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

RECEIVED

MAR 08 2002

BUREAU OF AIR REGULATION

March 7, 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. 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 annual 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 FDEP for the facility.

The Department's expeditious review of the application is appreciated. Please contact me if 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

62-210.200(11) F.A.C. "Actual Emissions" - *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.

40 CFR 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.

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

* Data reflects use of most recent stack testing data

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)
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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

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,

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

cc: Kennard Kosky, P.E., Golder Associates
Jeff Walker, CBGC

SENDER: *COMPLETE THIS SECTION*

- Complete items 1, 2, and 3. Also complete item 4 if Restricted Delivery is desired.
- Print your name and address on the reverse so that we can return the card to you.
- Attach this card to the back of the mailpiece, or on the front if space permits.

1. Article Addressed to:

Mr. Bruce Smith
General Manager
Cedar Bay Cogeneration Facility
P. O. Box 26324
Jacksonville, FL 32226

COMPLETE THIS SECTION ON DELIVERY

A. Received by *(Please Print Clearly)* Shelly Arnold
B. Date of Delivery 8/5/02

C. Signature
X Shelly Arnold
☐ Agent
☐ Addressee

D. Is delivery address different from item 1? ☐ Yes
If YES, enter delivery address below: ☐ No

JAX STA AUG - 5 2002

3. Service Type
☒ Certified Mail ☐ Express Mail
☐ Registered ☐ Return Receipt for Merchandise
☐ Insured Mail ☐ C.O.D.

4. Restricted Delivery? *(Extra Fee)* ☐ Yes

2. Article Number *(Copy from service* 7001 0320 0001 3692 8178

PS Form 3811, July 1999 Domestic Return Receipt 102595-00-M-0952

U.S. Postal Service
CERTIFIED MAIL RECEIPT
(Domestic Mail Only; No Insurance Coverage Provided)

7001 0320 0001 3692 8178

OFFICIAL USE

Postage	$	Postmark Here
Certified Fee		
Return Receipt Fee (Endorsement Required)		
Restricted Delivery Fee (Endorsement Required)		
Total Postage & Fees	$	

Sent To Bruce Smith

Street, Apt. No.; or PO Box No. PO Box 26324

City, State, ZIP+4 Jacksonville, FL 32226

PS Form 3800, January 2001 See Reverse for Instructions

SENDER: *COMPLETE THIS SECTION*

- Complete items 1, 2, and 3. Also complete item 4 if Restricted Delivery is desired.
- Print your name and address on the reverse so that we can return the card to you.
- Attach this card to the back of the mailpiece, or on the front if space permits.

1. Article Addressed to:

Mr. Bruce Smith
Cedar Bay Cogenerating Co., LP
PO Box 26324
Jacksonville, FL 32226

COMPLETE THIS SECTION ON DELIVERY

A. Received by *(Please Print Clearly)* Debra L Sumner

B. Date of Delivery 4/5/02

C. Signature x Debra L Sumner ☐ Agent ☐ Addressee

D. Is delivery address different from item 1? ☐ Yes ☐ No
If YES, enter delivery address below:

USPS NC JAX 32218 APR - 5 2002

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4. Restricted Delivery? *(Extra Fee)* ☐ Yes

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PS Form 3811, July 1999 Domestic Return Receipt 102595-00-M-0952

U.S. Postal Service
CERTIFIED MAIL RECEIPT
(Domestic Mail Only; No Insurance Coverage Provided)

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OFFICIAL USE

Postage	$
Certified Fee	
Return Receipt Fee (Endorsement Required)	
Restricted Delivery Fee (Endorsement Required)	
Total Postage & Fees	$

Postmark Here

Sent To Bruce Smith
Street, Apt. No.; or PO Box No. PO Box 26324
City, State, ZIP+4 Jacksonville, FL 32226

PS Form 3800, January 2001 See Reverse for Instructions

PLACE STICKER AT TOP OF ENVELOPE

SENDER: COMPLETE THIS SECTION

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- Print your name and address on the reverse so that we can return the card to you.
- Attach this card to the back of the mailpiece, or on the front if space permits.

1. Article Addressed to:

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

COMPLETE THIS SECTION ON DELIVERY

A. Received by (Please Print Clearly) Shelly Arnold
B. Date of Delivery

C. Signature
X Shelly Arnold
☐ Agent
☐ Addressee

D. Is delivery address different from item 1? ☐ Yes
If YES, enter delivery address below: ☐ No

JAN 17 2002

3. Service Type
☒ Certified Mail ☐ Express Mail
☐ Registered ☐ Return Receipt for Merchandise
☐ Insured Mail ☐ C.O.D.

4. Restricted Delivery? (Extra Fee) ☐ Yes

2. Article Number (Copy from service label)
7000 0520 0020 9371 4473

PS Form 3811, July 1999 Domestic Return Receipt 102595-99-M-0952

U.S. Postal Service
CERTIFIED MAIL RECEIPT
(Domestic Mail Only; No Insurance Coverage Provided)

7000 0520 0020 9371 4473

Mr. Bruce Smith

Postage	$
Certified Fee	
Return Receipt Fee (Endorsement Required)	
Restricted Delivery Fee (Endorsement Required)	
Total Postage & Fees	$

Postmark Here

Recipient's Name *(Please Print Clearly) (To be completed by mailer)*
Mr. Bruce Smith
Street, Apt. No.; or PO Box No.
P.O. Box 26324
City, State, ZIP+ 4
Jacksonville, Florida 32226

PS Form 3800, February 2000 See Reverse for Instructions

SENDER: *COMPLETE THIS SECTION*

- Complete items 1, 2, and 3. Also complete item 4 if Restricted Delivery is desired.
- Print your name and address on the reverse so that we can return the card to you.
- Attach this card to the back of the mailpiece, or on the front if space permits.

1. Article Addressed to: 0310337-005-AC Extension

Mr. Bruce Smith
General Manager
Cedar Bay Generating Company, L.P.
9640 Eastport Road
Jacksonville, Florida 32226

COMPLETE THIS SECTION ON DELIVERY

A. Received by (*Please Print Clearly*) B. Date of Delivery

C. Signature

X

☒ Agent
☒ Addressee

D. Is delivery address different from item 1? ☐ Yes
If YES, enter delivery address below: ☐ No

JAN 2 2 2002

3. Service Type
☒ Certified Mail ☐ Express Mail
☐ Registered ☐ Return Receipt for Merchandise
☐ Insured Mail ☐ C.O.D.

4. Restricted Delivery? (*Extra Fee*) ☐ Yes

2.

PS

SENDER: COMPLETE THIS SECTION

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- Print your name and address on the reverse so that we can return the card to you.
- Attach this card to the back of the mailpiece, or on the front if space permits.

1. Article Addressed to:

Mr. Bruce Smith
Cedar Bay Generating Company, L.P.
P.O. Box 26324
Jacksonville, FL 32226

COMPLETE THIS SECTION ON DELIVERY

A. Received by *(Please Print Clearly)*

B. Date of Delivery 10/3/01

C. Signature

X Debra L Sumner

☐ Agent
☐ Addressee

D. Is delivery address different from item 1? ☐ Yes
If YES, enter delivery address below: ☐ No

3. Service Type
☒ Certified Mail ☐ Express Mail
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☐ Insured Mail ☐ C.O.D.

4. Restricted Delivery? *(Extra Fee)* ☐ Yes

2. Article Number *(Copy from service label)*
7000 0520 0020 9371 1618

PS Form 3811, July 1999 Domestic Return Receipt 102595-00-M-0952

U.S. Postal Service
CERTIFIED MAIL RECEIPT
(Domestic Mail Only; No Insurance Coverage Provided)

7000 0520 0020 9371 1618

Mr. Bruce Smith

Postage	$	Postmark Here
Certified Fee		
Return Receipt Fee (Endorsement Required)		
Restricted Delivery Fee (Endorsement Required)		
Total Postage & Fees	$	

Recipient's Name *(Please Print Clearly) (To be completed by mailer)*
Mr. Bruce Smith
Street, Apt. No.; or PO Box No.
P.O. Box 26324
City, State, ZIP+4
Jacksonville, Florida 32226

PS Form 3800, February 2000 See Reverse for Instructions

Table 2. Operating Parameters for Cedar Bay Cogeneration Plant, Years 1997-2000

			AOR Year			
Unit	Parameter	Unit	1997	1998	1999	2000
1063 MMBtu/hr Boiler 1-A	Hours Operated	hrs	8,013	8,204	7,968	7,651
	Fuel Usage	tons	331,642	334,181	324,598	320,199
	Fuel Heat Content	MMBtu/ton	23.8	21.5	23.8	23.9
	Fuel Heat Content	Btu/lb	11,900	10,750	11,900	11,950
	Heat Input	MMBtu/hr	985.0	875.8	969.6	1000.2
	Capacity Factor		92.7%	82.4%	91.2%	94.1%
	CO emissions	tons/yr	176.0	208.0	196.3	179.2
	CO based lb/MMBtu		0.045	0.058	0.051	0.047
	NO_x emissions	tons/yr	593.1	581.6	587.56	594.4
	NO_x based lb/MMBtu		0.150	0.162	0.152	0.155
	PM_{10} emissions	tons/yr	49.4	67.2	66.4	48.1
	PM_{10} based lb/MMBtu		0.013	0.019	0.017	0.0126
	Sulfuric Acid Mist	tons/yr	0.120	0.120	0.120	0.115
	SAM based lb/MMBtu		3.04E-05	3.34E-05	3.09E-05	3.00E-05
	SO_2 emissions	tons/yr	659.0	658.1	659.7	650.5
	SO_2 based lb/MMBtu		0.167	0.183	0.171	0.170
	VOC emissions	tons/yr	3.30	3.20	5.18	4.97
	VOC based lb/MMBtu		0.0008	0.0009	0.0013	0.0013
1063 MMBtu/hr Boiler 1-B	Hours Operated	hrs	8,053	7,786	8,008	7,731
	Fuel Usage	tons	316,400	306,430	316,369	318,602
	Fuel Heat Content	MMBtu/ton	23.8	23.4	23.0	24.0
	Fuel Heat Content	Btu/lb	11,900	11,700	11,500	12,000
	Heat Input	MMBtu/hr	935.1	920.9	908.7	989.1
	Capacity Factor		88.0%	86.6%	85.5%	93.0%
	CO emissions	tons/yr	141.0	145.4	167.5	157.7
	CO based lb/MMBtu		0.037	0.041	0.047	0.041
	NO_x emissions	tons/yr	558.3	545.8	577.1	597.6
	NO_x based lb/MMBtu		0.148	0.152	0.163	0.156
	PM_{10} emissions	tons/yr	49.0	49.0	61.6	60.2
	PM_{10} based lb/MMBtu		0.013	0.014	0.017	0.016
	Sulfuric Acid Mist	tons/yr	0.110	0.110	0.120	0.116
	SAM based lb/MMBtu		2.92E-05	3.07E-05	3.40E-05	3.03E-05
	SO_2 emissions	tons/yr	636.0	618.5	622.0	671.0
	SO_2 based lb/MMBtu		0.169	0.173	0.176	0.176
	VOC emissions	tons/yr	8.30	8.30	9.25	8.93
	VOC based lb/MMBtu		0.0022	0.0023	0.0026	0.0023
1063 MMBtu/hr Boiler 1-C	Hours Operated	hrs	8,091	8,275	7,960	7,696
	Fuel Usage	tons	322,289	332,388	321,602	315,590
	Fuel Heat Content	MMBtu/ton	23.8	23.4	23.8	24.0
	Fuel Heat Content	Btu/lb	11,900	11,700	11,900	12,000
	Heat Input	MMBtu/hr	948.0	939.9	961.6	984.2
	Capacity Factor		89.2%	88.4%	90.5%	92.6%
	CO emissions	tons/yr	179.0	196.2	218.5	179.2
	CO based lb/MMBtu		0.047	0.050	0.057	0.047
	NO_x emissions	tons/yr	574.6	589.0	576.8	587.1
	NO_x based lb/MMBtu		0.150	0.151	0.151	0.155
	PM_{10} emissions	tons/yr	51.1	62.1	65.7	56.9
	PM_{10} based lb/MMBtu		0.013	0.016	0.017	0.015
	Sulfuric Acid Mist	tons/yr	0.120	0.120	0.119	0.115
	SAM based lb/MMBtu		3.13E-05	3.09E-05	3.12E-05	3.05E-05
	SO_2 emissions	tons/yr	614.0	659.0	644.5	643.6
	SO_2 based lb/MMBtu		0.160	0.169	0.168	0.170
	VOC emissions	tons/yr	3.20	3.20	3.46	3.35
	VOC based lb/MMBtu		0.0008	0.0008	0.0009	0.0009
Total Emissions for 3 Boilers	Capacity Factor		89.9%	85.8%	89.0%	93.2%
	Heat Input	10^6 MMBtu	23.09	22.13	22.66	22.87
	CO emissions	tons/yr	496.0	549.6	582.3	516.0
	NO_x emissions	tons/yr	1726.0	1716.4	1741.5	1779.0
	PM_{10} emissions	tons/yr	149.5	178.3	193.7	165.2
	Sulfuric Acid Mist	tons/yr	0.4	0.4	0.4	0.3
	SO_2 emissions	tons/yr	1909.0	1935.6	1926.2	1965.1
	VOC	tons/yr	14.8	14.7	17.9	17.3

Notes:
Million BTU per ton burned listed in Title V as 24.0 (calculated).
Maximum hourly rate = 52 tph
Maximum annual rate = 390,000 tpy
Maximum heat input to each boiler shall not exceed 1,063 MMBtu/hr. This reflects a combined total of 3,189 MMBtu/hr for all three units.
Boilers may operate continuously (8,760 hr/yr) but shall not exceed - 25.98 x 106 MMBtu/yr total annual heat input.

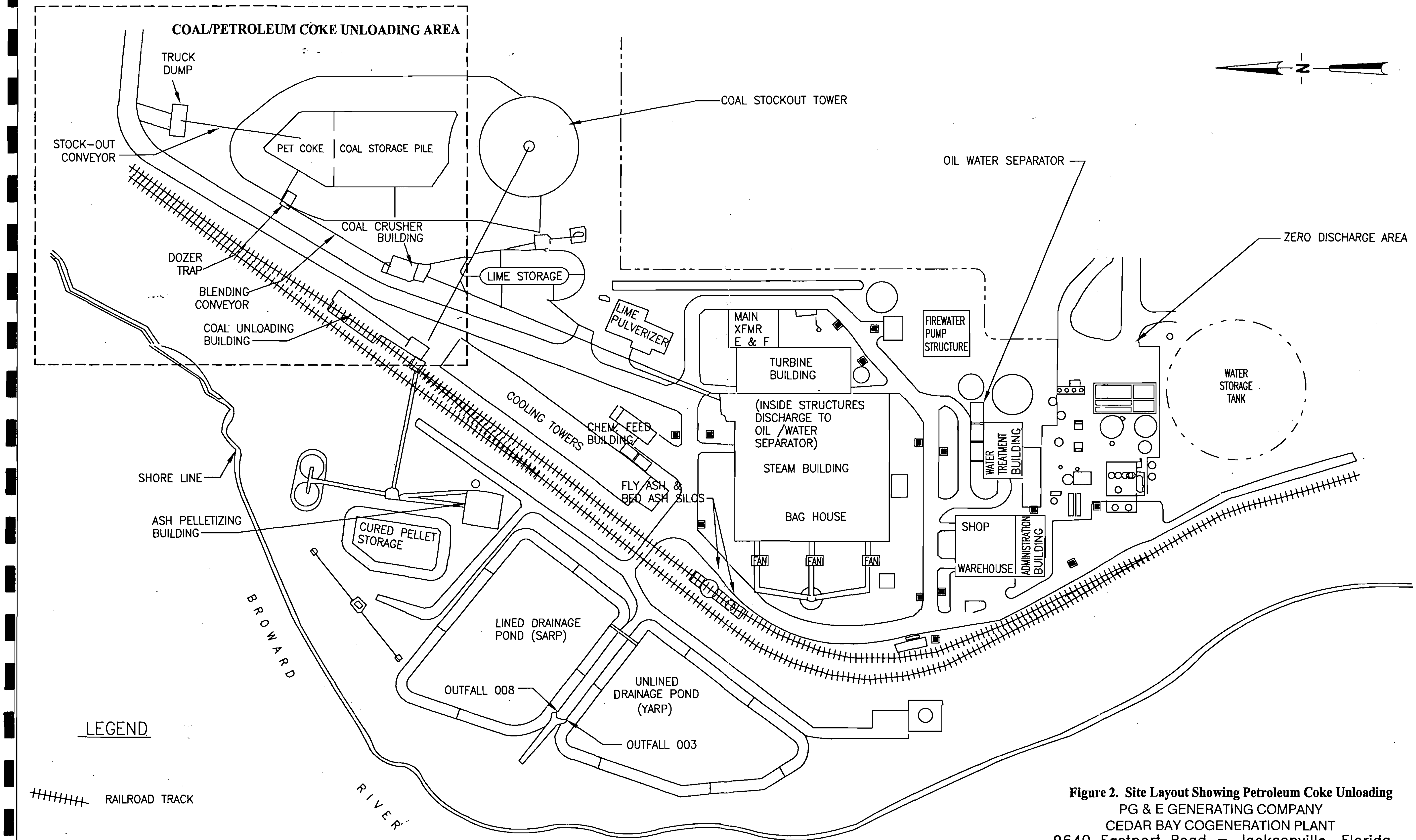

Figure 2. Site Layout Showing Petroleum Coke Unloading
PG & E GENERATING COMPANY
CEDAR BAY COGENERATION PLANT
9640 Eastport Road – Jacksonville, Florida

Source: BLACK & VEATCH DRAWING NUMBER 15637-1STU-S3400 REVISION 3. DATED: 1-6-92

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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

SENDER: COMPLETE THIS SECTION

- Complete items 1, 2, and 3. Also complete item 4 if Restricted Delivery is desired.
- Print your name and address on the reverse so that we can return the card to you.
- Attach this card to the back of the mailpiece, or on the front if space permits.

1. Article Addressed to:

Mr. Bruce Smith
General Manager
Cedar Bay Cogeneration Facility
P. O. Box 26324
Jacksonville, FL 32226

COMPLETE THIS SECTION ON DELIVERY

A. Received by (Please Print Clearly) Shelly Arnold B. Date of Delivery 8/5/02

C. Signature
X Shelly Arnold ☐ Agent ☐ Addressee

D. Is delivery address different from item 1? ☐ Yes
If YES, enter delivery address below: ☐ No

JAX STA AUG - 5 2002 JACK

3. Service Type
☒ Certified Mail ☐ Express Mail
☐ Registered ☐ Return Receipt for Merchandise
☐ Insured Mail ☐ C.O.D.

4. Restricted Delivery? *(Extra Fee)* ☐ Yes

2. Article Number *(Copy from service* 7001 0320 0001 3692 8178

PS Form 3811, July 1999 Domestic Return Receipt 102595-00-M-0952

U.S. Postal Service
CERTIFIED MAIL RECEIPT
(Domestic Mail Only; No Insurance Coverage Provided)

OFFICIAL USE

7001 0320 0001 3692 8178

Postage	$	Postmark Here
Certified Fee		
Return Receipt Fee (Endorsement Required)		
Restricted Delivery Fee (Endorsement Required)		
Total Postage & Fees	$	

Sent To
Bruce Smith

Street, Apt. No.; or PO Box No.
PO Box 26324

City, State, ZIP+4
Jacksonville, FL 32226

PS Form 3800, January 2001 See Reverse for Instructions

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

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 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)

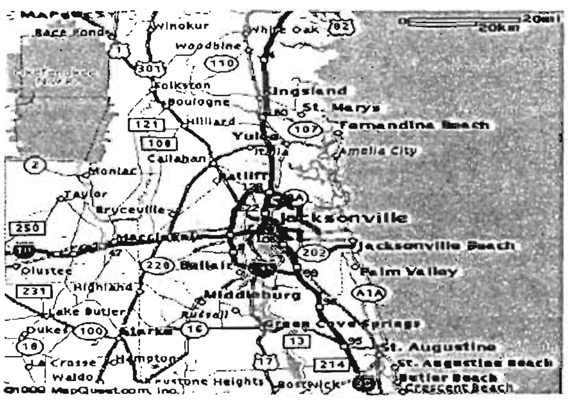
Industry Group No.	49	Electric, Gas and Sanitary Services
Industry No.	4911	Electric Services

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):

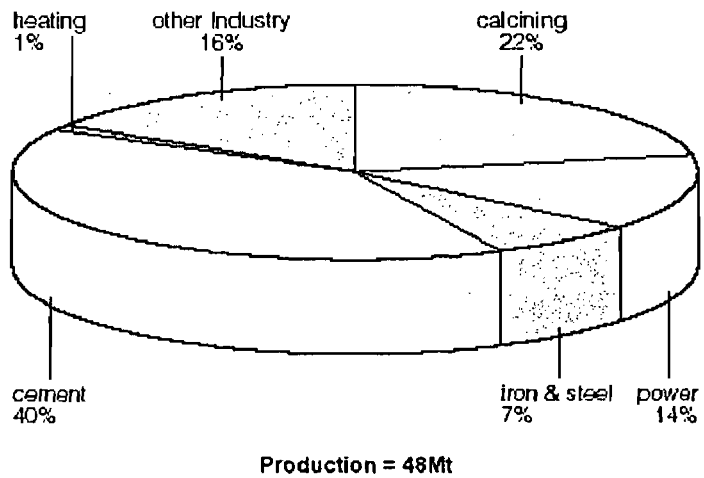
Emissions Unit No.	Emissions Unit Description
001	Pyroflow® Circulating Fluidized Bed (CFB) dry bottom boiler designated as "CFB Boiler A"
002	Pyroflow® Circulating Fluidized Bed (CFB) dry bottom boiler designated as "CFB Boiler B"
003	Pyroflow® Circulating Fluidized Bed (CFB) dry bottom boiler designated 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 (cents per million Btu)	Average Delivered Cost (dollars per short ton)	Total Coal Bill (million dollars)
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: Btu (per pound)	Average Quality: Sulfur (percent by weight)	Average Quality: Ash (percent by weight)	Average Delivered Cost: (cents per million Btu)	Average Delivered Cost: (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.

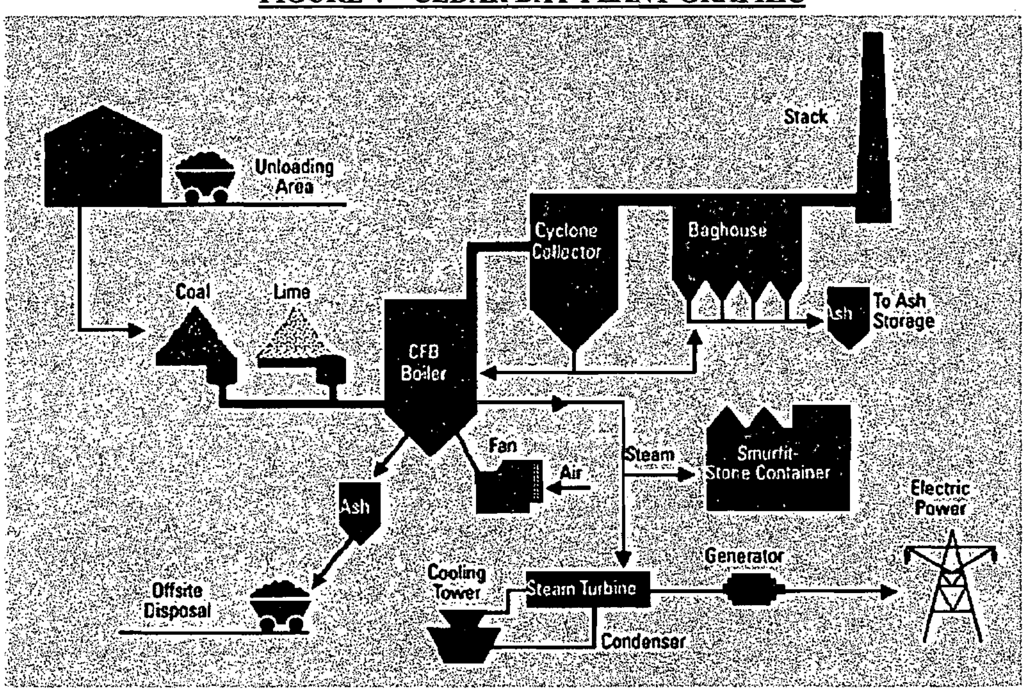
3.2 FLUIDIZED BED COMBUSTION

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.

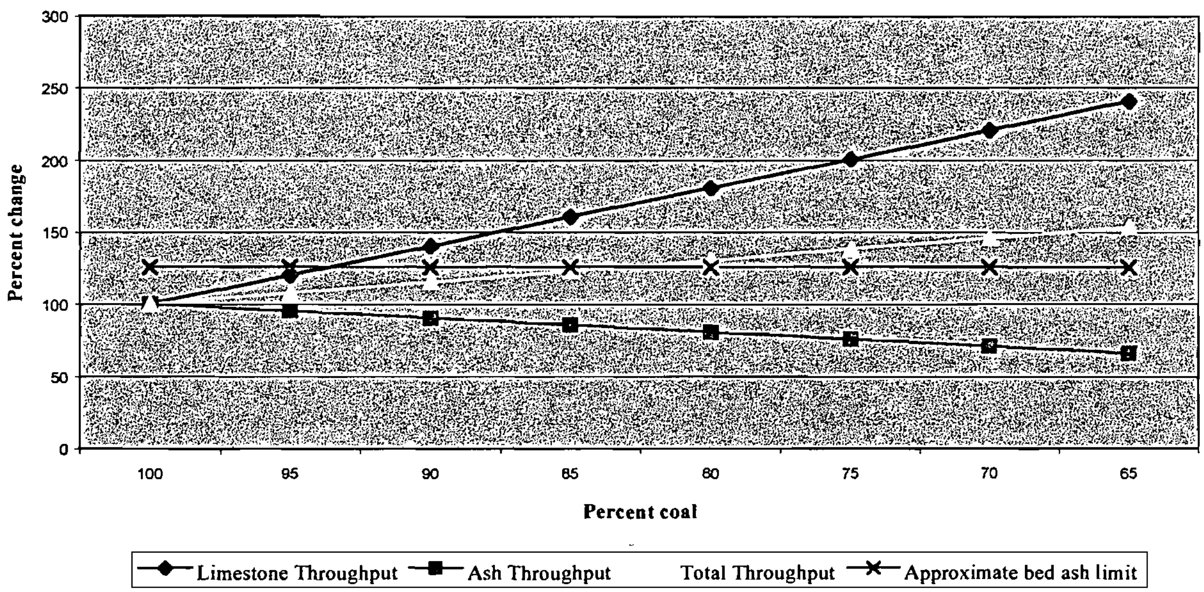
4.2.3 FLYASH THROUGHPUT

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)

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, 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

Memorandum

Florida Department of Environmental Protection

TO: Clair Fancy

THRU: Al Linero

FROM: Michael P. Halpin

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

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

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

KENNARD F. KOSKY
CERTIFICATE NO. 14996
STATE OF FLORIDA
PROFESSIONAL ENGINEER
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)
Stafford Campbell, Greater Arlington Civic Council

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G. Worley, EPA
J. Bunyak, NPS

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	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 1997	1998	1999	2000	2001	Basis
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					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					

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 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	Co-Firing	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.

