35% by weight)	tons	320,544	319,315	318,494	315,789	304,034	Co-firing Fuel x 0.35
Pet Coke	%	35%	35%	35%	35%	35%	maximum
Pet Coke - sulfur	%	5.45	5.45	5.45	5.45	5.45	Foster Wheeler
Pet Coke - ash	%	0.37	0.37	0.37	0.37	0.37	Foster Wheeler
Coal - ash	tons	67,863.6	71,754.7	69,914.1	61,754.7	67,191.5	Coal (tons) x Ash (%)
Pet Coke - ash	tons	1,186.0	1,181.5	1,178.4	1,168.4	1,124.9	Pet Coke (tons) x Ash (%)
Total Ash	tons	69,049.7	72,936.2	71,092.5	62,923.1	68,316.4	Coal ash + Pet Coke ash
SO_2 coal	tons	11,191.5	12,571.9	13,131.1	12,433.0	10,728.1	Coal (tons) x Sulfur (%)/100 x 2
SO_2 pet coke	tons	34,939.2	34,805.4	34,715.9	34,420.9	33,139.7	Pet Coke (tons) x Sulfur (%)/100 x 2
SO_2 total	tons	46,130.8	47,377.3	47,847.0	46,854.0	43,867.7	Coal SO
SO_2 emitted	tons	1,909.0	1,935.6	1,926.2	1,965.1	1,901.5	AOR
SO_2 removed	tons	44,221.8	45,441.7	45,920.8	44,888.9	41,966.2	SO_2 total - SO_2 emitted
SO_2 removed	%	95.9%	95.9%	96.0%	95.8%	95.7%	SO_2 removed/SO_2 total
$CaSO_4$ Formed	tons	93,971.3	96,563.5	97,581.6	95,388.8	89,178.3	SO_2 removed x 130/64
Ash and $CaSO_4$	tons	163,021.0	169,499.7	168,674.2	158,311.9	157,494.7	Ash (tons) + $CaSO_4$ formed (tons)
Total Bed and Fly Ash	tons	318,996.1	302,554.8	290,470.4	271,135.2	286,946.9	Ash and $CaSO_4$ + Limestone excess x 44/100
Fly Ash	tons	213,728.7	202,713.1	191,709.1	178,949.4	189,385.1	Total Bed and Fly Ash x Ratio Fly to Total Ash
Bed Ash	tons	**105,267.4**	**99,841.6**	**98,761.3**	**92,185.8**	**97,561.8**	Total Ash - Fly Ash
Limestone for SO_2 removal	tons	69,096.5	71,002.6	71,751.2	70,138.8	65,572.3	SO_2 removed x 100/64
Limestone Utilization		**19.9%**	**23.0%**	**24.8%**	**25.8%**	**22.1%**	
Limestone -total	**tons**	**347,623.5**	**308,601.0**	**289,244.4**	**271,608.9**	**296,736.9**	**Based on Actual Utilization: Limestone SO_2/Limestone Total**
Limestone excess	tons	278,527.0	237,598.4	217,493.2	201,470.1	231,164.6	Limestone Total - Limestone for SO_2 removal
Fuel	lb/hr	227,471.6	225,591.4	228,104.3	234,574.8	232,180.4	tons x 2,000/hours
Limestone	lb/hr	86,341.1	76,307.7	72,504.5	70,615.0	79,312.8	tons x 2,000/hours
Fly Ash	lb/hr	53,084.9	50,124.8	48,055.4	46,524.7	50,619.4	tons x 2,000/hours
Bed Ash	lb/hr	26,145.8	24,687.8	24,756.3	23,967.2	26,076.6	tons x 2,000/hours
Difference in Fuel	tons	-54,492.4	-60,669.9	-52,584.9	-52,138.1	-51,687.7	Co-firing Fuel - Coal (tons)
Difference in Fuel Ash	tons	-41,568.1	-44,796.7	-42,683.1	-37,574.3	-41,205.9	Co-firing Fuel - Coal (tons)
Difference in Limestone	tons	219,229.5	181,661.0	166,778.4	161,075.0	186,535.9	Co-firing Fuel - Coal (tons)
Difference in Total Bed and Fly Ash	tons	122,036.1	92,251.8	80,914.4	61,620.2	82,388.9	Co-firing Fuel - Coal (tons)
Difference in Fly Ash	tons	81,764.7	61,809.1	53,403.1	40,669.4	54,376.7	Co-firing Fuel - Coal (tons)

6c

Department of Environmental Protection

Jeb Bush
Governor

Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

David B. Struhs
Secretary

Foster Wheeler

Table 3. Data and Calculation for Co-firing Pet Coke with Coal at Cedar Bay Cogeneration Facility

Parameter	Units	Year					Basis
		1997	1998	1999	2000	2001	
Co-firing Fuel	MMBtu	23,093,877.8	22,768,176.6	23,005,399.1	22,809,944.9	21,904,349.0	Same as AOR
Co-firing Fuel	tons	915,838.6	912,329.1	909,984.1	902,252.9	868,668.2	Coal + Pet Coke (tons)
Coal (65% by weight)	tons	595,295.1	593,013.9	591,489.7	586,464.4	564,634.3	Co-firing Fuel x 0.65
Coal (65% by weight)	MMBtu	14,168,023	13,876,526	14,136,603	14,016,498	13,438,222	Coal (tons) x Coal heat content (MMBtu/ton)
Coal	%	65%	65%	65%	65%	65%	minimum
Pet Coke (35% by weight)	MMBtu	8,925,855	8,891,651	8,868,796	8,793,447	8,466,127	Pet Coke (tons) x 27.846 MMBtu/ton
Pet Coke (35% by weight)	tons	320,544	319,315	318,494	315,789	304,034	Co-firing Fuel x 0.35
Pet Coke	%	35%	35%	35%	35%	35%	maximum
Pet Coke - sulfur	%	5.45	5.45	5.45	5.45	5.45	Foster Wheeler
Pet Coke - ash	%	0.37	0.37	0.37	0.37	0.37	Foster Wheeler
Coal - ash	tons	67,863.6	71,754.7	69,914.1	61,754.7	67,191.5	Coal (tons) x Ash (%)
Pet Coke - ash	tons	1,186.0	1,181.5	1,178.4	1,168.4	1,124.9	Pet Coke (tons) x Ash (%)
Total Ash	tons	69,049.7	72,936.2	71,092.5	62,923.1	68,316.4	Coal ash + Pet Coke ash
SO_2 coal	tons	11,191.5	12,571.9	13,131.1	12,433.0	10,728.1	Coal (tons) x Sulfur (%)/100 x 2
SO_2 pet coke	tons	34,939.2	34,805.4	34,715.9	34,420.9	33,139.7	Pet Coke (tons) x Sulfur (%)/100 x 2
SO_2 total	tons	46,130.8	47,377.3	47,847.0	46,854.0	43,867.7	Coal SO
SO_2 emitted	tons	1,909.0	1,935.6	1,926.2	1,965.1	1,901.5	AOR
SO_2 removed	tons	44,221.8	45,441.7	45,920.8	44,888.9	41,966.2	SO_2 total - SO_2 emitted
SO_2 removed	%	95.9%	95.9%	96.0%	95.8%	95.7%	SO_2 removed/SO_2 total
$CaSO_4$ Formed	tons	93,971.3	96,563.5	97,581.6	95,388.8	89,178.3	SO_2 removed x 130/64
Ash and $CaSO_4$	tons	163,021.0	169,499.7	168,674.2	158,311.9	157,494.7	Ash (tons) + $CaSO_4$ formed (tons)
Total Bed and Fly Ash	tons	**273,059.1**	**277,900.5**	276,274.9	**265,560.1**	**261,845.9**	Ash and $CaSO_4$ + Limestone excess x 44/100
Fly Ash	tons	160,702.2	165,206.8	163,596.1	160,339.7	156,323.6	Total Bed and Fly Ash x Ratio Fly to Total Ash
Bed Ash	tons	79,150.4	81,368.8	84,278.5	82,599.1	80,530.2	Total Ash - Fly Ash
Limestone for SO_2 removal	tons	69,096.5	71,002.6	71,751.2	70,138.8	65,572.3	SO_2 removed x 100/64
Limestone Utilization		**26.0%**	**26.8%**	**27.2%**	**26.8%**	**26.0%**	
Limestone -total	**tons**	**265,593.2**	**264,575.4**	**263,895.4**	**261,653.3**	**251,913.8**	**0.29 x Co-firing Fuel (tons) Foster Wheeler report**
Limestone excess	tons	196,496.6	193,572.9	192,144.2	191,514.5	186,341.5	Limestone Total - Limestone for SO_2 removal
Fuel	lb/hr	227,471.6	225,591.4	228,104.3	234,574.8		tons x 2,000/hours
Limestone	lb/hr	65,966.8	65,421.5	66,150.2	68,026.7		tons x 2,000/hours
Fly Ash	lb/hr	39,914.4	40,850.6	41,008.4	41,686.4		tons x 2,000/hours
Bed Ash	lb/hr	19,659.0	20,120.0	21,126.0	21,474.8		tons x 2,000/hours
Difference in Fuel	tons	-54,492.4	-60,669.9	-52,584.9	-52,138.1	-51,687.7	Co-firing Fuel - Coal (tons)
Difference in Fuel Ash	tons	-41,568.1	-44,796.7	-42,683.1	-37,574.3	-41,205.9	Co-firing Fuel - Coal (tons)
Difference in Limestone	tons	137,199.2	137,635.4	141,429.4	151,119.4	141,712.8	Co-firing Fuel - Coal (tons)
Difference in Total Bed and Fly Ash	tons	42,892.5	36,272.5	38,318.6	33,423.8	32,295.8	Co-firing Fuel - Coal (tons)
Difference in Fly Ash	tons	28,738.2	24,302.8	25,290.1	22,059.7	156,323.6	Co-firing Fuel - Coal (tons)

Table 5b. Data and Calculation for Inlet Loading to Baghouses when Co-firing 20% Pet Coke (5.5%S) with Coal at Cedar Bay Cogeneration Facility

Parameter	Units	Year					Basis
		1997	1998	1999	2000	2001	
Fly Ash - Coal Firing	lb/hr/facility	32,776.59	34,841.29	34,668.95	35,951.12	36,085.47	Table 2, based on actual fly ash
Fly Ash - Coal Firing	lb/hr/unit	10,925.53	11,613.76	11,556.32	11,983.71	12,028.49	divided by 3 CFBs
PM Emission Rate with coal	grains/acfm	4.28	4.55	4.53	4.70	4.71	lb/hr x 7,000 grains/lb x 1/acfm x 1/60
Fly Ash - Co-Firing	lb/hr/facility	44,253.93	42,250.76	40,642.06	39,148.88	42,420.56	Table 2, based on actual fly ash
Fly Ash - Co-Firing	lb/hr/unit	14,751.31	14,083.59	13,547.35	13,049.63	14,140.19	divided by 3 CFBs
PM Emission Rate with coal	grains/acfm	5.78	5.52	5.31	5.11	5.54	lb/hr x 7,000 grains/lb x 1/acfm x 1/60
PM Emission Rate Increase	grains/acfm	1.50	0.97	0.78	0.42	0.83	Co-firing - Coal (grains/acf)
Maximum Projected	lb/hr/unit	17,000.00					Foster Wheeler Report (Figure 12)
Maximum Projected	grains/acfm	6.66					lb/hr x 7,000 grains/lb x 1/acfm x 1/60
Flow Rate of Unit	acfm	297,700					

Table 5a. Data and Calculation for Inlet Loading to Baghouses when Co-firing 20% Pet Coke (5.5%S) with Coal at Cedar Bay Cogeneration Facility

Parameter	Units	Year					Basis
		1997	1998	1999	2000	2001	
Fly Ash - Coal Firing	lb/hr/facility	32,776.59	34,841.29	34,668.95	35,951.12	36,085.47	Table 2, based on actual fly ash
Fly Ash - Coal Firing	lb/hr/unit	10,925.53	11,613.76	11,556.32	11,983.71	12,028.49	divided by 3 CFBs
PM Emission Rate with coal	grains/acfm	4.28	4.55	4.53	4.70	4.71	lb/hr x 7,000 grains/lb x 1/acfm x 1/60
Fly Ash - Co-Firing	lb/hr/facility	45,079.64	43,943.21	42,302.99	40,409.27	43,583.38	Table 2, based on actual fly ash
Fly Ash - Co-Firing	lb/hr/unit	15,026.55	14,647.74	14,101.00	13,469.76	14,527.79	divided by 3 CFBs
PM Emission Rate with coal	grains/acfm	5.89	5.74	5.53	5.28	5.69	lb/hr x 7,000 grains/lb x 1/acfm x 1/60
PM Emission Rate Increase	grains/acfm	1.61	1.19	1.00	0.58	0.98	Co-firing - Coal (grains/acf)
Maximum Projected	lb/hr/unit	17,000.00					Foster Wheeler Report (Figure 12)
Maximum Projected	grains/acfm	6.66					lb/hr x 7,000 grains/lb x 1/acfm x 1/60
Flow Rate of Unit	acfm	297,700					

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Table 3a. Data and Calculation for 20% Co-firing Pet Coke (5.5% S) with 80% Coal at Cedar Bay Cogeneration Facility Based on Utilization

20,575

Parameter	Units	Year 1997	1998	1999	2000	2001	Basis
Co-firing Fuel	MMBtu	23,093,877.8	22,768,176.6	23,005,399.1	22,809,944.9	21,904,349.0	Same as AOR
Co-firing Fuel	tons	938,424.6	937,378.6	931,800.1	923,883.5	890,091.6	Coal + Pet Coke (tons)
Coal (80% by weight)	tons	750,739.7	749,902.9	745,440.1	739,106.8	712,073.3	Co-firing Fuel x 0.80
Coal (80% by weight)	MMBtu	17,867,604	17,547,728	17,816,018	17,664,653	16,947,251	Coal (tons) x Coal heat content (MMBtu/ton)
Coal	**%**	**80%**	**80%**	**80%**	**80%**	**80%**	minimum
Pet Coke (20% by weight)	MMBtu	5,226,274	5,220,449	5,189,381	5,145,292	4,957,098	Pet Coke (tons) x 27.846 MMBtu/ton
Pet Coke (20% by weight)	tons	187,685	187,476	186,360	184,777	178,018	Co-firing Fuel x 0.20
Pet Coke	**%**	**20%**	**20%**	**20%**	**20%**	**20%**	maximum
Pet Coke - sulfur	%	5.45	5.45	5.45	5.45	5.45	Foster Wheeler
Pet Coke - ash	%	0.37	0.37	0.37	0.37	0.37	Foster Wheeler
Coal - ash	tons	85,584.3	90,738.2	88,111.0	77,827.9	84,736.7	Coal (tons) x Ash (%)
Pet Coke - ash	tons	694.4	693.7	689.5	683.7	658.7	Pet Coke (tons) x Ash (%)
Total Ash	tons	86,278.8	91,431.9	88,800.5	78,511.6	85,395.4	Coal ash + Pet Coke ash
SO2 coal	tons	14,113.9	15,897.9	16,548.8	15,669.1	13,529.4	Coal (tons) x Sulfur (%)/100 x 2
SO2 pet coke	tons	20,457.7	20,434.9	20,313.2	20,140.7	19,404.0	Pet Coke (tons) x Sulfur (%)/100 x 2
SO2 total	tons	34,571.6	36,332.8	36,862.0	35,809.7	32,933.4	Coal SO
SO2 emitted	tons	1,909.0	1,935.6	1,926.2	1,965.1	1,901.5	AOR
SO2 removed	tons	32,662.6	34,397.2	34,935.8	33,844.6	31,031.9	SO2 total - SO2 emitted
SO2 removed	%	94.5%	94.7%	94.8%	94.5%	94.2%	SO2 removed/SO2 total
CaSO4 Formed	tons	69,407.9	73,094.0	74,238.6	71,919.8	65,942.8	SO2 removed x 130/64
Ash and CaSO4	tons	155,686.7	164,525.9	163,039.2	150,431.4	151,338.2	Ash (tons) + CaSO4 formed (tons)
Total Bed and Fly Ash	tons	270,891.1	265,242.4	255,699.9	235,496.1	247,061.4	Ash and CaSO4 + Limestone excess x 44/100
Fly Ash	tons	181,498.2	177,713.7	168,760.7	155,427.5	163,060.7	Total Bed and Fly Ash x Ratio Fly to Total Ash
Bed Ash	tons	89,393.0	87,528.7	86,939.1	80,068.6	84,000.8	Total Ash - Fly Ash
Limestone for SO2 removal	tons	51,035.3	53,745.6	54,587.2	52,882.2	48,487.3	SO2 removed x 100/64
Limestone Utilization		**19.9%**	**23.0%**	**24.8%**	**25.8%**	**22.1%**	
Limestone -total	**tons**	**256,757.5**	**233,596.5**	**220,052.7**	**204,783.4**	**219,421.7**	**Based on Percent utilization**
Limestone excess	tons	205,722.2	179,850.8	165,465.5	151,901.2	170,934.4	Limestone Total - Limestone for SO2 removal
Fuel	lb/hr	233,081.4	231,785.4	233,572.9	240,198.5	237,906.5	tons x 2,000/hours
Limestone	lb/hr	63,772.2	57,761.3	55,160.3	53,241.2	58,647.7	tons x 2,000/hours
Fly Ash	lb/hr	45,079.6	43,943.2	42,303.0	40,409.3	43,583.4	tons x 2,000/hours
Bed Ash	lb/hr	22,203.0	21,643.2	21,792.9	20,816.9	22,452.0	tons x 2,000/hours
Difference in Fuel	tons	-31,906.4	-35,620.4	-30,768.9	-30,507.5	-30,264.3	Co-firing Fuel - Coal (tons)
Difference in Fuel Ash	tons	-24,339.0	-26,301.0	-24,975.1	-21,985.8	-24,127.0	Co-firing Fuel - Coal (tons)
Difference in Limestone	tons	128,363.5	106,656.5	97,586.7	94,249.5	109,220.7	Co-firing Fuel - Coal (tons)
Difference in Total Ash	tons	73,931.1	54,939.4	46,143.9	25,981.1	42,503.4	Co-firing Fuel - Coal (tons)
Difference in Fly Ash	tons	49,534.2	36,809.7	30,454.7	17,147.5	28,052.3	Co-firing Fuel - Coal (tons)
Difference in Fly Ash	tons	46,146.3	29,902.0	23,766.7	12,238.1	23,642.5	Co-firing Fuel - Coal (tons)

20% @ 5.5%
35% @ 4%

09K = limit

Table 3b. Data and Calculation for 35% Co-firing Pet Coke (4% S) with 65% Coal at Cedar Bay Cogeneration Facility Based on Utilization

Parameter	Units	Year 1997	1998	1999	2000	2001	Basis
Co-firing Fuel	MMBtu	23,093,877.8	22,768,176.6	23,005,399.1	22,809,944.9	21,904,349.0	Same as AOR
Co-firing Fuel	tons	901,104.9	897,501.5	895,381.7	887,774.5	854,693.3	Coal + Pet Coke (tons)
Coal (65% by weight)	tons	585,718.2	583,376.0	581,998.1	577,053.4	555,550.7	Co-firing Fuel x 0.65
Coal (65% by weight)	MMBtu	13,940,093	13,650,998	13,909,754	13,791,577	13,222,032	Coal (tons) x Coal heat content (MMBtu/ton)
Coal	**%**	**65%**	**65%**	**65%**	**65%**	**65%**	minimum
Pet Coke (35% by weight)	MMBtu	9,153,784	9,117,179	9,095,645	9,018,368	8,682,317	Pet Coke (tons) x 27.846 MMBtu/ton
Pet Coke (35% by weight)	tons	315,387	314,126	313,384	310,721	299,143	Co-firing Fuel x 0.35
Pet Coke	**%**	**35%**	**35%**	**35%**	**35%**	**35%**	maximum
Pet Coke - sulfur	%	4.09	4.09	4.09	4.09	4.09	Foster Wheeler
Pet Coke - ash	%	0.6	0.6	0.6	0.6	0.6	Foster Wheeler
Coal - ash	tons	66,771.9	70,588.5	68,792.2	60,763.7	66,110.5	Coal (tons) x Ash (%)
Pet Coke - ash	tons	1,892.3	1,884.8	1,880.3	1,864.3	1,794.9	Pet Coke (tons) x Ash (%)
Total Ash	tons	68,664.2	72,473.2	70,672.5	62,628.1	67,905.4	Coal ash + Pet Coke ash
SO2 coal	tons	11,011.5	12,367.6	12,920.4	12,233.5	10,555.5	Coal (tons) x Sulfur (%)/100 x 2
SO2 pet coke	tons	25,798.6	25,695.5	25,634.8	25,417.0	24,469.9	Pet Coke (tons) x Sulfur (%)/100 x 2
SO2 total	tons	36,810.1	38,063.0	38,555.1	37,650.5	35,025.3	Coal SO
SO2 emitted	tons	1,909.0	1,935.6	1,926.2	1,965.1	1,901.5	AOR
SO2 removed	tons	34,901.1	36,127.4	36,628.9	35,685.4	33,123.8	SO2 total - SO2 emitted
SO2 removed	%	94.8%	94.9%	95.0%	94.8%	94.6%	SO2 removed/SO2 total
CaSO4 Formed	tons	74,164.9	76,770.8	77,836.5	75,831.4	70,388.1	SO2 removed x 130/64
Ash and CaSO4	tons	142,829.1	149,244.1	148,509.0	138,459.5	138,293.5	Ash (tons) + CaSO4 formed (tons)
Total Bed and Fly Ash	tons	265,929.3	255,026.7	245,660.4	228,150.8	240,469.8	Ash and CaSO4 + Limestone excess x 44/100
Fly Ash	tons	178,173.7	170,869.1	162,134.7	150,579.6	158,710.2	Total Bed and Fly Ash x Ratio Fly to Total Ash
Bed Ash	tons	87,755.6	84,157.6	83,525.6	77,571.2	81,759.6	Total Ash - Fly Ash
Limestone for SO2 removal	tons	54,533.0	56,449.1	57,232.7	55,758.4	51,756.0	SO2 removed x 100/64
Limestone Utilization		**19.9%**	**23.0%**	**24.8%**	**25.8%**	**22.1%**	
Limestone -total	**tons**	**274,354.7**	**245,346.8**	**230,717.3**	**215,921.5**	**234,213.5**	**Based on Percent utilization**
Limestone excess	tons	219,821.7	188,897.7	173,484.6	160,163.1	182,457.6	Limestone Total - Limestone for SO2 removal
Fuel	lb/hr	223,812.1	221,924.9	224,443.9	230,810.6	228,445.2	tons x 2,000/hours
Limestone	lb/hr	68,142.9	60,666.8	57,833.6	56,137.0	62,601.3	tons x 2,000/hours
Fly Ash	lb/hr	44,253.9	42,250.8	40,642.1	39,148.9	42,420.6	tons x 2,000/hours
Bed Ash	lb/hr	21,796.3	20,809.6	20,937.2	20,167.6	21,853.0	tons x 2,000/hours
Difference in Fuel	tons	-69,226.1	-75,497.5	-67,187.3	-66,616.5	-65,662.6	Co-firing Fuel - Coal (tons)
Difference in Fuel Ash	tons	-41,953.5	-45,259.6	-43,103.2	-37,869.3	-41,617.0	Co-firing Fuel - Coal (tons)
Difference in Limestone	tons	145,960.7	118,406.8	108,251.3	105,387.6	124,012.5	Co-firing Fuel - Coal (tons)
Difference in Total Ash	tons	68,969.3	44,723.7	36,104.4	18,635.8	35,911.8	Co-firing Fuel - Coal (tons)
Difference in Fly Ash	tons	46,209.7	29,965.1	23,828.7	12,299.6	23,701.8	Co-firing Fuel - Coal (tons)
Difference in Fly Ash	tons	46,562.2	30,458.3	24,280.9	12,634.0	24,060.5	Co-firing Fuel - Coal (tons)

Table 4a. Data and Calculation for Co-firing 20% Pet Coke (5.5%S) with Coal at Cedar Bay Cogeneration Facility

Parameter	Units	Year					Basis
		1997	1998	1999	2000	2001	
CO emission rate with co-firing	lb/MMBtu	0.04	0.04	0.04	0.04	0.04	Foster Wheeler Report
CO emissions when co-firing	tons/year	461.9	455.4	460.1	456.2	438.1	MMBtu x lb/MMBtu (assumes same heat input)
CO emissions with coal	tons/year	496	549.6	582.26	516.01	485.1	AOR
Net CO Emissions	tons/year	-34.1	-94.2	-122.2	-59.8	-47.0	Cofiring - Actual Coal
NO_x emission rate with co-firing	lb/MMBtu	0.15	0.15	0.15	0.15	0.15	Foster Wheeler Report
NO_x emissions with co-firing	tons/year	1,732.0	1,707.6	1,725.4	1,710.7	1,642.8	MMBtu x lb/MMBtu (assumes same heat input)
NO_x emissions with coal	tons/year	1,726.0	1,716.4	1,741.5	1,779.0	1,656.9	AOR
Net NO_x emissions	tons/year	6.0	-8.8	-16.1	-68.3	-14.1	Cofiring - Actual Coal
PM_{10} emission rate with co-firing	lb/MMBtu	0.0129	0.0160	0.0150	0.0147	0.0157	average of actual test data
PM_{10} emissions with co-firing	tons/year	149.3	182.5	172.5	167.3	171.6	MMBtu x lb/MMBtu (assumes same heat input)
PM_{10} emissions with coal	tons/year	149.5	178.3	193.7	165.2	201.9	AOR
Net PM_{10} emissions	tons/year	-0.16	4.22	-21.20	2.05	-30.32	Cofiring - Actual Coal
SAM emission rate with co-firing	lb/MMBtu	5.69E-05	5.28E-05	5.18E-05	5.31E-05	5.65E-05	Test data increased for increased sulfur in fuel
SAM emissions with co-firing	tons/year	0.66	0.60	0.60	0.61	0.62	MMBtu x lb/MMBtu (assumes same heat input)
SAM emissions with coal	tons/year	0.35	0.35	0.35904	0.34617	0.3	AOR
Net SAM emissions	tons/year	0.31	0.25	0.24	0.26	0.32	Cofiring - Actual Coal
SO_2 emission rate with co-firing	lb/MMBtu	0.165	0.17	0.167	0.172	0.172	rate adjusted to meet past actuals
SO_2 emissions with co-firing	tons/year	1,905.2	1,935.3	1,921.0	1,961.7	1,883.8	MMBtu x lb/MMBtu (assumes same heat input)
SO_2 emissions with coal	tons/year	1909	1935.6	1926.19	1965.13	1901.5	AOR
Net SO_2 emissions	tons/year	-3.8	-0.3	-5.2	-3.5	-17.7	Cofiring - Actual Coal
VOC emission rate with co-firing	lb/MMBtu	0.0030	0.0030	0.0030	0.0030	0.0030	Test data from 1994 and 2001
VOC emissions when co-firing	tons/year	35.0	34.5	34.8	34.5	33.2	MMBtu x lb/MMBtu (assumes same heat input)
VOC emissions with coal	tons/year	14.8	14.7	17.89104	17.250215	48.7	AOR
Net VOC Emissions	tons/year	20.2	19.8	16.9	17.3	-15.5	Cofiring - Actual Coal

Table 4b. Data and Calculation for Co-firing 35% Pet Coke (4.1%S) with Coal at Cedar Bay Cogeneration Facility

Parameter	Units	Year					Basis
		1997	1998	1999	2000	2001	
CO emission rate with co-firing	lb/MMBtu	0.035	0.035	0.035	0.035	0.035	Foster Wheeler Report
CO emissions when co-firing	tons/year	404.1	398.4	402.6	399.2	383.3	MMBtu x lb/MMBtu (assumes same heat input)
CO emissions with coal	tons/year	496	549.6	582.26	516.01	485.1	AOR
Net CO Emissions	tons/year	-91.9	-151.2	-179.7	-116.8	-101.8	Cofiring - Actual Coal
NO_x emission rate with co-firing	lb/MMBtu	0.15	0.15	0.15	0.15	0.15	Foster Wheeler Report
NO_x emissions with co-firing	tons/year	1,732.0	1,707.6	1,725.4	1,710.7	1,642.8	MMBtu x lb/MMBtu (assumes same heat input)
NO_x emissions with coal	tons/year	1,726.0	1,716.4	1,741.5	1,779.0	1,656.9	AOR
Net NO_x emissions	tons/year	6.0	-8.8	-16.1	-68.3	-14.1	Cofiring - Actual Coal
PM_{10} emission rate with co-firing	lb/MMBtu	0.0129	0.0160	0.0150	0.0147	0.0157	average of actual test data
PM_{10} emissions with co-firing	tons/year	149.3	182.5	172.5	167.3	171.6	MMBtu x lb/MMBtu (assumes same heat input)
PM_{10} emissions with coal	tons/year	149.5	178.3	193.7	165.2	201.9	AOR
Net PM_{10} emissions	tons/year	-0.16	4.22	-21.20	2.05	-30.32	Cofiring - Actual Coal
SAM emission rate with co-firing	lb/MMBtu	6.05E-05	5.54E-05	5.41E-05	5.58E-05	6.01E-05	Test data increased for increased sulfur in fuel
SAM emissions with co-firing	tons/year	0.70	0.63	0.62	0.64	0.66	MMBtu x lb/MMBtu (assumes same heat input)
SAM emissions with coal	tons/year	0.35	0.35	0.35904	0.34617	0.3	AOR
Net SAM emissions	tons/year	0.35	0.28	0.26	0.29	0.36	Cofiring - Actual Coal
SO_2 emission rate with co-firing	lb/MMBtu	0.165	0.17	0.167	0.172	0.172	rate adjusted to meet past actuals
SO_2 emissions with co-firing	tons/year	1,905.2	1,935.3	1,921.0	1,961.7	1,883.8	MMBtu x lb/MMBtu (assumes same heat input)
SO_2 emissions with coal	tons/year	1909	1935.6	1926.19	1965.13	1901.5	AOR
Net SO_2 emissions	tons/year	-3.8	-0.3	-5.2	-3.5	-17.7	Cofiring - Actual Coal
VOC emission rate with co-firing	lb/MMBtu	0.0030	0.0030	0.0030	0.0030	0.0030	Test data from 1994 and 2001
VOC emissions when co-firing	tons/year	35.0	34.5	34.8	34.5	33.2	MMBtu x lb/MMBtu (assumes same heat input)
VOC emissions with coal	tons/year	14.8	14.7	17.89104	17.250215	48.7	AOR
Net VOC Emissions	tons/year	20.2	19.8	16.9	17.3	-15.5	Cofiring - Actual Coal

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subtracted from the calculated total bed and fly ash. The table also includes a calculation of the lb/hr values for coal, limestone, bed ash and fly ash. This information is used to calculate the differences in fuel and material handling with regard to past actual emissions and future actual emissions.

Tables 3a and 3b present calculations representing the co-firing of petroleum coke with coal based on the same operation conditions as experienced in 1997 through 2001. As discussed previously, the facility will operate in basically the same manner. Cedar Bay Generating Company is proposing to limit the sulfur content of the total co-firing fuel to 3.2 lb/MMBtu or less. This approach would provide Cedar Bay with greater flexibility and would allow Cedar Bay to use a range of petroleum cokes. Specifically, the fuel used at Cedar Bay could range from approximately 20 percent petroleum coke (~6 percent sulfur content) to approximately 35 percent petroleum coke (~4 percent sulfur content). This approach would limit the maximum SO_2 removal in the CFB to approximately 95 percent when meeting a target emission rate of approximately 0.16 lb/MMBtu. To demonstrate the ability of the CFB to operate within this range, calculations were preformed using the 4.1 and 5.5 percent sulfur petroleum cokes identified in the Foster Wheeler report. The calculations in Table 3a are based on a 5.5 percent sulfur petroleum coke with the same heat input for the given year with 80 percent by weight of coal and 20 percent by weight of petroleum coke. Table 3b presents calculations based ona 4.1 percent petroleum coke with 65 percent by weight of coal and 35 percent by weight of petroleum coke supplying the heat input for the year. The coal fuel parameters (i.e., heat, sulfur and ash contents) are based on those for each year while the petroleum coke parameters are those used in the Foster Wheeler report provided with the original calculation (Coke #4). The calculations provided are identical to those for Table 2 including historical limestone requirements. Projections by Foster Wheeler of the amount of limestone required as a function of the amount of fuel at 35 percent petroleum coke in the total fuel suggest better limestone utilization due to improved bed combustion. This information was summarized in Table 1 of the application (i.e., 22,500 lb limestone/hr / 78,000 lb fuel/hr = 0.29). Therefore the calculations presented in Tables 3a and 3b are conservative. The tables also include calculations of the lb/hr values for coal, limestone, bed ash and fly ash for co-firing petroleum coke and coal. The projected lb/hr values in the Foster Wheeler are also provided for comparison. As noted, the calculated values are similar to and less than those provided in the Foster Wheeler report. Also presented in the tables are differences between coal and co-firing for fuel, fuel ash, limestone, total ash and fly ash. As shown, there would be decreases in fuel and fuel ash and increases in limestone and total bed and fly ash when co-firing 20 to 35 percent petroleum coke. It should be noted that the amount of increase in total ash is a direct result of the additional limestone; there is not an increase in fuel ash. The high calcium content of the ash would continue to help make this by-product a marketable soil supplement.

Tables 4a and 4b present calculations for each pollutant when co-firing coal and petroleum coke, with the actual emissions and net emissions increase. Each pollutant is discussed below.

- CO – The calculated emissions are based on projections of Foster Wheeler. As shown there is a net emission decrease.

- NO_x – Each CFB is equipped with Selective Non-Catalytic Reduction (SNCR), which will be used to limit NO_x emission rates to levels that would not increase annual emissions above the PSD significant emission rate of 40 tons/year. As noted from the Foster Wheeler report the co-firing of petroleum coke with coal would reduce uncontrolled emissions by about 25 percent (Figure 5) with the benefit of lower ammonia usage (Figure 6).

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- PM/PM_{10} – The calculated emission are based on the average particulate emissions for each year. The emission rate from the baghouse for each CFB can be maintained because PM removal is not a function of loading, given the low loading rates to the baghouse. This information is provided in the ABB Emissions Control System Operations and Maintenance Manual, which is attached. As provided in the manual, the particulate emission rate can be maintained over a range of grain loading and flow rates. The baghouses are designed for an inlet grain loading o 19.5 grains/acf at 297,700 acfm. The grain loading (in grains/acf) for coal and co-firing are presented in Tables 5a and 5b. As shown in the table, the increase loading to the baghouses resulting from co-firing is less than 1 grain/acf. In addition, the maximum grain loading projected in the Foster Wheeler report is 6.7 grains/acf, which is much less than the design condition. This conclusion is supported by information available from EPA regarding fabric filters. In the Air Pollution Technology Fact Sheets for fabric filters EPA states that: "the effluent particle concentration from a fabric filter is nearly constant"... and "fabric filters can be considered constant outlet devices rather than constant efficiency devices." The annual PM/PM_{10} emissions would be maintained with no increase above the PSD significant emission rate of 40 tons/year.

- Sulfuric Acid Mist (SAM) – The emissions for sulfuric acid mist when co-firing were based on the actual emissions determined during initial testing when firing coal, and increased proportionally for the increased sulfur content of the fuel when co-firing. The test data determined a emission rate of <0.00003 lb/MMBtu for all units. This was increased based on the sulfur content of the fuel and was about 0.00006 lb/MMBtu. While there is an projected increase in SAM emissions, the amount is less than the PSD significant emission rate of 7 tons/year.

- SO_2 – The removal of SO_2 would be increased by increasing the efficiency of removal through the use of more limestone. The Foster Wheeler report indicated that an emission rate of 0.16 lb/MMBtu can be maintained by increasing the use of limestone. The calculations presented in Tables 4a and 4b were based on meeting the annual emissions by controlling the outlet SO_2 emission. For each year, the required emission rates to keep emissions at past actual emissions ranges from 0.165 to 0172 lb/MMBtu. This is within the emission reduction predicted in Foster Wheeler Report. Thus, the annual SO_2 emissions would be maintained with no increase above the PSD significant emission rate of 40 tons/year.

- VOC – For VOC emissions, the tests suggest an emission rate ranging from 0.0014 lb/MMBtu (1994) to 0.0047 lb/MMBtu (2001) when firing coal, with and average of 0.003 lb/MMBtu. For VOC emissions, the calculation in Table 4 shows a comparison of the reported AOR emissions using the 1994 emission rate with the average emission rate for co-firing. The increase presented is an artifact of the calculation and is not expected. Given that the combustion process is improved when co-firing petroleum coke with coal, and that petroleum coke has lower volatile matter and hydrocarbons, no increase in VOCs is expected. The annual VOC emissions would be maintained with no increase above the PSD significant emission rate of 40 tons/year.

2. <u>FDEP Request/Comment</u>: Notwithstanding Cedar Bay's reference to 40 CFR 52.21(b)(33), it does not appear that the original question posed in the Department's September 28th letter has been fully answered. Within that request, the Department is attempting to obtain reasonable assurance as to whether a PSD Review is required. The relevant statutes expressly contemplate that projections of the impact of a change must be made before construction.

Before a permit is issued, among other things, the owner or operator of the source must, using projections of post-change emissions, demonstrate that emissions from the modified source will not violate air quality requirements.

Specifically, section 165 states that "[n]o major emitting facility ... may be constructed unless a permit has been issued for such proposed facility" [CAA § 165, 42 U.S.C. § 7475]. Further, the owner or operator must demonstrate to the administrator's satisfaction that "emissions from construction or operation of such facility will not cause, or contribute to, air pollution in excess of" the NAAQS, among other things [CAA § 165(a)(3), 42 U.S.C. § 7475(a)(3)].

This statutory and regulatory structure has two important features relevant to this application:

(1) the permit must be obtained *before* the physical change is made, and
(2) whether a physical change requires a permit is determined in part by reference to anticipated results or consequences, which necessarily would occur *after* the physical change is made.

Thus, the only way for the owner or operator of the source to know whether a permit is required for any particular physical change is for the owner or operator to make a prediction as to whether the emissions increase will occur. This observation was described by EPA in the 1992 preamble to amendments to the NSR regulations as follows:

> Applicability of the CAA's NSR provisions must be determined in advance of construction and is pollutant specific. In cases involving existing sources, this requires a pollutant-by-pollutant projection of the emissions increases, if any, which will result from the physical or operational change. 57 Fed. Reg. 32,314, 32,316 n.8 (1992).

Any other construction of the statute would allow sources to make modifications or changes without a permit, while they wait to see if it would be proven that emissions would increase. Clearly Congress did not intend such an outcome, which would effectively allow avoidance of the *preconstruction* dimension of the program.

Concerning the attendant application, should the Department gain reasonable assurance that the PSD thresholds are not triggered, a permit condition (similar to the one referenced within your response) may be able to be implemented, with additional restrictions as deemed appropriate by the Department.

Additional Information: The comment is acknowledged. As requested, Cedar Bay Cogenerating Company, L.P. will demonstrate on a continuing basis for the next 5-years when co-firing that there is not a significant increase in any PSD air pollutant.

3. FDEP Request/Comment: According to prior data reported to FDEP by Cedar Bay, past actual SO_2 has been controlled at 90% with limestone throughputs averaging 120,000 TPY. The application has estimated past actual sulfur capture at over 93% and annual limestone throughput at 152,753 TPY. As indicated below, the Department intends to revise all related calculations.

Additional Information: Comment acknowledged. The actual usage of limestone is presented in Table 1. Table 6 presents a update of the material usage for the project. This information was used to update the fugitive emissions calculation presented in Appendix B of the application. The material handling has been revised. A truck dump is no longer planned. Petroleum coke will be received within the enclosed coal unloading building. Since this building is partially enclosed and has a water spray system for controlling fugitive dust, overall emissions will be lower than those presented in the application. Figure 3 has been updated to reflect this change.

4. FDEP Request/Comment: According to prior data reported to FDEP by Cedar Bay, past actual throughputs of bed (bottom) ash have averaged over 70,000 TPY during years 1998 through 2000. The application has provided a calculated past value of 51,325 TPY. The Department intends to revise all related calculations, and notes that the existing permit limits the throughput to 88,000 TPY.

Additional Information: Comment acknowledged. Table 6 presents an update of actual and potential bed and fly ash.

5. FDEP Request/Comment: Based upon a preliminary analysis by the Department, the co-firing of petcoke at 35% will necessitate an increase in limestone feed by over 100% in order to ensure that SO_2 emissions are not increased. The Department specifically requires additional information (beyond that which has been submitted) in order to ensure that annual PM_{10} emissions remain below a 15 TPY increase, while simultaneously maintaining SO_2 emissions below a 40 TPY increase. Please provide assumed collection efficiencies within submitted calculations.

Additional Information: As presented in the response to FDEP Request/Comment 1, the PM/PM_{10} emission rate will be maintained by the baghouses on each CFB boiler. This conclusion is based on the design data in the manufacturer's manual and the relatively low increase in grain loading resulting from co-firing (i.e., less than 1 grain/acf) compared to the baghouse design. In addition, the SO_2 emission rate can be maintained based on increasing the rate of limestone usage. The ability to increase the limestone usage and concomitantly increase efficiency is based on the calculations supplied herein and the manufacturer's report, which was supplied as Appendix A of the application.

Department of Environmental Protection

Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Jeb Bush
Governor

David B. Struhs
Secretary

Additional Information for
Co-firing Petroleum Coke with Coal
File No. PA 88-24 (PSD-FL-137)
Cedar Bay Cogenerating Project

This document provides additional information requested by the Department in the letter dated April 2, 2002 related to co-firing petroleum coke with coal at the Cedar Bay Cogeneration facility. The information is presented in the same format as requested.

1. FDEP Request/Comment: The technical basis for the development of the "Representative Future Actual Emissions" in Table B is unclear. Rather, in each case, the "Representative Future Actual Emissions" appear to simply represent values that are slightly less than the past actual emissions plus the PSD Significant Emission Rates. Please provide the basis for the emission calculations, which Cedar Bay utilized in the development of this table. The Department notes that the basis for the original BACT emission calculation was a 93% capacity factor.