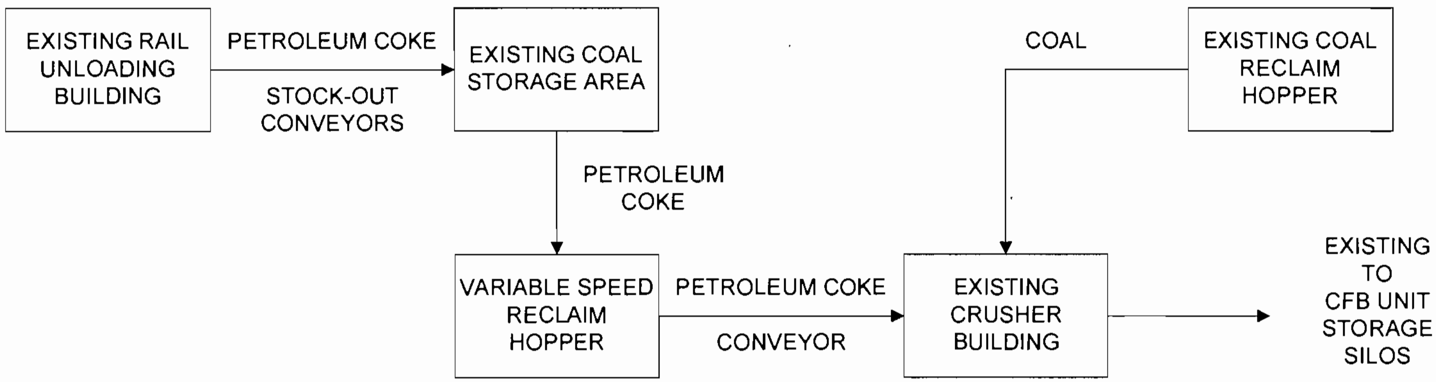


Figure 3
Process Flow Diagram for Petroleum Coke Unloading
Cedar Bay Cogeneration Facility
Jacksonville, Florida

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.

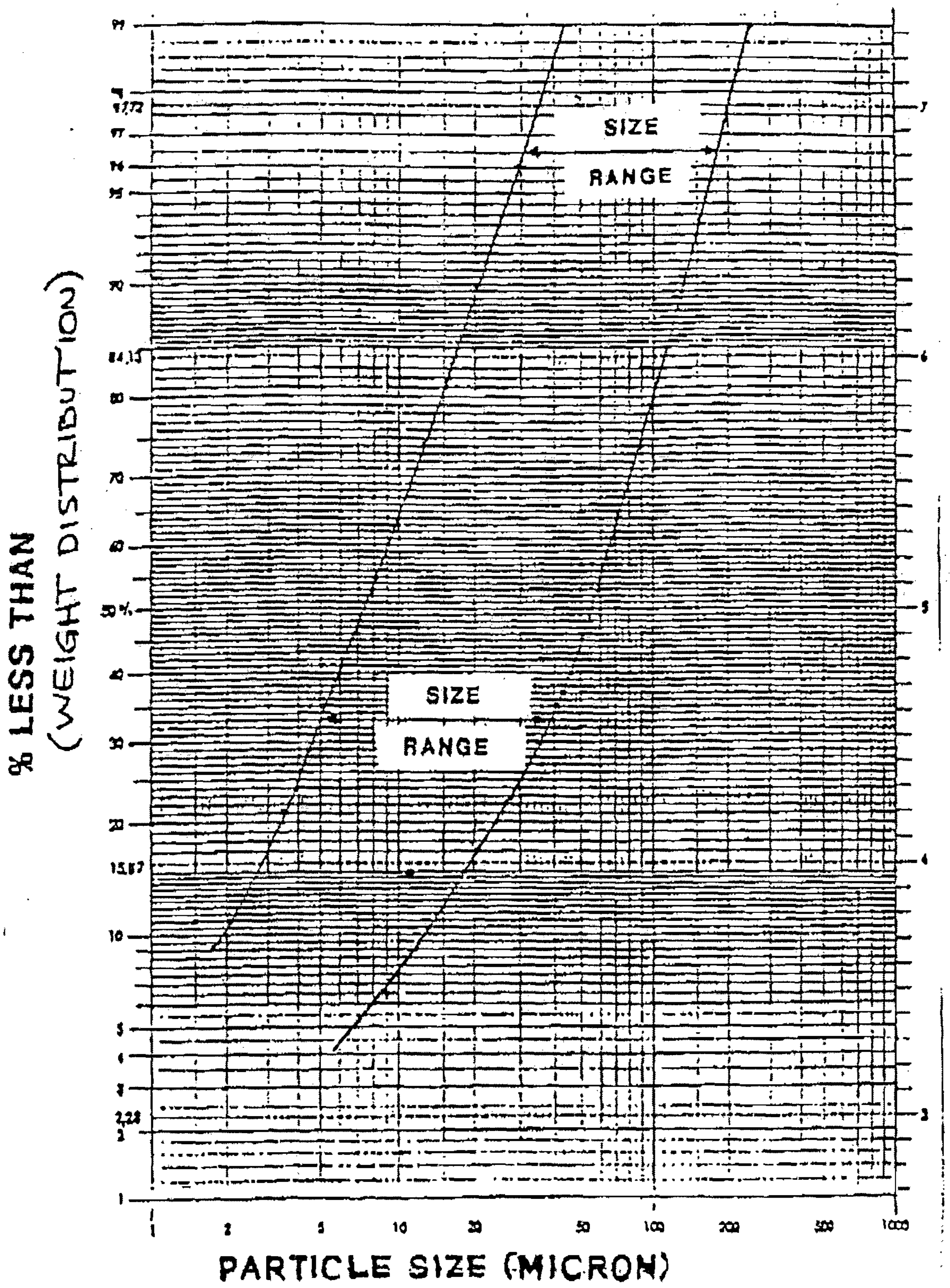
FLYASH RE-INJECTION

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

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.

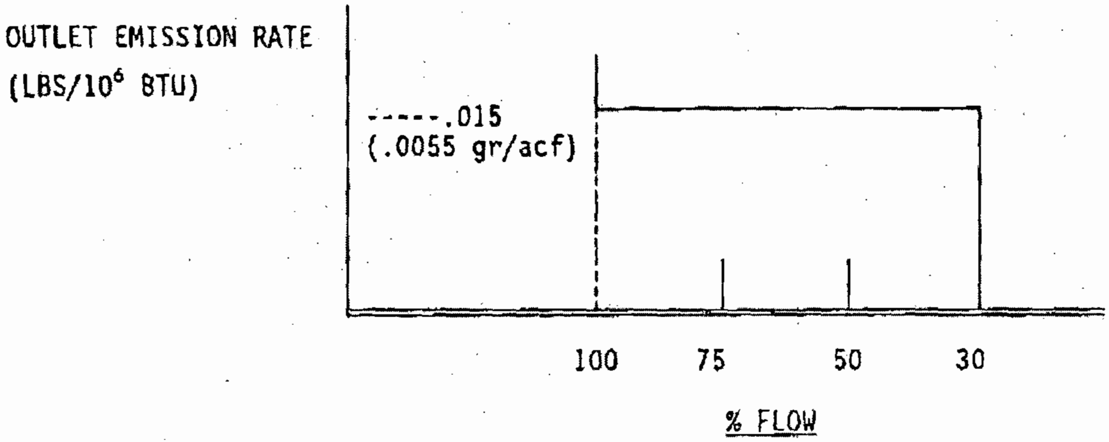
3.3.3.7 After raising bag, attach to bag support steel per Step 3, Drawing 326-11-00-E-01.

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.

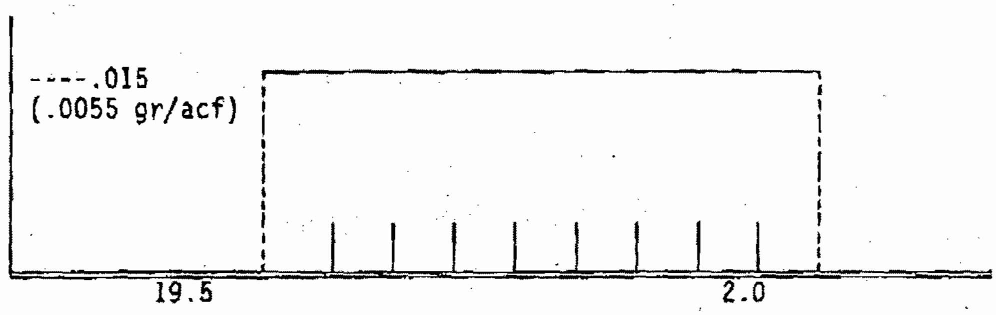
3.4 PERFORMANCE CURVES

OUTLET EMISSION RATE VS. FLUE GAS FLOW RATE



PERFORMANCE CURVE

OUTLET EMISSION RATE VS. INLET PARTICULATE LOAD



PARTICULATE LOAD (GRAINS/ACF)

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

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

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- Print your name and address on the reverse so that we can return the card to you.
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1. Article Addressed to:

Mr. Bruce Smith
Cedar Bay Cogenerating Co., LP
PO Box 26324
Jacksonville, FL 32226

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B. Date of Delivery 4/5/02

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City, State, ZIP+4 Jacksonville, FL 32226

PS Form 3800, January 2001 See Reverse for Instructions

al

PG&E National Energy Group

Cedar Bay Generating Plant

Owner: Cedar Bay Generating Company, L.P.

RECEIVED

MAR 08 2002

BUREAU OF AIR REGULATION

POB 26324
Jacksonville, FL 32226-6324

904.751.4000
Fax: 904.751.7320

March 7, 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. 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 annual 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 FDEP for the facility.

The Department's expeditious review of the application is appreciated. Please contact me if 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

62-210.200(11) F.A.C. "Actual Emissions" - 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.

40 CFR 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.

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)
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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

Table 4b. Maximum Predicted Concentrations of Styrene Emissions, Sea Ray Boats, Inc. Cape Canaveral Plant Compared to Florida Air Reference Concentrations (ARC)

Averaging Time	Year	Site Boundary (ug/m^3)	Residential Boundary (ug/m^3)	Florida ARC (ug/m^3)	Site Boundary (ppb)	Residential Boundary (ppb)	Florida ARC (ppb)
<u>Single Stack (75 feet high)-Original Concept</u>							
Annual	1987	2.2	1.5	1,000.0	0.5	0.4	235.0
	1988	2.1	1.7	1,000.0	0.5	0.4	235.0
	1989	2.0	1.6	1,000.0	0.5	0.4	235.0
	1990	2.6	1.5	1,000.0	0.6	0.4	235.0
	1991	2.4	1.4	1,000.0	0.6	0.3	235.0
Highest 24-hour	1987	27.7	27.7	507.0	6.5	6.5	119.2
	1988	32.1	32.1	507.0	7.5	7.5	119.2
	1989	27.3	27.3	507.0	6.4	6.4	119.2
	1990	26.1	21.9	507.0	6.1	5.1	119.2
	1991	29.3	22.0	507.0	6.9	5.2	119.2
Highest 8-hour	1987	53.3	48.7	2,130.0	12.5	11.4	500.6
	1988	50.7	46.5	2,130.0	11.9	10.9	500.6
	1989	58.0	58.0	2,130.0	13.6	13.6	500.6
	1990	58.3	54.3	2,130.0	13.7	12.8	500.6
	1991	54.4	47.3	2,130.0	12.8	11.1	500.6
<u>Single Stack (75 feet high)-Final Design</u>							
Annual	1987	1.3	0.7	1,000.0	0.3	0.2	235.0
	1988	1.3	0.7	1,000.0	0.3	0.2	235.0
	1989	1.2	0.7	1,000.0	0.3	0.2	235.0
	1990	1.5	0.7	1,000.0	0.4	0.2	235.0
	1991	1.4	0.6	1,000.0	0.3	0.1	235.0
Highest 24-hour	1987	15.9	10.3	507.0	3.7	2.4	119.2
	1988	20.8	10.4	507.0	4.9	2.4	119.2
	1989	17.1	9.3	507.0	4.0	2.2	119.2
	1990	15.4	10.1	507.0	3.6	2.4	119.2
	1991	17.3	9.0	507.0	4.1	2.1	119.2
Highest 8-hour	1987	31.8	28.3	2,130.0	7.5	6.6	500.6
	1988	29.8	22.7	2,130.0	7.0	5.3	500.6
	1989	32.2	21.9	2,130.0	7.6	5.2	500.6
	1990	33.5	27.2	2,130.0	7.9	6.4	500.6
	1991	29.4	22.4	2,130.0	6.9	5.3	500.6

Notes: ug/m^3 per ppb = 4.254567

ug/m^3 = micrograms per cubic meter

ppb = parts per billion

Table 5. Maximum 1-Hour Predicted Concentrations of Styrene Emissions, Sea Ray Boats, Inc. Cape Canaveral Plant Compared to Environmental Protection Agency (EPA) Recommended Odor Threshold for Styrene

Averaging Time	Year	Site Boundary (ug/m^3)	Residential Boundary (ug/m^3)	EPA Odor Threshold[a] (ug/m^3)	Site Boundary (ppb)	Residential Boundary (ppb)	EPA Odor Threshold[a] (ppb)
6 Vents (55 feet high)							
Highest 1-hour	1987	680	540	638	160	127	150
	1988	673	530	638	158	125	150
	1989	658	509	638	155	120	150
	1990	738	526	638	173	124	150
	1991	676	538	638	159	127	150
Single Stack (60 feet high)							
Highest 1-hour	1987	241	188	638	57	44	150
	1988	260	183	638	61	43	150
	1989	255	182	638	60	43	150
	1990	235	180	638	55	42	150
	1991	259	181	638	61	43	150
Single Stack (75 feet high)-Original Design							
Highest 1-hour	1987	103	103	638	24	24	150
	1988	103	98	638	24	23	150
	1989	109	98	638	26	23	150
	1990	123	98	638	29	23	150
	1991	102	94	638	24	22	150
Single Stack (75 feet high)-Final Design							
Highest 1-hour	1987	67	59	638	16	14	150
	1988	67	60	638	16	14	150
	1989	73	58	638	17	14	150
	1990	72	61	638	17	14	150
	1991	72	57	638	17	13	150

Notes: ug/m^3 per ppb = 4.254567 ; ug/m^3 = micrograms per cubic meter
ppb = parts per billion.

[a]Source: EPA, 1992. Reference Guide to Odor Thresholds for Hazardous Air Pollutants Listed in the Clean Air Act Amendments of 1990. EPA/600/R-92/047.

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

Best Available Copy

PLACE STICKER AT TOP OF ENVELOPE

SENDER: *COMPLETE THIS SECTION*

- Complete items 1, 2, and 3. Also complete item 4 if Restricted Delivery is desired.
- Print your name and address on the reverse so that we can return the card to you.
- Attach this card to the back of the mailpiece, or on the front if space permits.

1. Article Addressed to:

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

COMPLETE THIS SECTION ON DELIVERY

A. Received by *(Please Print Clearly)* Shelly Arnold

B. Date of Delivery

C. Signature

X

☐ Agent
☐ Addressee

D. Is delivery address different from item 1? ☐ Yes
If YES, enter delivery address below: ☐ No

JUL 17 2002

3. Service Type
☒ Certified Mail ☐ Express Mail
☐ Registered ☐ Return Receipt for Merchandise
☐ Insured Mail ☐ C.O.D.

4. Restricted Delivery? *(Extra Fee)* ☐ Yes

2. Article Number *(Copy from service label)*

July ... Domestic Return Receipt

U.S. Postal Service
CERTIFIED MAIL RECEIPT
(Domestic Mail Only; No Insurance Coverage Provided)

7000 0520 0020 9371 4473

Mr. Bruce Smith

Postage	$
Certified Fee	
Return Receipt Fee (Endorsement Required)	
Restricted Delivery Fee (Endorsement Required)	
Total Postage & Fees	$

Postmark Here

***Recipient's Name** (Please Print Clearly) (To be completed by mailer)*
Mr. Bruce Smith
Street, Apt. No.; or PO Box No.
P.O. Box 26324
City, State, ZIP+ 4
Jacksonville, Florida 32226

PS Form 3800, February 2000 See Reverse for Instructions

Best Available Copy

SENDER: *COMPLETE THIS SECTION*	*COMPLETE THIS SECTION ON DELIVERY*
■ Complete items 1, 2, and 3. Also complete item 4 if Restricted Delivery is desired. ■ Print your name and address on the reverse so that we can return the card to you. ■ Attach this card to the back of the mailpiece, or on the front if space permits.	A. Received by (*Please Print Clearly*) B. Date of Delivery C. Signature X ☐ Agent ☑ Addressee D. Is delivery address different from item 1? ☐ Yes If YES, enter delivery address below: ☐ No JAN 2 2002
1. Article Addressed to: 031033?-005-AC Extension Mr. Bruce Smith General Manager Cedar Bay Generating Company, L.P. 9640 Eastport Road Jacksonville, Florida 32226	3. Service Type ☒ Certified Mail ☐ Express Mail ☐ Registered ☐ Return Receipt for Merchandise ☐ Insured Mail ☐ C.O.D. 4. Restricted Delivery? (*Extra Fee*) ☐ Yes
2.	
PS	

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

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,

A. Bruce Nobbott
for C. H. Fancy, P.E.
Chief
Bureau of Air Regulation

cc: Kennard Kosky, P.E., Golder Associates
Jeff Walker, CBGC

BEST AVAILABLE COPY

SENDER: *COMPLETE THIS SECTION*

- Complete items 1, 2, and 3. Also complete item 4 if Restricted Delivery is desired.
- Print your name and address on the reverse so that we can return the card to you.
- Attach this card to the back of the mailpiece, or on the front if space permits.

1. Article Addressed to:

Mr. Bruce Smith
Cedar Bay Generating Company, L.P.
P.O. Box 26324
Jacksonville, FL 32226

COMPLETE THIS SECTION ON DELIVERY

A. Received by *(Please Print Clearly)*

B. Date of Delivery 10/3/01

C. Signature

X Debra L Sumner ☐ Agent ☐ Addressee

D. Is delivery address different from item 1? ☐ Yes
If YES, enter delivery address below: ☐ No

3. Service Type
☒ Certified Mail ☐ Express Mail
☐ Registered ☐ Return Receipt for Merchandise
☐ Insured Mail ☐ C.O.D.

4. Restricted Delivery? *(Extra Fee)* ☐ Yes

2. Article Number *(Copy from service label)*
7000 0520 0020 9371 1618

PS Form 3811, July 1999 Domestic Return Receipt 102595-00-M-0952

U.S. Postal Service
CERTIFIED MAIL RECEIPT
(Domestic Mail Only; No Insurance Coverage Provided)

7000 0520 0020 9371 1618

Mr. Bruce Smith

Postage	$
Certified Fee	
Return Receipt Fee (Endorsement Required)	
Restricted Delivery Fee (Endorsement Required)	
Total Postage & Fees	$

Postmark Here

Recipient's Name (Please Print Clearly) (To be completed by mailer)
Mr. Bruce Smith
Street, Apt. No.; or PO Box No.
P.O. Box 26324
City, State, ZIP+4
Jacksonville, Florida 32226

PS Form 3800, February 2000 See Reverse for Instructions

BEST AVAILABLE COPY

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

RECEIVED

SEP 1 0 2001

BUREAU OF

POB 26324
Jacksonville, FL 32226-6324

904.751.4000
Fax: 904 751 ...

Reflected in Site Cert. Superseded in PSD/TS? Handle with Pet coke

September 18, 2001

Mr. Scott Sheplak, 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 Draft Air Construction/PSD Permit No.

Dear Mr. Sheplak:

Cedar Bay Generating Company, L.P. would like to take the opportunity to provide written comments to the proposed Air Construction/PSD Permit Revision during the Public Notice period.

Material Handling Handling and Treatment

The previous PSD modification that became effective in March 2000 is now identified as PSD-FL-137D. One of the items in the original modification request was a request to modify the material handling and usage rates of the coal and limestone/aragonite. Due to the modification's intensive focus on SO2 limits and supporting air dispersion modeling, this particular item was apparently overlooked during the draft and final permit issuance.

Coal and limestone are staged in lined storage piles. Coal is supplied via rail and limestone/aragonite is supplied via ship, then truck. Cedar Bay Generating Company, L.P. is concerned that current PSD permit conditions do not allow sufficient material handling capacity to allow the facility to weather catastrophic events or business interruptions. It would be prudent to have the ability to increase the amount of coal and limestone "handled" at the facility.

Given that:

- Coal unloading and storage , as well as limestone/aragonite unloading and storage, represent fugitive particulate emissions for which no emission rate limits are set;
- There is no federal or state regulation limiting the quantities of these material or emissions on a monthly basis; and
- Compliance with a rigorous interpretation of the current monthly conditions would, in theory, render the storage piles to be eventually depleted if the boilers ran at full capacity for an extended period with even intermittent cessation of supply periods;

Cedar Bay therefore requests doubling the monthly limitations for coal and limestone/aragonite unloading and storage, and increasing the annual usage rate by one month's capacity. This would require separating the limits for these sources from the other material handling sources.

Thus, Cedar Bay proposes to modify Conditions II.B.2 as follows:

2. Material Handling and Usage Rate

a. The material handling/usage rates for coal unloading and storage and for limestone/aragonite unloading and storage shall not exceed the following:

	Handling/Usage Rate	
Material	TPM	TPY
Coal	234,000	1,287,000
Limestone/Aragonite	54,000	347,000

b. For fly ash and bed ash handling sources, the handling/usage rates shall not exceed the following:

	Handling/Usage Rate	
Material	TPM	TPY
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

It is important to note that the latest version of Cedar Bay's Conditions of Certification reflect these changes as requested in the PSD modification application although the material handling changes were not part of the proposed changes in the draft PSD permit.

Addition of language for a Pug Mill
As explained in a letter to the Department dated August 21, 2001, Cedar Bay desires to improve the flexibility for ash handling and transportation from the site with the installation of a pug mill. The pug mill will mix ash and water in an enclosed system and enable the removal of ash by other than sealed trucks. This process will enable the ash to be loaded, transported, and disposed in a Class 1 landfill while minimizing fugitive emissions.

While the PSD Modification Application in 1994 explicitly detailed "Dry Ash Unloading in Sealed Trucks", the resulting modification, PSD-FL-137(B), did not specifically reference the use of trucks as a means to remove ash from the site. Instead, Section II.B.4.added a stipulation that requires the Project site to option obtain(?) prior approval of the DEP and RESD for removal of bottom and fly ash by any other means other than rail. Cedar Bay has since obtained such permission once it was clear that long-term beneficial re-use opportunities were available.

The use of the pug mill will alter the process of loading the trucks but will enable the project to meet the visible emission limitation (VE) of five per cent (5%) opacity in accordance with rule 62-296.711, F.A.C. By wetting and blending the ash, the pug mill will produce a more uniform ash with less opportunity for dusting. There are no new vents or other air emission sources associated with the pug mill itself.

Therefore, Cedar Bay requests to modify PSD-FL-137(B) (in conjunction with the retirement of the pelletizer emission units) as follows:

From

II.1.B.4 Material handling sources shall be regulated as follow:

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

Coal Crusher Building	Limestone Pulverizer (2)/Conveyor
Coal Silo Conveyor	Limestone Storage Bins(2)
Bed Ash Hopper	Fly Ash Silo Vent
Bed Ash Separator	Fly Ash Separators(2)
Bed Ash Silo Vent	Pellet Vibratory System
Bed Ash Receiver Bin	Pellet Recycle tank
Fly Ash Receiver Bin	Cured Pellet Screening Conveyor System
	Pellet Recycle System
	Pelletizing Rail Loadout

The emissions from the above listed sources are subject to the particulate emission limitation requirement of 0.003 gr./disc (applicant requested limitation which is more stringent than what is allowed by Rule 62-296.711, 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 Chapter 62-297, F.A.C. and 40 CFR 60, Appendix A.

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

Ash Pellet Hydrator:	Scrubber
Ash Pellet Curing Silos:	Scrubber
Ash Pelletizing Pan:	Scrubber

The above listed sources are subject to a visible emissions (VE) and a particulate matter (PM) emissions limitation requirement of 5 percent opacity and a 0.01 gr/dscf(applicant requested limitation, which is more stringent than what is allowed by rule) , respectively, in accordance with Rule 62-296.711, F.A.C. Initial and subsequent compliance tests shall be conducted for VE and PM using EPA methods 9 and 5, respectively, in accordance with Rule 62-297, D=F.A.C. and 40 CFR 60, Appendix A.

c. Fugitive emissions from the following material handling and transport sources shall be controlled as follows:

Coal Car Unloading:	Wet Suppression using continuous water sprays during unloading
Dry Ash Rail Car Loadout:	Using closed or covered containers under negative air pressures during ash loadout; and using water sprays prior to removal of railcar loadout cap when loading open rail cars

The above listed sources are subject to a visible emission (VE) limitation requirement of five percent (5%) opacity in accordance with Rule 62-296.711, F.A.C. Initial and subsequent compliance test shall be conducted for VE using EPA Method 9 or other FDEP approved methods in accordance with Rule 62-297, F.A.C. and 40 CFR 60, Appendix A (July, 1992 version). Initial visible emission testing shall be conducted within 90 days after final DEP approval of these facilities or within 90 days after completion of construction of the source, whichever occurs last. Ash shipped in open rail cars will either be pelletized or be sprayed with water to create a crust on the top layer of non-pelletized ash. Removal of bottom and fly ash from the Project site by any means other than by rail shall require the prior approval of DEP and RESD of the method(s) of fugitive emissions control.