Additional Information: The "representative future actual emissions" were based on the average 1999/2000 actual emissions with an incremental addition for each pollutant to keep the emissions less than the PSD significant emission rates. The increment was added due to the potential variability of operations in any given year as well as pollutant variability. As indicated by the operation over the last five years, the facility operates at a high capacity given the requirement to provide power under contract to FPL and to supply steam to the host facility. Therefore, it is intended that the facility would operate in the same manner as in previous years with slight variability in operations and emission rates. Based on this premise, information on past actual performance and emissions when firing coal, and calculations of expected performance and emissions during the same period when co-firing petroleum coke with coal, were developed. This information and the associated calculations are presented in attached Tables 1 through 5. Each table is discussed below.

Table 1 presents information on the actual fuel and material used during operation of the facility from 1997 through 2001. This information was provided to the Department in the Annual Operating Reports (AORs) and includes fuel and limestone usage and generation of bed and fly ash. Information on the heat, ash and sulfur content of the fuel is also provided as these are used in subsequent calculations.

Table 2 presents operations information for coal firing during 1997 through 2001. The purpose of this table is for comparison with calculations for co-firing petroleum coke with coal. The information presented in this table is from the AORs and calculated based on data from the AORs. The far right column provides the basis of the information or the calculation. The amount of potential ash can be calculated directly. The amount of limestone required for SO_2 removal can be calculated based on the reaction of SO_2 with limestone ($CaCO_3$). The amount of byproduct formed by this reaction is calculated by assuming the formation of $CaSO_4$. The excess limestone is based on the actual limestone used minus that calculated for SO_2 removal. The CFB technology utilizes a reactant (i.e., limestone) to obtain high removal efficiencies. The total bed and fly ash, which includes ash from the fuel, excess reactant and $CaSO_4$, was also calculated. In this calculation, the CO_2 formed in the high temperature process of heating limestone is

PG&E National
Energy Group

Cedar Bay
Generating Plant
Owner: Cedar Bay Generating Company, L.P.

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RECEIVED

MAY 28 2002

BUREAU OF AIR REGULATION

May 24, 2002

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

Re: Cedar Bay Generating Plant Fiber Reject Test Burn
Permit Nos. PSD-FL-137 & Title V 0310337-003-AV
Site Certification PA 88-24

Dear Mr. Fancy:

Pursuant to the above referenced permits, Cedar Bay Generating Company, L.P. (Cedar Bay), is submitting here with a plan for a 30-day test burn of short fiber rejects (SFR). Specifically, in accordance with the Prevention of Significant Deterioration and Site Certification Permits, Specific Condition II.A.1.h and Title V Permit, Subsection A.64, Cedar Bay is providing you with the test protocol (Attachment 1, Short Fiber Reject Test Protocol) and notifying the Department that we hope to begin the test burn on or after August 27, 2002.

Cedar Bay will conduct this test to ascertain whether the facility can burn the SFR as supplemental fuel in compliance with existing emissions limitations, fuel usage and ash disposal requirements. As you may recall, this fuel was approved pending such as test burn as part of the original permitting of the facility. Various business reasons, including contractual obligations related to ash disposal, have prevented Cedar Bay from pursuing the use of SFR supplement the fuel supply during the life of this facility.

Cedar Bay's business circumstances have recently changed with respect to fuel supply and ash disposal. As indicated in various letters to the Department requesting approval to utilize petroleum coke as an additional fuel, Cedar Bay's long-term fuel supply contract has been terminated. Under Chapter 11 of the Bankruptcy Code, Cedar Bay's sole coal supplier Lodestar petitioned the court to terminate its contract with Cedar Bay for economic reasons. The petition was granted and Cedar Bay has executed separate contracts for coal supply and ash disposal. The new contracts remove previous barriers to ash disposal that gives Cedar Bay the flexibility to pursue combustion of SFR as was originally intended and approved by the Department.

We would be happy to answer any questions that the Department may have about the test plan. Please contact Mr. Jeff Walker, our Environmental Manager, at 904-751-4000 x22. We look forward to working with you and the other members of the Department to ensure that our test burn and, ultimately, the use of SFR is successful.

Sincerely,

Bruce Smith, General Manager
Cedar Bay Generating Company Limited Partnership

Enclosure

cc: A.A Linero, DEP (w/o enclosures)
Ernest Frye, DEP NE District (w/ enclosures)
Steve Pace, Jacksonville RESD (w/ enclosures)
Hamilton S. Oven, Jr. (w/o enclosures)
David Dee (w/ enclosures)

PG&E National Energy Group

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Generating Plant
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MAY 28 2002

BUREAU OF AIR REGULATION

May 24, 2002

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Bruce Smith, General Manager
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Table 1. Fuel and Material Handling Information from Annual Operating reports for Cedar Bay Cogeneration Facility

Material	Source of Information	Units	Year			
			1997	1998	1999	2000
Total Fuel Usage	Coal	tons/yr	970,331	972,999	962,569	954,391
Coal Sulfur Content	Coal Sulfur Content	%	0.94	1.06	1.11	1.06
Coal Ash Content	Coal Ash Content	%	11.40	12.10 11.86	11.82	10.53
Coal Heat Content	Coal Heat Content	MMBtu/ton	23.80	23.40	23.90	23.90
Coal Heat Content	Coal Heat Content	Btu/lb	11,900.00	11,700.00 11374	11,950.00 11769	11,950.00 11985
Total Limestone Throughput	Limestone Storage Bin 1	tons/yr	85,596	85,050	82,325	74,765
Total Limestone Throughput	Limestone Storage Bin 2	tons/yr	42,798	41,890	40,141	35,769
Total Limestone Throughput	Limestone Vib Pan Conv	tons/yr	66,337	66,337	--	--
Total Limestone Throughput	Pulv Limestone Feeders (6)	tons/yr	--	--	122,835	110,534
Total Lime Manufactured	Abs Dryer System Train 1	tons/yr	--	--	60,874	68,823
Total Lime Manufactured	Abs Dryer System Train 2	tons/yr	--	--	66,135	56,660
Total Bed Ash Throughput	Bed Ash Hopper	tons/yr	64,997	69,400	69,153	71,235
Total Bed Ash Throughput	Bed Ash Silo (Sep+Col)	tons/yr	64,997 ?	69,340 ?	69,153 69154	71,235
Total Fly Ash Throughput	Fly Ash Silo (Sep+Col) 1	tons/yr	65,982	70,452	69,153	69,140
Total Fly Ash Throughput	Fly Ash Silo (Sep+Col) 2	tons/yr	65,982	70,452	69,153	69,140
Total Fly Ash Throughput	Fly Ash Silos	tons/yr	131,964 ?	140,904 ?	138,306 138307	138,280
Total Fly/Bed Ash Processed	Dry Ash Rail Car Loadout	tons/yr	196,960	210,303	209,556	209,515

Table 2. Data and Calculation for Coal Firing at Cedar Bay Cogeneration Facility

Parameter	Units	1997	1998	1999	2000	2001	Basis
		Year					
Operation	hours	8,052.3	8,088.3	7,978.7	7,692.7	7,482.7	AOR
Coal	tons	970,331	972,999	962,569	954,391	920,356	AOR
Coal	MMBtu	23,093,878	22,768,177	23,005,399	22,809,945	21,904,349	AOR
Ash	%	11.40	12.10	11.82	10.53	11.90	AOR
Ash	tons	110,618	117,733	113,776	100,497	109,522	Coal (tons) x Ash (%)
Limestone total	tons	128,394	126,940	122,466	110,534	110,201	AOR
Sulfur	%	0.94	1.06	1.11	1.06	0.95	AOR
SO_2 total	tons	18,242.2	20,627.6	21,369.0	20,233.1	17,486.8	Coal (tons) x Sulfur (%)/100 x 2
SO_2 emitted	tons	1,909.0	1,935.6	1,926.2	1,965.1	1,901.5	AOR
SO_2 removed	tons	16,333.2	18,692.0	19,442.8	18,268.0	15,585.3	SO_2 total - SO_2 emitted ok
SO_2 removed	%	89.5%	90.6%	91.0%	90.3%	89.1%	SO_2 removed/SO_2 total ok
Limestone required for SO_2 removal	tons	25,520.7	29,206.2	30,379.4	28,543.7	24,352.0	SO_2 removed x 100/64 ok
% utilized		19.87	23.00	24.8	25.82	22.09	
Limestone excess	tons	102,873.3	97,733.8	92,086.6	81,990.2	85,849.0	Limestone total - Limestone for SO_2 (excess)
$CaSO_4$ Formed	tons	34,708.1	39,720.5	41,316.0	38,819.4	33,118.7	SO_2 removed x 130/64 ← to buy limestone
CO_2 emitted from SO_2 removal	tons	11,229.1	12,850.7	13,367.0	12,559.2	10,714.9	SO_2 removed x 44/64 ← became a gas
Ash and $CaSO_4$	tons	145,325.8	157,453.3	155,091.7	139,316.8	142,641.0	Ash (tons) + $CaSO_4$ formed (tons) why??
Actual Total Bed and Fly Ash	tons	196,960.0	210,303.0	209,556.0	209,515.0	204,558.0	AOR (EU-30) WHY
Calculated Total Bed and Fly Ash	tons	202,934.9	212,184.3	206,660.2	185,231.3	190,716.5	Ash and $CaSO_4$ + Limestone excess x 44/100 x .44?
Ratio of Ash & $CaSO_4$ to Total		1.36	1.34	1.35	1.50	1.43	Actual (Total) / calc. (Ash + $CaSO_4$) why
Ratio of Fly Ash to Total Ash		0.67	0.67	0.66	0.66	0.66	Actual Fly Ash / Total Dry Ash (EU-33) EU-30
Fuel	lb/hr	241,006.17	240,593.20	241,285.68	248,130.08	245,995.67	tons x 2,000/hours
Limestone	lb/hr	31,889.89	31,388.42	30,698.36	28,737.47	29,454.88	tons x 2,000/hours
Fly Ash	lb/hr	32,776.59	34,841.29	34,668.95	35,951.12	36,085.47	tons x 2,000/hours
Bed Ash	lb/hr	16,143.64	17,145.68	17,334.48	18,520.24	168,472.53 ??	tons x 2,000/hours

Reported bed ash
Fly Ash

Table 4. Data and Calculation for Co-firing Pet Coke with Coal at Cedar Bay Cogeneration Facility

Parameter	Units	Year					Basis
		1997	1998	1999	2000	2001	
CO emission rate with co-firing	lb/MMBtu	0.035	0.035	0.035	0.035	0.035	Foster Wheeler Report
CO emissions when co-firing	tons/year	404.1	398.4	402.6	399.2	383.3	MMBtu x lb/MMBtu (assumes same heat input)
CO emissions with coal	tons/year	496	549.6	582.26	516.01	485.1	AOR
Net CO Emissions	tons/year	-91.9	-151.2	-179.7	-116.8	-101.8	Cofiring - Actual Coal
NO_x emission rate with co-firing	lb/MMBtu	0.15	0.15	0.15	0.15	0.15	Foster Wheeler Report
NO_x emissions with co-firing	tons/year	1,732.0	1,707.6	1,725.4	1,710.7	1,642.8	MMBtu x lb/MMBtu (assumes same heat input)
NO_x emissions with coal	tons/year	1,726.0	1,716.4	1,741.5	1,779.0	1,656.9	AOR
Net NO_x emissions	tons/year	6.0	-8.8	-16.1	-68.3	-14.1	Cofiring - Actual Coal
PM_{10} emission rate with co-firing	lb/MMBtu	0.0129	0.0160	0.0150	0.0147	0.0157	average of actual test data
PM_{10} emissions with co-firing	tons/year	149.3	182.5	172.5	167.3	171.6	MMBtu x lb/MMBtu (assumes same heat input)
PM_{10} emissions with coal	tons/year	149.5	178.3	193.7	165.2	201.9	AOR
Net PM_{10} emissions	tons/year	-0.16	4.22	-21.20	2.05	-30.32	Cofiring - Actual Coal
SAM emission rate with co-firing	lb/MMBtu	7.59E-05	6.89E-05	6.72E-05	6.95E-05	7.53E-05	Test data increased for increased sulfur in fuel
SAM emissions with co-firing	tons/year	0.88	0.78	0.77	0.79	0.82	MMBtu x lb/MMBtu (assumes same heat input)
SAM emissions with coal	tons/year	0.35	0.35	0.35904	0.34617	0.3	AOR
Net SAM emissions	tons/year	0.53	0.43	0.41	0.45	0.52	Cofiring - Actual Coal
SO_2 emission rate with co-firing	lb/MMBtu	0.165	0.17	0.167	0.172	0.172	rate adjusted to meet past actuals
SO_2 emissions with co-firing	tons/year	1,905.2	1,935.3	1,921.0	1,961.7	1,883.8	MMBtu x lb/MMBtu (assumes same heat input)
SO_2 emissions with coal	tons/year	1909	1935.6	1926.19	1965.13	1901.5	AOR
Net SO_2 emissions	tons/year	-3.8	-0.3	-5.2	-3.5	-17.7	Cofiring - Actual Coal
VOC emission rate with co-firing	lb/MMBtu	0.0030	0.0030	0.0030	0.0030	0.0030	Test data from 1994 and 2001
VOC emissions when co-firing	tons/year	35.0	34.5	34.8	34.5	33.2	MMBtu x lb/MMBtu (assumes same heat input)
VOC emissions with coal	tons/year	14.8	14.7	17.89104	17.250215	48.7	AOR
Net VOC Emissions	tons/year	20.2	19.8	16.9	17.3	-15.5	Cofiring - Actual Coal

Table 5. Data and Calculation for Inlet Loading to Baghouses when Co-firing Pet Coke with Coal at Cedar Bay Cogeneration Facility

Parameter	Units	Year					Basis
		1997	1998	1999	2000	2001	
Fly Ash - Coal Firing	lb/hr/facility	32,776.59	34,841.29	34,668.95	35,951.12	36,085.47	Table 2, based on actual fly ash
Fly Ash - Coal Firing	lb/hr/unit	10,925.53	11,613.76	11,556.32	11,983.71	12,028.49	divided by 3 CFBs
PM Emission Rate with coal	grains/acfm	4.28	4.55	4.53	4.70	4.71	lb/hr x 7,000 grains/lb x 1/acfm x 1/60
Fly Ash - Co-Firing	lb/hr/facility	39,914.43	40,850.63	41,008.38	41,686.39	41,782.68	Table 2, based on actual fly ash
Fly Ash - Co-Firing	lb/hr/unit	13,304.81	13,616.88	13,669.46	13,895.46	13,927.56	divided by 3 CFBs
PM Emission Rate with coal	grains/acfm	5.21	5.34	5.36	5.45	5.46	lb/hr x 7,000 grains/lb x 1/acfm x 1/60
PM Emission Rate Increase	grains/acfm	0.93	0.79	0.83	0.75	0.74	Co-firing - Coal (grains/acf)
Maximum Projected	lb/hr/unit	17,000.00					Foster Wheeler Report (Figure 12)
Maximum Projected	grains/acfm	6.66					lb/hr x 7,000 grains/lb x 1/acfm x 1/60
Flow Rate of Unit	acfm	297,700					

by weight or by ht input? ..38.6% by ht input

LIME = 320 KTPY
Fly = 336 KTPY
BED = 88 KTPY

Table 3. Data and Calculation for Co-firing Pet Coke with Coal at Cedar Bay Cogeneration Facility

Parameter	Units	Year 1997	1998	1999	2000	2001	Basis
Co-firing Fuel	MMBtu	23,093,877.8	22,768,176.6	23,005,399.1	22,809,944.9	21,904,349.0	Same as AOR
Co-firing Fuel	tons	915,838.6	912,329.1	909,984.1	902,252.9	868,668.2	Coal + Pet Coke (tons) MBTU/(MBTU per blended ton)
Coal (65% by weight)	tons	595,295.1	593,013.9	591,489.7	586,464.4	564,634.3	Co-firing Fuel x 0.65
Coal (65% by weight)	MMBtu	14,168,023	13,876,526	14,136,603	14,016,498	13,438,222	Coal (tons) x Coal heat content (MMBtu/ton)
Coal	%	65%	65%	65%	65%	65%	minimum
Pet Coke (35% by weight)	MMBtu	8,925,855	8,891,651	8,868,796	8,793,447	8,466,127	Pet Coke (tons) x 27.846 MMBtu/ton
Pet Coke (35% by weight)	tons	320,544	319,315	318,494	315,789	304,034	Co-firing Fuel x 0.35
Pet Coke	%	35%	35%	35%	35%	35%	maximum
Pet Coke - sulfur	%	5.45	5.45	5.45	5.45	5.45	Foster Wheeler o/c
Pet Coke - ash	%	0.37	0.37	0.37	0.37	0.37	Foster Wheeler
Coal - ash	tons	67,863.6	71,754.7	69,914.1	61,754.7	67,191.5	Coal (tons) x Ash (%)
Pet Coke - ash	tons	1,186.0	1,181.5	1,178.4	1,168.4	1,124.9	Pet Coke (tons) x Ash (%)
Total Ash	tons	69,049.7	72,936.2	71,092.5	62,923.1	68,316.4	Coal ash + Pet Coke ash
SO_2 coal	tons	11,191.5	12,571.9	13,131.1	12,433.0	10,728.1	Coal (tons) x Sulfur (%)/100 x 2
SO_2 pet coke	tons	34,939.2	34,805.4	34,715.9	34,420.9	33,139.7	Pet Coke (tons) x Sulfur (%)/100 x 2
SO_2 total	tons	46,130.8	47,377.3	47,847.0	46,854.0	43,867.7	Coal SO_2
SO_2 emitted	tons	1,909.0	1,935.6	1,926.2	1,965.1	1,901.5	AOR
SO_2 removed	tons	44,221.8	45,441.7	45,920.8	44,888.9	41,966.2	SO_2 total - SO_2 emitted
SO_2 removed	%	95.9%	95.9%	96.0%	95.8%	95.7%	SO_2 removed/SO_2 total
$CaSO_4$ Formed	tons	93,971.3	96,563.5	97,581.6	95,388.8	89,178.3	SO_2 removed x 130/64 limestone required (theoretical)
Ash and $CaSO_4$	tons	163,021.0	169,499.7	168,674.2	158,311.9	157,494.7	Ash (tons) + $CaSO_4$ formed (tons)
Total Bed and Fly Ash	tons	239,852.5	246,575.5	247,874.6	242,938.8	236,853.8	Ash and $CaSO_4$ + Limestone excess x 44/100 what?
Fly Ash	tons	160,702.2	165,206.8	163,596.1	160,339.7	156,323.6	Total Bed and Fly Ash x Ratio Fly to Total Ash
Bed Ash	tons	79,150.4	81,368.8	84,278.5	82,599.1	80,530.2	Total Ash - Fly Ash
Limestone for SO_2 removal	tons	69,096.5	71,002.6	71,751.2	70,138.8	65,572.3	SO_2 removed x 100/64
Limestone -total	tons	265,593.2	264,575.4	263,895.4	261,653.3	251,913.8	0.29 x Co-firing Fuel (tons) Foster Wheeler report
Limestone excess	tons	196,496.6	193,572.9	192,144.2	191,514.5	186,341.5	Limestone Total - Limestone for SO_2 removal
MY LIMESTONE TOTAL		347742					
Fuel	lb/hr	227,471.6	225,591.4	228,104.3	234,574.8	232,180.4	tons x 2,000/hours
Limestone	lb/hr	65,966.8	65,421.5	66,150.2	68,026.7	67,332.3	tons x 2,000/hours
Fly Ash	lb/hr	39,914.4	40,850.6	41,008.4	41,686.4	41,782.7	tons x 2,000/hours
Bed Ash	lb/hr	19,659.0	20,120.0	21,126.0	21,474.8	21,524.4	tons x 2,000/hours
Difference in Fuel	tons	-54,492.4	-60,669.9	-52,584.9	-52,138.1	-51,687.7	Co-firing Fuel - Coal (tons)
Difference in Fuel Ash	tons	-41,568.1	-44,796.7	-42,683.1	-37,574.3	-41,205.9	Co-firing Fuel - Coal (tons)
Difference in Limestone	tons	137,199.2	137,635.4	141,429.4	151,119.4	141,712.8	Co-firing Fuel - Coal (tons)
Difference in Total Bed and Fly Ash	tons	42,892.5	36,272.5	38,318.6	33,423.8	32,295.8	Co-firing Fuel - Coal (tons)
Difference in Fly Ash	tons	28,738.2	24,302.8	25,290.1	22,059.7	21,315.3	Co-firing Fuel - Coal (tons)

HEAT CONTENT OF A BLENDED TON?

35% (27.846 MBTU)
+ 65% (23.30 MBTU)
MBTU/TON 25.2161 (1997)

11,82
10.53

.109

How do you get this? Has fuel diff been taken out? I don't get it

2.12%
2.22%

CEDAR BAY COGENERATING PLANT
SHORT FIBER REJECT TEST BURN PROTOCOL

PURPOSE

Cedar Bay's Conditions of Certification, Prevention of Significant Deterioration and Title V permits allow the combustion of short fiber rejects (SFR) in a single boiler pending the completion of a 30-day test burn designed to ascertain whether the circulating fluidized bed boiler can burn the rejects as supplemental fuel without exceeding permitted limitations on emissions, fuel usage or other environmental conditions and without causing any operational problems which would affect reliable operation The 30-day test may proceed after submission of a test plan to Florida Department of Environmental Protection (FDEP) and the Air and Water Quality Division of the City of Jacksonville (RESD). This plan is intended to be used for submission to FDEP and RESD and as a guide for the plant to complete the test burn.

RATIONALE FOR SFR COMBUSTION

The Smurfit Stone facility recycles corrugated cardboard to produce recycled paper and linerboard. Cedar Bay entered into a contractual arrangement to supply steam for this process in order to qualify as a cogeneration facility. The arrangement resulted in reduced air emissions by replacing the boilers at the Smurfit Stone facility. Additionally through these agreements, Cedar Bay accepts Smurfit Stone's wastewater for cooling tower make-up, minimizing the discharge of wastewater to the Broward River and to accept a portion of SFR for energy recovery purposes. To date Cedar Bay has met its obligation to accept the material but has made arrangements for the material to be disposed in a landfill due to other contractual constraints. Recently, these contractual constraints have been eliminated and so Cedar Bay is anxious to confirm the ability to burn SFR as originally intended.

SFR DESCRIPTION

Short Fiber Rejects (SFR) is a by-product of the Smurfit Stone recycling process. Bales of corrugated cardboard are shredded, mixed with water and reduced to a pulp. Heavy trash material such as staples, glass, metal and stones sink to the bottom of the pulp slurry and are removed. The slurry is then spun in a centrifuge to remove any additional heavy material. From the centrifuge the slurry passes through a coarse screen, which removes additional contaminants such as wax or plastic. The slurry passes on to another centrifuge and then short and long fibers are separated using two fine mesh screens and a reverse cleaner. The short fibers are pressed to remove liquids and the SFR is transferred to roll-off containers for disposal.

SFR COMBUSTION PROCESS & EQUIPMENT

The Cedar Bay facility was constructed to support combustion of the SFR in two boilers (Boilers B and C) with a dedicated material handling and conveyance system to transport the SFR to the boilers. A detailed description of the process and equipment is found in our operating procedure, which is attached.

SFR is collected from Smurfit Stone's process in dedicated 30 cubic yard capacity roll-off boxes for disposal. Currently Cedar Bay arranges for these to be transferred to a landfill. The plan is to continue to use this method to collect and deliver the material to Cedar Bay's fiber waste handling system on the western boundary of the Smurfit Stone facility. The roll-off boxes will be transported within Smurfit Stone's property to the location of Cedar Bay's fiber waste handling system. The SFR will be unloaded into a receiving hopper as described in the referenced operating procedure. The receiving hopper is equipped with a live bottom via drag chain feeder and interfaces with Cedar Bay's distributed control system (DCS). The DCS system allows this system, as well as most of the Cedar Bay plant, to be controlled and monitored from Cedar Bay's Control Room.

SFR will be discharged from the receiving hopper by a variable speed drag conveyor to a 24" wide conveyor belt (SFR conveyor). This conveyor is rated at 16 tons per hour at a belt speed of 75 feet per minute. The conveyor is equipped with skirt boards; hood covers, automatic vertical gravity take-up with grab safety devices, speed switch, and pull cord switches and belt alignment switches.

SFR will be discharged from the SFR conveyor into the SFR surge hopper. The surge hopper is sized for a minimum capacity of 20 cubic yards and is equipped with four variable speed screw conveyors, each with their own speed switch. The surge hopper also has three capacitance type level switches. One switch monitors low level, one switch to monitor high level and one switch for emergency high level. Upon actuation of the high level switch, the DCS system will automatically run the drag chain feeder in the receiving hopper in low speed to prevent overfill of the surge hopper. The feeder will return to high speed when the high level switch is no longer actuated. The emergency high-level switch will stop both conveyor and feeder immediately after actuation.

The SFR feed system will feed the SFR to the loop seal feed points of Boiler C and discharge through air locks (rotary valves) to the coal drag chain conveyors feeding the loop seals. The coal conveyors will introduce the coal/fiber waste mix into the loop seal fuel feed port.

The fiber waste will provide less than 5% of the heat input to C boiler when the feed rate is 150 tons/day and the boiler is at full load.

SCOPE OF TEST BURN

Operational Feasibility: In order to confirm that co-firing of SFR is feasible without adverse impact to operations the following will be monitored using the dedicated operational performance monitoring software:

- SFR Material Handling & Transport – facility personnel will monitor the performance of the SFR conveyance system described above to identify any operational problems that would interfere with the ability to properly transport and feed the SFR to Boiler C, including continuous monitoring of the following parameters:
    1. Fiber Flow (KLBS/HR)
    2. Fiber Master Demand (%)

- Boiler Operations – facility personnel will monitor boiler performance during the 30-day test burn to determine the impact of SFR combustion on performance and operations. Key parameters that will be continuously monitored are as follows:
    1. Coal flow (KLBS/HR)
    2. Coal Master Demand (%)
    3. Main Steam Flow (KLBS/HR)
    4. Main Steam Temperature (DEG F)
    5. Main Steam Pressure (PSIG)
    6. Reheat Flow (KLBS/HR)
    7. Reheat Temperature (DEG F)
    8. Reheat Pressure (PSIG)
    9. Reheat Attemperator Water Flow (KLBS/HR)
    10. Primary Air Grid Nozzle Flow (KLBS/HR)
    11. Primary Air Temperature (DEG F)
    12. Secondary Air Flow (KLBS/HR)
    13. Secondary Temperature (DEG F)
    14. Bed Temperature (DEG F)

15. Cyclone Outlet Temperature (DEG F)
16. Combustor Lower Temperature (DEG F)
17. Combustor Middle Temperature (DEG F)
18. Combustor Upper Temperature (DEG F)
19. ReheatII Outlet Gas Temperature (DEG F)
20. Economizer Inlet Gas Temperature (DEG F)
21. Economizer Outlet Gas Temperature (DEG F)
22. Primary Air Air Heater Cold End Temperature (DEG F)
23. Secondary Air Air Heater Cold End Temperature (DEG F)

- Ash Handling/Air Pollution Control Equipment – facility personnel will monitor the performance of the ash transport system and emission control equipment to ensure proper operation. Parameters that will be continuously monitored:
    1. Baghouse DP "Average" (PSIG)
    2. Baghouse Inlet Temperature (DEG F)
    3. Opacity (%)
    4. Ammonia Flow (ACFM)

Environmental Compliance: facility personnel will monitor the applicable parameters during the test burn to ensure compliance with all permit conditions:

- The amount of SFR burned will be monitored and recorded to ensure that the 210 cubic yard/day (wet basis) limit is not exceeded.
- CEM Monitoring – the CEM system will be used throughout the 30-day test period to confirm compliance with CO, NOx, SO2, Opacity and heat input limitations.
- Limestone Flow (KLBS/HR)
- Stack Testing for Particulate Matter, Particulate Matter less than 10 microns, Lead, Mercury, and Beryllium will be completed during the 30-day test burn to confirm compliance with these limitations. The tests will be conducted by a qualified test firm.

The following test methods and procedures will be used during the test burn:

Purpose / Substance	Test Method
Selection of sample site and sample traverse	EPA Method 1
Determination of stack gas flow	EPA Method 2
Gas analysis for calculation of percent O2 and CO2	EPA Method 3 or 3A
Determining stack gas moisture content to convert the flow rate from actual standard cubic feet (ascf) to dry standard cubic feet (dscf)	EPA Method 4
PM	EPA Method 5, 17, or 29
PM10	EPA Method 201 or 201A
VE	EPA Method 9
Pb	EPA Method 12 or 29
Hg	EPA Method 101A or 29
Be	EPA Method 104 or 29

PREREQUISITES

Prior to initiation of the test burn the following will be completed:

This test burn protocol will be submitted at least 90 days prior to the test to the FDEP (Air Regulation, Power Plant Siting & NE Regional office) and RESD, City of Jacksonville.

Arrangements will be made with an outside vendor to conduct stack testing.

The SFR material handling equipment will be confirmed to be in operating condition.

The CEM data acquisition system will be updated with the most recent Btu/lb (heat content) analysis for accurate heat input determinations.

Verify that all desired data points are arranged to be captured in the plant data collection system.

TESTING PROCEDURE

The plant should be operating in a steady state while maintaining as close to the following parameters as possible:

Main steam temp 1000 deg F +/- 10 deg F
Reheat steam temp 1000 deg F +/- 10 deg F
Main steam pressure 2410 +/- 100 psia
Boiler Blowdown in normal operation
Condenser level in auto
Deaerator level in auto
Steam drum level in auto
Plant in stable condition (no plugged fuel feeders etc) with no major maintenance occurring
Bottom ash screw coolers in steady state operation.

The outside emission testing company should have their equipment in place and ready to collect data from the exit ductwork on Boiler C.

At the point the silo level reaches 0% indication on the DCS or the fuel level reaches the pant leg of the silo the blended test fuel can be fed to the fuel silo. Past experience indicates that it will take about 3 hours for the test burn material to reach the boiler.

Normal automatic operations should be maintained. Boiler operation will be at steady state full load operation at least one hour prior to commencing stack test achieving a minimum 704 Klbs/hr steam flow and 956.7 lbs/mmBtu heat input during emission testing.

Fiber Reject Operation Procedure (See Attachment A)

The test burn will proceed in accordance with the operating procedure attached to this protocol.

Sampling

Fuel – for determination of daily proximate analysis (% moisture,% ash,% volatile,% fixed carbon, % sulfur and BTU/lb determination

- Coal sampling will continue to be collected via the automatic coal sampler per ASTM D2234.
- Daily Fiber Reject samples will be obtained by daily grab sample at the receiving hopper .

Operations will clearly mark each sample container with the date the sample was collected and an assigned ID number. The samples will be routed to the Procurement Department for proper shipping to Commercial Testing and Engineering.

Ash sample collection should be conducted in conjunction with the fuel samples for metals analysis. Flyash will be collected below the bottom dump gates of the flyash separator while the bottom ash will be off the sample port on the drag chain.

SCHEDULE

August 27th – September 25th 2002.

DATA COLLECTION

The plant data collection system has been programmed to collect pertinent data points.

CALCULATIONS AND REPORT

To be provided at the conclusion of the test burn

Cedar Bay Generating Plant

Volume 2 – Operations Procedures

Title – Fiber Waste Feed System – BMW

Proposed: 10/5/96
Reviewed: 5/8/02 **Approved By:**

1.0 Purpose

To establish safe operating guidelines for the operation of the Fiber Waste Feed System.

2.0 Scope

The text provided will be utilized as reference material for day-to-day operation by operations personnel as well as aid in qualification and training.

3.0 Responsibility

The General Manager is responsible for ensuring the plant policies and procedures accurately describe the methods used to operate and maintain CBGP, including associated engineering, environmental, safety and health, and administrative functions. Also the General Manager is responsible for implementing this procedure as it pertains to the Policy Section of the Plant Policy and Procedures Manual.

The Office Manager is responsible for implementing this procedure as it pertains to the Administrative Section of the Plant Policies and Procedures Manual, control and distribution of issued policies and procedures, and maintaining controlled copies of the Plant Policies and Procedures Manual.

The Engineering Manager is responsible for implementing this procedure as it pertains to the Engineering Section of the Plant Policies and Procedures Manual, and be responsible for receipt of revisions to and maintenance of the Plant Manuals.

The Department Managers are responsible for implementing this procedure as it pertains to their respective Department Section(s) of the Plant Policy and Procedures Manual. For the purpose of this procedure any reference to Department Manager responsibilities shall include the General Manager, Office Manager, Engineering Manager, Operations Manager, Maintenance Manager, Environmental Manager, and Health and Safety Manager.

The Process Owner is responsible for maintaining technical and programmatic information concerning the respective system or process as assigned by the Department Manager, and ultimately responsible for the content of the corresponding policy or procedure. The Process Owner is responsible for the review of the policy or procedure to ensure consistency, accuracy of technical content and format.

Note: Unless specifically noted as otherwise in the policy or procedure, the responsible actionee may elect to identify a designee to perform the prescribed responsibilities.

4.0 Definitions

Short Fiber Rejects (SFR) is a by-product of the Smurfit Stone recycling process. Bales of corrugated cardboard are shredded, mixed with water and reduced to a pulp. Heavy trash material such as staples, glass, metal and stones sink to the bottom of the pulp slurry and are removed. The slurry is then spun in a centrifuge to remove any additional heavy material. From the centrifuge the slurry passes through a coarse screen, which removes additional contaminants such as wax or plastic. The slurry passes on to another centrifuge and then short and long fibers are separated using two fine mesh screens and a reverse cleaner. The short fibers are pressed to remove liquids and the SFR is transferred to roll-off containers for disposal.

5.0 Procedure

SFR is collected from Smurfit Stone's process in dedicated 30 cubic yard capacity roll-off boxes for disposal. This procedure will describe the method in which Cedar Bay will handle the SFR once delivered to the receiving hopper located on the western boundary of the Smurfit Stone facility. The receiving hopper is sized to contain approximately two roll-off boxes. SFR will be fed into C-boiler via the SG1C Wood Feed System.

5.1 System Designation: (BMW) Fiber Waste Feed System.

5.2 Component Description / Purpose:

5.2.1 Receiving Hopper (BMW-FDR-1)

The receiving hopper is equipped with a live bottom via drag chain feeder that is designed to operate at two speeds (8 and 16 tons per hour) and interfaces with Cedar Bay's distributed control system (DCS).

5.2.2 Conveyor 1 (BMW-CVY-1)

Conveyor 1 is a 24" wide belt that is rated at 16 tons per hour at a belt speed of 75 feet per minute. Conveyor 1 is fed from Feeder 1 (drag chain). The conveyor is equipped with skirt boards, hood covers, automatic vertical gravity take-up with grab safety devices, speed switch, pull cord switches and belt alignment switches.

5.2.3 Surge Hopper (BMW-HPR-1)

The surge hopper is sized for a minimum capacity of 20 cubic yards and is equipped with two variable speed screw conveyors, each with their own speed switch. The surge hopper also has three capacitance type level switches.

One switch monitors low level, one switch to monitor high level and one switch for emergency high level. Upon actuation of the high level switch, the DCS system will automatically run the drag chain feeder in the receiving hopper in low speed to prevent overfill of the surge hopper. The feeder will return to high speed when the level switch is no longer actuated. The emergency high-level switch will stop both conveyor and feeder immediately after actuation.

5.2.4 Screw Feeders (BMW-FDR-2D, BMW-FDR-2B)

Variable speed drives that discharge to two horizontal drag chain conveyors. The screw feeders have a low and high-speed control that allows the operator to vary the fiber waste flow to maintain level in the surge hopper.

5.2.5 Chain Conveyors (BMW-CVY-3C1, BMW-CVY-3C2)

Two drag chain conveyors, one for each of the loop seal feed points on Boiler 1C, discharge through air locks (rotary valves) to the coal drag chain conveyors feeding the loop seals.

5.2.6 Rotary Valves (BMW-ROT-5C1, BMW-ROT-5C2)

Two rotary valves that feed coal drag chain conveyors 3C1 and 3C4.

5.3 Reference material:

1. Black and Veatch turn over package.

5.4 General precautions:

1. Hard hats and safety glasses must be worn at all times.
2. Keep hands and body parts away from conveyors.
3. Hearing protection and correct respirators must be worn in designated areas, or when necessary.
4. Ensure selected equipment has been thoroughly walked down, all guards in place, all applicable safety tags and locks removed per the clearance procedure and all affected personnel informed of system operations.

5.5 System interlocks and permissives:

1. Boiler on solid fuel.
2. No system failures/trips.
3. Woodfeeders in forward

5.6 Start Up Procedure

5.6.1 Prerequisites:

1. Boiler on solid fuel with appropriate coal feeders running.
   a. 3C1 coal feeder fed by rotary valve 5C1
   b. 3C4 coal feeder fed by rotary valve 5C2
   c. Communicate with operations personnel to feed waste fiber into Feeder 1.

5.6.2 Procedure:

1. Open knife gates between coal conveyor and waste fiber rotary valves.
2. Start Wood Feed System 1. Rotary valve 5C1 will start first, followed by Conveyor 3C1 and Feeder 2D.
3. Start waste fiber conveyor 1
4. Start waste fiber feeder 1
5. Increase speed on waste fiber feed system (Feeder 2D) to desired feed rate.
6. Observe O2 for indication of burn and monitor downcomer temperature.

5.7 Shut Down Procedure

5.7.1 Prerequisites:

Communicate with operations personnel to stop feeding waste fiber into feeder 1

5.7.2 Procedure:

1. Stop Feeder 1. Stopping Feeder 1 will also purge and stop Conveyor 1.
2. When Surge Hopper is empty stop waste fiber feed system to boilers.
3. Close knife gates between coal conveyors and rotary valves.

5.8 Normal Operating Procedure

5.8.1 Prerequisites:

Boiler at full load (760 klbh) and all coal feeders in service.
Boiler O2 indications checked and working properly.

5.8.2 Procedure:

1. Increase rotary feeder speed slowly and monitor O2.
2. Set rotary feeder speed to accomplish up to 150 tons per day burn.
3. Adjust BTU controller to compensate for blend of coal and wood fiber. Wood fiber BTU is approximately 2,434 btu/lb.

Wood Fiber Analysis(Proximate) As Received:
% Moisture-63.57
% Ash-9.43
% Sulfur-.03
% Fixed carbon-4.42

5.9 Routine checks:

Check oil levels in rotary valves.
Check drag chain tension and adjust as necessary.
Check Conveyor rollers and belt integrity.
Visually inspect hoppers and drag chain casings.

5.10 Maintenance:

5.10.1 Safety tag list - Electrical:

1. 1BMW-CVY-1 Mcc 321
2. 1BMW-FDR-1 Mcc322
3. 1BMW-VLV-3C1 Mcc322
4. 1BMW-VLV-5C1 Mcc322
5. 1BMW-VLV-5C2 Mcc322
6. 1BMW-VLV-3C2 Mcc321
7. 1BMW-FDR-2A Mcc321
8. 1BMW-FDR-2B Mcc321
9. 1BMW-FDR-2C Mcc322
10. 1BMW-FDR-2D Mcc322

5.10.2 Safety tag list - Mechanical:

1. 1BMW-VLV-3C1 Knife gate
2. 1BMW-VLV-3C2 Knife gate
3. 1BMW-VLV-5C1 Knife gate
4. 1BMW-VLV-5C2 Knife gate

TECHNICAL EVALUATION

AND

PRELIMINARY DETERMINATION

Cedar Bay Generating Company, LP

Co-Firing of Petroleum Coke

U.S. Generating Company / Cedar Bay Cogeneration Facility

Duval County

0310337-005-AC

Department of Environmental Protection
Division of Air Resources Management
Bureau of Air Regulation
New Source Review Section

May 24, 2002

1. GENERAL INFORMATION

1.1 APPLICANT NAME AND ADDRESS

Cedar Bay Generating Company, L.P.
Cedar Bay Cogeneration Facility
9640 Eastport Road
Jacksonville, Florida 32218

Authorized Representative: Bruce Smith, General Manager

1.2 REVIEWING AND PROCESS SCHEDULE

August 29, 2001	Received permit application and fee
September 28, 2001	Request For Additional Information
April 2, 2002	Second Request For Additional Information
May 18, 2002	Application complete

2. FACILITY INFORMATION

2.1 FACILITY LOCATION

The facility is located in Jacksonville, Duval County. The UTM coordinates are Zone 17; 441.61 km E; 3365.552 km N. This site is approximately 54 kilometers from the Okefenokee National Wildlife Refuge and 98 kilometers from the Wolf Island National Wildlife Refuge, Class I PSD Areas.

2.2 STANDARD INDUSTRIAL CLASSIFICATION CODES (SIC)

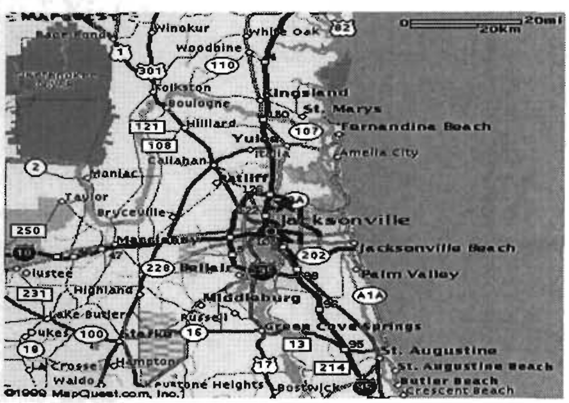
Industry Group No.	49	Electric, Gas and Sanitary Services
Industry No.	4911	Electric Services

2.3 FACILITY CATEGORY

This facility consists of three circulating fluidized bed (CFB) steam generators (boilers) designated as Boilers A, B, and C, a coal handling area, a limestone handling area, and an ash handling area. Crushed coal is the primary fuel for Boilers A, B and C. The fuel for Boilers B and C can also be supplemented with short fiber recycle rejects received from Stone Container Corporation. No. 2 fuel oil is used as supplemental fuel in all three boilers normally only for start-ups.

This facility is classified as a Major or Title V Source of air pollution because emissions of at least one regulated air pollutant, such as particulate matter (PM/PM_{10}), sulfur dioxide (SO_2), nitrogen oxides (NOX), carbon monoxide (CO) or volatile organic compounds (VOC) exceeds 100 tons per year (TPY).

This facility is within an industry included in the list of the 28 Major Facility Categories per Table 62-212.400-1, F.A.C. Because emissions are greater than 100 TPY for at least one criteria pollutant, the facility is also a Major Facility with respect to Rule 62-212.400, Prevention of Significant Deterioration (PSD). This facility is a major source of hazardous air pollutants (HAPs). See Figures 1 and 2 below.