To:

II.1.B.4 Material handling sources shall be regulated as follow:

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

Coal Crusher Building	Limestone Pulverizer (2)/Conveyor
Coal Silo Conveyor	Limestone Storage Bins(2)
Bed Ash Hopper	Fly Ash Silo Vent
Bed Ash Separator	Fly Ash Separators(2)
Bed Ash Silo Vent	

The emissions from the above listed sources are subject to the particulate emission limitation requirement of 0.003 gr./disc (applicant requested limitation which is more stringent than what is allowed by Rule 62-296.711, 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 Chapter 62-297, F.A.C. and 40 CFR 60, Appendix A.

b.Fugitive emissions from the following material handling and transport sources shall be controlled as follows:

Coal Car Unloading:	Wet Suppression using continuous water sprays during unloading
Dry Ash Rail Car Loadout:	Using closed or covered containers under negative air pressures during ash loadout; and using water sprays prior to removal of railcar loadout cap when loading open rail cars
Dry Ash Truck Loadout:	Using sealed trailers under negative air
Wet Ash Truck Loadout:	Using a pug mill to mix water with ash

The above listed sources are subject to a visible emission (VE) limitation requirement of five percent (5%) opacity in accordance with Rule 62-296.711, F.A.C. Initial and subsequent compliance test shall be conducted for VE using EPA Method 9 or other FDEP approved methods in accordance with Rule 62-297, F.A.C. and 40 CFR 60, Appendix A (July, 1992 version). Initial visible emission testing shall be conducted within 90 days after final DEP approval of these facilities or within 90 days after completion of construction of the source, whichever occurs last. Ash shipped in open rail cars will either be pelletized or be sprayed with water to create a crust on the top layer of non-pelletized ash. ~~Removal of bottom and fly ash from the Project site by any means other than by rail shall require the prior approval of DEP and RESD of the method(s) of fugitive emissions control.~~

We hope that these proposed changes are satisfactory to you and we look forward to working with you to ensure that we can operate the Cedar Bay facility in a reliable, environmentally responsible, and cost-effective manner. Please contact me at 904-751-4000 extension 22 with any questions or comments.

Sincerely,

Jeffrey A. Walker

Jeffrey A. Walker
Environmental Manager, Cedar Bay

cc: Robert Dehart, PG&E National Energy Group
Bruce Smith, Cedar Bay

0310337-005-AC / PSD-FL-137 G(7)

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

RECEIVED
AUG 29 2001
BUREAU OF AIR REGULATION

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 terminate its contract with Cedar Bay for economic reasons. The price for coal under the contract is currently less than the price that Lodestar could obtain in the spot market. As a result, Cedar Bay has evaluated various options for obtaining fuel (including alternate suppliers of coal), 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)

RECEIVED

AUG 29 2001

BUREAU OF AIR REGULATION

APPLICATION FOR MODIFICATION OF PETROLEUM COKE AND COAL HANDLING FACILITIES

CEDAR BAY COGENERATION FACILITY JACKSONVILLE, FLORIDA

Prepared For:

Cedar Bay Generating Company, L.P.
9640 Eastport Road
Jacksonville, Florida 32218

Prepared By:

Golder Associates Inc.
6241 NW 23rd Street, Suite 500
Gainesville, Florida 32653-1500

July 2001
0137573

DISTRIBUTION:
10 Copies - Cedar Bay
2 Copies - Golder Associates Inc

PART I

Department of
Environmental Protection

Division of Air Resources Management

APPLICATION FOR AIR PERMIT - TITLE V SOURCE

See Instructions for Form No. 62-210.900(1)

I. APPLICATION INFORMATION

Identification of Facility

1. Facility Owner/Company Name: **Cedar Bay Generating Company, L.P.**	
2. Site Name: **Cedar Bay Cogeneration Facility**	
3. Facility Identification Number: **0310337**	[ ] Unknown
4. Facility Location: **U.S. Generating Cedar Bay Facility** Street Address or Other Locator: **9640 Eastport Road** City: **Jacksonville** County: **Duval** Zip Code: **32226**	
5. Relocatable Facility? [ ] Yes [X] No	6. Existing Permitted Facility? [X] Yes [ ] No

Application Contact

1. Name and Title of Application Contact: **Jeffery Walker, Environmental Manager**
2. Application Contact Mailing Address: Organization/Firm: **U.S. Generating Company** Street Address: **9640 Eastport Road (PO Box 26324 Zip Code: 32226-6324)** City: **Jacksonville** State: **FL** Zip Code: **32218**
3. Application Contact Telephone Numbers: Telephone: (**904**) **751-4000, Ext. 22** Fax: (**904**) **751-7320**

Application Processing Information (DEP Use)

1. Date of Receipt of Application:	8-29-01
2. Permit Number:	0310337-005-AC
3. PSD Number (if applicable):	PSD-FL-137A (Revision)
4. Siting Number (if applicable):	

Purpose of Application

Air Operation Permit Application

This Application for Air Permit is submitted to obtain: (Check one)

[ ] Initial Title V air operation permit for an existing facility which is classified as a Title V source.

[ ] Initial Title V air operation permit for a facility which, upon start up of one or more newly constructed or modified emissions units addressed in this application, would become classified as a Title V source.

Current construction permit number: ______________________________

[ ] Title V air operation permit revision to address one or more newly constructed or modified emissions units addressed in this application.

Current construction permit number: ______________________________

Operation permit number to be revised: ______________________________

[ ] Title V air operation permit revision or administrative correction to address one or more proposed new or modified emissions units and to be processed concurrently with the air construction permit application. (Also check Air Construction Permit Application below.)

Operation permit number to be revised/corrected: ______________________________

[ ] Title V air operation permit revision for reasons other than construction or modification of an emissions unit. Give reason for the revision; e.g., to comply with a new applicable requirement or to request approval of an "Early Reductions" proposal.

Operation permit number to be revised: ______________________________

Reason for revision: ______________________________

Air Construction Permit Application

This Application for Air Permit is submitted to obtain: (Check one)

[X] Air construction permit to construct or modify one or more emissions units.

[ ] Air construction permit to make federally enforceable an assumed restriction on the potential emissions of one or more existing, permitted emissions units.

[ ] Air construction permit for one or more existing, but unpermitted, emissions units.

Owner/Authorized Representative or Responsible Official

1.	Name and Title of Owner/Authorized Representative or Responsible Official: **Bruce Smith, General Manager**
2.	Owner/Authorized Representative or Responsible Official Mailing Address: Organization/Firm: **Cedar Bay Generating Company** Street Address: **P.O. Box 26324** City: **Jacksonville** State: **FL** Zip Code: **32226-6324**
3.	Owner/Authorized Representative or Responsible Official Telephone Numbers: Telephone: (**904**) **751-4000, Ext. 18** Fax: (**904**) **751-7320**
4.	Owner/Authorized Representative or Responsible Official Statement: *I, the undersigned, am the owner or authorized representative*(check here [* **X** *], if so) or the responsible official (check here [ ], if so) of the Title V source addressed in this application, whichever is applicable. I hereby certify, based on information and belief formed after reasonable inquiry, that the statements made in this application are true, accurate and complete and that, to the best of my knowledge, any estimates of emissions reported in this application are based upon reasonable techniques for calculating emissions. The air pollutant emissions units and air pollution control equipment described in this application will be operated and maintained so as to comply with all applicable standards for control of air pollutant emissions found in the statutes of the State of Florida and rules of the Department of Environmental Protection and revisions thereof. I understand that a permit, if granted by the Department, cannot be transferred without authorization from the Department, and I will promptly notify the Department upon sale or legal transfer of any permitted emissions unit.* [signature] 8/28/01 Signature Date

* Attach letter of authorization if not currently on file.

Professional Engineer Certification

1.	Professional Engineer Name: **Kennard F. Kosky** Registration Number: **14996**
2.	Professional Engineer Mailing Address: Organization/Firm: **Golder Associates Inc.** Street Address: **6241 NW 23rd Street, Suite 500** City: **Gainesville** State: **FL** Zip Code: **32653-1500**
3.	Professional Engineer Telephone Numbers: Telephone: (**352**) **336 - 5600** Fax: (**352**) **336 - 6603**

4. Professional Engineer Statement:

I, the undersigned, hereby certify, except as particularly noted herein, that:*

(1) To the best of my knowledge, there is reasonable assurance that the air pollutant emissions unit(s) and the air pollution control equipment described in this Application for Air Permit, when properly operated and maintained, will comply with all applicable standards for control of air pollutant emissions found in the Florida Statutes and rules of the Department of Environmental Protection; and

(2) To the best of my knowledge, any emission estimates reported or relied on in this application are true, accurate, and complete and are either based upon reasonable techniques available for calculating emissions or, for emission estimates of hazardous air pollutants not regulated for an emissions unit addressed in this application, based solely upon the materials, information and calculations submitted with this application.

If the purpose of this application is to obtain a Title V source air operation permit (check here [ ], if so), I further certify that each emissions unit described in this Application for Air Permit, when properly operated and maintained, will comply with the applicable requirements identified in this application to which the unit is subject, except those emissions units for which a compliance schedule is submitted with this application.

If the purpose of this application is to obtain an air construction permit for one or more proposed new or modified emissions units (check here [ ], if so), I further certify that the engineering features of each such emissions unit described in this application have been designed or examined by me or individuals under my direct supervision and found to be in conformity with sound engineering principles applicable to the control of emissions of the air pollutants characterized in this application.

If the purpose of this application is to obtain an initial air operation permit or operation permit revision for one or more newly constructed or modified emissions units (check here [X], if so), I further certify that, with the exception of any changes detailed as part of this application, each such emissions unit has been constructed or modified in substantial accordance with the information given in the corresponding application for air construction permit and with all provisions contained in such permit.

Bernard F. Koski

Signature

August 9, 2001

Date

(seal)

BERNARD F. KOSKI
CERTIFICATE
STATE OF
FLORIDA
REGISTERED

* Attach any exception to certification statement.

Scope of Application

Emissions Unit ID	Description of Emissions Unit	Permit Type	Processing Fee
001	CFB Boiler A	AC1D	NA
002	CFB Boiler B	AC1D	NA
003	CFB Boiler C	AC1D	NA
034	Pet Coke Truck Unloading and Conveyors	AC1F	NA

Application Processing Fee

Check one: [ ] Attached - Amount: $: ____________________ [X] Not Applicable

Construction/Modification Information

1. Description of Proposed Project or Alterations: **Applicant is seeking authorization to co-fire up to 35 percent of petroleum coke with coal in the 3 existing circulating fluidized bed (CFB) boilers. A new truck unloading area for petroleum coke will be added. This will include a truck dump, transfer conveyor, dozer trap, and coal blending conveyor.**
2. Projected or Actual Date of Commencement of Construction **1 DEC 2001**
3. Projected Date of Completion of Construction: **1 DEC 2002**

Application Comment

This application is a request to co-fire petroleum coke with coal under 40 CFR 52.21(b)(21)(v) as a non-PSD modification. The facility has a final Title V permit 0310337-002-AV. The facility was initially permitted under Florida's Power Plant Siting Act (PPSA) DEP File PA88-24 and received Permit No. PSD-FL-137.

II. FACILITY INFORMATION

A. GENERAL FACILITY INFORMATION

Facility Location and Type

1. Facility UTM Coordinates: Zone: **17**	East (km): **441.610**	North (km): **3365.552**	
2. Facility Latitude/Longitude: Latitude (DD/MM/SS): **30 / 25 / 21**		Longitude (DD/MM/SS): **81 / 36 / 23**	
3. Governmental Facility Code: **0**	4. Facility Status Code: **A**	5. Facility Major Group SIC Code: **49**	6. Facility SIC(s): **4911**
7. Facility Comment (limit to 500 characters):			

Facility Contact

1. Name and Title of Facility Contact: **Jeffery Walker, Environmental Manager**
2. Facility Contact Mailing Address: Organization/Firm: **U.S. Generating Company** Street Address: **9640 Eastport Road** City: **Jacksonville** State: **FL** Zip Code: **32226**
3. Facility Contact Telephone Numbers: Telephone: (**904**) **751-4000, Ext. 22** Fax: (**904**) **751-7320**

Facility Regulatory Classifications

Check all that apply:

1. [ ] Small Business Stationary Source?	[ ] Unknown
2. [X] Major Source of Pollutants Other than Hazardous Air Pollutants (HAPs)?	
3. [ ] Synthetic Minor Source of Pollutants Other than HAPs?	
4. [X] Major Source of Hazardous Air Pollutants (HAPs)?	
5. [ ] Synthetic Minor Source of HAPs?	
6. [X] One or More Emissions Units Subject to NSPS?	
7. [ ] One or More Emission Units Subject to NESHAP?	
8. [ ] Title V Source by EPA Designation?	
9. Facility Regulatory Classifications Comment (limit to 200 characters):	

List of Applicable Regulations

The applicable facility regulation contained in the Title V permit will not change as a result of this application.

B. FACILITY POLLUTANTS

List of Pollutants Emitted

1. Pollutant Emitted	2. Pollutant Classif.	3. Requested Emissions Cap lb/hour	tons/year	4. Basis for Emissions Cap	5. Pollutant Comment
PM	**A**				**Particulate Matter – Total**
PM_{10}	**A**				**Particulate Matter – PM_{10}**
NO_X	**A**				**Nitrogen Oxides**
SO_2	**A**				**Sulfur Dioxide**
CO	**A**				**Carbon Monoxide**
VOC	**A**				**Volatile Organic Compounds**
SAM	**B**				**Sulfuric Acid Mist**

C. FACILITY SUPPLEMENTAL INFORMATION

Supplemental Requirements

1.	Area Map Showing Facility Location: [X] Attached, Document ID: **See Part II** [ ] Not Applicable [ ] Waiver Requested
2.	Facility Plot Plan: [X] Attached, Document ID: **See Part II** [ ] Not Applicable [ ] Waiver Requested
3.	Process Flow Diagram(s): [X] Attached, Document ID: **See Part II** [ ] Not Applicable [ ] Waiver Requested
4.	Precautions to Prevent Emissions of Unconfined Particulate Matter: [ ] Attached, Document ID: ________ [X] Not Applicable [ ] Waiver Requested
5.	Fugitive Emissions Identification: [ ] Attached, Document ID: ________ [X] Not Applicable [ ] Waiver Requested
6.	Supplemental Information for Construction Permit Application: [X] Attached, Document ID: **See Part II** [ ] Not Applicable
7.	Supplemental Requirements Comment:

Additional Supplemental Requirements for Title V Air Operation Permit Applications

8. List of Proposed Insignificant Activities: [ ] Attached, Document ID: ________ [X] Not Applicable
9. List of Equipment/Activities Regulated under Title VI: [ ] Attached, Document ID: ________ [ ] Equipment/Activities On site but Not Required to be Individually Listed [X] Not Applicable
10. Alternative Methods of Operation: [ ] Attached, Document ID: ________ [X] Not Applicable
11. Alternative Modes of Operation (Emissions Trading): [ ] Attached, Document ID: ________ [X] Not Applicable
12. Identification of Additional Applicable Requirements: [ ] Attached, Document ID: ________ [X] Not Applicable
13. Risk Management Plan Verification: [ ] Plan previously submitted to Chemical Emergency Preparedness and Prevention Office (CEPPO). Verification of submittal attached (Document ID: ________) or previously submitted to DEP (Date and DEP Office: ________) [ ] Plan to be submitted to CEPPO (Date required: ________) [X] Not Applicable
14. Compliance Report and Plan: [ ] Attached, Document ID: ________ [X] Not Applicable
15. Compliance Certification (Hard-copy Required): [ ] Attached, Document ID: ________ [X] Not Applicable

III. EMISSIONS UNIT INFORMATION

A separate Emissions Unit Information Section (including subsections A through J as required) must be completed for each emissions unit addressed in this Application for Air Permit. If submitting the application form in hard copy, indicate, in the space provided at the top of each page, the number of this Emissions Unit Information Section and the total number of Emissions Unit Information Sections submitted as part of this application.

A. GENERAL EMISSIONS UNIT INFORMATION
(All Emissions Units)

Emissions Unit Description and Status

1. Type of Emissions Unit Addressed in This Section: (Check one)

[X] This Emissions Unit Information Section addresses, as a single emissions unit, a single process or production unit, or activity, which produces one or more air pollutants and which has at least one definable emission point (stack or vent).

[ ] This Emissions Unit Information Section addresses, as a single emissions unit, a group of process or production units and activities which has at least one definable emission point (stack or vent) but may also produce fugitive emissions.

[ ] This Emissions Unit Information Section addresses, as a single emissions unit, one or more process or production units and activities which produce fugitive emissions only.

2. Regulated or Unregulated Emissions Unit? (Check one)

[X] The emissions unit addressed in this Emissions Unit Information Section is a regulated emissions unit.

[ ] The emissions unit addressed in this Emissions Unit Information Section is an unregulated emissions unit.

3. Description of Emissions Unit Addressed in This Section (limit to 60 characters):
Boiler A

4. Emissions Unit Identification Number: [ ] No ID
ID: **001** [ ] ID Unknown

5. Emissions Unit Status Code:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code:	8. Acid Rain Unit?
A	**25-JAN-1994**	**49**	[ ]

9. Emissions Unit Comment: (Limit to 500 Characters)

Circulating Fluidized Bed (CFB) Boiler A with limestone injection for SO_2 emissions reduction. Ammonia injection for NO_x emissions reduction. Fuel is primarily bituminous coal with No. 2 fuel oil for startup. Combustion products are flue gas with fly ash and bed ash.

Emissions Unit Control Equipment

1. Control Equipment/Method Description (Limit to 200 characters per device or method):

Baghouse
Efficiency = (1-emission)/load = 0.0055 gr/acr / 19.5 gr/acr = 99.97%

Ammonia injection
Efficiency = 54% for NO_x (estimated)

Dry limestone injection
Efficiency from 89 to 95% based on Quarterly Reports

Air preheater
Reduction Efficiency not determined.
Intake air is preheated via flue gas to reduce fuel requirements.

Control of Oxygen
Reduction Efficiency not determined.
Flue gas recirculates with intake air.

2. Control Device or Method Code(s): **016, 032/107, 041, 027, 033**

Emissions Unit Details

1. Package Unit: **NA**
   Manufacturer: **Foster Wheeler** Model Number: **Pyroflow®**
2. Generator Nameplate Rating: MW
3. Incinerator Information:
   Dwell Temperature: °F
   Dwell Time: seconds
   Incinerator Afterburner Temperature: °F

B. EMISSIONS UNIT CAPACITY INFORMATION
(Regulated Emissions Units Only)

Emissions Unit Operating Capacity and Schedule

1. Maximum Heat Input Rate:			1,063	mmBtu/hr
2. Maximum Incineration Rate:		lb/hr		tons/day
3. Maximum Process or Throughput Rate:		104,000 lb/hr coal; 39,000 ton/month coal; 390,000 TPY coal		
4. Maximum Production Rate:		800,000 lb/hr steam		
5. Requested Maximum Operating Schedule:				
	24	hours/day	7	days/week
	52	weeks/year	8,760	hours/year

6. Operating Capacity/Schedule Comment (limit to 200 characters):

Limits set by PSD-FL-137A

CFB Boilers A, B, and C feed a common steam turbine with a nominal rating of 250 MW and supply steam to an adjacent recycled liner board mill.

C. EMISSIONS UNIT REGULATIONS
(Regulated Emissions Units Only)

List of Applicable Regulations

40 CFR 60.40a	Applicability >250 MMBtu/hr
40 CFR 60.41a	Definitions
40 CFR 60.42a	Standard for particulate matter
40 CFR 60.43a(a)	Standard for sulfur dioxide
40 CFR 60.43a(g)	Compliance with the emission limitation and percent reduction requirements
40 CFR 60.44a	Standard for nitrogen oxides
40 CFR 60.46a	Compliance provisions
40 CFR 60.47a	Emission monitoring
40 CFR 60.48a	Compliance determination procedures and methods
40 CFR 60.49a	Reporting requirements
FAC 62-204.800	Standards of performance for New Stationary Sources
FAC 62-210.550	Stack Height Policy
FAC 62-210.700	Excess Emissions
FAC 62-212-300	General preconstruction review
FAC 62-212-400	Prevention of Significant Deterioration
FAC 62-296.405	Fossil Fuel Steam Generators with more than 240 MMBtu/hr heat input
FAC 62-296.570(4)(a)	Reasonable Available Control Technology - Requirements for major VOC and NO_x emission Facilities
FAC 62-296.702	Fossil Fuel Steam Generators
FAC 62-296.711	Material Handling, Sizing, Screening, Crushing, and Grinding Operations
FAC 62-297.401(5)	EPA Method 5
FAC 62-297.401(6)	EPA Method 6
FAC 62-297.401(7)	EPA Method 7
FAC 62-297.401(8)	EPA Method 8
FAC 62-297.401(9)	EPA Method 9
FAC 62-297.401(10)	EPA Method 10
FAC 62-297.401(12)	EPA Method 12
FAC 62-297.401(13)	EPA Method 13
FAC 62-297.401(15)	EPA Method 15
FAC 62-297.401(17)	EPA Method 17
FAC 62-297.401(19)	EPA Method 19
FAC 62-297.401(25)	EPA Method 25
FAC 62-297.401(32)(a)	EPA Method 101A
FAC 62-297.401(35)	EPA Method 104
FAC 62-297.401(41)	EPA Method 201
FAC 62-297.520	EPA Performance Specifications
FAC 62-297.570	Test Reports
FAC 62-297.620	Exceptions and Approval of Alternate Procedures and Requirements

D. EMISSION POINT (STACK/VENT) INFORMATION
(Regulated Emissions Units Only)

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram? **B1**	2. Emission Point Type Code: **2**

3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking (limit to 100 characters per point):

Boiler Stack (B1)

4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:
001 = Boiler A; 002 = Boiler B; 003 = Boiler C

5. Discharge Type Code: **V**	6. Stack Height: **403** feet	7. Exit Diameter: **13.26** feet
8. Exit Temperature: **265** °F	9. Actual Volumetric Flow Rate: **1,004,000** acfm	10. Water Vapor: **5** %

11. Maximum Dry Standard Flow Rate: **895,403** dscfm	12. Nonstack Emission Point Height: feet

13. Emission Point UTM Coordinates:

Zone: **17** East (km): **441.871** North (km): **3365.587**

14. Emission Point Comment (limit to 200 characters):

The 3 CFB boilers share a common stack designated as point B1. Flue gas from the boilers is discharged through this stack. Prior to the stack, each flue gas stream is passed through a baghouse which removes fly ash.

Stack information based on Title V Application.

E. SEGMENT (PROCESS/FUEL) INFORMATION
(All Emissions Units)

Segment Description and Rate: Segment 1 of 2

1. Segment Description (Process/Fuel Type) (limit to 500 characters):

   a) **Segment 1 of 2: Bituminous coal used in boiler (when co-firing with petroleum coke).**
   b) **Segment 2 of 2.**

2. Source Classification Code (SCC): **1-01-002-17**	3. SCC Units: **Tons burned**	
4. Maximum Hourly Rate: **29.9**	5. Maximum Annual Rate: **258,575**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **1.7% per load, 1.2% annual**	8. Maximum % Ash: **10 (typical)**	9. Million Btu per SCC Unit: **20.4**

10. Segment Comment (limit to 200 characters):

   Based on 65% coal (by weight). See Part II, Appendix B.

Segment Description and Rate: Segment 2 of 2

1. Segment Description (Process/Fuel Type) (limit to 500 characters):

   a) **Segment 1 of 2.**
   b) **Segment 2 of 2: Petroleum coke used in boiler when co-firing with coal.**

2. Source Classification Code (SCC): **1-01-008-01**	3. SCC Units: **tons burned**	
4. Maximum Hourly Rate: **16.1**	5. Maximum Annual Rate: **139,233**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **6**	8. Maximum % Ash: **0.5 (typical)**	9. Million Btu per SCC Unit: **28**

10. Segment Comment (limit to 200 characters):

   Based on 35% petroleum coke (by weight). See Part II, Appendix B.

F. EMISSIONS UNIT POLLUTANTS
(All Emissions Units)

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
PM	016	027	EL
PM_{10}	016	027	EL
NO_X	032/107	027	EL
SO_2	041	027	EL
CO	033	027	EL
VOC	027		EL
SAM	041	027	EL

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: SO_2
2. Total Percent Efficiency of Control:
3. Potential Emissions: 318.9 lb/hour 866 tons/year
4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year
6. Emission Factor: 0.30 lb/MMBtu* 0.20 lb/MMBtu**
   Reference: Permit PA-88-24A, PSD-FL-137B
7. Emissions Method Code: 5
8. Calculation of Emissions (limit to 600 characters):

   1,063 MMBtu/hr x 0.3 lb/MMBtu = 318.9 lb/hr
   1,063 MMBtu/hr x 0.2 lb/MMBtu x 8,760 hr/yr x ton/2,000 lb x 0.93 (capacity factor) = 866 TPY

9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):

   Limited by modification to PSD-FL-137. * 3-hour rolling average; ** 30-day rolling average. Annual emissions limited for 3 boilers when co-firing coke with coal to not trigger PSD review. See Part II.

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: OTHER
2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: see comment
4. Equivalent Allowable Emissions: 318.9 lb/hour 866 tons/year
5. Method of Compliance (limit to 60 characters):

   Continuous Emissions Monitoring

6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):

   3-hour rolling average for SO_2 = 0.30 lb/MMBtu
   30-day rolling average for SO_2 = 0.20 lb/MMBtu
   Annual emissions for 3 boilers limited when co-firing petroleum coke with coal to not trigger PSD review. See Part II.

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **CO**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **186** lb/hour **649** tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **0.175 lb/MMBtu** Reference: **PSD-FL-137A**	7. Emissions Method Code: **5**
8. Calculation of Emissions (limit to 600 characters): **1,063 MMBtu/hr x 0.175 lb/MMBtu - 186 lb/hr** **Annual potential emissions based on maximum emissions for 3 boilers so that PSD is not triggered. See Part II.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **See Part II.**	

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **See Part II**	4. Equivalent Allowable Emissions: **186** lb/hour **649** tons/year
5. Method of Compliance (limit to 60 characters): **Continuous Emissions Monitoring and Method 10**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **See Part II** **8-hour rolling average for CO = 0.175 lb/MMBtu**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **NO_x**

2. Total Percent Efficiency of Control: **54% (estimated)**

3. Potential Emissions: **180.7** lb/hour **736.1** tons/year

4. Synthetically Limited? [X]

5. Range of Estimated Fugitive Emissions:
[ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year

6. Emission Factor: **0.17 lb/MMBtu***
Reference: **PSD-FL-137A**

7. Emissions Method Code: **5**

8. Calculation of Emissions (limit to 600 characters):

1,063 MMBtu/hr x 0.17 lb/MMBtu = 180.7 lb/hr
180.7 lb/hr x 8,760 hr/yr x ton/2,000 lb x 0.93 (capacity factor) = 736.1 TPY

9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):

Limited by modification to PSD-FL-137. * 30-day rolling average. Annual emissions limited for 3 boilers when co-firing coke with coal to not trigger PSD review. See Part II.

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **OTHER**

2. Future Effective Date of Allowable Emissions:

3. Requested Allowable Emissions and Units: **See Part II**

4. Equivalent Allowable Emissions: **180.7** lb/hour **736.1** tons/year

5. Method of Compliance (limit to 60 characters):

Continuous Emissions Monitoring and Method 7, 7A, B, C, D, or E

6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):

30-day rolling average for NO_x = 0.17 lb/MMBtu
Annual emissions for 3 boilers limited when co-firing petroleum coke with coal to not trigger PSD review. See Part II.

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **VOC**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **16.0** lb/hour **57.6** tons/year	4. Synthetically Limited? [**X**]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **0.015** Reference: **PSD-FL-137A**	7. Emissions Method Code: **5**
8. Calculation of Emissions (limit to 600 characters): **1,063 MMBtu/hr x 0.015 lb/MMBtu = 16 lb/hr** **Annual potential emissions based on maximum emissions for 3 boilers so that PSD is not triggered. See Part II.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **See Part II**	

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **See Part II**	4. Equivalent Allowable Emissions: **16.0** lb/hour **57.6** tons/year
5. Method of Compliance (limit to 60 characters): **Method 18 or 25**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **See Part II** **0.015 lb/MMBtu VOC**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: PM (TSP)	2. Total Percent Efficiency of Control: 99.97%
3. Potential Emissions: 19.1 lb/hour 78 tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: 0.018 lb/MMBtu Reference: PSD-FL-137A	7. Emissions Method Code: 5
8. Calculation of Emissions (limit to 600 characters): 1,063 MMBtu/hr x 0.018 lb/MMBtu = 19.1 lb/hr 19.1 lb/hr x 8,760 hr/yr x ton/2,000 lbs x 0.93 (capacity factor) = 78 TPY	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): Limited by modification to PSD-FL-137. Annual emissions limited for 3 boilers when co-firing coke with coal to not trigger PSD review. See Part II.	

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: See Part II	4. Equivalent Allowable Emissions: 19.1 lb/hour 78 tons/year
5. Method of Compliance (limit to 60 characters): Method 5 or 17, 40 CFR Appendix A	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): 0.018 lb/MMBtu Annual emissions for 3 boilers limited when co-firing petroleum coke with coal to not trigger PSD review. See Part II.	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **PM_{10}**	2. Total Percent Efficiency of Control: **99.97%**
3. Potential Emissions: **19.1** lb/hour **78** tons/year	4. Synthetically Limited? [**X**]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **0.018 lb/MMBtu** Reference: **PSD-FL-137A**	7. Emissions Method Code: **5**
8. Calculation of Emissions (limit to 600 characters): **1,063 MMBtu/hr x 0.018 lb/MMBtu = 19.1 lb/hr** **19.1 lb/hr x 8,760 hr/yr x ton/2,000 lbs x 0.93 (capacity factor) = 78 TPY**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Limited by modification to PSD-FL-137. Annual emissions limited for 3 boilers when co-firing coke with coal to not trigger PSD review. See Part II.**	

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **See Part II**	4. Equivalent Allowable Emissions: **19.1** lb/hour **78** tons/year
5. Method of Compliance (limit to 60 characters): **Method 5 or 17, 40 CFR Appendix A**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **0.018 lb/MMBtu** **Annual emissions for 3 boilers limited when co-firing petroleum coke with coal to not trigger PSD review. See Part II.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **SAM**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **0.50** lb/hour **2.0** tons/year	4. Synthetically Limited? [**X**]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **4.66 x 10^{-4} lb/MMBtu** Reference: **PSD-FL-137A**	7. Emissions Method Code: **5**
8. Calculation of Emissions (limit to 600 characters): **1,063 MMBtu/hr x 0.000466 lb/MMBtu = 0.5 lb/hr**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Limited by modification to PSD-FL-137. Annual emissions limited for 3 boilers when co-firing coke with coal to not trigger PSD review. See Part II.**	

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **See Part II**	4. Equivalent Allowable Emissions: **0.50** lb/hour **2.0** tons/year
5. Method of Compliance (limit to 60 characters): **Method 8**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **4.66 x 10^{-4} lb/MMBtu** **Annual emissions for 3 boilers limited when co-firing petroleum coke with coal to not trigger PSD review. See Part II.**	

H. VISIBLE EMISSIONS INFORMATION
(Only Regulated Emissions Units Subject to a VE Limitation)

Visible Emissions Limitation: Visible Emissions Limitation 1 of 1

1. Visible Emissions Subtype: **VE, VES**	2. Basis for Allowable Opacity: [ ] Rule [X] Other
3. Requested Allowable Opacity: Normal Conditions: **20** % Exceptional Conditions: **27** % Maximum Period of Excess Opacity Allowed: **6** min/hour	
4. Method of Compliance: **COM, Method 9**	
5. Visible Emissions Comment (limit to 200 characters): **27% opacity for oil-burning during startup PSD-FL-137A**	

I. CONTINUOUS MONITOR INFORMATION
(Only Regulated Emissions Units Subject to Continuous Monitoring)

Continuous Monitoring System: Continuous Monitor 1 of 1

1. Parameter Code: **See comment**	2. Pollutant(s):
3. CMS Requirement:	[X] Rule [ ] Other
4. Monitor Information: Manufacturer: **various** Model Number:	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment (limit to 200 characters): **Baghouse flue has CEMs for NO_x, SO_2, CO, CO_2, and VE. Manufacturers, models, and serial numbers previously submitted.**	

J. EMISSIONS UNIT SUPPLEMENTAL INFORMATION
(Regulated Emissions Units Only)

Supplemental Requirements

1. Process Flow Diagram [ ] Attached, Document ID: ________ [X] Not Applicable [ ] Waiver Requested
2. Fuel Analysis or Specification [X] Attached, Document ID: Part II [ ] Not Applicable [ ] Waiver Requested
3. Detailed Description of Control Equipment [ ] Attached, Document ID: ________ [X] Not Applicable [ ] Waiver Requested
4. Description of Stack Sampling Facilities [ ] Attached, Document ID: ________ [X] Not Applicable [ ] Waiver Requested
5. Compliance Test Report [ ] Attached, Document ID: ________ [ ] Previously submitted, Date: ________ [X] Not Applicable
6. Procedures for Startup and Shutdown [ ] Attached, Document ID: ________ [X] Not Applicable [ ] Waiver Requested
7. Operation and Maintenance Plan [ ] Attached, Document ID: ________ [X] Not Applicable [ ] Waiver Requested
8. Supplemental Information for Construction Permit Application [ ] Attached, Document ID: ________ [X] Not Applicable
9. Other Information Required by Rule or Statute [X] Attached, Document ID: See Part II [ ] Not Applicable
10. Supplemental Requirements Comment:

Additional Supplemental Requirements for Title V Air Operation Permit Applications

11. Alternative Methods of Operation
    [ ] Attached, Document ID:________ [X] Not Applicable

12. Alternative Modes of Operation (Emissions Trading)
    [ ] Attached, Document ID:________ [X] Not Applicable

13. Identification of Additional Applicable Requirements
    [ ] Attached, Document ID:________ [X] Not Applicable

14. Compliance Assurance Monitoring Plan
    [ ] Attached, Document ID:________ [X] Not Applicable

15. Acid Rain Part Application (Hard-copy Required)

    [ ] Acid Rain Part - Phase II (Form No. 62-210.900(1)(a))
    Attached, Document ID:________

    [ ] Repowering Extension Plan (Form No. 62-210.900(1)(a)1.)
    Attached, Document ID:________

    [ ] New Unit Exemption (Form No. 62-210.900(1)(a)2.)
    Attached, Document ID:________

    [ ] Retired Unit Exemption (Form No. 62-210.900(1)(a)3.)
    Attached, Document ID:________

    [ ] Phase II NOx Compliance Plan (Form No. 62-210.900(1)(a)4.)
    Attached, Document ID:________

    [ ] Phase NOx Averaging Plan (Form No. 62-210.900(1)(a)5.)
    Attached, Document ID:________

    [X] Not Applicable

III. EMISSIONS UNIT INFORMATION

A separate Emissions Unit Information Section (including subsections A through J as required) must be completed for each emissions unit addressed in this Application for Air Permit. If submitting the application form in hard copy, indicate, in the space provided at the top of each page, the number of this Emissions Unit Information Section and the total number of Emissions Unit Information Sections submitted as part of this application.

A. GENERAL EMISSIONS UNIT INFORMATION
(All Emissions Units)

Emissions Unit Description and Status

1. Type of Emissions Unit Addressed in This Section: (Check one)

[X] This Emissions Unit Information Section addresses, as a single emissions unit, a single process or production unit, or activity, which produces one or more air pollutants and which has at least one definable emission point (stack or vent).

[ ] This Emissions Unit Information Section addresses, as a single emissions unit, a group of process or production units and activities which has at least one definable emission point (stack or vent) but may also produce fugitive emissions.

[ ] This Emissions Unit Information Section addresses, as a single emissions unit, one or more process or production units and activities which produce fugitive emissions only.

2. Regulated or Unregulated Emissions Unit? (Check one)

[X] The emissions unit addressed in this Emissions Unit Information Section is a regulated emissions unit.

[ ] The emissions unit addressed in this Emissions Unit Information Section is an unregulated emissions unit.

3. Description of Emissions Unit Addressed in This Section (limit to 60 characters):
Boiler B

4. Emissions Unit Identification Number: [ ] No ID
ID: **002** [ ] ID Unknown

5. Emissions Unit Status Code:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code:	8. Acid Rain Unit?
A	**25-JAN-1994**	**49**	[ ]

9. Emissions Unit Comment: (Limit to 500 Characters)

Circulating Fluidized Bed (CFB) Boiler B with limestone injection for SO_2 emissions reduction. Ammonia injection for NO_x emissions reduction. Fuel is primarily bituminous coal with No. 2 fuel oil for startup. Combustion products are flue gas with fly ash and bed ash.

Emissions Unit Control Equipment

1. Control Equipment/Method Description (Limit to 200 characters per device or method):

Baghouse
Efficiency = (1-emission)/load = 0.0055 gr/acr / 19.5 gr/acr = 99.97%

Ammonia injection
Efficiency = 54% for NO_x (estimated)

Dry limestone injection
Efficiency from 89 to 95% based on Quarterly Reports

Air preheater
Reduction Efficiency not determined.
Intake air is preheated via flue gas to reduce fuel requirements.

Control of Oxygen
Reduction Efficiency not determined.
Flue gas recirculates with intake air.

2. Control Device or Method Code(s): **016, 032/107, 041, 027, 033**

Emissions Unit Details

1. Package Unit: **NA**			
Manufacturer:	**Foster Wheeler**	Model Number:	**Pyroflow®**
2. Generator Nameplate Rating:		MW	
3. Incinerator Information:			
	Dwell Temperature:		°F
	Dwell Time:		seconds
	Incinerator Afterburner Temperature:		°F

B. EMISSIONS UNIT CAPACITY INFORMATION
(Regulated Emissions Units Only)

Emissions Unit Operating Capacity and Schedule

1. Maximum Heat Input Rate:		1,063	mmBtu/hr
2. Maximum Incineration Rate:	lb/hr		tons/day
3. Maximum Process or Throughput Rate:		104,000 lb/hr coal; 39,000 ton/month coal; 390,000 TPY coal	
4. Maximum Production Rate:		800,000 lb/hr steam	
5. Requested Maximum Operating Schedule:			
	24 hours/day	7	days/week
	52 weeks/year	8,760	hours/year
6. Operating Capacity/Schedule Comment (limit to 200 characters): Limits set by PSD-FL-137A CFB Boilers A, B, and C feed a common steam turbine with a nominal rating of 250 MW and supply steam to an adjacent recycled liner board mill.			

C. EMISSIONS UNIT REGULATIONS
(Regulated Emissions Units Only)

List of Applicable Regulations

40 CFR 60.40a	Applicability >250 MMBtu/hr
40 CFR 60.41a	Definitions
40 CFR 60.42a	Standard for particulate matter
40 CFR 60.43a(a)	Standard for sulfur dioxide
40 CFR 60.43a(g)	Compliance with the emission limitation and percent reduction requirements
40 CFR 60.44a	Standard for nitrogen oxides
40 CFR 60.46a	Compliance provisions
40 CFR 60.47a	Emission monitoring
40 CFR 60.48a	Compliance determination procedures and methods
40 CFR 60.49a	Reporting requirements
FAC 62-204.800	Standards of performance for New Stationary Sources
FAC 62-210.550	Stack Height Policy
FAC 62-210.700	Excess Emissions
FAC 62-212-300	General preconstruction review
FAC 62-212-400	Prevention of Significant Deterioration
FAC 62-296.405	Fossil Fuel Steam Generators with more than 240 MMBtu/hr heat input
FAC 62-296.570(4)(a)	Reasonable Available Control Technology - Requirements for major VOC and NO_x emission Facilities
FAC 62-296.702	Fossil Fuel Steam Generators
FAC 62-296.711	Material Handling, Sizing, Screening, Crushing, and Grinding Operations
FAC 62-297.401(5)	EPA Method 5
FAC 62-297.401(6)	EPA Method 6
FAC 62-297.401(7)	EPA Method 7
FAC 62-297.401(8)	EPA Method 8
FAC 62-297.401(9)	EPA Method 9
FAC 62-297.401(10)	EPA Method 10
FAC 62-297.401(12)	EPA Method 12
FAC 62-297.401(13)	EPA Method 13
FAC 62-297.401(15)	EPA Method 15
FAC 62-297.401(17)	EPA Method 17
FAC 62-297.401(19)	EPA Method 19
FAC 62-297.401(25)	EPA Method 25
FAC 62-297.401(32)(a)	EPA Method 101A
FAC 62-297.401(35)	EPA Method 104
FAC 62-297.401(41)	EPA Method 201
FAC 62-297.520	EPA Performance Specifications
FAC 62-297.570	Test Reports
FAC 62-297.620	Exceptions and Approval of Alternate Procedures and Requirements

D. EMISSION POINT (STACK/VENT) INFORMATION
(Regulated Emissions Units Only)

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram? **B1**	2. Emission Point Type Code: **2**

3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking (limit to 100 characters per point):

Boiler Stack (B1)

4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:
001 = Boiler A; 002 = Boiler B; 003 = Boiler C

5. Discharge Type Code: **V**	6. Stack Height: **403** feet	7. Exit Diameter: **13.26** feet
8. Exit Temperature: **265** °F	9. Actual Volumetric Flow Rate: **1,004,000** acfm	10. Water Vapor: **5** %

11. Maximum Dry Standard Flow Rate: **895,403** dscfm	12. Nonstack Emission Point Height: feet

13. Emission Point UTM Coordinates:

Zone: **17** East (km): **441.871** North (km): **3365.587**

14. Emission Point Comment (limit to 200 characters):

The 3 CFB boilers share a common stack designated as point B1. Flue gas from the boilers is discharged through this stack. Prior to the stack, each flue gas stream is passed through a baghouse which removes fly ash.

Stack information based on Title V Application.

E. SEGMENT (PROCESS/FUEL) INFORMATION
(All Emissions Units)

Segment Description and Rate: Segment 1 of 2

1. Segment Description (Process/Fuel Type) (limit to 500 characters): a) **Segment 1 of 2: Bituminous coal used in boiler (when co-firing with petroleum coke).** b) **Segment 2 of 2.**		
2. Source Classification Code (SCC): **1-01-002-17**		3. SCC Units: **Tons burned**
4. Maximum Hourly Rate: **29.9**	5. Maximum Annual Rate: **258,575**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **1.7% per load,** **1.2% annual**	8. Maximum % Ash: **10 (typical)**	9. Million Btu per SCC Unit: **20.4**
10. Segment Comment (limit to 200 characters): **Based on 65% coal (by weight). See Part II, Appendix B.**		

Segment Description and Rate: Segment 2 of 2

1. Segment Description (Process/Fuel Type) (limit to 500 characters): a) **Segment 1 of 2.** b) **Segment 2 of 2: Petroleum coke used in boiler when co-firing with coal.**		
2. Source Classification Code (SCC): **1-01-008-01**		3. SCC Units: **tons burned**
4. Maximum Hourly Rate: **16.1**	5. Maximum Annual Rate: **139,233**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **6**	8. Maximum % Ash: **0.5 (typical)**	9. Million Btu per SCC Unit: **28**
10. Segment Comment (limit to 200 characters): **Based on 35% petroleum coke (by weight). See Part II, Appendix B.**		

F. EMISSIONS UNIT POLLUTANTS
(All Emissions Units)

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
PM	016	027	EL
PM_{10}	016	027	EL
NO_X	032/107	027	EL
SO_2	041	027	EL
CO	033	027	EL
VOC	027		EL
SAM	041	027	EL

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **SO_2**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **318.9** lb/hour **866** tons/year	4. Synthetically Limited? [**X**]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **0.30 lb/MMBtu* 0.20 lb/MMBtu**** Reference: **Permit PA-88-24A, PSD-FL-137B**	7. Emissions Method Code: **5**

8. Calculation of Emissions (limit to 600 characters):

1,063 MMBtu/hr x 0.3 lb/MMBtu = 318.9 lb/hr
1,063 MMBtu/hr x 0.2 lb/MMBtu x 8,760 hr/yr x ton/2,000 lb x 0.93 (capacity factor) = 866 TPY

9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):

Limited by modification to PSD-FL-137. * 3-hour rolling average; ** 30-day rolling average. Annual emissions limited for 3 boilers when co-firing coke with coal to not trigger PSD review. See Part II.

Allowable Emissions Allowable Emissions **1** of **1**

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **see comment**	4. Equivalent Allowable Emissions: **318.9** lb/hour **866** tons/year

5. Method of Compliance (limit to 60 characters):

Continuous Emissions Monitoring

6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):

3-hour rolling average for SO_2 = 0.30 lb/MMBtu
30-day rolling average for SO_2 = 0.20 lb/MMBtu
Annual emissions for 3 boilers limited when co-firing petroleum coke with coal to not trigger PSD review. See Part II.

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **CO**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **186** lb/hour **649** tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **0.175 lb/MMBtu** Reference: **PSD-FL-137A**	7. Emissions Method Code: **5**
8. Calculation of Emissions (limit to 600 characters): **1,063 MMBtu/hr x 0.175 lb/MMBtu - 186 lb/hr** **Annual potential emissions based on maximum emissions for 3 boilers so that PSD is not triggered. See Part II.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **See Part II.**	

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **See Part II**	4. Equivalent Allowable Emissions: **186** lb/hour **649** tons/year
5. Method of Compliance (limit to 60 characters): **Continuous Emissions Monitoring and Method 10**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **See Part II** **8-hour rolling average for CO = 0.175 lb/MMBtu**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **NO_x**	2. Total Percent Efficiency of Control: **54% (estimated)**
3. Potential Emissions: **180.7** lb/hour **736.1** tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **0.17 lb/MMBtu*** Reference: **PSD-FL-137A**	7. Emissions Method Code: **5**
8. Calculation of Emissions (limit to 600 characters): **1,063 MMBtu/hr x 0.17 lb/MMBtu = 180.7 lb/hr** **180.7 lb/hr x 8,760 hr/yr x ton/2,000 lb x 0.93 (capacity factor) = 736.1 TPY**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Limited by modification to PSD-FL-137. * 30-day rolling average. Annual emissions limited for 3 boilers when co-firing coke with coal to not trigger PSD review. See Part II.**	

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **See Part II**	4. Equivalent Allowable Emissions: **180.7** lb/hour **736.1** tons/year
5. Method of Compliance (limit to 60 characters): **Continuous Emissions Monitoring and Method 7, 7A, B, C, D, or E**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **30-day rolling average for NO_x = 0.17 lb/MMBtu** **Annual emissions for 3 boilers limited when co-firing petroleum coke with coal to not trigger PSD review. See Part II.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **VOC**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **16.0** lb/hour **57.6** tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **0.015** Reference: **PSD-FL-137A**	7. Emissions Method Code: **5**

8. Calculation of Emissions (limit to 600 characters):

1,063 MMBtu/hr x 0.015 lb/MMBtu = 16 lb/hr
Annual potential emissions based on maximum emissions for 3 boilers so that PSD is not triggered. See Part II.

9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):

See Part II

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **See Part II**	4. Equivalent Allowable Emissions: **16.0** lb/hour **57.6** tons/year

5. Method of Compliance (limit to 60 characters):

Method 18 or 25

6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):

See Part II
0.015 lb/MMBtu VOC

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **PM (TSP)**	2. Total Percent Efficiency of Control: **99.97%**
3. Potential Emissions: **19.1** lb/hour **78** tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **0.018 lb/MMBtu** Reference: **PSD-FL-137A**	7. Emissions Method Code: **5**

8. Calculation of Emissions (limit to 600 characters):

1,063 MMBtu/hr x 0.018 lb/MMBtu = 19.1 lb/hr
19.1 lb/hr x 8,760 hr/yr x ton/2,000 lbs x 0.93 (capacity factor) = 78 TPY

9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):

Limited by modification to PSD-FL-137. Annual emissions limited for 3 boilers when co-firing coke with coal to not trigger PSD review. See Part II.

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **See Part II**	4. Equivalent Allowable Emissions: **19.1** lb/hour **78** tons/year

5. Method of Compliance (limit to 60 characters):

Method 5 or 17, 40 CFR Appendix A

6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):

0.018 lb/MMBtu
Annual emissions for 3 boilers limited when co-firing petroleum coke with coal to not trigger PSD review. See Part II.

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: PM_{10}	2. Total Percent Efficiency of Control: 99.97%
3. Potential Emissions: 19.1 lb/hour 78 tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: 0.018 lb/MMBtu Reference: PSD-FL-137A	7. Emissions Method Code: 5
8. Calculation of Emissions (limit to 600 characters): 1,063 MMBtu/hr x 0.018 lb/MMBtu = 19.1 lb/hr 19.1 lb/hr x 8,760 hr/yr x ton/2,000 lbs x 0.93 (capacity factor) = 78 TPY	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): Limited by modification to PSD-FL-137. Annual emissions limited for 3 boilers when co-firing coke with coal to not trigger PSD review. See Part II.	

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: See Part II	4. Equivalent Allowable Emissions: 19.1 lb/hour 78 tons/year
5. Method of Compliance (limit to 60 characters): Method 5 or 17, 40 CFR Appendix A	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): 0.018 lb/MMBtu Annual emissions for 3 boilers limited when co-firing petroleum coke with coal to not trigger PSD review. See Part II.	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **SAM**	2. Total Percent Efficiency of Control:	
3. Potential Emissions: **0.50** lb/hour **2.0** tons/year		4. Synthetically Limited? [**X**]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year		
6. Emission Factor: **4.66×10^{-4} lb/MMBtu** Reference: **PSD-FL-137A**		7. Emissions Method Code: **5**
8. Calculation of Emissions (limit to 600 characters): **1,063 MMBtu/hr x 0.000466 lb/MMBtu = 0.5 lb/hr**		
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Limited by modification to PSD-FL-137. Annual emissions limited for 3 boilers when co-firing coke with coal to not trigger PSD review. See Part II.**		

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **See Part II**	4. Equivalent Allowable Emissions: **0.50** lb/hour **2.0** tons/year
5. Method of Compliance (limit to 60 characters): **Method 8**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **4.66×10^{-4} lb/MMBtu** **Annual emissions for 3 boilers limited when co-firing petroleum coke with coal to not trigger PSD review. See Part II.**	

H. VISIBLE EMISSIONS INFORMATION
(Only Regulated Emissions Units Subject to a VE Limitation)

Visible Emissions Limitation: Visible Emissions Limitation 1 of 1

1. Visible Emissions Subtype: **VE, VES**	2. Basis for Allowable Opacity: [ ] Rule [X] Other
3. Requested Allowable Opacity: Normal Conditions: **20** % Exceptional Conditions: **27** % Maximum Period of Excess Opacity Allowed: **6** min/hour	
4. Method of Compliance: **COM, Method 9**	
5. Visible Emissions Comment (limit to 200 characters): **27% opacity for oil-burning during startup PSD-FL-137A**	

I. CONTINUOUS MONITOR INFORMATION
(Only Regulated Emissions Units Subject to Continuous Monitoring)

Continuous Monitoring System: Continuous Monitor 1 of 1

1. Parameter Code: **See comment**	2. Pollutant(s):
3. CMS Requirement:	[X] Rule [ ] Other
4. Monitor Information: Manufacturer: **various** Model Number:	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment (limit to 200 characters): **Baghouse flue has CEMs for NO_x, SO_2, CO, CO_2, and VE. Manufacturers, models, and serial numbers previously submitted.**	

J. EMISSIONS UNIT SUPPLEMENTAL INFORMATION
(Regulated Emissions Units Only)

Supplemental Requirements

1. Process Flow Diagram [ ] Attached, Document ID: ________ [X] Not Applicable [ ] Waiver Requested
2. Fuel Analysis or Specification [X] Attached, Document ID: Part II [ ] Not Applicable [ ] Waiver Requested
3. Detailed Description of Control Equipment [ ] Attached, Document ID: ________ [X] Not Applicable [ ] Waiver Requested
4. Description of Stack Sampling Facilities [ ] Attached, Document ID: ________ [X] Not Applicable [ ] Waiver Requested
5. Compliance Test Report [ ] Attached, Document ID: ________ [ ] Previously submitted, Date: ________ [X] Not Applicable
6. Procedures for Startup and Shutdown [ ] Attached, Document ID: ________ [X] Not Applicable [ ] Waiver Requested
7. Operation and Maintenance Plan [ ] Attached, Document ID: ________ [X] Not Applicable [ ] Waiver Requested
8. Supplemental Information for Construction Permit Application [ ] Attached, Document ID: ________ [X] Not Applicable
9. Other Information Required by Rule or Statute [X] Attached, Document ID: See Part II [ ] Not Applicable
10. Supplemental Requirements Comment:

Additional Supplemental Requirements for Title V Air Operation Permit Applications

11. Alternative Methods of Operation [ ] Attached, Document ID: ________ [X] Not Applicable
12. Alternative Modes of Operation (Emissions Trading) [ ] Attached, Document ID: ________ [X] Not Applicable
13. Identification of Additional Applicable Requirements [ ] Attached, Document ID: ________ [X] Not Applicable
14. Compliance Assurance Monitoring Plan [ ] Attached, Document ID: ________ [X] Not Applicable
15. Acid Rain Part Application (Hard-copy Required) [ ] Acid Rain Part - Phase II (Form No. 62-210.900(1)(a)) Attached, Document ID: ________ [ ] Repowering Extension Plan (Form No. 62-210.900(1)(a)1.) Attached, Document ID: ________ [ ] New Unit Exemption (Form No. 62-210.900(1)(a)2.) Attached, Document ID: ________ [ ] Retired Unit Exemption (Form No. 62-210.900(1)(a)3.) Attached, Document ID: ________ [ ] Phase II NOx Compliance Plan (Form No. 62-210.900(1)(a)4.) Attached, Document ID: ________ [ ] Phase NOx Averaging Plan (Form No. 62-210.900(1)(a)5.) Attached, Document ID: ________ [X] Not Applicable

III. EMISSIONS UNIT INFORMATION

A separate Emissions Unit Information Section (including subsections A through J as required) must be completed for each emissions unit addressed in this Application for Air Permit. If submitting the application form in hard copy, indicate, in the space provided at the top of each page, the number of this Emissions Unit Information Section and the total number of Emissions Unit Information Sections submitted as part of this application.