3. PROJECT DESCRIPTION

This project addresses the following emissions unit(s):

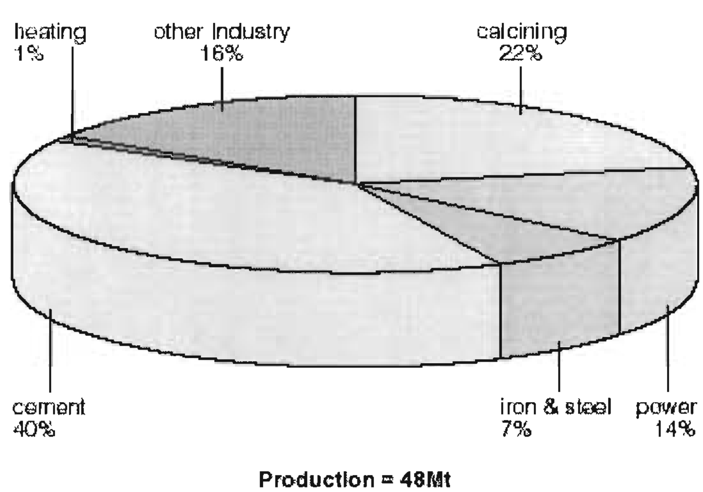
Emissions Unit No.	Emissions unit Description
001	Pyroflow® Circulating Fluidized Bed (CFB) dry bottom boiler designated as "CFB Boiler A"
002	Pyroflow® Circulating Fluidized Bed (CFB) dry bottom boiler designated as "CFB Boiler B"
003	Pyroflow® Circulating Fluidized Bed (CFB) dry bottom boiler designated as "CFB Boiler C"

The applicant proposes to combust up to 35% of its fuel (on a weight basis) as petroleum coke (petcoke). The facility currently combusts coal as its primary fuel. The applicant indicates that this permit modification can be made in such a way that emission levels will not increase beyond historical levels, thus not triggering a PSD Review. The applicant further proposes to maintain and submit to the Department and RESD, on an annual basis for a period of 5-years from the date each emission unit begins firing petroleum coke, data demonstrating in accordance with 40 CFR 52.21(b)(21)(v) and 40 CFR 52.21(b)(33) that the operational change associated with the use of petroleum coke did not result in significant emission increases for CO, NO_X, PM, SO_2 and SAM. A general review of petcoke, CFB Boilers and a review of the P.T.E. and emission analysis follow.

3.1 PETCOKE DISCUSSION

Much of this review was obtained from The Clean Coal Centre of the United Kingdom, in an article entitled "*The use of petroleum coke in a coal-fired plant*". Petroleum coke is a by-product from oil refineries and is composed mainly of carbon though it also contains high levels of sulfur and heavy metals such as vanadium and nickel. There has been considerable interest in petcoke for several years, where it is available, as it is generally significantly cheaper than coal. The price does vary depending on the volumes produced and worldwide demand. The world production of petcoke grew by 50% from 1987 to 1998. It reached nearly 50 Mt in 1999 and is expected to reach 100 Mt by 2010. The USA is the world's largest producer, producing three-quarters of world supplies. There are three types of petroleum coke, which can be produced depending on the process of production. The three processes are delayed, fluid and flexicoking with delayed coking producing over 90%. All three types of petcoke have higher calorific values than coal and contain less volatile matter and ash. The main uses of petcoke are as an energy source for power generation, cement production and the iron and steel production, which account for about two thirds of production and the remainder is used mainly as a carbon source.

FIGURE 3 - 1999 WORLD PETROLEUM COKE MARKET PROFILE



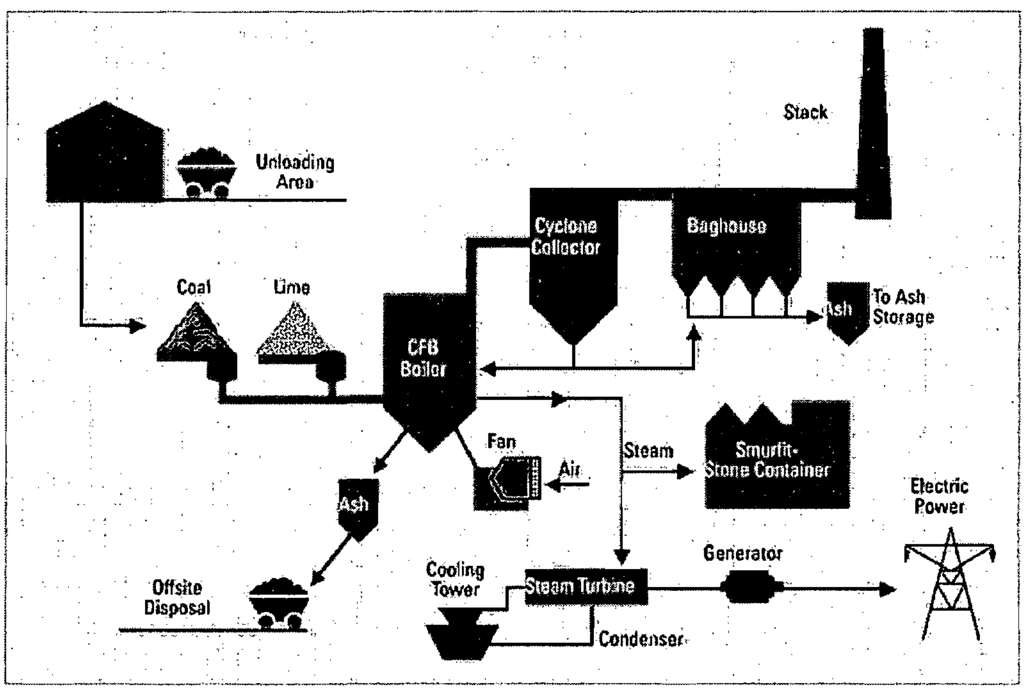
3.2 FLUIDIZED BED COMBUSTION

In a circulating fluidized-bed boiler, a portion of air is introduced through the bottom of the bed. The bed material normally consists of fuel, limestone and ash. Water-cooled membrane walls with specially designed air nozzles support the bottom of the bed, which distributes the air uniformly. The fuel and limestone (for sulfur capture) are fed into the lower bed. In the presence of fluidizing air, the fuel and limestone quickly and uniformly mix under the turbulent environment and behave like a fluid. Carbon particles in the fuel are exposed to the combustion air. The balance of combustion air is introduced at the top of the lower, dense bed. This staged combustion limits the formation of nitrogen oxides (NO_X). The captured solids, including any unburned carbon and unutilized carbon oxide (CaO), are re-injected directly back into the combustion chamber without passing through an external recirculation. This internal solids circulation provides longer residence time for fuel and limestone, resulting in good combustion and improved sulfur capture.

CFB plants are particularly suited for firing petcoke as the long residence times promote high burnout. The low combustion temperature allows SO_2 capture via limestone injection, while minimizing NO_X emissions. In fact, according to Foster Wheeler, CFB boilers are generally capable of removing over 98% of SO_2. The technology is flexible enough to handle a wide range of coals plus petroleum coke as well as blends of coal and coke. Furthermore, the low volatile content of the petcoke is compensated by the substantial amount of hot solids within the boiler providing a constant source of ignition. CFB plants have incurred problems with pluggage but these can be virtually eliminated with appropriate design. Petroleum coke has been fired successfully since the 1980s in a wide variety of CFB plant. In the early years, plants tended to be smaller, generating tens of MW whereas more recently plant generating hundreds of MW are common.

The 135 MW AES Deepwater cogeneration plant has been firing 100% petcoke in an arch-type furnace since 1986. The 1344 MW St Johns River Power Park in Florida has been co-firing coal and up to 20% petroleum coke in two wall-fired units and the plant has not experienced any significant problems with corrosion, slagging or fouling and the increased operational costs have been more than offset by the lower fuel costs. The U.S. Department of Energy (DOE) and JEA have entered into an agreement to repower the JEA Northside Generating Station with CFB technology from Foster Wheeler. When operational, the plant will demonstrate CFB technology for coal firing in large-scale applications while providing increased plant electric output, reduced emissions and broad fuel flexibility. The Mt. Poso cogeneration plant in Southern California is permitted to combust petcoke, various coals and tire-derived fuel (TDF) in the CFB unit owned by Millennium Energy Partners, LLC.

FIGURE 4 – PLANT GRAPHIC



4. PROJECT EMISSIONS

4.1 MAXIMUM POTENTIAL TO EMIT

The following table summarizes the potential project emissions increases/decreases at the facility, based upon the applicant's submittals:

Pollutant	1999 Actual Emissions (TPY)	2000 Actual Emissions (TPY)	1999–2000 Average (TPY)	Projected Emissions Co-firing Petcoke	Projected Emissions Change	PSD Significant Emission Rates (TPY)	Subject To PSD Review?
NO_X	1741.5	1779.0	1760.2	1718.1	-42.1	40	NO
CO	582.3	516.0	549.1	400.9	-148.2	100	NO
VOC	17.89	17.25	17.57	34.65	17.08	40	NO
SO_2	1926.2	1965.1	1945.6	1941.3	-4.3	40	NO
PM_{10}	193.7	165.2	179.4	169.9	-9.5	15	NO

[1] Based upon

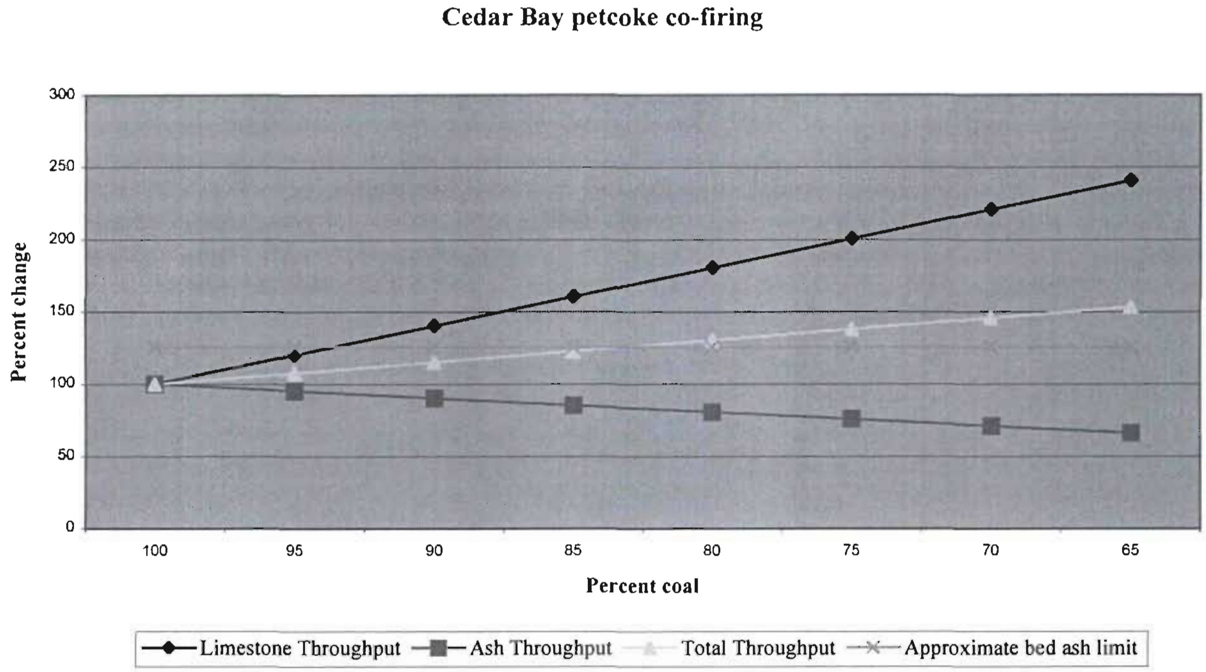
4.2 BOTTLE-NECKING ISSUES

The existing permit provides certain limitations to the throughputs of raw and spent materials. As can be seen from Figure 4 above, there are two primary raw material inputs (coal and limestone) and two primary spent material streams (fly ash and bed ash). A review of data reported to FDEP by Cedar Bay during years 1999 and 2000 shows the following actual annual throughputs along with their respective limits, each in tons per year (TPY).

	COAL	LIMESTONE	FLY ASH	BED ASH
*ANNUAL **LIMIT***	*1,170,000*	*320,000*	*336,000*	*88,000*
1999	962,569	122,835	138,306	69,153
2000	954,391	110,534	138,280	71,235

Co-firing of petcoke will result in a lower amount of coal being fired. Additionally, since petcoke has a higher BTU content per ton of fuel than does coal, the combined throughput of petcoke and coal should decrease. Therefore, it is improbable that the commencement of co-firing will cause the facility to approach the coal throughput limit. Concerning limestone, the Department estimates that the facility will need to (approximately) double the throughput, in order to achieve the necessary SO_2 scrubbing required to ensure that the PSD significance level is not exceeded. As can be seen from the above table, limestone throughputs can nearly triple before the permitted limit is exceeded, indicating that it is unlikely that limestone throughput limits will be exceeded while co-firing petcoke. Like limestone, the past actual throughputs of flyash are well below permitted levels (approximately 40%). Since the ash content of petcoke is lower than that of coal, it is also unlikely that permitted throughputs of flyash will be exceeded, and Department calculations bear this out. However, the Department estimates that the throughput limit associated with bed ash could be problematic for the facility.

It can be observed from the above table that historically, the flyash to bed ash ratio has been approximately 2:1. Simply stated, for each 1,000 ton of combined limestone and ash entering the boilers, approximately 667 tons will end up as fly ash and 333 tons will become bed ash. Accordingly, at an increased limestone and ash throughput of approximately 54,000 TPY, the flyash would be expected to increase by about 36,000 TPY whereas the bed ash would increase by about 18,000 TPY. This increased throughput of bed ash is roughly equivalent to the permit limit, as the historical average of approximately 70,000 TPY is 18,000 TPY less than the limit. In summary, the 88,000 TPY of bed ash limit likely becomes an upper bound for the amount of co-firing, which the facility can accommodate. What follows is a Department estimate of the equivalent amount of petcoke, which corresponds to the 88,000 TPY throughput limit on bed ash (125% of the past actual).



Based upon the graph above, a practical limit of petcoke firing is approximately 17% (83% coal).

During the year 2000, the Auburndale facility was offline for a period of time (which the applicant contends was abnormal) due to problems associated with the over-injection of steam to control NO_x and then for the installation of the SCR. These downtimes consisted of an unplanned maintenance outage in 2000, an extended annual planned outage, and a forced outage in November 2000. Since the over-injection of steam was causing combustion turbine blade damage, it was uncertain whether the extent of the potential damage would allow operation of the unit until its annual planned outage in October 2000. As a result, the Auburndale Cogeneration Facility was shut down in June 2000 for 3.8 days to perform an internal combustor visual inspection. The installation of the SCR caused the annual planned outage in October to be extended to 17.2 days, which is 10.2 days longer than the normal annual combustor inspection outage that typically lasts 5 to 7 days. Finally, a forced outage in November associated with SCR start-up problems caused the facility to be down for 7.1 days. Therefore, the applicant contends there were 21.1 days of abnormal outage time during 2000 that were associated with over-injection for NO_x control and the installation of the SCR.

As described above, the actual emissions from the existing facility is complicated by the staged emission limit and problems experienced with over-injecting steam in the turbine. Therefore, using the last 2 years to determine "actual emissions", as suggested in the definition of actual emissions in Rule 62-210.200 F.A.C., is not considered to be representative of normal operations. Given these circumstances, the applicant proposes that the latest year of operation (i.e., year 2000), adjusted for forced outages resulting directly from the problems associated with the NO_x issues, be considered "representative" of "actual emissions". The data available from the facility and the Acid Rain continuous emissions monitoring (CEM) system is as follows for the year 2000.

<u>Auburndale Cogeneration Facility – Year 2000 Fuel Usage and NO_X Emissions</u>

Hours of Operation:	8,139
Heat Input Gas:	8,765,886 MMBtu/year
Heat Input Oil:	189,361 MMBtu/year
NO_X Emissions:	247.61 tons/year

Forced Outages: 506 hours

The applicant proposes that the 247.61 tons/year be adjusted to 8,645 hours of operation: 247.61 tons/year x 8,645/8,139 = 263 tons/year, increasing the year 2000 actual emissions by 15.39 tons. A NO_x emissions cap of 302 tons/year is therefore proposed by the applicant for the Auburndale Facility (263 tons/year actual plus 39 tons/year = 302 tons/year), which is the maximum that could be authorized without a PSD review. This NO_x emissions cap is proposed as a facility-wide cap for both the existing cogeneration facility and the new peaking unit. It is noted that the existing potential NO_x emissions authorized for the existing unit is 344.3 tons/year, meaning that the applicant's proposal represents a 42 TPY (12 percent) reduction in potential NO_x emissions currently authorized by the Department for the existing unit alone.

5. RULE APPLICABILITY

This facility is located in an area designated, in accordance with Rule 62-204.340, F.A.C., as attainment for all pollutants. Rule 62-4.030, F.A.C., prohibits modification of any existing emissions unit without first receiving a permit. It further specifies that a permitted installation may only be modified in a manner that is consistent with the terms of such a permit. Rule 62-210.200, F.A.C., defines "modification" to mean generally a physical change or change in the method of operation that results in an increase in actual emissions of regulated air pollutants. Rules 62-210.300(1) and 62-212.300(1)(a), F.A.C., also reiterate the requirement for construction permits. Additionally, Rule 62-210.300 requires an Air Construction permit for all new sources of air pollution unless specifically exempt.

FDEP deems that burning of petcoke is a change in the method of operation. Given that the source is major with regard to PSD, an analysis needs to be performed to verify that the burning of petcoke will not result in a significant net emissions increase and that, consequently, use of petcoke is not a major modification subject to PSD review. The emission units affected by this permit shall comply with all applicable provisions of the Florida Administrative Code (including applicable portions of the Code of Federal Regulations incorporated therein).

6. AIR POLLUTION CONTROL METHODS

The applicant proposes to limit NO_X emissions through the use of an approved facility-wide NO_X cap and the use of water injection (thereby limiting unit specific emissions to 25 ppmvd @ 15% O_2). Although the applicant proposes to net out of a PSD review for NO_X, the unit must still conform to the NSPS requirements. The Department points out that based upon current combustion turbine reviews, a PSD review (BACT Determination) for NO_X would not authorize emissions above 15 ppmvd and could likely result in the requirement to utilize a hot SCR.

6.1 STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

The minimum project control technology basis is 40 CFR 60, Subpart GG, Standards of Performance for Stationary Gas Turbines (NSPS). Subpart GG was adopted by the Department by reference in Rule 62-204.800, F.A.C. The key emission limit required by this subpart is 75 ppmvd NO_X at 15% O2. The limit proposed by Auburndale is consistent with the requirements of this subpart.

6.2 DEPARTMENT'S DETERMINATION FOR NO_X

The Department has determined that the application of an emissions cap for NO_X, combined with additional "unit specific" emissions limits will eliminate the requirement for a PSD review for that pollutant. Concerning the precise value and implementation method of the proposed cap, the Department makes the following determinations:

6.2.1 AMOUNT OF NO_X CAP AUTHORIZED

It is recognized that some amount of the applicant's requested "adjustment" of the Year 2000 actual emissions may be in order. However, an adjustment that presumes that representative annual operating hours should be 8645 hours/year (98.7% of the hours in a year) rather than 8139 (92.9% of a year) appears aggressive. Accordingly, the Department will allow an adjustment, which yields 95% of a year's worth of operating hours (approximately 5.6 TPY over Year 2000 emissions). Representative emissions are deemed to be 253 TPY and baseline emissions are therefore set to be 39 TPY above that value, or 292 TPY (as an increase of 40 TPY triggers a PSD review for NO_X).

6.2.2 METHOD OF IMPLEMENTATION FOR THE NO_X CAP

The applicant originally requested a facility-wide cap, which would allow the greatest flexibility. The method, by which the applicant wished to demonstrate compliance with the cap, was to utilize CEMS on both emissions units and to be bound by the facility-wide cap, with no additional emissions limitation placed upon the existing unit beyond the limits already in existence. The applicant pointed out that the Department had previously issued some permits in this fashion, suggesting that consideration should be given to this established precedence. The Department recognizes that some of these past permitting actions may exist, but does not intend to perpetuate related errors. Accordingly, a cap will be authorized in strict accordance with the EPA's New Source Review Training Course and related guidance. This guidance specifically requires that increases from the proposed modification shall be added to source-wide contemporaneous increases, less source-wide creditable decreases. The Department maintains that as a prerequisite to performing the analysis, new potential emission increases from the proposed project (without netting) must be identified. These may then be compared to the proposed decreases from any existing emissions units, to ascertain whether the project will indeed net out. All emission increases and decreases must be creditable, contemporaneous and not otherwise needed to meet a regulatory compliance requirement. Among other requirements, *creditable* is defined as permanent, real, quantifiable and federally enforceable.
Avoidance of PSD through "netting" cannot be authorized without an itemization of the creditable emission reductions {from existing source(s)}, which are being permanently proposed. In this case, the applicant wishes to increase NO_X emissions by 115 TPY at the new source. Therefore, the emissions of the existing unit will need to be reduced by 115 TPY in order for netting to be authorized. Since the baseline emissions for the existing unit are 292 TPY and the existing NO_X limit is 15 ppmvd, the new limits imposed upon the existing unit shall be 177 TPY [292 – 115] as well as 9 ppmvd on an equivalent annual basis [15 ppmvd * 177/292]. Methods of compliance with each of these limits shall be specified within the permit.