A. GENERAL EMISSIONS UNIT INFORMATION
(All Emissions Units)

Emissions Unit Description and Status

1. Type of Emissions Unit Addressed in This Section: (Check one)

[X] This Emissions Unit Information Section addresses, as a single emissions unit, a single process or production unit, or activity, which produces one or more air pollutants and which has at least one definable emission point (stack or vent).

[ ] This Emissions Unit Information Section addresses, as a single emissions unit, a group of process or production units and activities which has at least one definable emission point (stack or vent) but may also produce fugitive emissions.

[ ] This Emissions Unit Information Section addresses, as a single emissions unit, one or more process or production units and activities which produce fugitive emissions only.

2. Regulated or Unregulated Emissions Unit? (Check one)

[X] The emissions unit addressed in this Emissions Unit Information Section is a regulated emissions unit.

[ ] The emissions unit addressed in this Emissions Unit Information Section is an unregulated emissions unit.

3. Description of Emissions Unit Addressed in This Section (limit to 60 characters):
Boiler C

4. Emissions Unit Identification Number: [ ] No ID
ID: **003** [ ] ID Unknown

5. Emissions Unit Status Code:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code:	8. Acid Rain Unit?
A	**25-JAN-1994**	**49**	[ ]

9. Emissions Unit Comment: (Limit to 500 Characters)

Circulating Fluidized Bed (CFB) Boiler C with limestone injection for SO_2 emissions reduction. Ammonia injection for NO_x emissions reduction. Fuel is primarily bituminous coal with No. 2 fuel oil for startup. Combustion products are flue gas with fly ash and bed ash.

Emissions Unit Control Equipment

1. Control Equipment/Method Description (Limit to 200 characters per device or method):

Baghouse
Efficiency = (1-emission)/load = 0.0055 gr/acr / 19.5 gr/acr = 99.97%

Ammonia injection
Efficiency = 54% for NO_x (estimated)

Dry limestone injection
Efficiency from 89 to 95% based on Quarterly Reports

Air preheater
Reduction Efficiency not determined.
Intake air is preheated via flue gas to reduce fuel requirements.

Control of Oxygen
Reduction Efficiency not determined.
Flue gas recirculates with intake air.

2. Control Device or Method Code(s): **016, 032/107, 041, 027, 033**

Emissions Unit Details

1. Package Unit: **NA** Manufacturer: **Foster Wheeler**	Model Number: **Pyroflow®**
2. Generator Nameplate Rating:	MW
3. Incinerator Information: Dwell Temperature: Dwell Time: Incinerator Afterburner Temperature:	 °F seconds °F

B. EMISSIONS UNIT CAPACITY INFORMATION
(Regulated Emissions Units Only)

Emissions Unit Operating Capacity and Schedule

1. Maximum Heat Input Rate:		1,063	mmBtu/hr
2. Maximum Incineration Rate:	lb/hr		tons/day
3. Maximum Process or Throughput Rate:	104,000 lb/hr coal; 39,000 ton/month coal; 390,000 TPY coal		
4. Maximum Production Rate:	800,000 lb/hr steam		
5. Requested Maximum Operating Schedule:			
	24 hours/day	7	days/week
	52 weeks/year	8,760	hours/year
6. Operating Capacity/Schedule Comment (limit to 200 characters): Limits set by PSD-FL-137A. CFB Boilers A, B, and C feed a common steam turbine with a nominal rating of 250 MW and supply steam to an adjacent recycled liner board mill.			

C. EMISSIONS UNIT REGULATIONS
(Regulated Emissions Units Only)

List of Applicable Regulations

40 CFR 60.40a	Applicability >250 MMBtu/hr
40 CFR 60.41a	Definitions
40 CFR 60.42a	Standard for particulate matter
40 CFR 60.43a(a)	Standard for sulfur dioxide
40 CFR 60.43a(g)	Compliance with the emission limitation and percent reduction requirements
40 CFR 60.44a	Standard for nitrogen oxides
40 CFR 60.46a	Compliance provisions
40 CFR 60.47a	Emission monitoring
40 CFR 60.48a	Compliance determination procedures and methods
40 CFR 60.49a	Reporting requirements
FAC 62-204.800	Standards of performance for New Stationary Sources
FAC 62-210.550	Stack Height Policy
FAC 62-210.700	Excess Emissions
FAC 62-212-300	General preconstruction review
FAC 62-212-400	Prevention of Significant Deterioration
FAC 62-296.405	Fossil Fuel Steam Generators with more than 240 MMBtu/hr heat input
FAC 62-296.570(4)(a)	Reasonable Available Control Technology - Requirements for major VOC and NO_x emission Facilities
FAC 62-296.702	Fossil Fuel Steam Generators
FAC 62-296.711	Material Handling, Sizing, Screening, Crushing, and Grinding Operations
FAC 62-297.401(5)	EPA Method 5
FAC 62-297.401(6)	EPA Method 6
FAC 62-297.401(7)	EPA Method 7
FAC 62-297.401(8)	EPA Method 8
FAC 62-297.401(9)	EPA Method 9
FAC 62-297.401(10)	EPA Method 10
FAC 62-297.401(12)	EPA Method 12
FAC 62-297.401(13)	EPA Method 13
FAC 62-297.401(15)	EPA Method 15
FAC 62-297.401(17)	EPA Method 17
FAC 62-297.401(19)	EPA Method 19
FAC 62-297.401(25)	EPA Method 25
FAC 62-297.401(32)(a)	EPA Method 101A
FAC 62-297.401(35)	EPA Method 104
FAC 62-297.401(41)	EPA Method 201
FAC 62-297.520	EPA Performance Specifications
FAC 62-297.570	Test Reports
FAC 62-297.620	Exceptions and Approval of Alternate Procedures and Requirements

D. EMISSION POINT (STACK/VENT) INFORMATION
(Regulated Emissions Units Only)

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram? **B1**	2. Emission Point Type Code: **2**

3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking (limit to 100 characters per point):

Boiler Stack (B1)

4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:
001 = Boiler A; 002 = Boiler B; 003 = Boiler C

5. Discharge Type Code: **V**	6. Stack Height: **403** feet	7. Exit Diameter: **13.26** feet
8. Exit Temperature: **265** °F	9. Actual Volumetric Flow Rate: **1,004,000** acfm	10. Water Vapor: **5** %

11. Maximum Dry Standard Flow Rate: **895,403** dscfm	12. Nonstack Emission Point Height: feet

13. Emission Point UTM Coordinates:

Zone: **17** East (km): **441.871** North (km): **3365.587**

14. Emission Point Comment (limit to 200 characters):

The 3 CFB boilers share a common stack designated as point B1. Flue gas from the boilers is discharged through this stack. Prior to the stack, each flue gas stream is passed through a baghouse which removes fly ash.

Stack information based on Title V Application.

E. SEGMENT (PROCESS/FUEL) INFORMATION
(All Emissions Units)

Segment Description and Rate: Segment 1 of 2

1. Segment Description (Process/Fuel Type) (limit to 500 characters): a) **Segment 1 of 2: Bituminous coal used in boiler (when co-firing with petroleum coke).** b) **Segment 2 of 2.**		
2. Source Classification Code (SCC): **1-01-002-17**	3. SCC Units: **Tons burned**	
4. Maximum Hourly Rate: **29.9**	5. Maximum Annual Rate: **258,575**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **1.7% per load,** **1.2% annual**	8. Maximum % Ash: **10 (typical)**	9. Million Btu per SCC Unit: **20.4**
10. Segment Comment (limit to 200 characters): **Based on 65% coal (by weight). See Part II, Appendix B.**		

Segment Description and Rate: Segment 2 of 2

1. Segment Description (Process/Fuel Type) (limit to 500 characters): a) **Segment 1 of 2.** b) **Segment 2 of 2: Petroleum coke used in boiler when co-firing with coal.**		
2. Source Classification Code (SCC): **1-01-008-01**	3. SCC Units: **tons burned**	
4. Maximum Hourly Rate: **16.1**	5. Maximum Annual Rate: **139,233**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **6**	8. Maximum % Ash: **0.5 (typical)**	9. Million Btu per SCC Unit: **28**
10. Segment Comment (limit to 200 characters): **Based on 35% petroleum coke (by weight). See Part II, Appendix B.**		

F. EMISSIONS UNIT POLLUTANTS
(All Emissions Units)

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
PM	016	027	EL
PM_{10}	016	027	EL
NO_X	032/107	027	EL
SO_2	041	027	EL
CO	033	027	EL
VOC	027		EL
SAM	041	027	EL

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: SO_2	2. Total Percent Efficiency of Control:
3. Potential Emissions: 318.9 lb/hour 866 tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: 0.30 lb/MMBtu* 0.20 lb/MMBtu** Reference: Permit PA-88-24A, PSD-FL-137B	7. Emissions Method Code: 5
8. Calculation of Emissions (limit to 600 characters): 1,063 MMBtu/hr x 0.3 lb/MMBtu = 318.9 lb/hr 1,063 MMBtu/hr x 0.2 lb/MMBtu x 8,760 hr/yr x ton/2,000 lb x 0.93 (capacity factor) = 866 TPY	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): Limited by modification to PSD-FL-137. * 3-hour rolling average; ** 30-day rolling average. Annual emissions limited for 3 boilers when co-firing coke with coal to not trigger PSD review. See Part II.	

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: see comment	4. Equivalent Allowable Emissions: 318.9 lb/hour 866 tons/year
5. Method of Compliance (limit to 60 characters): Continuous Emissions Monitoring	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): 3-hour rolling average for SO_2 = 0.30 lb/MMBtu 30-day rolling average for SO_2 = 0.20 lb/MMBtu Annual emissions for 3 boilers limited when co-firing petroleum coke with coal to not trigger PSD review. See Part II.	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **NO_x**	2. Total Percent Efficiency of Control: **54% (estimated)**
3. Potential Emissions: **180.7** lb/hour **736.1** tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **0.17 lb/MMBtu*** Reference: **PSD-FL-137A**	7. Emissions Method Code: **5**
8. Calculation of Emissions (limit to 600 characters): **1,063 MMBtu/hr x 0.17 lb/MMBtu = 180.7 lb/hr** **180.7 lb/hr x 8,760 hr/yr x ton/2,000 lb x 0.93 (capacity factor) = 736.1 TPY**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Limited by modification to PSD-FL-137. * 30-day rolling average. Annual emissions limited for 3 boilers when co-firing coke with coal to not trigger PSD review. See Part II.**	

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **See Part II**	4. Equivalent Allowable Emissions: **180.7** lb/hour **736.1** tons/year
5. Method of Compliance (limit to 60 characters): **Continuous Emissions Monitoring and Method 7, 7A, B, C, D, or E**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **30-day rolling average for NO_x = 0.17 lb/MMBtu** **Annual emissions for 3 boilers limited when co-firing petroleum coke with coal to not trigger PSD review. See Part II.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **VOC**
2. Total Percent Efficiency of Control:
3. Potential Emissions: **16.0** lb/hour **57.6** tons/year
4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year
6. Emission Factor: **0.015**
   Reference: **PSD-FL-137A**
7. Emissions Method Code: **5**
8. Calculation of Emissions (limit to 600 characters):

   1,063 MMBtu/hr x 0.015 lb/MMBtu = 16 lb/hr
   Annual potential emissions based on maximum emissions for 3 boilers so that PSD is not triggered. See Part II.
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):

   See Part II

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **OTHER**
2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **See Part II**
4. Equivalent Allowable Emissions: **16.0** lb/hour **57.6** tons/year
5. Method of Compliance (limit to 60 characters):

   Method 18 or 25
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):

   See Part II
   0.015 lb/MMBtu VOC

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **PM (TSP)**	2. Total Percent Efficiency of Control: **99.97%**
3. Potential Emissions: **19.1** lb/hour **78** tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **0.018 lb/MMBtu** Reference: **PSD-FL-137A**	7. Emissions Method Code: **5**
8. Calculation of Emissions (limit to 600 characters): **1,063 MMBtu/hr x 0.018 lb/MMBtu = 19.1 lb/hr** **19.1 lb/hr x 8,760 hr/yr x ton/2,000 lbs x 0.93 (capacity factor) = 78 TPY**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Limited by modification to PSD-FL-137. Annual emissions limited for 3 boilers when co-firing coke with coal to not trigger PSD review. See Part II.**	

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **See Part II**	4. Equivalent Allowable Emissions: **19.1** lb/hour **78** tons/year
5. Method of Compliance (limit to 60 characters): **Method 5 or 17, 40 CFR Appendix A**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **0.018 lb/MMBtu** **Annual emissions for 3 boilers limited when co-firing petroleum coke with coal to not trigger PSD review. See Part II.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **PM_{10}**	2. Total Percent Efficiency of Control: **99.97%**
3. Potential Emissions: **19.1** lb/hour **78** tons/year	4. Synthetically Limited? [**X**]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **0.018 lb/MMBtu** Reference: **PSD-FL-137A**	7. Emissions Method Code: **5**

8. Calculation of Emissions (limit to 600 characters):

1,063 MMBtu/hr x 0.018 lb/MMBtu = 19.1 lb/hr
19.1 lb/hr x 8,760 hr/yr x ton/2,000 lbs x 0.93 (capacity factor) = 78 TPY

9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):

Limited by modification to PSD-FL-137. Annual emissions limited for 3 boilers when co-firing coke with coal to not trigger PSD review. See Part II.

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **See Part II**	4. Equivalent Allowable Emissions: **19.1** lb/hour **78** tons/year

5. Method of Compliance (limit to 60 characters):

Method 5 or 17, 40 CFR Appendix A

6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):

0.018 lb/MMBtu
Annual emissions for 3 boilers limited when co-firing petroleum coke with coal to not trigger PSD review. See Part II.

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **SAM**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **0.50** lb/hour **2.0** tons/year	4. Synthetically Limited? [**X**]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **4.66 x 10^{-4} lb/MMBtu** Reference: **PSD-FL-137A**	7. Emissions Method Code: **5**
8. Calculation of Emissions (limit to 600 characters): **1,063 MMBtu/hr x 0.000466 lb/MMBtu = 0.5 lb/hr**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Limited by modification to PSD-FL-137. Annual emissions limited for 3 boilers when co-firing coke with coal to not trigger PSD review. See Part II.**	

Allowable Emissions Allowable Emissions **1** of **1**

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **See Part II**	4. Equivalent Allowable Emissions: **0.50** lb/hour **2.0** tons/year
5. Method of Compliance (limit to 60 characters): **Method 8**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **4.66 x 10^{-4} lb/MMBtu** **Annual emissions for 3 boilers limited when co-firing petroleum coke with coal to not trigger PSD review. See Part II.**	

H. VISIBLE EMISSIONS INFORMATION
(Only Regulated Emissions Units Subject to a VE Limitation)

Visible Emissions Limitation: Visible Emissions Limitation 1 of 1

1. Visible Emissions Subtype: **VE, VES**	2. Basis for Allowable Opacity: [ ] Rule [X] Other
3. Requested Allowable Opacity: Normal Conditions: **20** % Exceptional Conditions: **27** % Maximum Period of Excess Opacity Allowed: **6** min/hour	
4. Method of Compliance: **COM, Method 9**	
5. Visible Emissions Comment (limit to 200 characters): **27% opacity for oil-burning during startup PSD-FL-137A**	

I. CONTINUOUS MONITOR INFORMATION
(Only Regulated Emissions Units Subject to Continuous Monitoring)

Continuous Monitoring System: Continuous Monitor 1 of 1

1. Parameter Code: **See comment**	2. Pollutant(s):
3. CMS Requirement:	[X] Rule [ ] Other
4. Monitor Information: Manufacturer: **various** Model Number:	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment (limit to 200 characters): **Baghouse flue has CEMs for NO_x, SO_2, CO, CO_2, and VE. Manufacturers, models, and serial numbers previously submitted.**	

J. EMISSIONS UNIT SUPPLEMENTAL INFORMATION
(Regulated Emissions Units Only)

Supplemental Requirements

1. Process Flow Diagram [ ] Attached, Document ID: ________ [X] Not Applicable [ ] Waiver Requested
2. Fuel Analysis or Specification [X] Attached, Document ID: Part II [ ] Not Applicable [ ] Waiver Requested
3. Detailed Description of Control Equipment [ ] Attached, Document ID: ________ [X] Not Applicable [ ] Waiver Requested
4. Description of Stack Sampling Facilities [ ] Attached, Document ID: ________ [X] Not Applicable [ ] Waiver Requested
5. Compliance Test Report [ ] Attached, Document ID: ________ [ ] Previously submitted, Date: ________ [X] Not Applicable
6. Procedures for Startup and Shutdown [ ] Attached, Document ID: ________ [X] Not Applicable [ ] Waiver Requested
7. Operation and Maintenance Plan [ ] Attached, Document ID: ________ [X] Not Applicable [ ] Waiver Requested
8. Supplemental Information for Construction Permit Application [ ] Attached, Document ID: ________ [X] Not Applicable
9. Other Information Required by Rule or Statute [X] Attached, Document ID: See Part II [ ] Not Applicable
10. Supplemental Requirements Comment:

Additional Supplemental Requirements for Title V Air Operation Permit Applications

11. Alternative Methods of Operation [ ] Attached, Document ID:________ [X] Not Applicable
12. Alternative Modes of Operation (Emissions Trading) [ ] Attached, Document ID:________ [X] Not Applicable
13. Identification of Additional Applicable Requirements [ ] Attached, Document ID:________ [X] Not Applicable
14. Compliance Assurance Monitoring Plan [ ] Attached, Document ID:________ [X] Not Applicable
15. Acid Rain Part Application (Hard-copy Required) [ ] Acid Rain Part - Phase II (Form No. 62-210.900(1)(a)) Attached, Document ID:________ [ ] Repowering Extension Plan (Form No. 62-210.900(1)(a)1.) Attached, Document ID:________ [ ] New Unit Exemption (Form No. 62-210.900(1)(a)2.) Attached, Document ID:________ [ ] Retired Unit Exemption (Form No. 62-210.900(1)(a)3.) Attached, Document ID:________ [ ] Phase II NOx Compliance Plan (Form No. 62-210.900(1)(a)4.) Attached, Document ID:________ [ ] Phase NOx Averaging Plan (Form No. 62-210.900(1)(a)5.) Attached, Document ID:________ [X] Not Applicable

III. EMISSIONS UNIT INFORMATION

A separate Emissions Unit Information Section (including subsections A through J as required) must be completed for each emissions unit addressed in this Application for Air Permit. If submitting the application form in hard copy, indicate, in the space provided at the top of each page, the number of this Emissions Unit Information Section and the total number of Emissions Unit Information Sections submitted as part of this application.

A. GENERAL EMISSIONS UNIT INFORMATION
(All Emissions Units)

Emissions Unit Description and Status

1. Type of Emissions Unit Addressed in This Section: (Check one)

[ ] This Emissions Unit Information Section addresses, as a single emissions unit, a single process or production unit, or activity, which produces one or more air pollutants and which has at least one definable emission point (stack or vent).

[ ] This Emissions Unit Information Section addresses, as a single emissions unit, a group of process or production units and activities which has at least one definable emission point (stack or vent) but may also produce fugitive emissions.

[X] This Emissions Unit Information Section addresses, as a single emissions unit, one or more process or production units and activities which produce fugitive emissions only.

2. Regulated or Unregulated Emissions Unit? (Check one)

[X] The emissions unit addressed in this Emissions Unit Information Section is a regulated emissions unit.

[ ] The emissions unit addressed in this Emissions Unit Information Section is an unregulated emissions unit.

3. Description of Emissions Unit Addressed in This Section (limit to 60 characters):
Truck unloading and conveyors associated with petroleum coke unloading.

4. Emissions Unit Identification Number: [ ] No ID
ID: **034** [ ] ID Unknown

5. Emissions Unit Status Code:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code:	8. Acid Rain Unit?
C		**49**	[ ]

9. Emissions Unit Comment: (Limit to 500 Characters)

Emission unit consists of truck dump, transfer stock-out conveyor (truck or rail), dozer trap (truck or rail), and blending conveyor (truck or rail).

Emissions Unit Control Equipment

1. Control Equipment/Method Description (Limit to 200 characters per device or method): **Water spraying as needed to reduce fugitive dust emissions.**	
2. Control Device or Method Code(s): **061**	

Emissions Unit Details

1. Package Unit: **NA** Manufacturer:	Model Number:	
2. Generator Nameplate Rating:	MW	
3. Incinerator Information: Dwell Temperature: Dwell Time: Incinerator Afterburner Temperature:		°F seconds °F

B. EMISSIONS UNIT CAPACITY INFORMATION
(Regulated Emissions Units Only)

Emissions Unit Operating Capacity and Schedule

1. Maximum Heat Input Rate:			mmBtu/hr
2. Maximum Incineration Rate:	lb/hr		tons/day
3. Maximum Process or Throughput Rate:		**48.3 tons/hr**	
4. Maximum Production Rate:			
5. Requested Maximum Operating Schedule:			
24	hours/day	**7**	days/week
52	weeks/year	**8,760**	hours/year
6. Operating Capacity/Schedule Comment (limit to 200 characters):			
Maximum throughput rate based on 35 percent by weight of petroleum coke for CFB boilers. See Part II.			

C. EMISSIONS UNIT REGULATIONS
(Regulated Emissions Units Only)

List of Applicable Regulations

Rule 62-296.320(4)(c)1.
Rule 62-296.320(4)(c)3.
Rule 62-296.320(4)(c)4.

D. EMISSION POINT (STACK/VENT) INFORMATION
(Regulated Emissions Units Only)

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram? **See Part II**	2. Emission Point Type Code: **4**
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking (limit to 100 characters per point): **Fugitive emissions from truck unloading and associated conveyor.**	
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:	

5. Discharge Type Code: **F**	6. Stack Height: feet	7. Exit Diameter: feet
8. Exit Temperature: °F	9. Actual Volumetric Flow Rate: acfm	10. Water Vapor: %

11. Maximum Dry Standard Flow Rate: dscfm	12. Nonstack Emission Point Height: feet
13. Emission Point UTM Coordinates: Zone: East (km): North (km):	
14. Emission Point Comment (limit to 200 characters): **Points of emission include truck dump, stock-out conveyor, dozer trap, and blending conveyor. See Part II.**	

E. SEGMENT (PROCESS/FUEL) INFORMATION
(All Emissions Units)

Segment Description and Rate: Segment 1 of 1

1. Segment Description (Process/Fuel Type) (limit to 500 characters): **Petroleum Coke, Mineral Products -- Bulk materials unloading operation**		
2. Source Classification Code (SCC): **3-05-104-04**	3. SCC Units: **Tons processed**	
4. Maximum Hourly Rate: **43.9**	5. Maximum Annual Rate: **384,939**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **6**	8. Maximum % Ash: **0.5**	9. Million Btu per SCC Unit:
10. Segment Comment (limit to 200 characters): **Petroleum coke for 3 CFB Boilers. See Part II.**		

Segment Description and Rate: Segment ____ of ____

1. Segment Description (Process/Fuel Type) (limit to 500 characters):		
2. Source Classification Code (SCC):	3. SCC Units:	
4. Maximum Hourly Rate:	5. Maximum Annual Rate:	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit:
10. Segment Comment (limit to 200 characters):		

F. EMISSIONS UNIT POLLUTANTS
(All Emissions Units)

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
PM	061		WP
PM_{10}	061		WP

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **PM (TSP)**	2. Total Percent Efficiency of Control: **70**
3. Potential Emissions: **0.034** lb/hour **0.124** tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **See Part II** Reference:	7. Emissions Method Code: **3**
8. Calculation of Emissions (limit to 600 characters): **See Part II.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):	

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **Work Practice**	4. Equivalent Allowable Emissions: **0.034** lb/hour **0.124** tons/year
5. Method of Compliance (limit to 60 characters): **Water spraying as needed.**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **PM_{10}**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **0.016** lb/hour **0.059** tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **See Part II** Reference:	7. Emissions Method Code: **3**
8. Calculation of Emissions (limit to 600 characters): **See Part II**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):	

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **Work Practice**	4. Equivalent Allowable Emissions: **0.016** lb/hour **0.059** tons/year
5. Method of Compliance (limit to 60 characters): **Water spraying as needed.**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):	

H. VISIBLE EMISSIONS INFORMATION
(Only Regulated Emissions Units Subject to a VE Limitation)

Visible Emissions Limitation: Visible Emissions Limitation **1** of **1**

1. Visible Emissions Subtype:	2. Basis for Allowable Opacity: [X] Rule [ ] Other
3. Requested Allowable Opacity: Normal Conditions: **20** % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance:	
5. Visible Emissions Comment (limit to 200 characters): **Rule 62-296.320(4)(b)1. F.A.C.**	

I. CONTINUOUS MONITOR INFORMATION
(Only Regulated Emissions Units Subject to Continuous Monitoring)

Continuous Monitoring System: Continuous Monitor ______ of______

1. Parameter Code:	2. Pollutant(s):
3. CMS Requirement: [ ] Rule [ ] Other	
4. Monitor Information: Manufacturer: Model Number: Serial Number:	
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment (limit to 200 characters):	

J. EMISSIONS UNIT SUPPLEMENTAL INFORMATION
(Regulated Emissions Units Only)

Supplemental Requirements

1. Process Flow Diagram [X] Attached, Document ID: See Part II [ ] Not Applicable [ ] Waiver Requested
2. Fuel Analysis or Specification [ ] Attached, Document ID: ________ [X] Not Applicable [ ] Waiver Requested
3. Detailed Description of Control Equipment [ ] Attached, Document ID: ________ [X] Not Applicable [ ] Waiver Requested
4. Description of Stack Sampling Facilities [ ] Attached, Document ID: ________ [X] Not Applicable [ ] Waiver Requested
5. Compliance Test Report [ ] Attached, Document ID: ________ [ ] Previously submitted, Date: ________ [X] Not Applicable
6. Procedures for Startup and Shutdown [ ] Attached, Document ID: ________ [X] Not Applicable [ ] Waiver Requested
7. Operation and Maintenance Plan [ ] Attached, Document ID: ________ [X] Not Applicable [ ] Waiver Requested
8. Supplemental Information for Construction Permit Application [X] Attached, Document ID: See Part II [ ] Not Applicable
9. Other Information Required by Rule or Statute [X] Attached, Document ID: See Part II [ ] Not Applicable
10. Supplemental Requirements Comment:

Additional Supplemental Requirements for Title V Air Operation Permit Applications

11. Alternative Methods of Operation
[ ] Attached, Document ID:________ [X] Not Applicable

12. Alternative Modes of Operation (Emissions Trading)
[ ] Attached, Document ID:________ [X] Not Applicable

13. Identification of Additional Applicable Requirements
[ ] Attached, Document ID:________ [X] Not Applicable

14. Compliance Assurance Monitoring Plan
[ ] Attached, Document ID:________ [X] Not Applicable

15. Acid Rain Part Application (Hard-copy Required)

[ ] Acid Rain Part - Phase II (Form No. 62-210.900(1)(a))
Attached, Document ID:________

[ ] Repowering Extension Plan (Form No. 62-210.900(1)(a)1.)
Attached, Document ID:________

[ ] New Unit Exemption (Form No. 62-210.900(1)(a)2.)
Attached, Document ID:________

[ ] Retired Unit Exemption (Form No. 62-210.900(1)(a)3.)
Attached, Document ID:________

[ ] Phase II NOx Compliance Plan (Form No. 62-210.900(1)(a)4.)
Attached, Document ID:________

[ ] Phase NOx Averaging Plan (Form No. 62-210.900(1)(a)5.)
Attached, Document ID:________

[X] Not Applicable

PART II

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 35 percent (by weight) of petroleum coke with coal at the Cedar Bay Cogeneration Facility (Facility). Specifically, Cedar Bay requests FDEP to change the Prevention of Significant Deterioration (PSD) permit for the Facility (PSD-FL-137) and Title V permit 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 petroleum coke, there will not be any significant net emissions increase at the Facility, and thus the requirements of the PSD review process are not triggered.

There are four power plants in Florida that currently are authorized to co-fire petroleum coke with coal. These units include St. John River Power Park Units 1 and 2, Seminole Electric Cooperative's Seminole Units 1 and 2, City of Lakeland's McIntosh Unit 3, and Tampa Electric Company's Big Bend Units 3 and 4. All of these units are pulverized coal units with wet flue gas desulfurization and electrostatic precipitators. At these facilities, the authorizations for co-firing up to 25-percent petroleum coke with coal involved no PSD review. When co-firing petroleum coke with coal, no significant increase in annual emissions of particulate matter (PM), sulfur dioxide (SO_2), nitrogen oxides (NO_x), and sulfuric acid mist was made a permit condition of these authorizations. Petroleum coke has been successfully co-fired in many of these units for about 5 years.

More recently, FDEP authorized Jacksonville Electric Authority to repower Northside Units 1 and 2 using coal and petroleum coke. Up to 100 percent of petroleum coke was authorized by FDEP (PSD-FL-265). These units are circulating fluidized bed (CFB) boilers.

The existing Cedar Bay Cogeneration Facility is located at 9640 Eastport Road, Jacksonville, Duval County, Florida (Figure 1). The cogeneration facility consists of three 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 NO_x are controlled using selective non-catalytic reduction (SNCR). The reaction products of the limestone and SO_2, as well as 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 35 percent (by weight) of petroleum coke with coal. The air permit application consists of the appropriate applications form [DEP 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 FEASIBILITY OF CO-FIRING PETROLEUM COKE

A feasibility study was conducted by Foster Wheeler Energy Services, Inc. (Foster Wheeler) for co-firing petroleum coke with coal in the three Cedar Bay CFB boilers. The full report is attached as Appendix A. The report concludes that co-firing up to 20-percent petroleum coke (by weight) with coal at maximum continuous rating (MCR) is technically feasible without any changes to the boiler systems. For up to 35-percent petroleum coke (by weight) with coal, changes to the limestone feed system are needed. The report concludes that air pollution control systems are capable of maintaining the emissions at the current levels. Based on the results of this feasibility report, authorization of up to 35-percent petroleum coke with coal is being requested in this application with the changes noted in the report.

The PSD permit and the Title V permit (Final Permit No. 0310377-002-AV) for the Facility have specific conditions that limit the amount of coal, limestone, bottom ash, and flyash handled at the Facility. Table 1 presents a comparison of the information in the Foster Wheeler report for co-firing 35-percent petroleum coke with coal. As shown on the table, the projected amounts at MCR will be less, and in some cases much less, than the amount currently authorized for coal.

2.2 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 1997 through 2000 are summarized in Table 2. The reported emissions are for carbon monoxide (CO), NO_x, SO_2, PM (identified as PM_{10} in the table), volatile organic compounds (VOC), and sulfuric acid mist. 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 production and emissions have been relatively constant over the last 4 years. Capacity factors for the three units have been at or near 90 percent.

2.3 PETROLEUM COKE HANDLING

The Facility currently receives coal by rail and limestone by truck. When co-firing petroleum coke with coal, facilities will be added to the existing coal yard to receive coke by rail or truck, store coke on a separate portion of the existing coal storage area, and blend coke with coal. Petroleum coke received by rail will utilize the same unloading methods as currently used for coal. When transferred to the coal storage pile, the petroleum coke will be separated from coal using a conveyor. A new dozer trap and blending conveyor will be used for both rail and truck delivery. For delivery by truck, a new truck dump will be added to the north end of the existing coal yard. From the truck dump, a new conveyor will convey the petroleum coke to a storage pile, which will be located in a portion of the existing coal storage area. The dozer trap will be added to receive petroleum coke from the storage pile for blending. A blending conveyor, with a weight scale, will transfer the petroleum coke to the crusher house. Figure 2 presents a site plan showing the location of the new facilities, and Figure 3 presents a simplified process flow diagram for truck unloading.

Potential increases in fugitive emissions may occur as a result of the material handling operations associated with the additional limestone usage. However, the fugitive emissions from storing petroleum coke will not likely be higher than the fugitive emissions from the current operation with coal. Coal is stored in the same area and transported to the crusher house using bulldozers and conveyors. Indeed, the fugitive emissions associated with using petroleum coke will be lower because petroleum coke has a higher heating value and less is needed for the same amount of heat input to the CFB boilers.

The estimated potential increases in fugitive emissions are 0.124 ton per year (TPY) for PM and 0.059 TPY for PM_{10} based on receiving petroleum coke by truck. This method of delivery would produce worst-case emissions since the truck dump will not be covered like the existing rail receiving facility. Water spraying was assumed as the method reasonably available to control fugitive emissions. The calculations of fugitive emissions are presented in Appendix B. As noted in the appendix, the methods used were the same as used in the original PSD permit application and Title V permit application.

No additional fugitive PM emissions will result for other operations. Control devices (i.e., baghouses or bag filters) control fugitive PM in the crusher house, storage silos, and ash handling operations.

3.0 RULE APPLICABILITY

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 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 petroleum coke is an operational change, and physical changes will be made to receive and handle petroleum coke. In addition, physical changes may be made to the boiler systems (i.e., limestone feed system). Therefore, the project is a modification as defined in the Department Rules in 62-210.200 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 co-firing of petroleum coke with coal, there will be no significant net increase in actual emissions.

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 of the co-firing permits authorized by the Department. Cedar Bay Cogeneration Company, L.P. 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 to authorize co-firing up to 35-percent (by weight) of petroleum coke with coal. 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, PM_{10}, VOC, and sulfuric acid mist when co-firing the maximum mixture of petroleum coke with coal. This mixture would not exceed 35-percent (by weight) petroleum coke with coal. This maximum amount of petroleum coke co-fired with coal will be maintained at the level demonstrating that there is no significant net increase in emissions. If this mixture were less than 35 percent (by weight), additional testing would be conducted at any higher percentages of petroleum coke but would not exceed 35-percent by weight.

Table 1. Material Usage of Coal, Limestone, Bottom Ash and Fly Ash for Co-firing Petroleum Coke with Coal at Cedar Bay Cogeneration Facility

	Units	Coal	Co-Firing	Difference	Permit Limits	Title V Permit Condition
Fuel	lb/hr/unit[a]	82,500	78,000	-4,500	104,000	Section III. A.3.
	lb/hr/plant[b]	247,500	234,000	-13,500	312,000	Section III. A.3.
	tons/month[c]	89,100	84,240	-4,860	117,000	Section III. A.3.
	tons/year[d]	1,008,167	953,176	-54,991	1,170,000	Section III. A.3.
Limestone	lb/hr/unit[a]	12,500	22,500	10,000	NA	
	lb/hr/plant[b]	37,500	67,500	30,000	NA	
	tons/month[c]	13,500	24,300	10,800	27,000	Section III. B.1.
	tons/year[d]	152,753	274,955	122,202	320,000	Section III. B.1.
Fly Ash	lb/hr/unit[a]	13,000	15,500	2,500	NA	
	lb/hr/plant[b]	39,000	46,500	7,500	NA	
	tons/month[c]	14,040	16,740	2,700	28,000	Section III. B.1.
	tons/year[d]	158,863	189,413	30,551	336,000	Section III. B.1.
Bottom Ash	lb/hr/unit[a]	4,200	7,000	2,800	NA	
	lb/hr/plant[b]	12,600	21,000	8,400	NA	
	tons/month[c]	4,536	7,560	3,024	8,000	Section III. B.1.
	tons/year[d]	51,325	85,541	34,217	88,000	Section III. B.1.

Footnotes: [a] from Foster Wheeler Report for one CFB unit.
[b] based on three CFB units.
[c] based on 24 hour/day and 30 days/month per permit condition.
[d] based on 8,760 hours/year at 93% capacity factor.

Note: Data on usage from Foster Wheeler Report and based on lb/hr values for a single unit.
Calculations based on 3 CFB units.

Table 2. Operating Parameters for Cedar Bay Cogeneration Plant, Years 1997-2000

			AOR Year			
Unit	Parameter	Unit	1997	1998	1999	2000
1063 MMBtu/hr Boiler 1-A	Hours Operated	hrs	8,013	8,204	7,968	7,651
	Fuel Usage	tons	331,642	334,181	324,598	320,199
	Fuel Heat Content	MMBtu/ton	23.8	21.5	23.8	23.9
	Fuel Heat Content	Btu/lb	11,900	10,750	11,900	11,950
	Heat Input	MMBtu/hr	985.0	875.8	969.6	1000.2
	Capacity Factor		92.7%	82.4%	91.2%	94.1%
	CO emissions	tons/yr	176.0	208.0	196.3	179.2
	CO based lb/MMBtu		0.045	0.058	0.051	0.047
	NO_x emissions	tons/yr	593.1	581.6	587.56	594.4
	NO_x based lb/MMBtu		0.150	0.162	0.152	0.155
	PM_{10} emissions	tons/yr	49.4	67.2	66.4	48.1
	PM_{10} based lb/MMBtu		0.013	0.019	0.017	0.0126
	Sulfuric Acid Mist	tons/yr	0.120	0.120	0.120	0.115
	SAM based lb/MMBtu		3.04E-05	3.34E-05	3.09E-05	3.00E-05
	SO_2 emissions	tons/yr	659.0	658.1	659.7	650.5
	SO_2 based lb/MMBtu		0.167	0.183	0.171	0.170
	VOC emissions	tons/yr	3.30	3.20	5.18	4.97
	VOC based lb/MMBtu		0.0008	0.0009	0.0013	0.0013
1063 MMBtu/hr Boiler 1-B	Hours Operated	hrs	8,053	7,786	8,008	7,731
	Fuel Usage	tons	316,400	306,430	316,369	318,602
	Fuel Heat Content	MMBtu/ton	23.8	23.4	23.0	24.0
	Fuel Heat Content	Btu/lb	11,900	11,700	11,500	12,000
	Heat Input	MMBtu/hr	935.1	920.9	908.7	989.1
	Capacity Factor		88.0%	86.6%	85.5%	93.0%
	CO emissions	tons/yr	141.0	145.4	167.5	157.7
	CO based lb/MMBtu		0.037	0.041	0.047	0.041
	NO_x emissions	tons/yr	558.3	545.8	577.1	597.6
	NO_x based lb/MMBtu		0.148	0.152	0.163	0.156
	PM_{10} emissions	tons/yr	49.0	49.0	61.6	60.2
	PM_{10} based lb/MMBtu		0.013	0.014	0.017	0.016
	Sulfuric Acid Mist	tons/yr	0.110	0.110	0.120	0.116
	SAM based lb/MMBtu		2.92E-05	3.07E-05	3.40E-05	3.03E-05
	SO_2 emissions	tons/yr	636.0	618.5	622.0	671.0
	SO_2 based lb/MMBtu		0.169	0.173	0.176	0.176
	VOC emissions	tons/yr	8.30	8.30	9.25	8.93
	VOC based lb/MMBtu		0.0022	0.0023	0.0026	0.0023
1063 MMBtu/hr Boiler 1-C	Hours Operated	hrs	8,091	8,275	7,960	7,696
	Fuel Usage	tons	322,289	332,388	321,602	315,590
	Fuel Heat Content	MMBtu/ton	23.8	23.4	23.8	24.0
	Fuel Heat Content	Btu/lb	11,900	11,700	11,900	12,000
	Heat Input	MMBtu/hr	948.0	939.9	961.6	984.2
	Capacity Factor		89.2%	88.4%	90.5%	92.6%
	CO emissions	tons/yr	179.0	196.2	218.5	179.2
	CO based lb/MMBtu		0.047	0.050	0.057	0.047
	NO_x emissions	tons/yr	574.6	589.0	576.8	587.1
	NO_x based lb/MMBtu		0.150	0.151	0.151	0.155
	PM_{10} emissions	tons/yr	51.1	62.1	65.7	56.9
	PM_{10} based lb/MMBtu		0.013	0.016	0.017	0.015
	Sulfuric Acid Mist	tons/yr	0.120	0.120	0.119	0.115
	SAM based lb/MMBtu		3.13E-05	3.09E-05	3.12E-05	3.05E-05
	SO_2 emissions	tons/yr	614.0	659.0	644.5	643.6
	SO_2 based lb/MMBtu		0.160	0.169	0.168	0.170
	VOC emissions	tons/yr	3.20	3.20	3.46	3.35
	VOC based lb/MMBtu		0.0008	0.0008	0.0009	0.0009
Total Emissions for 3 Boilers	Capacity Factor		89.9%	85.8%	89.0%	93.2%
	Heat Input	10^6 MMBtu	23.09	22.13	22.66	22.87
	CO emissions	tons/yr	496.0	549.6	582.3	516.0
	NO_x emissions	tons/yr	1726.0	1716.4	1741.5	1779.0
	PM_{10} emissions	tons/yr	149.5	178.3	193.7	165.2
	Sulfuric Acid Mist	tons/yr	0.4	0.4	0.4	0.3
	SO_2 emissions	tons/yr	1909.0	1935.6	1926.2	1965.1
	VOC	tons/yr	14.8	14.7	17.9	17.3

Notes:

Million BTU per ton burned listed in Title V as 24.0 (calculated).

Maximum hourly rate = 52 tph

Maximum annual rate = 390,000 tpy

Maximum heat input to each boiler shall not exceed 1,063 MMBtu/hr. This reflects a combined total of 3,189 MMBtu/hr for all three units.

Boilers may operate continuously (8,760 hr/yr) but shall not exceed - 25.98 x 106 MMBtu/yr total annual heat input.

Figure 1
Cedar Bay Cogeneration Facility - Site Location

Source: Golder, 2001.

Golder Associates

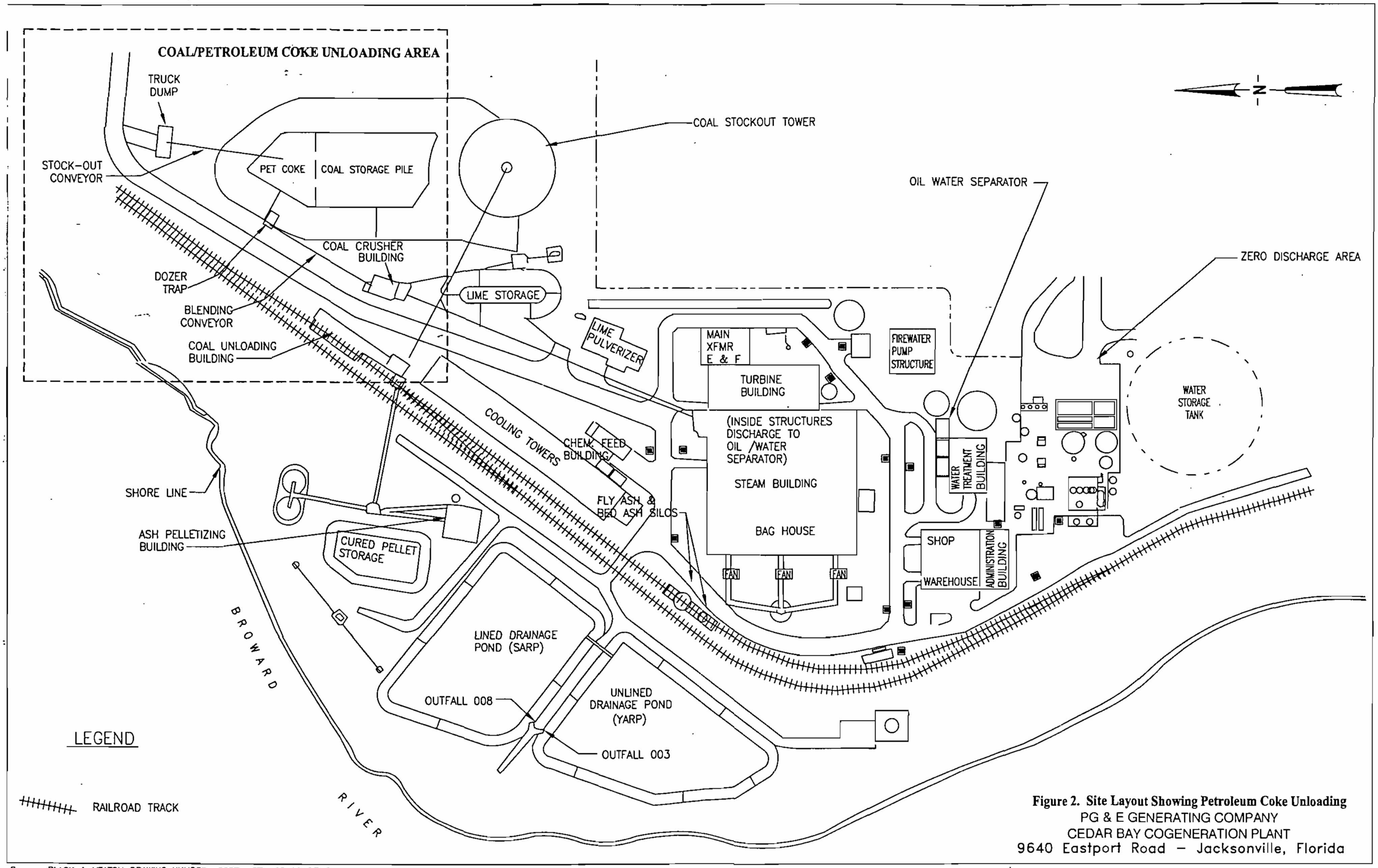

Figure 2. Site Layout Showing Petroleum Coke Unloading
PG & E GENERATING COMPANY
CEDAR BAY COGENERATION PLANT
9640 Eastport Road – Jacksonville, Florida

Source: BLACK & VEATCH DRAWING NUMBER 15637-1STU-S3400 REVISION 3. DATED: 1-6-92

0137573\4\4.4\4.4.2\Figure 2.dwg (7/12/01 by ARZ)

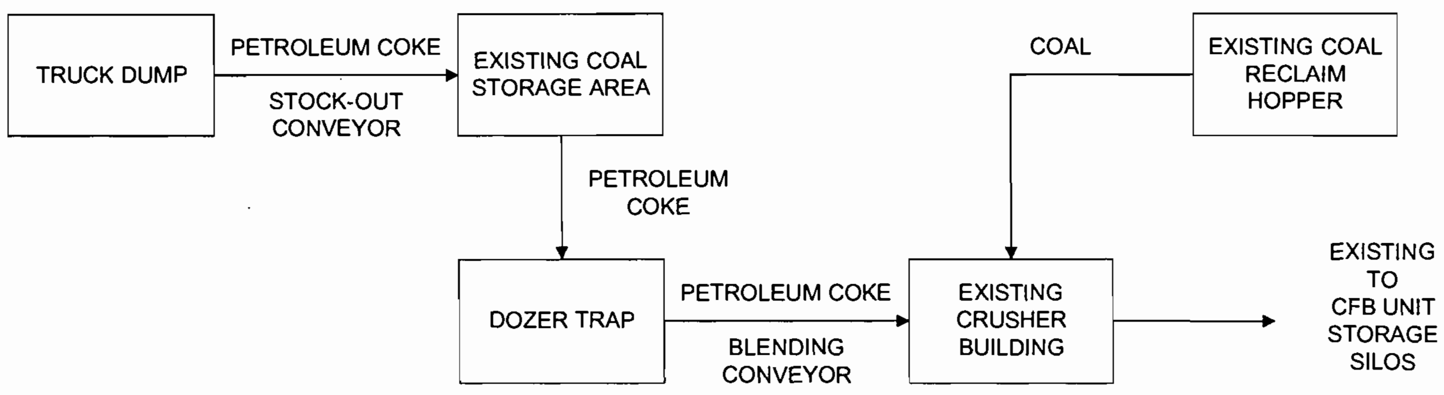

Figure 3
Process Flow Diagram for Petroleum Coke Unloading
Cedar Bay Cogeneration Facility
Jacksonville, Florida

Process Flow Legend:
Solid / Liquid
Gas
Steam

Golder Associates

APPENDIX A

REPORT ON FEASIBILITY STUDY FOR CO-FIRING PETROLEUM COKE IN CEDAR BAY CFB BOILERS

FOSTER WHEELER ENERGY SERVICES, INC.

Report on Feasibility Study for Co-firing Petroleum Coke in Cedar Bay CFB Boilers

for

PG&E National Energy Group
Cedar Bay Generating Company, L.P.
Jacksonville, Florida

Report on Feasibility Study for Co-firing Petroleum Coke in Cedar Bay CFB Boilers

for

PG&E National Energy Group
Cedar Bay Generating Company, L.P.
Jacksonville, Florida

Prepared by:

____

Song Wu, Principal Engineer

Engineering Technology Department, FWDC

Approved by:

____

PK Chelian

Manager Engineering / FWESI

EXECUTIVE SUMMARY

This is an engineering study by Foster Wheeler Energy Services Inc for the co-firing of petroleum coke and bituminous coal in the CFB boilers at PG&E National Energy Group's Cedar Bay Plant. The plant provided the fuel analyses of four candidate petroleum cokes for this study. The main objective of the study is to evaluate the potential impact of co-firing on the boiler capacity, emissions, CFB process as well as on the major auxiliary equipment.

Boiler "C" was designated for the study. Boilers A, B and C are similar. The process and operating conditions of the May 22, 1999 performance evaluation test on this boiler form the basis for the study.

The following are highlights of the study:

The boiler can deliver the same MCR capacity while co-firing petroleum coke at different blend ratios subject to equipment modifications / system improvements identified in this report. While co-firing petroleum coke all the emissions (SO_2, NOx, CO and particulate matter) can be maintained at the current levels. Due to the usually low concentrations of trace elements in the petroleum coke, the trace element emissions including mercury are also expected to be at the current level or lower.

The boiler as such can readily co-fire up to 20% petroleum coke by heat input. The equipment upgrades proposed for co-firing higher blend ratios are as explained below. For co-firing ratio in the range of 20% to 35% coke by heat input the changes are limited to limestone feed system. For blend ratio in the range of 35% to 65% modification to loopseal configuration and loopseal fluidizing nozzles would be necessary to increase the solids flow capacity. For blend ratios higher than 65% modification to boiler heating surfaces, upgrading of limestone preparation and transport system as well as bottom ash handling system would be required.

The conclusion of this study is co-firing petroleum coke up to 80% by heat input would be feasible by appropriate modifications to the present equipment. The boiler as such can co-fire petroleum coke up to 20% by heat input. All the emissions including trace elements could be maintained at the present level while firing coal only.

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1.0 INTRODUCTION

Foster Wheeler Energy Services, Inc. (FWESI) was awarded a contract for engineering study by Cedar Bay Generating Company, L.P. (CBGC) to evaluate co-firing of petroleum coke and bituminous coal in the CFB boilers at the Cedar Generating Plant. CBGC provided the fuel analyses of four candidate petroleum cokes for this study. The main objective of the study is to evaluate the potential for co-firing petroleum coke at different proportions without impacting the present level of boiler emissions. The limitations if any on the boiler process as well as on the major auxiliary equipment were identified to facilitate co-firing petroleum coke at the maximum proportion.

The plant has three identical CFB boilers (A, B & C). Boiler "C" performance data from the last performance evaluation test was selected as the basis for this study.

2.0 BOILER DESCRIPTION

PG&E national energy group operates three 745,000 lb/hr, 1005 °F main steam, 1005 °F reheat steam and 1980 psig Foster Wheeler CFB boilers at the Cedar Bay Cogeneration Facility in Jacksonville, Florida. The steam is used to generate power for sale to Florida Power and Light Co. Process steam is also sold to an adjacent recycled-liner board mill owned by Seminole Kraft Corp. The power plant is operated in an automatic dispatch mode which requires the plant to cycle load on a daily basis.

Each boiler has two cyclones with fuel being fed to the furnace from four 50% capacity feed systems through six feed points. Four feed points are located in the loopseal return legs and two are on the front wall. Limestone is pneumatically fed to the furnace through eight (8) injection points to control the SO_2 emission (permit level: 0.3 lb/MMBtu 3-hour average and 0.2 lb/MMBtu 30 day average and 318.9 lb/hr 30 day average). Bottom ash removal from the furnace is through three water-cooled screw coolers. Fly ash collected by the baghouse is transported to the main flyash silo. The boiler is also equipped with a fly ash reinjection system to improve sorbent utilization. An aqueous ammonia injection system is used to control the NOx emissions (permit level 0.17 lb/MMBtu 30 day average and 180.7 lb/hr 30 day average).