6.2.3 DETERMINATION OF PTE FOR OTHER POLLUTANTS BASED UPON NETTING OUTCOME

Since the new emissions unit (EU-006) will be limited to 115 TPY of NO_X emissions, a de-facto limit on the hours of operation is calculable. The Department has determined that a limit of 1400 hours of operation (regardless of the authorized fuel mix) per consecutive 12-month is the de-facto limit which sets the PTE of each pollutant as per the table below:

Pollutant	Proposed Gas Emission limit	Proposed Oil Emission limit	TPY[1]	PSD Significant Emission Rates (TPY)	Subject To PSD Review?
CO	10 ppmvd @ 15% O_2	10 ppmvd @ 15% O_2	23.4	100	NO
VOC	4 ppmvd @ 15% O_2	5 ppmvd @ 15% O_2	5.7	40	NO
SO_2	2 grains / 100 SCF	74.9 lb/hr (0.05% S)	16.2	40	NO
PM_{10}	2.9 lb/hr	58.5 lb/hr	3.1	15	NO

[1] Based upon gas firing 1000 hours and oil firing for 400 hours/year; CO emissions may be higher due to low load operation.

6.3 ADDITIONAL COMPLIANCE PROCEDURES

Pollutant	Compliance Procedures for EU-006	
NO_X emission limit	EPA Method 20 (Initial and annual / annual RATA) NO_X CEMS data (24-hour block average) used for daily compliance of new emissions unit NO_X CEMS data (12-month rolling average) used for annual compliance of both units NO_X CEMS data (12-month rolling average) used for compliance of EU-001	<u>*Established to avoid PSD*</u>
CO emission limit	EPA Method 10 (Initial and annual / annual RATA) CO CEMS data (12-month rolling average)	<u>*Established to avoid PSD*</u>
VOC emission limit	EPA Method 25A (Initial and upon permit renewal)	<u>*Not established by BACT*</u>
SO_2 emission limit	Fuel Sampling	<u>*Not established by BACT*</u>
PM_{10} emission limit	EPA Method 9 (Initial and annual)	<u>*Not established by BACT*</u>

Specific permit conditions regarding short and long-term limits for EU-001 and EU-006 shall further describe these limitations, however the limits for EU-001 are <u>in addition to</u> existing emission limits, not in lieu of existing limits.

7. HAZARDOUS AIR POLLUTANT ANALYSIS

An evaluation of HAP emissions from the project indicates that the emissions are less than 25 tons/year for all HAPS and less than 10 tons/year for a single HAP. Therefore, the requirements of 40CFR 63.43 for maximum achievable control technology are not applicable to the project.

8. SOURCE IMPACT ANALYSIS

The applicant's initial request for this project indicated that the increase in NO_X emissions would exceed the PSD Significant Emission Rates listed in Table 62-212.400-2, F.A.C. A significant impact analysis was subsequently performed. However, the applicant later modified the request so as to avoid a PSD review as described in this technical evaluation. Therefore, an air quality analysis is not required by rule. However, since the analyses were performed, the Department is providing a brief summary of those modeling results, as provided by the applicant, but without Department review.

An ambient air quality impact assessment was done in support of the original application. The modeling approach followed EPA and DEP guidelines for determining compliance with AAQS and PSD increments. Two air quality dispersion models were used to analyze air quality impacts for this project. These models were ISCST3 and CALPUFF. Both analyses resulted in no adverse impacts due to the proposed project

9. CONCLUSION

Based on the foregoing technical evaluation of the application, additional information submitted by the applicant and other available information, the Department has made a preliminary determination that the proposed project will comply with all applicable state and federal air pollution regulations.

Michael P. Halpin, P.E. Review Engineer
Department of Environmental Protection, Bureau of Air Regulation
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Department of Environmental Protection

Jeb Bush
Governor

Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

David B. Struhs
Secretary

April 2, 2002

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. Bruce Smith
Cedar Bay Cogenerating Company, L.P.
P.O. Box 26324
Jacksonville, FL 32226

Re: Request for Additional Information
Co-firing Petroleum Coke with Coal
File No. PA 88-24 (PSD-FL-137)
Cedar Bay Cogenerating Project

Dear Mr. Smith:

The Department is in receipt of your reply to our September 28, 2001 request for additional information. The application remains incomplete. In order to continue processing your application, the Department will need the additional information below. Should your response to any of the below items require new calculations, please submit the new calculations, assumptions, reference material and appropriate revised pages of the application form.

1. The technical basis for the development of the "Representative Future Actual Emissions" in Table B is unclear. Rather, in each case, the "Representative Future Actual Emissions" appear to simply represent values that are slightly less than the past actual emissions plus the PSD Significant Emission Rates. Please provide the basis for the emission calculations, which Cedar Bay utilized in the development of this table. The Department notes that the basis for the original BACT emission calculation was a 93% capacity factor.

2. Notwithstanding Cedar Bay's reference to 40 CFR 52.21(b)(33), it does not appear that the original question posed in the Department's September 28th letter has been fully answered. Within that request, the Department is attempting to obtain reasonable assurance as to whether a PSD Review is required. The relevant statutes expressly contemplate that projections of the impact of a change must be made before construction. Before a permit is issued, among other things, the owner or operator of the source must, using projections of post-change emissions, demonstrate that emissions from the modified source will not violate air quality requirements.

   Specifically, section 165 states that "[n]o major emitting facility ... may be constructed unless a permit has been issued for such proposed facility" [CAA § 165, 42 U.S.C. § 7475]. Further, the owner or operator must demonstrate to the administrator's satisfaction that "emissions from construction or operation of such facility will not cause, or contribute to, air pollution in excess of" the NAAQS, among other things [CAA § 165(a)(3), 42 U.S.C. § 7475(a)(3)].

   This statutory and regulatory structure has two important features relevant to this application:
   (1) the permit must be obtained *before* the physical change is made, and
   (2) whether a physical change requires a permit is determined in part by reference to anticipated results or consequences, which necessarily would occur *after* the physical change is made.

   Thus, the only way for the owner or operator of the source to know whether a permit is required for any particular physical change is for the owner or operator to make a prediction as to whether the emissions increase will occur. This observation was described by EPA in the 1992 preamble to amendments to the NSR regulations as follows:

> Applicability of the CAA's NSR provisions must be determined in advance of construction and is pollutant specific. In cases involving existing sources, this requires a pollutant-by-pollutant projection of the emissions increases, if any, which will result from the physical or operational change. 57 Fed. Reg. 32,314, 32,316 n.8 (1992).

Any other construction of the statute would allow sources to make modifications or changes without a permit, while they wait to see if it would be proven that emissions would increase. Clearly Congress did not intend such an outcome, which would effectively allow avoidance of the *preconstruction* dimension of the program.

Concerning the attendant application, should the Department gain reasonable assurance that the PSD thresholds are not triggered, a permit condition (similar to the one referenced within your response) may be able to be implemented, with additional restrictions as deemed appropriate by the Department.

3. According to prior data reported to FDEP by Cedar Bay, past actual SO_2 has been controlled at 90% with limestone throughputs averaging 120,000 TPY. The application has estimated past actual sulfur capture at over 93% and annual limestone throughput at 152,753 TPY. As indicated below, the Department intends to revise all related calculations.

4. According to prior data reported to FDEP by Cedar Bay, past actual throughputs of bed (bottom) ash have averaged over 70,000 TPY during years 1998 through 2000. The application has provided a calculated past value of 51,325 TPY. The Department intends to revise all related calculations, and notes that the existing permit limits the throughput to 88,000 TPY.

5. Based upon a preliminary analysis by the Department, the co-firing of petcoke at 35% will necessitate an increase in limestone feed by over 100% in order to ensure that SO_2 emissions are not increased. The Department specifically requires additional information (beyond that which has been submitted) in order to ensure that annual PM_{10} emissions remain below a 15 TPY increase, while simultaneously maintaining SO_2 emissions below a 40 TPY increase. Please provide assumed collection efficiencies within submitted calculations.

Rule 62-4.050(3), F.A.C. requires that all applications for a Department permit must be certified by a professional engineer registered in the State of Florida. This requirement also applies to responses to Department requests for additional information of an engineering nature. Please note that per Rule 62-4.055(1): *"The applicant shall have ninety days after the Department mails a timely request for additional information to submit that information to the Department.......... Failure of an applicant to provide the timely requested information by the applicable date shall result in denial of the application."*

If you have any questions, please call Michael P. Halpin, P.E. at 850/921-9519.

Sincerely,

Michael P. Halpin

Michael P. Halpin, P.E. FDEP/DARM
New Source Review Section

Ken Kosky, P.E. Golder Associates
Hamilton S. Oven, P.E. PPSO
James L. Manning, P.E. RESD
Chris Kirts, DEP-NED
Stafford Campbell, Greater Arlington Civic Council

110534

The following SO2 emissions were reported to the Department for Cedar Bay Unit 1 Boilers A,B & C for yrs 1997 thru 2000:

Year	SO2 - TPY
2000	1965.1
1999	1926.2
1998	1935.6
1997	1909

Based upon the above data, the following facility capture efficiency is calculated (assumes that all SO2 other than what exit stacks is captured at facility):

Year	capture %
2000	90.29%
1999	90.99%
1998	90.62%
1997	89.54%

All 3 boilers combined	MMBtu
max hourly ht input =	3189
max daily heat input =	76536
max annual ht input =	27935640

X93%=

25980000

The following Coal throughputs were obtained from AOR data and applicant's submittals.

Boiler A

Year	Coal-TPY	SO2 - TPY	Ht Content	%S Content
2000	320199	6788.2188	11950	1.06
1999	324598	7206.0756	11900	1.11
1998	334181	7084.6372	10750	1.06
1997	331642	6234.8696	11900	0.94

Boiler B

Year	Coal-TPY	SO2 - TPY	Ht Content	%S Content
2000	318602	6754.3624	12000	1.06
1999	316369	7023.3918	11500	1.11
1998	306430	6496.316	11700	1.06
1997	316400	5948.32	11900	0.94

Boiler C

Year	Coal-TPY	SO2 - TPY	Ht Content	%S Content
2000	315590	6690.508	12000	1.06
1999	321602	7139.5644	11900	1.11
1998	332388	7046.6256	11700	1.06
1997	322289	6059.0332	11900	0.94

3 Boilers Combined

Year	Coal-TPY	SO2 - TPY	Ht Content	%S Content
2000	954391	20233.089	11983	1.06
1999	962569	21369.032	11769	1.11
1998	972999	20627.579	11374	1.06
1997	970331	18242.223	11900	0.94
Average	965073	20118	11756	1.0%

The following calculation is to determine the incremental SO2 which the facility (at 93% CF) will need to handle as a result of combusting 35% petcoke with %S content = **5.45%**

petcoke MMBtu/day	**petcoke TPD**	**petcoke TPY**	**incremental SO2 - TPY**	**Heat Value Btu/lb**
26788	962	326547.83	35594	13923

The following calculation is to determine the decremental SO2 which the facility (at 93% CF) will not need to handle as a result of combusting 35% petcoke instead of the equivalent (heat basis) amount of coal (1998 ht content, 1999 %S):

coal amount offset by combusting petcoke MMBtu/day	**TPD**	**coal TPY**	**decremental amount of SO2 by not combusting coal**
26788	1178	399740	8874

684,156 TPY to ML

342,078 each

The following is an estimate of the annual SO2 facility emissions increase as a result of combusting 35% Petcoke rather than the typical coal (assumes 1999 efficiency):

net additional SO2 handled - TPY	**facility SO2 capture eff.**	**net change in SO2 emitted**	**reqd SO2 capture eff. for SO2 inc of 39 TPY**
26719	90.99%	***2408 TPY***	99.85%

88,000 TPY limit → bed ash

The following SO2 emissions were reported to the Department for Cedar Bay Unit 1 Boilers A,B & C for yrs 1997 thru 2000:

Year	SO2 - TPY
2000	1965.1
1999	1926.2
1998	1935.6
1997	1909

Based upon the above data, the following facility capture efficiency is calculated (assumes that all SO2 other than what exit stacks is captured at facility):

Year	capture %
2000	90.29%
1999	90.99%
1998	90.62%
1997	89.54%

All 3 boilers combined	MMBtu
max hourly ht input =	3189
max daily heat input =	76536
max annual ht input =	27935640

The following Coal throughputs were obtained from AOR data and applicant's submittals.

Boiler A

Year	Coal-TPY	SO2 - TPY	Ht Content	%S Content
2000	320199	6788.2188	11950	1.06
1999	324598	7206.0756	11900	1.11
1998	334181	7084.6372	10750	1.06
1997	331642	6234.8696	11900	0.94

Boiler B

Year	Coal-TPY	SO2 - TPY	Ht Content	%S Content
2000	318602	6754.3624	12000	1.06
1999	316369	7023.3918	11500	1.11
1998	306430	6496.316	11700	1.06
1997	316400	5948.32	11900	0.94

Boiler C

Year	Coal-TPY	SO2 - TPY	Ht Content	%S Content
2000	315590	6690.508	12000	1.06
1999	321602	7139.5644	11900	1.11
1998	332388	7046.6256	11700	1.06
1997	322289	6059.0332	11900	0.94

3 Boilers Combined

Year	Coal-TPY	SO2 - TPY	Ht Content	%S Content
2000	954391	20233.089	11983	1.06
1999	962569	21369.032	11769	1.11
1998	972999	20627.579	11374	1.06
1997	970331	18242.223	11900	0.94
Average	965073	20118	11756	1

The following calculation is to determine the incremental SO2 which the facility will need to handle as a result of combusting 35% petcoke with %S content = **5.45%**

petcoke MMBtu/day	petcoke TPD	petcoke TPY	incremental SO2 - TPY	Heat Value of petcoke MMBtu
26788	3848	1404506.8	153091	13923

The following calculation is to determine the decremental SO2 which the facility will not need to handle as a result of combusting 35% petcoke instead of the equivalent (heat basis) amount of coal (1998 ht content, 1999 %S):

coal amount offset by combusting petcoke MMBtu/day	coal amount offset by combusting petcoke TPD	coal TPY	decremental SO2 amt. by not combusting coal SO2 -TPY
26788	4557	1663349	34681

The following is an estimate of the annual SO2 facility emissions increase as a result of combusting 35% Petcoke rather than the typical coal (assumes 1999 efficiency):

net additional SO2	facility SO2	net change in SO2	reqd SO2 capture eff

Emission Limitations and Standards

{Permitting Note: The attached Table 1-1, Summary of Air Pollutant Standards and Terms, summarizes information for convenience purposes only. This table does not supersede any of the terms or conditions of this permit. For PM, VE, NO_X and SO_2, meeting the PSD limits assures compliance with the NSPS limits.}

@ 93% capacity Factor

A.5. Emission Limits. The maximum emission limits from each CFB boiler are:

Pollutant Name	Pollutant Acronym	lbs/MMBtu	lbs/hr	TPY
Carbon Monoxide	CO[5]	0.175[1]	186[1]	758[4]
Nitrogen Oxides	NO_X	0.17[2]	180.7[2]	736.1
Sulfur Dioxide	SO_2	0.30[3]	318.9[3]	--
	SO_2	0.20[4]	--	866
Volatile Organic Compound	VOC	0.015	16.0	65
Particulate Matter	PM	0.018	19.1	78
Particulate Matter less than 10 microns	PM_{10}	0.018	19.1	78
Sulfuric Acid Mist	H_2SO_4 mist	4.66×10^{-4}	0.50	2.0
Fluorides	Fl	7.44×10^{-4}	0.79	3.2
Lead	Pb	6.03×10^{-5}	0.06	0.26
Mercury	Hg	2.89×10^{-5}	0.03	0.13
Beryllium	Be	8.70×10^{-6}	0.01	0.04

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

1. Eight-hour rolling average, except for initial and annual compliance tests and the CEM certification, when the 1-hour standard applies.
2. Thirty-day rolling average.
3. Three-hour rolling average.
4. Twelve-month rolling average.
5. See Specific Condition **A.13.b.** for alternative CO emission limits during specific operating modes.

[PSD-FL-137(A & D)]

A.6. Visible Emissions. Visible emissions (VE) shall not exceed 20 percent opacity (6-minute average), except for one 6-minute period per hour when VE shall not exceed 27% opacity. Because CFB Boilers A, B & C share a common stack, visible emissions violations from the stack will be attributed to all three units unless opacity meter results show the specific unit causing the violation.
[40 CFR 60.42a(b); and, PSD-FL-137(A)]

Golder Associates Inc.

6241 NW 23rd Street, Suite 500
Gainesville, FL 32653-1500
Telephone (352) 336-5600
Fax (352) 336-6603

Golder Associates

TRANSMITTAL LETTER

To: Mike Halpin, P.E.
FDEP Bureau of Air Regulation
111 South Magnolia Drive
Tallahessee, FL 32301

850-488-1344

Date: April 25, 2002
Project No.: 0137573-0100

Sent by: **lsh**

- ☐ Mail
- ☐ Air Freight
- ☐ Hand Carried
- ☐ UPS
- ☒ Federal Express

Per: **Ken Kosky**

Quantity	Item	Description
1	CD	PDF files of Cedar Bay Emission Control Manual

Remarks:

P:\Projects\2001\0137573 PGE-Cedar Bay\4\4.1\LOT042502.doc

TECHNICAL EVALUATION

PRELIMINARY DETERMINATION

AND

DRAFT REVISED BACT DETERMINATION

Cedar Bay Generating Company, L.P.
Cedar Bay Generating Plant
Duval County

DEP File No. PA 88-24
PSD-FL-137

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

December 6, 1999

1. GENERAL INFORMATION

1.1 APPLICANT NAME AND ADDRESS

Cedar Bay Generating Company, L.P.
Cedar Bay Generating Plant
9640 East Port Road
Jacksonville, Florida 32218

Authorized Representative: J.A. Walker, Environmental Manager

1.2 REVIEWING AND PROCESS SCHEDULE

March 22, 1999	Submitted permit application
May 24, 1999	Revised application received by Department
September 3, 1999	Department's request for additional information
November 15, 1999	Received response to request for additional information
November 15, 1999	Application complete

2. FACILITY INFORMATION

2.1 FACILITY LOCATION

The facility is located in Jacksonville, Duval County. The UTM coordinates are Zone 17; 441.08 km E; 3365.06 km N. This site is approximately 54 kilometers from the Okefenokee National Wildlife Refuge and 98 kilometers from the Wolf Island National Wildlife Refuge, Class I PSD Areas.

2.2 STANDARD INDUSTRIAL CLASSIFICATION CODES (SIC)

Industry Group No.	49	Electric, Gas and Sanitary Services
Industry No.	4911	Electric Services

2.3 FACILITY CATEGORY

This facility consists of three circulating fluidized bed steam generators (boilers) designated as Boilers A, B, and C, a coal handling area, a limestone handling area, and an ash handling area. Crushed coal is the primary fuel for Boilers A, B and C. The fuel for Boilers B and C can also be supplemented with short fiber recycle rejects received from Stone Container Corporation. No. 2 fuel oil is used as supplemental fuel in all three boilers normally only for start-ups.

This facility is classified as a Major or Title V Source of air pollution because emissions of at least one regulated air pollutant, such as particulate matter (PM/PM_{10}), sulfur dioxide (SO_2), nitrogen oxides (NO_X), carbon monoxide (CO), or volatile organic compounds (VOC) exceeds 100 tons per year (TPY).

This facility is within an industry included in the list of the 28 Major Facility Categories per Table 62-212.400-1, F.A.C. Because emissions are greater than 100 TPY for at least one criteria pollutant, the facility is also a Major Facility with respect to Rule 62-212.400, Prevention of Significant Deterioration (PSD). This facility is a major source of hazardous air pollutants (HAPs).

3. PROJECT DESCRIPTION

This project addresses the following emissions unit(s):

Emissions Unit No.	Emissions unit Description
001	Pyroflow® Circulating Fluidized Bed (CFB) dry bottom boiler designated as "CFB Boiler A"
002	Pyroflow® Circulating Fluidized Bed (CFB) dry bottom boiler designated as "CFB Boiler B"
003	Pyroflow® Circulating Fluidized Bed (CFB) dry bottom boiler designated as "CFB Boiler C"

The applicant proposes six changes to its current PSD permit. These changes are itemized briefly as follows:

A) Startup and Shutdown Definition – allow for excess emissions of CO during specific operating modes identified as startup or shutdown

B) Method of compliance for SO_2 – allow for an increase in the 3-hour SO_2 emission rate

C) Heat Input – allow for operational flexibility between emissions units

D) Mercury Testing – request to delete this requirement

E) Test Methods – allow for Method 29 as the method of compliance with metals requirements

F) Short Fiber rejects – request to modify condition describing the burning of short fiber rejects generated by Seminole Kraft

4. DETAILS OF APPLICANT'S REQUEST

Each requested change will be discussed within this section, including a summary of the applicant's request.

A) <u>Startup and Shutdown Definition</u>

Cedar Bay desires to obtain a modification regarding provisions for CO excess emissions during the various startup conditions for the circulating bed (CFB) boilers. There are two typical startup scenarios: 1) cold startup, and 2) warm startup. A third startup scenario occurs following some outages due to refractory replacement during a boiler outage. Each of these and the potential excess emissions are described below.