3.0 BASIS FOR STUDY

The reference point for the study is the four-hour average data from the performance evaluation test on Boiler "C". The following are the main assumptions used for the study,

- Boiler load at 100% MCR corresponds to a main steam flow of 767,160 lb/hr;
- Coal and limestone analyses from the last test is used for this study;
- One coke (CBGC supplied analysis coke #4) is selected to be studied for 6 coke blend ratios (0%, 20%, 40%, 50%, 60%, 80% coke by heat input).
- Heat and mass balance data is provided for the case of 50% blend using coke #4 at the boiler

load of 745,000 klb/hr and 700,000 klb/hr .

- Heat and mass balance data is also provided for 50% coke/coal blend using Coke #1 and coke #3 at 767,160 lb/hr.

4.0 FEED STOCK EVALUATION

4.1 Petroleum Coke Analyses

The chemical analyses of four candidate coke samples are summarized in Table 1.

Table 1 Fuel Analysis Data (%as fired unless otherwise indicated)

FUEL TYPE	Coke #1	Coke #2	Coke #3	Coke #4	CB Bit Coal
Fixed C	84.83	80.57	85.89	82.34	49.98
Volatile	9.46	9.46	11.32	9.51	34.30
Ash	0.57	0.37	0.58	0.37	8.72
Moisture	5.14	9.6	2.21	7.78	7
Total.	100.00	100.00	100.00	100.00	100.00
S	4.09	5.84	5.17	5.45	1.52
H	3.53	3.52	3.76	3.37	4.94
C	84.58	80.57	85.88	81.23	72.79
N	1.59		1.61	1.66	1.35
O	0.50		0.78	0.14	3.68
Ash	0.60	0.37	0.58	0.37	8.72
H2O	5.14	9.60	2.21	7.78	7.00
Total	100.00	99.90	100.00	100.00	100.00
V, ppm	2410*	1815	808*	683*	
Ni, ppm	316*	340	217*	167*	
HHV, as fired, Btu/lb	14512.0	13712.0	14557.0	13923.0	12557.0
HHV, dry basis, Btu/lb	15298	15168	14886	15098	13502
VM, %daf	10.03	10.51	11.64	10.35	40.70
C/H Ratio, -	23.96	22.89	22.84	24.10	14.73
SO_2 input, lb/MMBtu	5.64	8.52	7.10	7.83	2.42

*Calculated based on fuel ash analyses; may be lower than actual content in fuel

The four petroleum cokes have fairly similar C/H ratios and volatile matter contents (% daf) that are typical of delayed coke. The heating values on a dry basis also fall into a very narrow range (less than 3.0 % difference).

The main difference lies in the sulfur content, which in terms of lb/MMBtu of SO_2 input for coke #2 is 15% higher than coke #1. High sulfur content in the coke will require a high percent sulfur capture and greater limestone usage than current level.

In this project, since petroleum coke is co-fired with coal, the risk of vanadium related problems is low. Since all four petroleum cokes are similar in terms of fuel analysis, coke #4 is selected for detailed study because it has a typical and more complete chemical analysis. Coke #1 and coke #3 are studied only for a blend ratio of 50% coke by heat input.

4.2 Coal and Limestone

The coal and limestone compositions as determined based on the May 22, 1999 performance evaluation test are used for this study. The coal analysis is shown in Table 1. Table 2 gives the limestone analysis. Figure 1 is the size distribution of the limestone.

Table 2 Limestone Analyses (wt% as received)

	Reference Limestone
CaCO3	95.84
MgCO3	0.52
Inert	3.28
Moisture	0.37
Total	100.00
RI, mol/mol	2.70

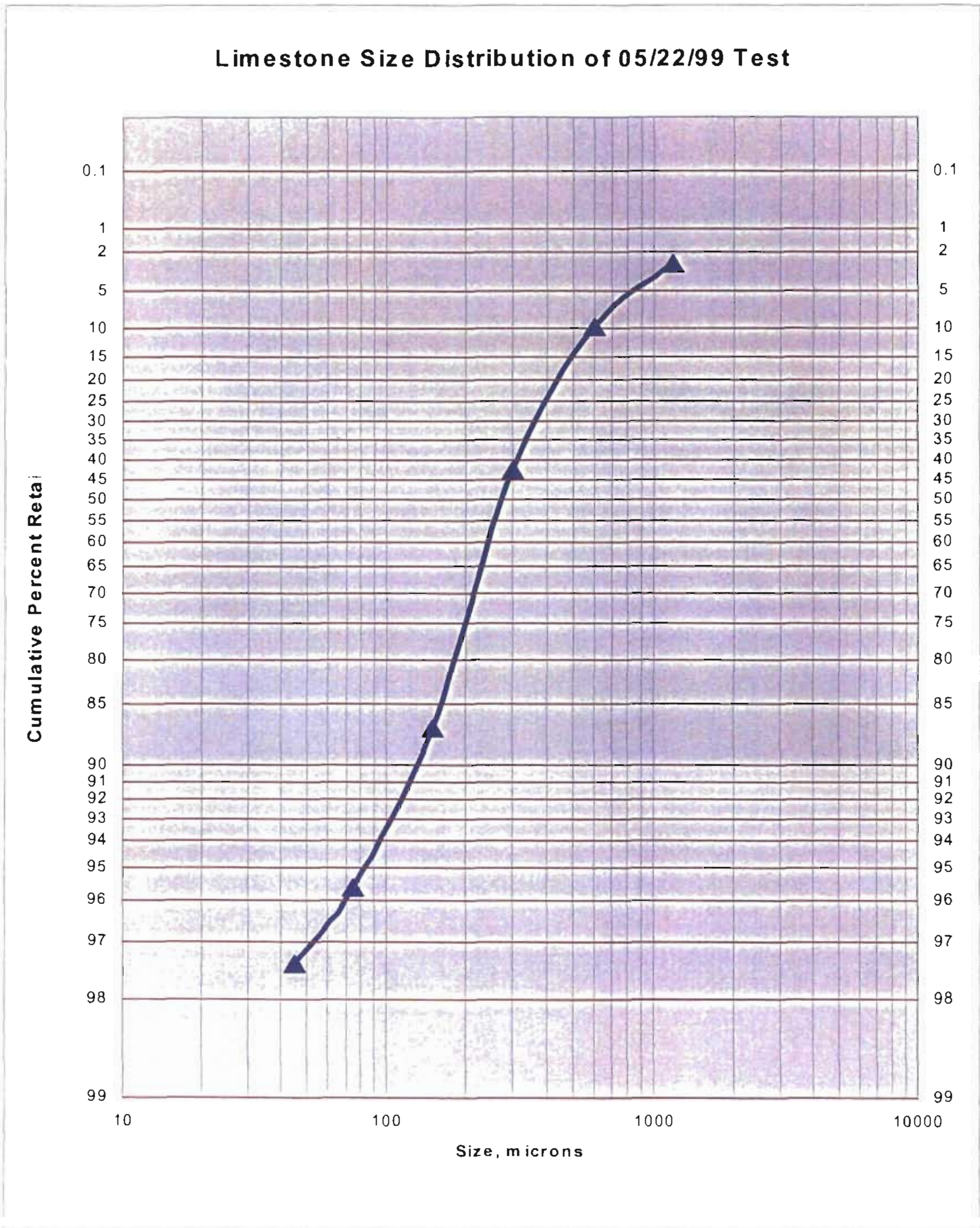
Limestone Size Distribution of 05/22/99 Test
Cumulative Percent Retai
Size, microns
0.1
1
2
5
10
15
20
25
30
35
40
45
50
55
60
65
70
75
80
85
90
91
92
93
94
95
96
97
98
99
10
100
1000
10000

Figure 1

5.0 IMPACT ON BOILER PROCESSES

5.1 Boiler Emissions Overview

The projected stack emission levels of SO_2, NOx, and CO are plotted in Figure 2. The SO2 emission is controlled by limestone addition and the current level can be maintained for the entire range of blend ratios. More discussion on sulfur capture and limestone consumption is given in the next section.

The current level of NOx can also be maintained with the existing ammonia injection system.

The predicted CO emission is lower while co-firing coke than the case of firing coal only. As shown in Figure 2, when firing 50% coke blend, about 40% reduction in CO can be expected, as compared to coal firing.

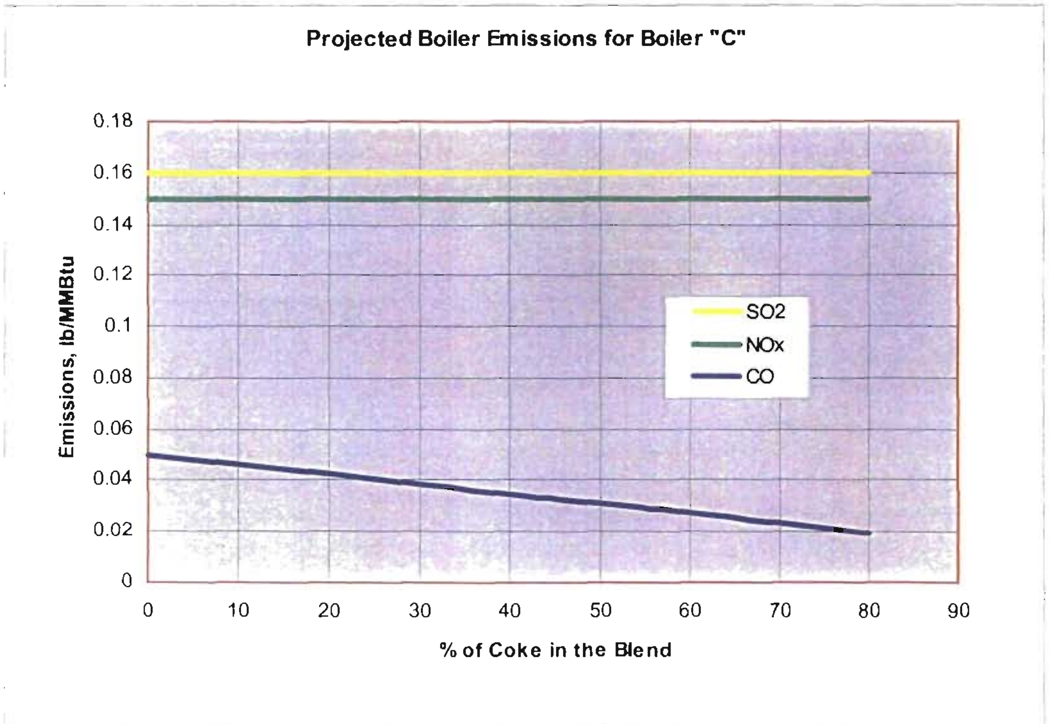

Figure 2

There should be no problem in maintaining the particulate matter emission rate when co-firing petcoke with coal. A detailed examination of the baghouse performance is given in section 6.5.

Currently, the plant is running with coal only and with very low levels of trace element emissions Due to the various thermal processes occurring in an oil refinery, the trace element concentrations, such as mercury, lead and fluoride in the heavy residue coke are extremely low (very significantly lower than that of typical coal). Considering the very low concentrations in petroleum coke, it is expected the trace elements emissions while co-firing petcoke will be lower than the present level.

5.2 Sulfur Capture and Limestone Requirement

Due to the high sulfur content in coke, the sulfur input increases rapidly while co-firing. Figure 3 shows the uncontrolled SO_2 levels and sulfur capture requirement for different blend ratios. For high blend ratios the percent sulfur capture in the high nineties are necessary in order to maintain the present level of emission.

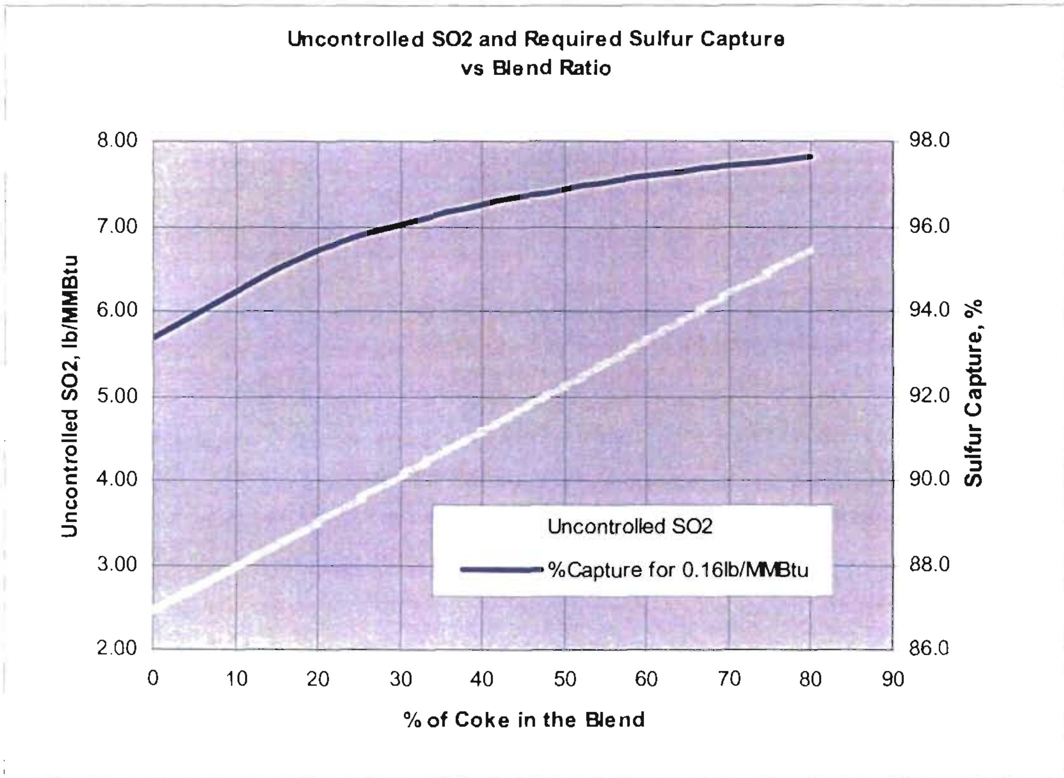

Figure 3

Figure 4 shows the projected limestone requirements at different blend ratios. When firing a 50% blend, the limestone flow rate is 25,600 lb/hr, or, 210% of the limestone flow when firing 100% coal.

Currently, the plant is controlling average SO_2 emissions at about 0.16 lb/MMBtu, or 80% of the permit level (0.20 lb/MMBtu). This control target is quite conservative. With a properly tuned SO_2 trim mechanism of the limestone feed rate control it is possible to smooth out the fluctuations in the feed rate. With these considerations, Foster Wheeler believes that the current level of SO_2 emission can be maintained.

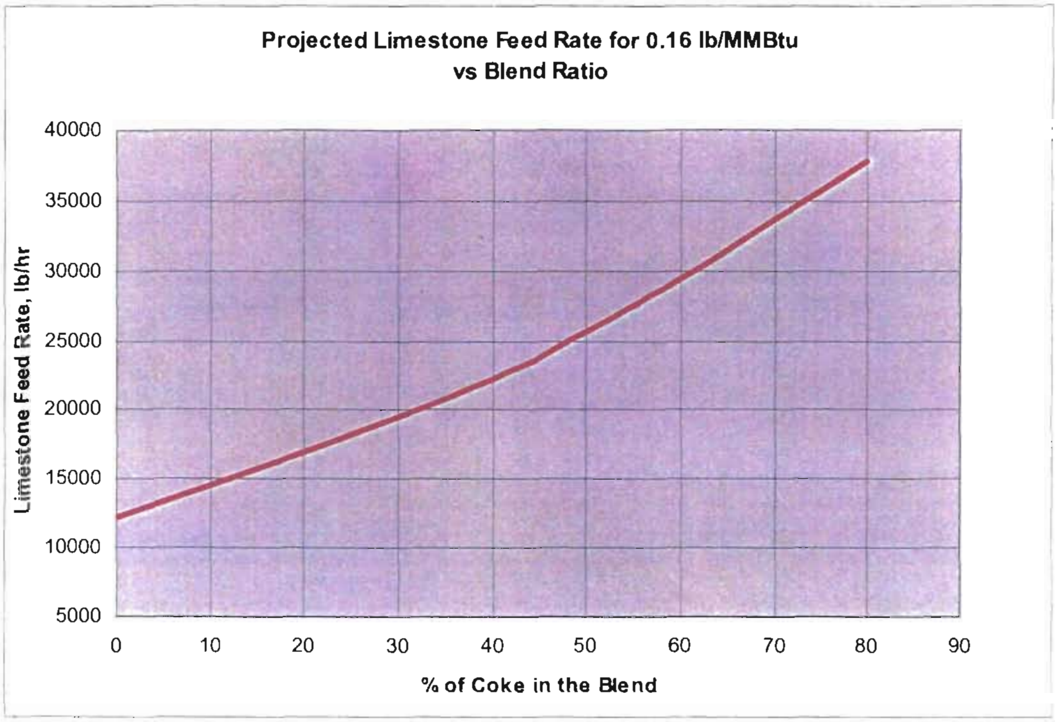

Figure 4

5.3 NOx Emissions and NH_3 Consumption

Due to its low volatile matter content, petroleum coke combustion in CFBs usually generates low NOx emissions. It is anticipated that NOx emissions while co-firing will be lower than firing 100% bituminous coal. Figure 5 presents the projected uncontrolled NOx emission levels developed based on commercial experience of CFB boilers firing petroleum coke. Also plotted in Figure 5 is the current control target of 0.15 lb/MMBtu of NOx (permit level: 0.17 lb/MMBtu).

Figure 5 indicates that at higher coke blending ratios, the NOx level before NH_3 injection and the required NOx reduction percentage is lower. Therefore less ammonia injection is needed when more coke is fired. Figure 6 depicts the projected aqueous ammonia (30.3% purity) flow at various blend ratios. A 35% reduction in ammonia consumption can be expected by firing a 50% coke, 50% coal blend.

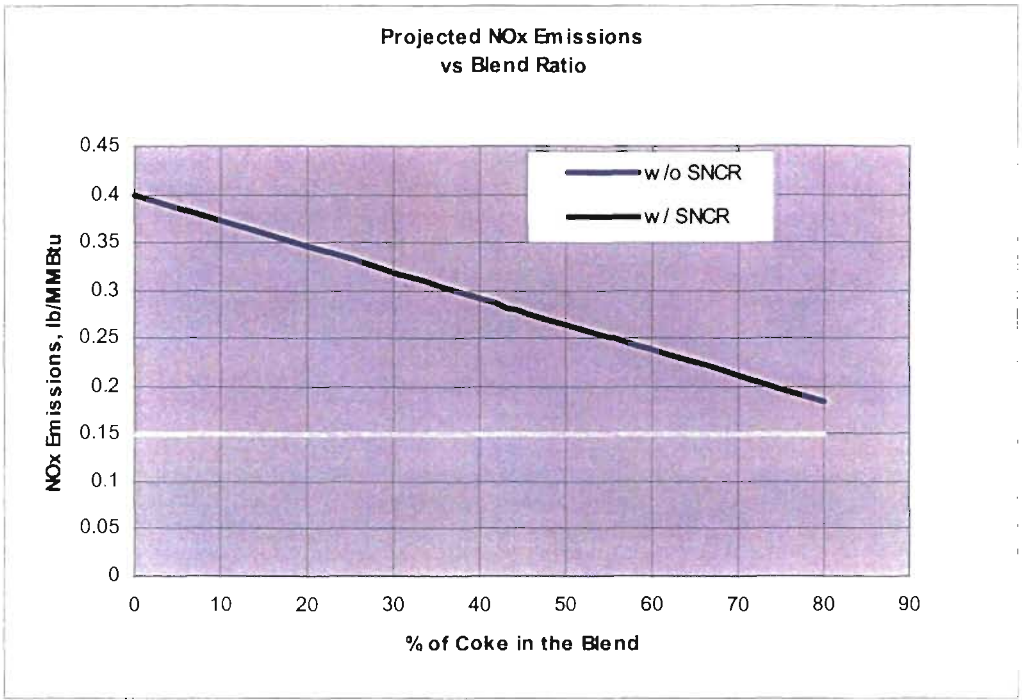

Figure 5

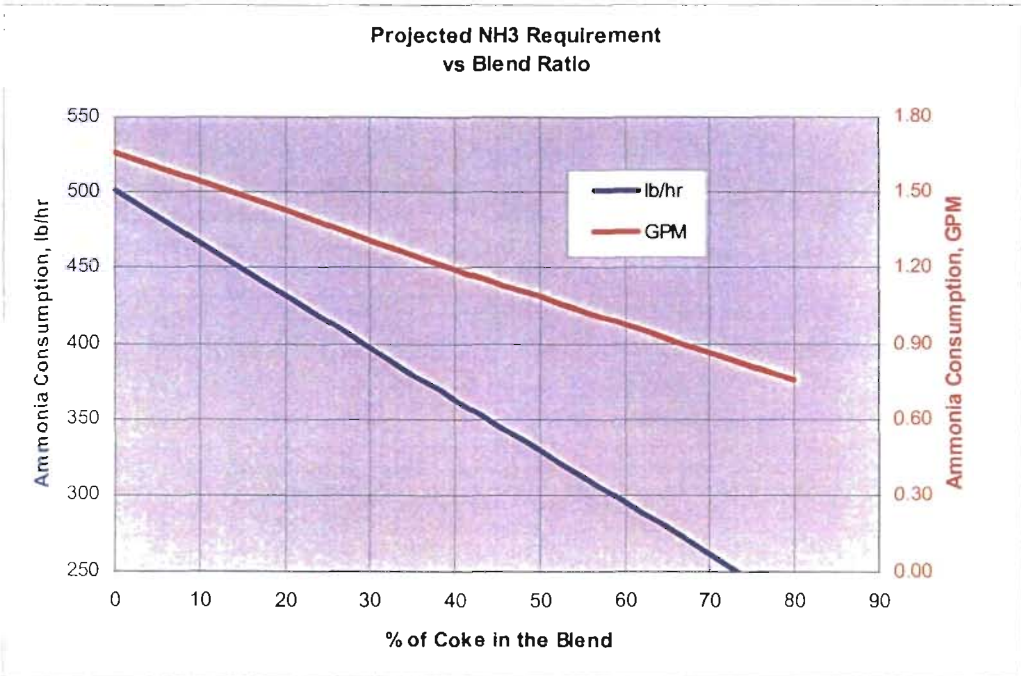

Figure 6

5.4 Other Process Impact

Solids Throughput and Ash Split: Due to the high sulfur content and large limestone requirement related to petroleum coke, the solids throughput of the CFB system will increase when co-firing coke (see Figure 7 for solids throughput). Therefore during co-firing, there is adequate amount of circulating material. However, because an increased portion of the circulating bed material will be limestone products, the limestone sizing becomes more critical. The limestone size distribution indicated in Figure 1 is suggested for the coke firing. The existing equipment should be capable of producing limestone of the appropriate size distribution.

The bottom ash fraction is also predicted and the results are shown in Figure 7.

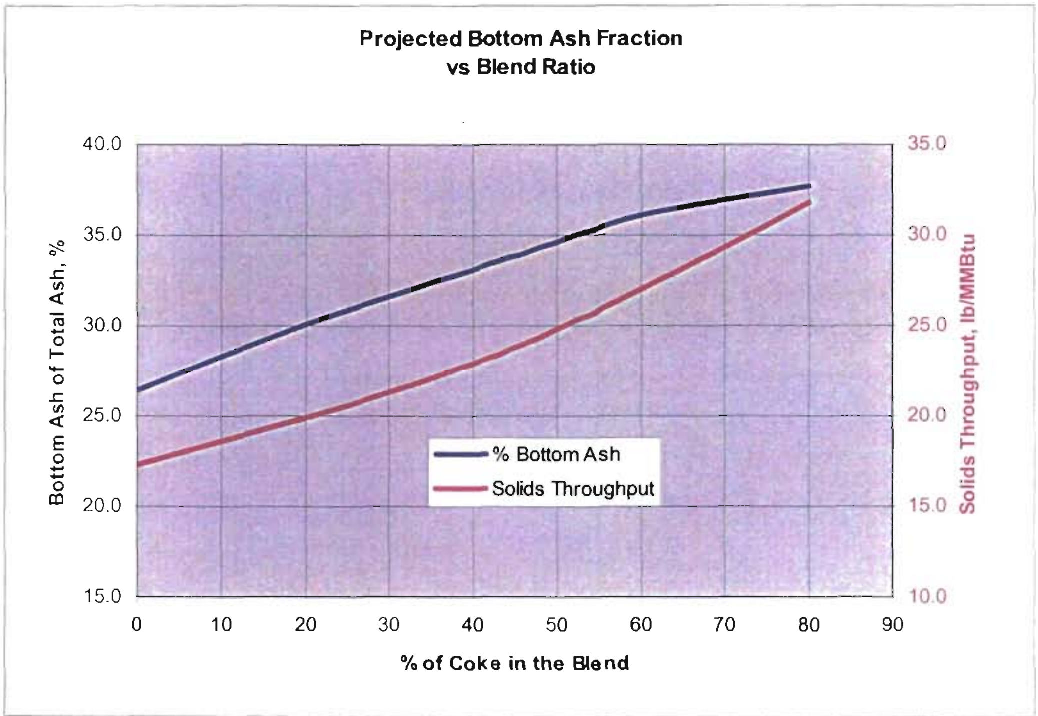

Figure 7

Furnace and Backend Heat Transfer, Temperatures and Fouling: On one hand, as discussed above, there will be an increased amount of solids throughput with coke co-firing, which should lead to higher solids circulating rate and better heat transfer, and thus lower furnace temperatures. On the other hand, coke-fired CFB boilers are known to have greater fouling tendency in the heat transfer surfaces than CFB boilers fired with only coal. Although in the furnace, the circulating material tends to scrub the tube surfaces to keep them clean, fouling could lead to reduced heat transfer and higher combustor temperature. Considering the above competing factors, it is expected that the combustor temperature will not be much different as compared to the 100% coal fired case. Other factors such as load, excess air and primary air to total air ratio will have more dominant impact on furnace temperature.

When co-firing coke, deposit formation on tubes in the back pass may increase, more frequent sootblowing may be necessary to maintain adequate heat transfer.

Erosion Tendency: The main factors determining surface erosion rates are particle velocity (which depends on gas velocity), particle abrasiveness and solids loading. There is a slight reduction in gas velocity due to co-firing. Although solids throughput is higher for co-firing cases, because of the low ash content of the coke, the additional solids products are mainly spent limestone particles that are relatively soft. Therefore, surface erosion is not expected to accelerate during coke co-firing.