Cold Startup

A cold startup occurs when the boiler has been shutdown long enough for the boiler internal components to cool down. With three CFB boilers, approximately 15 to 20 cold startups may occur per year. The cold startup involves firing distillate fuel oil up to 10 hours, and excess emissions may occur during this period. This length of time may be required in order to raise the bed temperature to the minimum temperature necessary to support coal combustion. During the cold startup period, the hourly emission rates of carbon monoxide (CO) in lb/MMBtu can range from 10 to 20 times the permitted 8-hour rolling average limit of 0.175 lb/MMBtu. Because the heat input during these conditions is relatively low, the CO emissions in lb/hr are approximately 1 to 3 times the 8-hour rolling average permit limit of 186 lb/hr. During these cold startups, emissions of sulfur dioxide (SO_2) and nitrogen oxides (NO_X) are well within permit limits.

Warm Startup

A warm startup occurs when the boiler has been shutdown, but not long enough for the boiler internal components to completely cool down. With three CFB boilers, approximately 20 to 30 warm startups may occur per year. The warm startup involves firing distillate fuel oil. The length of time required in order to raise the bed temperature to the minimum temperature necessary to support coal combustion is dependent upon the duration of boiler shutdown prior to startup. During the warm startup period, the hourly emission rates of CO in lb/MMBtu can range from 5 to 10 times the permitted 8-hour rolling average limit of 0.175 lb/MMBtu, and up to 3 occurrences of excess emissions above the 8-hour rolling average CO limit are possible. Because the heat input during these conditions is relatively low, the CO emissions in lb/hr are normally within the permit limit of 186 lb/hr. During these warm startup periods, emissions of SO_2 and NO_X are well within permit limits.

Refractory Replacement

Refractory curing occurs when portions of the refractory on a boiler are replaced during a boiler outage and is a required portion of the startup process following these outages. The new refractory must be cured at controlled temperatures by firing distillate oil for up to 24 hours. There may be up to a total of 4 to 6 refractory cures per year for the three CFB boilers. During this period, there is low heat input to the boiler and only No. 2 fuel oil is fired. As a result, the curing contributes to periods of excess CO emissions as high as 10-20 times the permit limit in lb/MMBtu and 2-3 times the lb/hr rate limit. It is normal operating procedure to transition from refractory cure to warm start-up to bring the boiler online. During the refractory cure, as in other startup modes, emissions of SO_2 and NO_X are well within permit limits.

B) Method of compliance for SO_2

Cedar Bay proposes a change to the 3-hour rolling average with no modification to the existing 12-month rolling average. All other SO_2 emission limitations would remain the same. The chief reason for this request is that the units are not capable of routinely meeting the 3-hour limit, but over a longer period the units are capable of meeting the current limit.

C) Heat Input

Cedar Bay requests that the total heat input limitation remain in effect for all three boilers but the individual limits be removed from the permit to allow this flexibility. No increases in emissions are otherwise requested as a part of this change.

D) Mercury Testing

The applicant requests that this requirement be removed from its PSD permit. The only ability that the facility has to control mercury is through the fuel quality and any baghouse removal, i.e. no specific mercury removal equipment is employed and no standard is used to evaluate such tests.

E) Test Methods

The applicant requests the ability to demonstrate compliance with the particulate (PM10) and metals requirements by method 29. Current permit requirements are individual methods currently itemized as Method 5 (or 17) for PM, Method 12 (Pb), Method 101A (Hg) and Method 104 (Be). Cost and time are stated as the chief reasons.

F) Short Fiber Rejects

The applicant requests that the PSD permit condition, which requires it to burn short fiber rejects (generated by Seminole Kraft, which is now Smurfit Stone Container), be modified. The applicant indicates that "after consultation with Smurfit Stone Container Corporation" it proposes specific language that is consistent with a SETTLEMENT AND RELEASE AGREEMENT made on July 24, 1998 between the two parties. The result of such a change would tend to reduce the applicant's permitted *requirement* to burn the rejects, but still allow for its use as a supplemental fuel, provided that certain requirements were met.

5. RULE APPLICABILITY

The proposed project is subject to preconstruction review requirements under the provisions of Chapter 403, Florida Statutes, and Chapters 62-4, 62-204, 62-210, 62-212, 62-214, 62-296, and 62-297 of the Florida Administrative Code (F.A.C.).

This facility is located in an area designated, in accordance with Rule 62-204.340, F.A.C., as attainment for all pollutants.

Rule 62-4.030, F.A.C., prohibits modification of any existing emissions unit without first receiving a permit. It further specifies that a permitted installation may only be modified in a manner that is consistent with the terms of such a permit. Rule 62-210.200, F.A.C., defines "modification" to mean generally a change that results in an increase in actual emissions of regulated air pollutants. Rules 62-210.300(1) and 62-212.300(1)(a), F.A.C., also reiterate the requirement for construction permits. Not all of the items within the applicant's request have the potential to increase emissions and the Department believes that only items 4A), B) and C) have this ability. The emission units affected by this permit shall comply with all applicable provisions of the Florida Administrative Code (including applicable portions of the Code of Federal Regulations incorporated therein) and, specifically, the following Chapters and Rules.

5.1 STATE REGULATIONS

Chapter 62-4	Permits
Rule 62-204.220	Ambient Air Quality Protection
Rule 62-204.240	Ambient Air Quality Standards
Rule 62-204.800	Federal Regulations Adopted by Reference
Rule 62-210.200	Definitions
Rule 62-210.300	Permits Required
Rule 62-210.350	Public Notice and Comments
Rule 62-210.370	Reports
Rule 62-210.550	Stack Height Policy
Rule 62-210.650	Circumvention
Rule 62-210.700	Excess Emissions
Rule 62-210.900	Forms and Instructions
Rule 62-212.300	General Preconstruction Review Requirements
Rule 62-212.400	Prevention of Significant Deterioration
Rule 62-213	Operation Permits for Major Sources of Air Pollution
Rule 62-214	Requirements For Sources Subject To The Federal Acid Rain Program
Rule 62-296.320	General Pollutant Emission Limiting Standards

5.2 FEDERAL RULES

40 CFR 52.21	Prevention of Significant Deterioration of Air Quality
40 CFR 60	Applicable sections of Subpart A, General Requirements
40 CFR 72	Acid Rain Permits (applicable sections)
40 CFR 73	Allowances (applicable sections)
40 CFR 75	Monitoring (applicable sections including applicable appendices)
40 CFR 77	Acid Rain Program-Excess Emissions (future applicable requirements)

6. DISCUSSION OF RELEVANT ISSUES

As noted in Section 5, the Department has no reason to believe that those items requested above (noted as items 4D, E and F) have the ability to cause any change in regulated emissions at the facility. Accordingly, this discussion is limited to those items that have that ability (specifically items 4A, B and C) which are denoted individually below.

6.1 STARTUP AND SHUTDOWN DEFINITION

The applicant describes 3 cases where excess emissions of CO are requested. The applicant points out that no change in operation (from past history) is occurring or being requested; that the purpose of this action is to clarify those situations where excess emissions of CO do occur, as well as the magnitude and duration of each. For simplicity, these cases are summarized in tabular form along with their maximum potential CO emissions. Current permit limits for CO are 0.175 lb/MMBtu and 186 lb/hr.

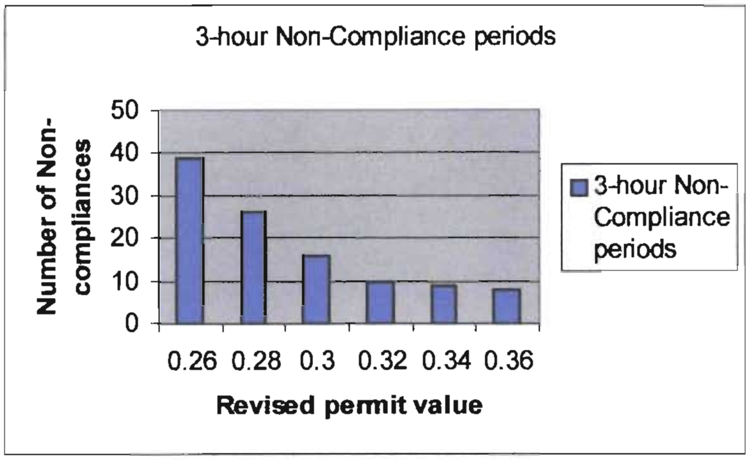
CASE	CO EMISSION (LBS/HR)	CO EMISSION (LB/MMBTU)	MAX. NO./YR.	LENGTH (HOURS)	MAXIMUM PTE (TPY)
Cold Startup	558	3.5	20	10	55.8
Warm Startup	186	1.75	30	10	27.9
Refractory Replacement	558	3.5	6	24	40.2

As can be seen from the table above, the maximum cumulative CO emissions that the facility has the potential to emit during these operating modes can be as high as 123.9 TPY. However, on an incremental basis the annual emission increase may be compared to the permitted full load rate of 186 lb/hr. On this basis, the request results in an emission increase of 64 TPY over the original BACT.
The Department notes that for each of these operating modes to be incurred, that a corresponding period of shutdown (i.e. no emissions) must have occurred, suggesting that the net annual PTE increase of CO is certainly closer to zero. This will form the basis of the Department's action.

6.2 METHOD OF COMPLIANCE FOR SO_2

The applicant has provided data, which shows that due to the normal variability of boiler operations, the current 3-hour SO_2 limit of 0.24 lb/MMBtu cannot be routinely achieved. Daily emission data was provided for the first 10 months of 1997 as well as the entire calendar year 1998 on all 3 boilers. These emission levels demonstrate a daily range of SO_2 emissions from 0.10 lb/MMBtu to 0.20 lb/MMBtu, with a mean of approximately 0.16 lb/MMBtu. The 12-month rolling average permitted rate is 0.20 lb/MMBtu. During this window, 72 exceedances of the 3-hour limit were observed with no exceedance of the 12-month rolling average. These exceedances are reported as required to the regulating agencies. The purpose of this action is to eliminate the potential for non-compliance within the current operating practices. Given that the applicant is not seeking an increase in the 12-month rolling average emission rate, no annual increase of SO_2 emissions can occur. However, some likelihood exists that the 3-hour SO_2 standard (NAAQS) could be adversely impacted and the Department requested that the applicant model the request.
Cedar Bay contracted with Golder Associates to perform the air modeling analyses in order to be certain that the requested increase causes no adverse impacts to the three-hour ambient air quality standard of 1300 $\mu g/m^3$ (State of Florida standard as well as National Standard). The results of the modeling indicate that Cedar Bay may operate with a 3-hour SO_2 limit of 0.40 lb/MMBtu (1277 lb/hr) and still demonstrate compliance with the applicable 3-hour average Ambient Air Quality Standards (AAQS). Although the modeling analysis does not show compliance with the 3-hour PSD Class I and II increments by all increment consuming and expanding sources in the vicinity of the facility, Cedar Bay does not contribute significantly to any predicted exceedances. Therefore, this request is permittable by Florida air permitting rules. As such, Cedar Bay proposes a 3-hour rolling average of 0.36 lb/MMBtu and 382 lb/hr for each boiler. No changes are proposed to the existing 12-month rolling average.

The chart below represents the basis for the Department's determination, incorporating an analysis of the data referred to above. One of the purposes of this chart is to demonstrate that some number of (past) non-compliance periods would have occurred even if the applicant's requested limit of 0.36 lb/MMBtu had existed. The purpose of



the request as well as the Department's action should be to provide for a limit, which satisfactorily allows common cause process variability to occur. The limit should not be so high as to incorporate special causes of process failure to occur and be "covered up". Accordingly, the Department concludes that a 3-hour limit of 0.30 lb/MMBtu should be adequate to allow these common causes to occur. Periods of non-compliance beyond this carry a more unusual connotation and should be reported and adequately addressed by the applicant.
It is noted that the Department recently issued a construction permit for a fluidized bed boiler (PSD-FL-265). In that permit, the SO_2 limits were set at 0.20 lb/MMBtu on a 24-hour block average (with no 3-hour limit). Therefore, although the Department will allow for an increase in the applicant's request to increase the 3-hour limit, it will additionally require that the 12-month rolling average be reduced to a 30-day rolling average with the same (0.20 lb/MMBtu) value.

6.3 HEAT INPUT

Cedar Bay desires some operational flexibility with each individual boiler due to the parallel boiler configuration and concurrent steam demands. Additionally, each boiler (although built to the same specifications) has it's own idiosyncrasies. Cedar Bay requests that the total heat input limitation remain in effect for all three boilers but the individual limits be removed from the permit to allow this flexibility. In addition, Cedar Bay is requesting that the same permit note that is present in the Title V permit be added to the PSD permit. The applicant once again notes that no change in operation is requested, nor will emission changes result. Given that the combined (three boiler) heat input will not change from permitted values, the Department has no reason to expect any emission increases to result. The Department will provide permit language, which allows for the requested flexibility within prescribed limits. However, the Department intends to provide a limit on this flexibility by imposing the requirement that no individual boiler may exceed its rated heat input of 1063 MMBtu/hr by 10%.

6.4 DEPARTMENT DETERMINATION

The Department has determined that each of the applicant's requested items can be accommodated in some fashion. A summary of the Department's determination is as follows:

REQUEST	DEPARTMENT DETERMINATION
Startup and Shutdown Definition (CO)	Warm startup – emissions up to 186 lb/hr without lb/MMBtu limit Cold startup – up to 10 hours (per cold startup) of CO data may be eliminated from the data used to determine compliance with the 8-hour rolling average limit with sufficient documentation Refractory Curing – Must notify agency at least 24 hours prior to commencing; CO data may be eliminated from the data used to determine compliance with the 8-hour rolling average limit with sufficient documentation Annual CO cap – CO emissions shall be limited to 758 TPY per boiler
Method of compliance for SO_2	Increase the 3-hour limit to 0.30 lb/MMBtu. Decrease the 0.20 lb/MMBtu 12-month rolling average to a 30-day rolling average.
Heat Input	The heat input limit shall be based upon the number of operating boilers at the facility. Specifically, the combined maximum heat input shall not exceed: 1063 MMBtu/hr if only one boiler is operating 2126 MMBtu/hr if only two boilers are operating and 3189 MMBtu/hr if all three boilers are operating No individual boiler shall operate at a heat input greater than 110% of 1063 MMBtu/hr (1169 MMBtu/hr).
Mercury Testing	The pertinent permit condition may be removed with no PSD implications. Should a change in fuel quality or particulate removal system/subsystem occur, the Department may require mercury testing to be reimplemeted.
Test Methods	The pertinent permit condition may be modified with no PSD implications.
Short Fiber Rejects	The pertinent permit condition may be modified with no PSD implications.

6.5 ADDITIONAL COMPLIANCE PROCEDURE

Pollutant	Compliance Procedure
CO (12-month rolling average)	CO CEMS data used for compliance with 758 TPY boiler cap

7. SOURCE IMPACT ANALYSIS

An ambient air quality impact assessment was done in support of the original PSD application dated 01/19/90. As mentioned in section 6.2, additional modeling to determine compliance with the 3-hour SO_2 AAQS and the 3-hour SO_2 PSD increments was done for this request. This additional modeling demonstrates compliance with the 3-hour SO_2 AAQS, but does not show by compliance by all increment consuming sources in the vicinity with the 3-hour SO_2 PSD Class I and Class II increments. However Cedar Bay's contribution to any predicted exceedances is less than significant; therefore, this request is permittable by Florida air permitting rules.

8. CONCLUSION

Based on the foregoing technical evaluation of the application and additional information submitted by the applicant and other available information, the Department has made a preliminary determination that the proposed project as outlined by the Department's BACT Determination will comply with all applicable state and federal air pollution regulations.

Department of Environmental Protection

Jeb Bush
Governor

Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

David B. Struhs
Secretary

April 2, 2002

Post-it® Fax Note 7671	Date 4-3	# of pages ▶ 3
To Rob Clark	From Mike Halpin	
Co./Dept. Ausley	Co. FDEP	
Phone # 425-5456	Phone # 921-9519	
Fax # 222-7560	Fax # 922-6979	

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. Bruce Smith
Cedar Bay Cogenerating Company, L.P.
P.O. Box 26324
Jacksonville, FL 32226

Re: Request for Additional Information
Co-firing Petroleum Coke with Coal
File No. PA 88-24 (PSD-FL-137)
Cedar Bay Cogenerating Project

Dear Mr. Smith:

The Department is in receipt of your reply to our September 28, 2001 request for additional information. The application remains incomplete. In order to continue processing your application, the Department will need the additional information below. Should your response to any of the below items require new calculations, please submit the new calculations, assumptions, reference material and appropriate revised pages of the application form.

1. The technical basis for the development of the "Representative Future Actual Emissions" in Table B is unclear. Rather, in each case, the "Representative Future Actual Emissions" appear to simply represent values that are slightly less than the past actual emissions plus the PSD Significant Emission Rates. Please provide the basis for the emission calculations, which Cedar Bay utilized in the development of this table. The Department notes that the basis for the original BACT emission calculation was a 93% capacity factor.

2. Notwithstanding Cedar Bay's reference to 40 CFR 52.21(b)(33), it does not appear that the original question posed in the Department's September 28th letter has been fully answered. Within that request, the Department is attempting to obtain reasonable assurance as to whether a PSD Review is required. The relevant statutes expressly contemplate that projections of the impact of a change must be made before construction. Before a permit is issued, among other things, the owner or operator of the source must, using projections of post-change emissions, demonstrate that emissions from the modified source will not violate air quality requirements.

   Specifically, section 165 states that "[n]o major emitting facility ... may be constructed unless a permit has been issued for such proposed facility" [CAA § 165, 42 U.S.C. § 7475]. Further, the owner or operator must demonstrate to the administrator's satisfaction that "emissions from construction or operation of such facility will not cause, or contribute to, air pollution in excess of" the NAAQS, among other things [CAA § 165(a)(3), 42 U.S.C. § 7475(a)(3)].

   This statutory and regulatory structure has two important features relevant to this application:
   (1) the permit must be obtained *before* the physical change is made, and
   (2) whether a physical change requires a permit is determined in part by reference to anticipated results or consequences, which necessarily would occur *after* the physical change is made.

   Thus, the only way for the owner or operator of the source to know whether a permit is required for any particular physical change is for the owner or operator to make a prediction as to whether the emissions increase will occur. This observation was described by EPA in the 1992 preamble to amendments to the NSR regulations as follows:

> Applicability of the CAA's NSR provisions must be determined in advance of construction and is pollutant specific. In cases involving existing sources, this requires a pollutant-by-pollutant projection of the emissions increases, if any, which will result from the physical or operational change. 57 Fed. Reg. 32,314, 32,316 n.8 (1992).

Any other construction of the statute would allow sources to make modifications or changes without a permit, while they wait to see if it would be proven that emissions would increase. Clearly Congress did not intend such an outcome, which would effectively allow avoidance of the *preconstruction* dimension of the program.

Concerning the attendant application, should the Department gain reasonable assurance that the PSD thresholds are not triggered, a permit condition (similar to the one referenced within your response) may be able to be implemented, with additional restrictions as deemed appropriate by the Department.

3. According to prior data reported to FDEP by Cedar Bay, past actual SO_2 has been controlled at 90% with limestone throughputs averaging 120,000 TPY. The application has estimated past actual sulfur capture at over 93% and annual limestone throughput at 152,753 TPY. As indicated below, the Department intends to revise all related calculations.

4. According to prior data reported to FDEP by Cedar Bay, past actual throughputs of bed (bottom) ash have averaged over 70,000 TPY during years 1998 through 2000. The application has provided a calculated past value of 51,325 TPY. The Department intends to revise all related calculations, and notes that the existing permit limits the throughput to 88,000 TPY.

5. Based upon a preliminary analysis by the Department, the co-firing of petcoke at 35% will necessitate an increase in limestone feed by over 100% in order to ensure that SO_2 emissions are not increased. The Department specifically requires additional information (beyond that which has been submitted) in order to ensure that annual PM_{10} emissions remain below a 15 TPY increase, while simultaneously maintaining SO_2 emissions below a 40 TPY increase. Please provide assumed collection efficiencies within submitted calculations.

Rule 62-4.050(3), F.A.C. requires that all applications for a Department permit must be certified by a professional engineer registered in the State of Florida. This requirement also applies to responses to Department requests for additional information of an engineering nature. Please note that per Rule 62-4.055(1): *"The applicant shall have ninety days after the Department mails a timely request for additional information to submit that information to the Department.......... Failure of an applicant to provide the timely requested information by the applicable date shall result in denial of the application."*

If you have any questions, please call Michael P. Halpin, P.E. at 850/921-9519.

Sincerely,

Michael P. Halpin

Michael P. Halpin, P.E. FDEP/DARM
New Source Review Section

Ken Kosky, P.E. Golder Associates
Hamilton S. Oven, P.E. PPSO
James L. Manning, P.E. RESD
Chris Kirts, DEP-NED
Stafford Campbell, Greater Arlington Civic Council

Permitting Application - Events

Events Scheduled

90 of 90

AIRS ID 0310337 Site Name CEDAR BAY COGENERATION INC.

Permit #

Type/Subtype AC / 1D Received 08/29/2001

Project # 005 Project Name (CEDAR BAY GENERATING CO.)

> Receive Request: Done

Event	Begin Date	Period	Due Date	Rmn	Status	End Date
	08/29/2001	1	08/30/2001		Done	08/29/2001
Fee Verification	08/29/2001	2	08/31/2001		Sufficient Fee	08/29/2001
Completeness Review	08/29/2001	30	09/28/2001		Incomplete	09/28/2001
RESET CLOCK	09/28/2001	1	09/29/2001		Done	09/28/2001
Awaiting Additional Information	09/28/2001	180	03/27/2002		Received	03/08/2002
Completeness Review	03/08/2002	30	04/07/2002		Incomplete	04/02/2002
RESET CLOCK	04/02/2002	1	04/03/2002		Done	04/02/2002
Awaiting Additional Information	04/02/2002	45	05/17/2002	44	Pending	

FLORIDA DEPARTMENT OF ENVIRONMENTAL PROTECTION

Department of Environmental Protection

Jeb Bush
Governor

Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

David B. Struhs
Secretary

January 14, 2002

CERTIFIED MAIL – Return Receipt Requested

Mr. Bruce Smith
Cedar Bay Generating Company, L.P.
P.O. Box 26324
Jacksonville, Florida 32226

Re: Extension of Time to Respond to Additional Information Request Regarding Application for Revision of PSD-FL-137A to Allow Co-firing of Petcoke, DEP Project #: 0310337-005-AC

Dear Mr. Smith:

The Department received your letter, dated January 11, 2002, requesting an extension of time to respond to our request for additional information regarding your application to burn petcoke, which was sent to you on September 28, 2001.

In accordance with the provisions of Rule 62-4.055, F.A.C., "...If an applicant requires more than ninety days in which to respond to a request for additional information, the applicant may notify the Department in writing of the circumstances, at which time the application shall be held in active status for one additional period of up to ninety days. Additional extensions shall be granted for good cause shown by the applicant. A showing that the applicant is making a diligent effort to obtain the requested additional information shall constitute good cause. Failure of an applicant to provide the timely requested information by the applicable deadline shall result in denial of the application."

A 90-day extension of time to respond is hereby granted. Failure to submit the requested additional information by March 27, 2002, shall be grounds for denial of the application.

If you should have any questions regarding this extension, please contact Jonathan Holtom, P.E., at (850) 921-9531.

Sincerely,

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

cc: Jeff Walker, CBGC
Kennard Kosky, P.E., Golder Associates
Hamilton S. Oven, Jr.
Ernest Frye, DEP NE District
Steve Pace, Jacksonville RESD

Mailed 1/14/02

PG&E National Energy Group

Cedar Bay
Generating Plant
Owner Cedar Bay Generating Company, L.P.

POB 26324
Jacksonville, FL 32226-6324

904.751.4000
Fax: 904.751.7320

January 11, 2002

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

RE: Cedar Bay Cogeneration Facility
Co-firing Petroleum Coke with Coal
Revision of PSD-FL-137A

Dear Mr. Fancy:

In a letter dated September 28, 2001, the Department requested additional information related to the request to co-fire petroleum coke with coal at the Cedar Bay Cogeneration Facility. Cedar Bay Generating respectfully request an extension of time to respond to the request pursuant to Rule 62-4.055.

As you know the request to co-fire petcoke is directly related to the bankruptcy of our long-term coal supply contractor and the subsequent termination of our coal contract. Our main focus has been maintaining our coal supply in the short term and securing coal supply and delivery contracts for a longer period. Petcoke remains a technically viable fuel alternative, which we do intend to pursue, however we require additional time to complete our analysis and respond to your request.

Rule 62-4.055 authorizes the Department to grant one additional period of up to ninety days. We will respond in the near future and well within the additional ninety-day period.

If you have any questions, please do not hesitate to contact Jeff Walker of my staff at (904) 751-4000 extension 22.

Sincerely,

Bruce Smith, General Manager
Cedar Bay Generating Company, LP

Cc: A.A Linero, DEP
Scott Gorland, DEP
Jonathan Holtom, DEP
Ernest Frye, DEP NE District
Steve Pace, Jacksonville RESD
Hamilton S. Oven, Jr.
Ken Kosky
David Dee

PG&E National Energy Group™

Cedar Bay
Generating Plant
Owner: Cedar Bay Generating Company, LP

POB 26324
Jacksonville, FL 32226-6324

904.751.4000
Fax: 904.751.7320

January 11, 2002

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

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Co-firing Petroleum Coke with Coal
Revision of PSD-FL-137A

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Cedar Bay Generating Company, LP

Cc: A.A Linero, DEP
Scott Gorland, DEP
Jonathan Holtom, DEP
Ernest Frye, DEP NE District
Steve Pace, Jacksonville RESD
Hamilton S. Oven, Jr.
Ken Kosky
David Dee

PG&E National Energy Group
Cedar Bay
Generating Plant
Owner: Cedar Bay Generating Company, L.P.

POB 26324
Jacksonville, FL 32226-6324

904.751.4000
Fax: 904.751.7320

January 11, 2002

RECEIVED
JAN 14 2002
BUREAU OF AIR REGULATION

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

RE: Cedar Bay Cogeneration Facility
Co-firing Petroleum Coke with Coal
Revision of PSD-FL-137A

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Cedar Bay Generating Company, LP

Cc: A.A Linero, DEP
Scott Gorland, DEP
Jonathan Holtom, DEP
Ernest Frye, DEP NE District
Steve Pace, Jacksonville RESD
Hamilton S. Oven, Jr.
Ken Kosky
David Dee

-9-

RECEIVED

OCT 22 2001

BUREAU OF AIR REGULATION

STAFFORD CAMPBELL
3861 WAYLAND STREET
JACKSONVILLE, FLORIDA 32277

October 19, 2001

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

Re: Cedar Bay Cogeneration Facility, Request to Modify Permit (PSD-FL-137) to Allow Firing of Petroleum Coke with Bituminous Coal

Dear Mr. Fancy,

This will follow up my letter of September 19 captioned as above. I appreciated Mr. Scott Sheplak's telephone call yesterday afternoon and Mr. Jonathan Holtom's call this morning updating us with regard to the status of Cedar Bay's request. The reason for our concern was that Cedar Bay representatives did not appear before the Jacksonville Environmental Protection Board's Air Committee meeting on October 17, as had been anticipated, with the result that neither the E.P.B. nor we had reliable information we could pass on to our organization.

Through Messrs. Sheplak's and Holtom's courtesy, we understand the project is now in abeyance pending Cedar Bay's response to your request for further information. As a means of staying current, we welcomed the suggestion that I be added to your distribution list covering this project and the draft permit which may be forthcoming. Please accept this as my formal request to be so included.

Dating from the controversy with the AES Corporation in the early 1990's, our organization representing local residents has been particularly sensitive to any action with respect to air regulation that does not serve to *improve* local air quality. That was the motivation behind our letter of September 19 and our anxiety to be kept fully informed. We welcome your understanding and cooperation.

Respectfully,

S. Campbell

Stafford Campbell
Greater Arlington Civic Council

cc: Mrs. Barbara Broward, Chair Air Committee, Environmental Protection Board
Mr. Scott Sheplak, D.E.P., Tallahassee.
Mr. Jonathan Holtom, D.E.P., Tallahassee.

STAFFORD CAMPBELL
3861 WAYLAND STREET
JACKSONVILLE, FLORIDA 32277

JACKSONVILLE FL 322
PM
19 OCT
2001

USA 34

Mr. Jonathan Holtom
Bureau of Air Regulation
Florida Department of Environmental Protection
2600 Blair Stone Road, Mail Station 5505
Tallahassee, FL 32399-2400

32399+6542

RECEIVED

OCT 22 2001

BUREAU OF AIR REGULATION

STAFFORD CAMPBELL
3861 WAYLAND STREET
JACKSONVILLE, FLORIDA 32277

COPY

October 19, 2001

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

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Stafford Campbell
Greater Arlington Civic Council

cc: Mrs. Barbara Broward, Chair Air Committee, Environmental Protection Board
Mr. Scott Sheplak, D.E.P., Tallahassee.
✓Mr. Jonathan Holtom, D.E.P., Tallahassee.

STAFFORD CAMPBELL
3861 WAYLAND STREET
JACKSONVILLE, FLORIDA 32277

JACKSONVILLE FL 322
PM
10 OCT
2001

USA 34

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

32399+2400

Jonathan,
Need to add him to "cc list" on draft.
S.H. 10/23

FOR ~~Scott~~ Jonathan f.y.i. 30

DATE 10/18 TIME 11 A.M. P.M.

FROM Stafford Campbell

FIRM

PHONE 904-744-1312
AREA CODE NUMBER EXTENSION

☐ FAX
☐ MOBILE
AREA CODE NUMBER TIME TO CALL

TELEPHONED	X	PLEASE CALL	X
RETURNED YOUR CALL		WILL CALL AGAIN	
CAME TO SEE YOU		RUSH	
WANTS TO SEE YOU		SPECIAL ATTENTION	
WAITING TO SEE YOU		HOLDING LINE	

MESSAGE please call him for Clair on Cedar Bay Co-Generation FAC. in Jacksonville needs status on his letter of 9/19 to Clair & status of project see my e-mail!

SIGNED Vickie

TOPS FORM 4007 MADE IN U.S.A.

MESSAGE

I haven't seen this.

Sheplak, Scott

From: Gibson, Victoria
Sent: Thursday, October 18, 2001 12:56 PM
To: Sheplak, Scott
Cc: Adams, Patty
Subject: Status of Response to Mr. Stafford Campbell

Please return a call to Mr. Stafford Campbell for Clair. I received his call this morning at 11:30 am in regards to the Cedar Bay Co-Generation Facility in Jacksonville, Florida. Mr. Campbell is a member of the Greater Arlington Civic Council and wrote a letter address to Clair on September 19th. He and the council are concerned with the modification to the companies PSD Permit. Please call him this afternoon or tomorrow morning with a status update on the response to his letter, in addition to, an update on the status of the Cedar Bay Co-Generation Facility's project. He mentioned to me that Cedar Bay was to have appeared before the Air committee on the 17th, however, he says they withdrew and did not make this meeting. It is very important to him to receive your return call, since he will meet with the council very soon and would like to give them a report. Mr. Campbell can be reached at this phone number:

904-744-1312

Thank you.

Vickie

Victoria Gibson
Administrative Secretary
DEP/DARM/Bureau of Air Regulation
850-921-9504

Copy on all Correspondence

10/18/01 ~3pm. Summary Conversation w/ Mr. Stafford Campbell

Re: Cedar Bay petcoke project

PSD-FL-137

DOAH 88 5740

PA88-24A

They're concerned about not having the ability for public participation.

Don't think that the draft AC permit has been issued yet. When a draft is issued there is a public comment period.

He plans to send a letter to be included in the cc list for the draft permit.

~~[illegible]~~ To status of the project, Jonathan Holtom is processing the project.

We've requested add'l info.

FLORIDA DEPARTMENT OF ENVIRONMENTAL PROTECTION

Department of Environmental Protection

Jeb Bush
Governor

Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

David B. Struhs
Secretary

September 28, 2001

CERTIFIED MAIL – Return Receipt Requested

Mr. Bruce Smith
Cedar Bay Generating Company, L.P.
P.O. Box 26324
Jacksonville, Florida 32226

Re: Revision of PSD-FL-137A to Allow Co-firing of Petcoke

Dear Mr. Smith:

The Department received the application that you submitted, requesting approval to co-fire up to 35% petcoke in your boilers, on August 29, 2001. Based on a telephone conversation with Mr. Jeffery Walker, it is our understanding that this project is undergoing additional evaluation as to its overall economic feasibility. Because of potential adjustments to the scope of the project, or the potential withdrawal of the project, as a result of these evaluations, raises questions about the accuracy and completeness of the application that has been submitted.

Based on the evaluation of the application, it is considered incomplete. Please provide the following information and the Department will resume review of the application. Also, please provide all assumptions, calculations and reference material.

1. Provide a pollutant emissions analysis that compares the facility's past actual pollutant emissions, pursuant to Rule 62-210.200, F.A.C., Definitions – Actual Emissions, to future allowable pollutant emissions that show there is no significant pollutant emissions increase pursuant to Table 400-2, F.A.C. If there is a significant increase for any pollutant, please submit the information and evaluation(s) required pursuant to Rule 62-212.400(5), F.A.C.

This information requires a written response to the Department within ninety days of receipt of this notice unless additional time is requested pursuant to Rule 62-4.055, F.A.C. If you should have any questions, please contact Jonathan Holtom, P.E., at (850) 921-9531.

Sincerely,

R Bruce Mitchell
for C. H. Fancy, P.E.
Chief
Bureau of Air Regulation

cc: Kennard Kosky, P.E., Golder Associates
Jeff Walker, CBGC

In addition to the incompleteness letter sent today, please provide the following information and the Department will resume review of the application. Also, please include all assumptions, calculations and reference material.

1. Provide a pollutant emissions analysis that compares the facility's past actual pollutant emissions, pursuant to Rule 62-210.200, F.A.C., Definitions - Actual Emissions, to future allowable pollutant emissions that show that there is no significant pollutant emissions increase pursuant to Table 400-2, F.A.C. If there is a significant increase for any pollutant, please submit the information required pursuant to Rule 62-212.400 (5), F.A.C.

RECEIVED
SEP 26 2001
BUREAU OF AIR REGULATION

STAFFORD CAMPBELL
3861 WAYLAND STREET
JACKSONVILLE, FLORIDA 32277

September 19, 2001

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

Re: Cedar Bay Cogeneration Facility, Request to Modify Permit (PSD-FL-137) to Allow Firing of Petroleum Coke with Bituminous Coal

Dear Mr. Fancy,

As an intervenor in the Settlement Stipulation resolving DOAH Case No. 88-5740, which resulted in the 1993 revision of the Conditions of Certification for the Cedar Bay Cogeneration Facility (PA88-24A), I have been made aware of Cedar Bay's current request to modify certain of the conditions contained in Part II.A.1, as well as corresponding provisions of PSD-FL-137.

While we can understand Cedar Bay's desire to be able to utilize a mix of petroleum coke with coal for economic reasons, we are more concerned about any possibility of retreat from the actual, existing emission performance that may result from a fuel substitution. This concern applies particularly to SO_2 emissions and, to a lesser extent, PM_{10}.

With respect to SO_2 emissions, the 1993 revised conditions specify a rolling average of 0.20 lbs/MMBtu. The absence of exceedences reported might indicate that for the past eight years the plant has not had undue difficulty in meeting or bettering that requirement. Contemporaneously, presumably due to fuel selection and/or evolving technology, Cedar Bay's parent company has since been issued a permit for their coal-burning facility in Indiantown, Florida, which limits permitted SO_2 emissions to 0.17 lbs/MMBtu.

At present, the Jacksonville Electric Authority (JEA) is repowering its Northside Generating Station with two circulating fluidized bed boilers (CFB's) manufactured, as are those at Cedar Bay, by Foster-Wheeler, though somewhat larger in capacity. Firing at an even higher ratio of petroleum coke to coal than that proposed by Cedar Bay, JEA has committed to an SO_2 emission standard of 0.15 lbs/MMBtu. We respectfully submit that it is reasonable that this (0.15 lbs) be established as the 2001 new-permit limit for coal/ coke firing, and that new permittees as well as those seeking modification of an existing permit be required to adjust their fuel choices and emission technologies to meet that standard.

Petroleum coke is publicly perceived as a "dirty" fuel and, in addition to the desirability of demonstrating that the use of alternatives in a fuel mix *can* be accompanied by a *reduction* in SO_2 emissions through fuel choice, boiler operating constraints, and the utilization of best available control technologies, it is also important to insist upon strict fugitive-dust control in connection with the transportation and handling of pet coke at the site through rigorous control of the PM_{10} standard.

We would welcome your comment.

Respectfully,

Stafford Campbell
for Greater Arlington Civic Council

cc: Mr. James Manning, Director, Regulatory and Environmental Services Division
Mr. Steve Pace, Chief Air Division, Regulatory and Environmental Services Division
Mrs. Barbara Broward, Chair Air Committee, Environmental Protection Board
Mr. Frank Stallwood, Regional Business Director, PG&E National Energy Group

To: Jonathan Holtom

COPY

STAFFORD CAMPBELL
3861 WAYLAND STREET
JACKSONVILLE, FLORIDA 32277

cc: M. Golden
D. Dee
B. Smith
R. Breitmoser

RECEIVED
SEP 20 20
USGEN
FILE #

September 19, 2001

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

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BEST AVAILABLE COPY

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Stafford Campbell
Greater Arlington Civic Council

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Mr. Steve Pace, Chief Air Division, Regulatory and Environmental Services Division
Mrs. Barbara Broward, Chair Air Committee, Environmental Protection Board
Mr. Frank Stallwood, Regional Business Director, PG&E National Energy Group

Jonathan - Patty says you have this. Feel free to borrow reference books on CFB units & also Power Gen. Conference proceedings that might shed light on how these do with petcoke.

Additional petcoke tends to:

- increase CO, H_2SO_4
- increase SO_2 (they have scrubbers)
- increase heat input
- lower ash

Make sure you get ~~to~~ talk with F.W. if you want qualified reasonable assurance.

TEC Big Bend

0570039

Pet Coke

- SO_2 Control ?
CFB or Scrubber

- Past actuals not exceeded.

* Past Act vs Future Allowable

capable of accomodating ?

PG&E National Energy Group

Cedar Bay
Generating Plant
Owner: Cedar Bay Generating Company, L.P.

POB 26324
Jacksonville, FL 32226-6324

904.751.4000
Fax: 904.751.7320

August 28, 2001

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

RE: Request to Modify PSD Permit (PSD-FL-137) To Allow Co-Firing of Petroleum Coke with Bituminous Coal at Cedar Bay Cogeneration Facility

Dear Mr. Fancy:

On behalf of Cedar Bay Generating Company, L.P. (Cedar Bay), I have enclosed an original and three copies of an Application for Air Permit – Title V Source (Form 62-210.900(1)) and supporting documentation for Cedar Bay's request for approval to co-fire limited amounts of petroleum coke (pet coke) with bituminous coal at the Cedar Bay Cogeneration Facility (Facility) in Jacksonville, Florida. Although a change to the Facility's PSD permit is being requested, the limited use of pet coke will not cause any significant net emissions increase at the Facility and, therefore, the requirements of the PSD review process will not be triggered by this request.

The enclosed materials are being submitted in support of Cedar Bay's request to modify the Facility's PSD permit. In the near future, Cedar Bay will submit a separate request to modify the Conditions of Certification for the Facility, so that the Conditions of Certification and the PSD permit will be revised in a consistent manner.

Since operations began, Cedar Bay has been obtaining its fuel (bituminous coal) from Lodestar, a Kentucky-based mining company, pursuant to a long-term contract which requires Cedar Bay to purchase all of its coal from Lodestar. Unfortunately, Lodestar has filed for protection under Chapter 11 of the Bankruptcy Code. Under Chapter 11 of the Bankruptcy Code, Lodestar may termina·· its contract with Cedar Bay for economic reasons. The price for coal under the contract is cu rently less than the price that Lodestar could obtain in the spot market. As a result, C ar Bay has evaluated various options for obtaining fuel (including alternate suppliers of coa while continuing its negotiations with Lodestar.

Options under consideration in the event the Lodestar rejects the Cedar Bay contract include:

- 100% Domestic Coal
- Domestic Coal and up to 35% petroleum coke
- 100% foreign coal
- Foreign coal and up to 35% petroleum coke

Currently, Lodestar continues to supply coal and remove ash for disposal.

At this time, the limited use of pet coke is a promising alternative for Cedar Bay and consequently, Cedar Bay is seeking authorization to co-fire pet coke because Cedar Bay must take steps to ensure that it has a sufficient and suitable fuel supply for the Facility.

Cedar Bay has asked Foster Wheeler Energy Services, Inc. (Foster Wheeler), to evaluate the feasibility of using pet coke as a supplemental fuel at the Facility. Foster Wheeler is knowledgeable about the use of pet coke at other electrical power plants in Florida, the specific design of the Facility, and other relevant factors. Based on its professional experience and its site-specific analyses, Foster Wheeler concluded that pet coke could be co-fired at the Cedar Bay Facility and, subject to certain qualifications, the use of pet coke could even improve the performance of the Facility's boilers. Foster Wheeler specifically addressed the fuel blend (up to 35% pet coke) that is being proposed in the attached application. Foster Wheeler's report is attached hereto as an appendix to the PSD application.

We would be happy to answer any questions that the Department may have about the Facility or this application. If you have questions about the Facility, please contact Mr. Jeff Walker, our Project Manager, at 904-751-4000 x22. If you have questions about the application, you may wish to contact Mr. Ken Kosky, our consultant, at 352-336-5600 or Mr. David Dee, our environmental counsel, at 850-681-0311.

We look forward to working with you and the other members of the Department on this project.

Sincerely,

Bruce Smith, General Manager
Cedar Bay Generating Company, LP

Cc: A.A Linero, DEP (w/o enclosures)
Scott Gorland, DEP (w/o enclosures)
Jonathan Holtom, DEP (w/o enclosures)
Ernest Frye, DEP NE District (w/ enclosures)
Steve Pace, Jacksonville RESD (w/ enclosures)
Hamilton S. Oven, Jr. (w/o enclosures)
Ken Kosky (w/ enclosures)
David Dee (w/ enclosures)