6.0 IMPACT ON BOILER AUXILARY EQUIPMENT

6.1 Fuel Handling Equipment

The fuel feeding system consists of two fuel silos and four gravimetric belt feeders, of which two feed the two front wall feed points, the other two feed into chain conveyers (two for each side) which deliver fuel to the four feed chutes on the loopseal return legs. The maximum feeder capacity is 50,000 lb/hr per feeder. Each fuel silo feeds to one front wall and one rear wall feeder on the side of the boiler where the silo is located.

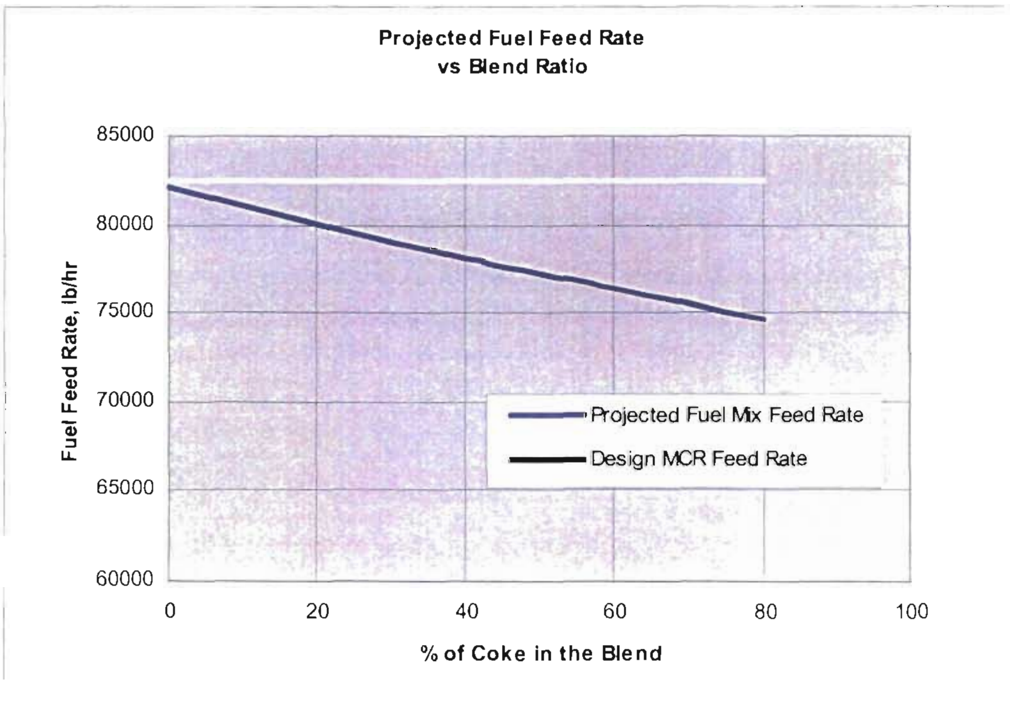

Figure 8

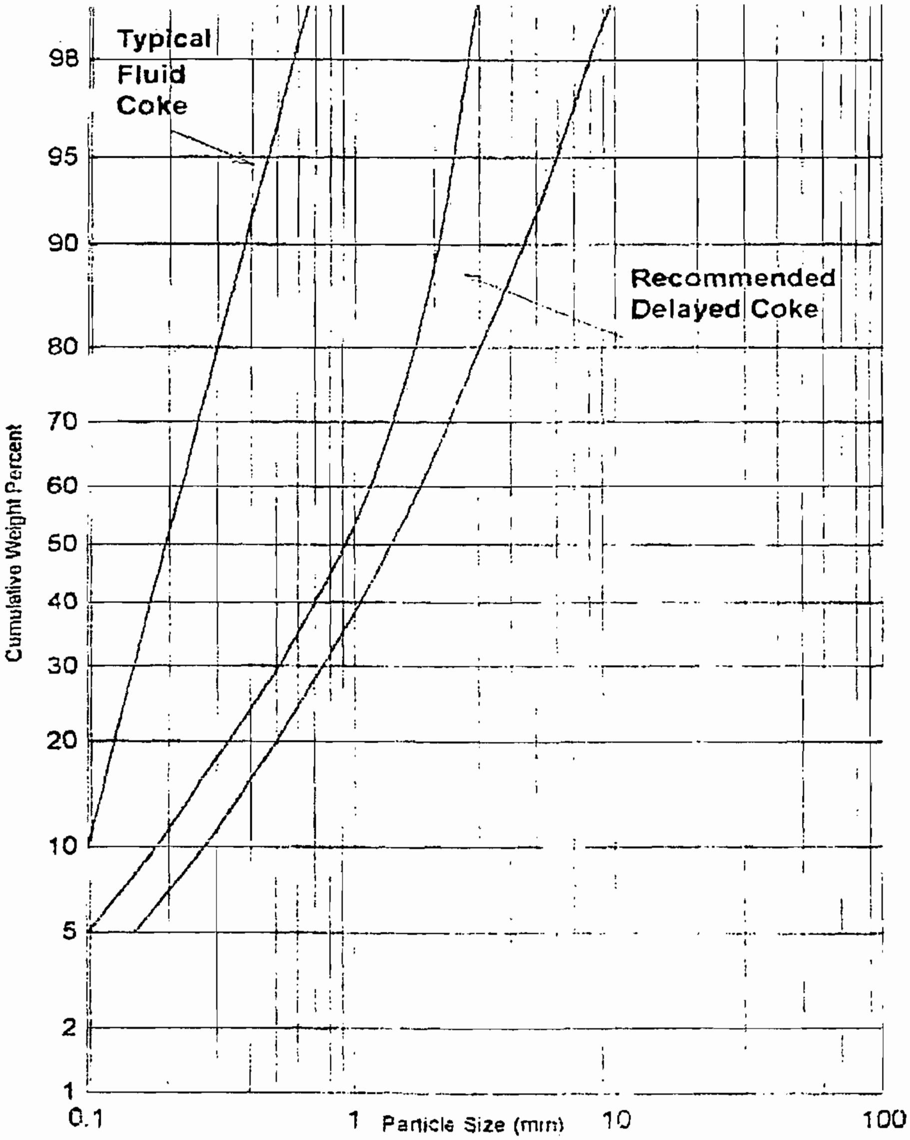

Figure 9 Typical Petcoke Size Distribution

Projected fuel feeding rates are plotted in Figure 8. Because coke has higher heating value, the feed rate reduces with increasing blending ratio and for all blend ratios the fuel feed rates are less than the design MCR coal feed rate. Therefore fuel feeding system capacity has plenty of redundancy for co-firing.

Handling of delayed coke is similar to that of coal. The main difference lies in the heating value, volatile matter and sulfur content. Ideally, in order to have good feed material consistency, the coal and coke should be premixed before loading to the fuel silo. This way all six feed points of the boiler will receive the same fuel blend to ensure uniform conditions in the furnace. Premixed fuel feeding is recommended for a co-firing test.

Figure 9 provides recommended size distribution range for delayed coke.

6.2 Limestone Handling System

The limestone system consists of limestone crushers, a limestone silo, two gravimetric belt feeders and two pneumatic transport trains that deliver limestone to eight feed points of the boiler (three front, three rear, one on each side). The design capacity of each feed chain is 16,000lb/hr (8 ton/hr). However, the plant has reported that the actual feed rate is limited at 4.2 ton/hr per feeder by the rotary valve capacity.

The limestone feed rates for different blend ratios are shown in Figure 4. The current set up can provide limestone for a co-firing blend ratio of about 20%. For higher blend ratios, the rotary valves downstream of the belt feeders have to be modified to match the design capacity of the rest of the feed system (16,000 lb/hr each chain). The maximum feed capacity can cover the projected limestone feed rates for up to 65% coke co-firing.

As an alternative, a base amount of limestone can be premixed with fuel and fed through the fuel feeders (which has plenty of capacity), the rest of the required limestone can be fed through the limestone system for SO_2 emissions control. For long-term co-firing, the rotary valves need to be upgraded in capacity. A third limestone feed train of same capacity may be installed to provide necessary redundancy.

6.3 PA, SA and ID Fans

Projected flow rate requirements for the three fans are plotted in Figure 10. Air and gas flow decrease slightly with the increasing blend ratio. Therefore at the max load (767,000lb/hr main steam flow), the fans are not expected to be a limiting factor.

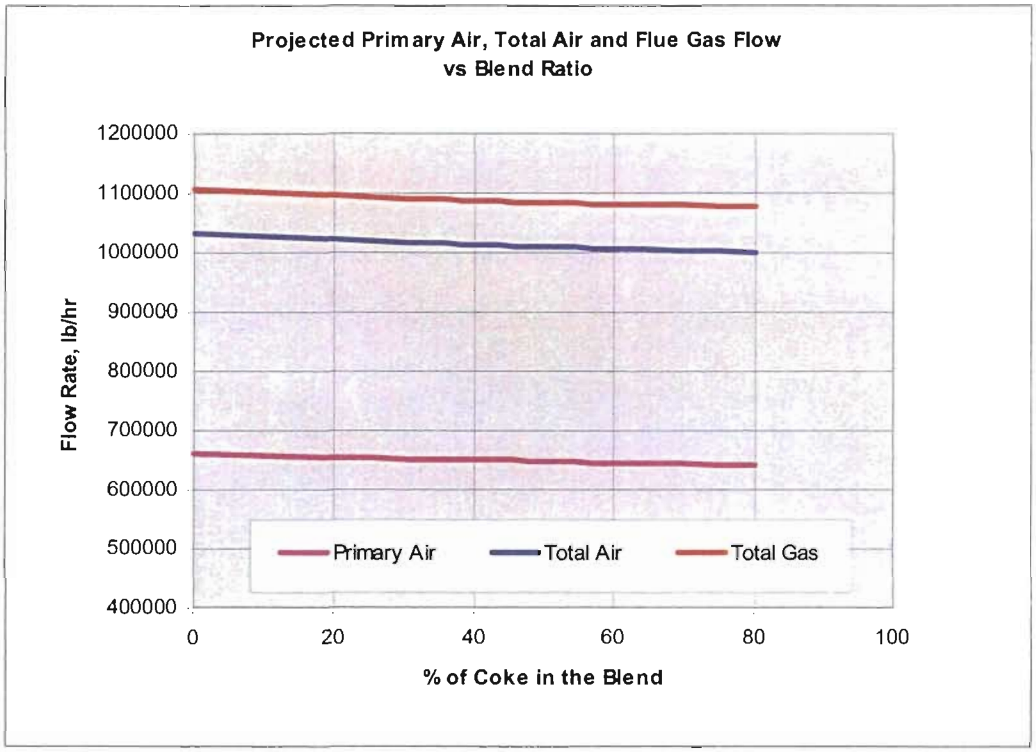

Figure 10

The flow requirement of high-pressure blowers for loopseals would be same as the current operation up to a coke blend of 35%.

6.4 Bottom Ash Handling

Bottom ash handling system consists of ash drains (3), ash cooling screws (3) and ash conveyers to transport ash to the ash silo. The ash drain/cooling screw design capacity is 2,950 lb/hr, and maximum capacity is 5,500 lb/hr.

The ash handling capacity of two cooling screws in service (with the third screw in standby) is used as reference in comparison with the projected bottom ash flow rates in Figure 11.

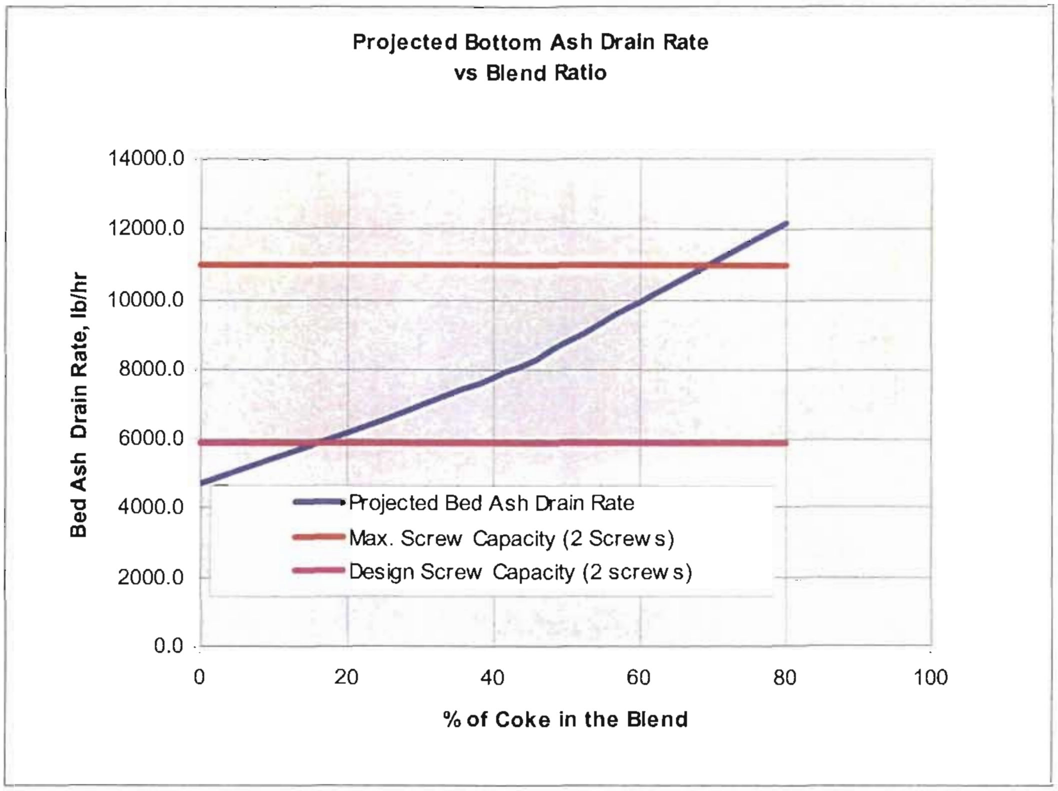

Figure 11

It appears that the maximum capacity of the two screws will allow up to 70% coke co-firing.

6.5 Flyash Handling Equipment

Fly ash system consists of the air heater hopper, baghouse, and pneumatic (vacuum) transport system that transport ash to the ash silo.

The impact on baghouse can be judged from the ash and gas flows. Figure 12 shows that the projected fly ash flow increases with increasing blend ratio, but the flue gas volume flow reduces slightly with co-firing. Although the flue gas volumes are higher than design flue gas volume (297,700 ACFM), the plant had often run with even higher volume flow without problems. The particulate loading for the 80% coke blend is 6.7 grains/ACF which is very low as compared to the design loading of 19.5 grains ACF specified by the baghouse vendor. The high design solids inlet loading of baghouse included the additional loading from fly ash re-injection (FAR) system. The FAR system is not being used at the plant. Based on the above, it is expected that the existing baghouse can maintain current emission levels, although more frequent back-purging/cleaning cycles may be necessary.

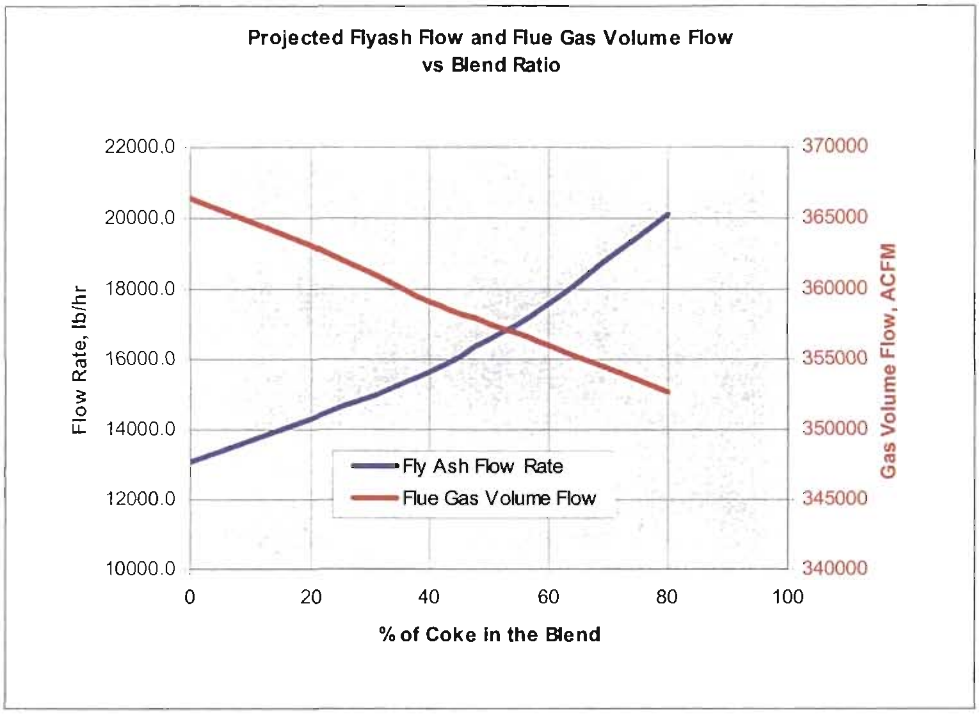

Figure 12

6.6 Start Up Burners

There are currently six #2 oil fired start up burners (1 on front wall, 3 on rear wall and 1 on each side wall). Each burner is 68 MMBtu/hr in capacity, making the total SUB capacity of 384 MMBtu/hr, or 37% of the heat input at the reference load. The burner capacity will be adequate for start-up.

7.0 CONCLUSIONS AND RECOMMENDATIONS

An engineering study has been completed for the co-firing of petroleum coke at PG&E National Energy Group's Cedar Bay Plant. Boiler "C" is designated for the study. The process and operating conditions of the May 22, 1999 performance evaluation test, including the test coal and limestone, form the basis for the study. Four candidates of petroleum coke were evaluated and one (coke #4) was selected for detailed engineering study. The following conclusions can be made,

1. On a dry basis, all four coke analyses have similar chemical compositions that are typical of delayed coke, except sulfur content, which has significant variation. Lower sulfur content is desirable due to associated limestone cost. On a normalized lb/MMBtu basis, coke #1 has the lowest sulfur content; #3 and #4 are higher; and #2 has the highest sulfur content.

2. When co-firing petroleum coke, SO_2, NOx and particulate matter emissions can be maintained at the current levels with existing equipment. Reductions in CO emissions are expected for coke

co-firing. Due to the usually very low concentrations of trace elements in the petroleum coke, the trace element emissions, including mercury, are also expected to be similar to or less than the current levels.

3. Due to high sulfur content in coke, percent sulfur capture in the mid to high nineties will be required to meet SO_2 compliance for co-firing, which should not be a problem. Limestone feed rates will be much higher than the current level. For 50% coke by heat input case, the projected limestone flow is 210% of the current consumption rate.

4. The uncontrolled NOx concentration before the DeNOx system will be lower when co-firing coke. Thus a smaller percentage reduction is required for the DeNOx system, resulting in a smaller ammonia consumption rate. A 35% reduction in ammonia consumption can be expected when firing a 50% coke blend.

5. The solids throughput and bottom ash fraction are expected to increase with higher coke blend ratios.

6. Furnace temperatures are expected to be close to the current levels. High levels of coke co-firing are known to have increased fouling tendency. The surfaces in the backpass are likely to have more ash deposit and more vigorous sootblowing may be needed.

7. Erosion rate of heat transfer surfaces when co-firing coke is not expected to exceed the current level at comparable boiler load.

8. Coke co-firing will require a lower fuel feed rate and slightly less combustion air and generates less flue gas. Therefore, fuel feeding system, PA, SA and ID fans are not expected to be limiting factors for co-firing at the reference load.

9. Startup burner capacity is adequate for start with coke blend.

10. Rotary valves downstream of the limestone feeders is a limiting factor in the limestone handling system which limit feeder capacity to 4.3 ton/hr, as compared to feeder design capacity of 8 ton/hr. The current limestone feeding system can support up to about 20% coke-co-firing. If the rotary valves are upgraded, the system maximum capacity could cover up to 65% coke co-firing. If all three boilers are co-firing coke in the future, capacity of limestone crushing and transport to the boiler house would also need to be upgraded.

11. Baghouse is expected to maintain the particulate emissions at current emission levels even though the solid loading at the baghouse inlet will be much higher than the current levels. More frequent back purging/cleaning is expected but is within the design capacity.

12. Bottom ash drain and cooling screw capacities are expected to be adequate for co-firing up to 70% coke by heat input.

APPENDIX B

CALCULATIONS:
FUGITIVE DUST COAL PETROLEUM COKE USAGE

Calculations of Petroleum Coke and Limestone Unloading

Petroleum Coke Fugitive Emissions:
The same equations as the PSD Approval and Title V Permit Application are used to determine fugitive emissions. AP-42, 4th Edition 11.2.3:

$EF = k \times (0.0032) \times (U/5)^{1.3}/(M/2)^{1.4}$

where: EF is the emission factor in lb/ton
k is particle size factor; 0.74 for PM and 0.35 for PM_{10}
U is wind speed; 7.8 miles/hour previously used
M is percent moisture; 6 percent previously used

$EF_{PM} = 0.74 \times (0.0032) \times (7.8/5)^{1.3}/(6/2)^{1.4}$
$EF_{PM} =$ 0.0009067 lb/ton
$EF_{PM10} = 0.35 \times (0.0032) \times (7.8/5)^{1.3}/(6/2)^{1.4}$
$EF_{PM10} =$ 0.0004289 lb/ton
Control efficiency = 70% based on water spraying.

Specific Condition Section III. A3. limit fuel use to:

	Pet Coke:	Coal Limits:
Annual	390,950 tons/year	1,117,000 tons/year
Monthly	40,950 tons/month	117,000 tons/month
Hourly	109,200 lb/hr	312,000 lb/hr

Petroleum Coke based on 35 percent by weight of permit limits. This is conservative since petroleum coke has higher heating content and less weight would be needed to reach load than coal. (See calculations of petroleum coke usage based on maximum heat input for each unit.)

PM Emisions from Truck Dump:

	Uncontrolled	Controlled
Annual	0.177 tons/year	0.053 tons/year
Monthly	0.019 tons/month	0.006 tons/month
Hourly	0.050 lb/hr	0.015 lb/hr

PM_{10} Emissions from Truck Dump:

	Uncontrolled	Controlled
Annual	0.084 tons/year	0.025 tons/year
Monthly	0.009 tons/month	0.003 tons/month
Hourly	0.023 lb/hr	0.007 lb/hr

PM Emisions from Conveyor to Pile:

	Uncontrolled	Controlled
Annual	0.177 tons/year	0.053 tons/year
Monthly	0.019 tons/month	0.006 tons/month
Hourly	0.050 lb/hr	0.015 lb/hr

PM_{10} Emissions from Conveyor to Pile:

	Uncontrolled	Controlled
Annual	0.084 tons/year	0.025 tons/year
Monthly	0.009 tons/month	0.003 tons/month
Hourly	0.023 lb/hr	0.007 lb/hr

Limestone Fugitive Emissions:

Annual	129,600	tons/year
Monthly	10,800	tons/month
Hourly	30,000	lb/hr

Based on increase in limestone usage from Foster Wheeler Report. Coal only estimated at 12,500 lb/hr/unit and co-firing at 35% petroleum coke is 22,500 lb/hr/unit. Same emission factor used as coal.

PM Emisions from Additional Limestone

	Uncontrolled		Controlled	
Annual	0.059	tons/year	0.018	tons/year
Monthly	0.005	tons/month	0.001	tons/month
Hourly	0.014	lb/hr	0.004	lb/hr

PM_{10} Emissions from Additional Limestone

	Uncontrolled		Controlled	
Annual	0.028	tons/year	0.008	tons/year
Monthly	0.002	tons/month	0.001	tons/month
Hourly	0.006	lb/hr	0.002	lb/hr

Total PM Emisions from Co-firing

	Uncontrolled		Controlled	
Annual	0.413	tons/year	0.124	tons/year
Monthly	0.042	tons/month	0.013	tons/month
Hourly	0.113	lb/hr	0.034	lb/hr

Total PM_{10} Emissions from Co-firing

	Uncontrolled		Controlled	
Annual	0.195	tons/year	0.059	tons/year
Monthly	0.020	tons/month	0.006	tons/month
Hourly	0.053	lb/hr	0.016	lb/hr

Calculations of Maximum Coal and Petroleum Coke when Co-firing at 35% Petroleum Coke by Weight

Total Heat Input (MMBtu/hr) = [0.65 total lb/hr (coal) x heat content(coal) + 0.35 total lb/hr (pet coke) x heat content (pet coke)]/10^6
Coal = 0.65 total; Pet coke = 0.35 total; Coal = 0.65 x pet coke/0.35; therefore Coal = 0.65/0.35 Pet coke or 1.857 pet coke

Heat Input	1,063 MMBtu/hr/unit			
lb/hr pet coke =	35.00% lb/hr (coal)			

Calculation using Current Coal and Average Pet Coke Heat Contents:

Heat content Coal = 12,557 Btu/lb Pet Coke = 14,176 Btu/lb

1,063MMBtu/hr = total [0.65 lb/hr coal x 12,557 Btu/lb + 0.35 x 14,176Btu/lb)]/10^6

1,063MMBtu/hr * 10^6 = [1.857 lb/hr x 12,557 Btu/lb + lb/hr x 14,176 Btu/lb)]

1,063MMBtu/hr * 10^6 = 2.857 lb/hr pet coke x (12,557 Btu/lb + 14,176Btu/lb)

1,063MMBtu/hr * 10^6 /(12,557 Btu/lb + 14,176Btu/lb)= 2.857 lb/hr

2.857 lb/hr = 1,063MMBtu/hr * 10^6 /(12,557 Btu/lb + 14,176Btu/lb)

lb/hr total =	80,999			
lb/hr coal =	52,649	& heat input (MMBtu/hr) =	661	62%
lb/hr pet coke =	28,350	& heat input (MMBtu/hr) =	402	38%
Total lb/hr =	80,999	& heat input (MMBtu/hr) =	1,063	100%

	Total	Coal	Pet Coke
Maximum 1 Unit	80,999 lb/hr	52,649 lb/hr	28,350 lb/hr
	29,160 tons/month	18,954 tons/month	10,206 tons/month
	349,915 tons/year	227,445 tons/year	122,470 tons/year
Maximum 3 Units	242,996 lb/hr	157,948 lb/hr	85,049 lb/hr
	87,479 tons/month	56,861 tons/month	30,618 tons/month
	976,262 tons/year	634,571 tons/year	341,692 tons/year

Calculation using Low Coal and Typical Pet Coke Heat Contents:

Max Heat Input = 1,063 MMBtu/hr/unit

Heat content Coal = 10,221 Btu/lb Pet Coke = 14,000 Btu/lb

1,063MMBtu/hr = total [0.65 lb/hr coal x 10,221 Btu/lb + 0.35 x 14,000Btu/lb)]/10^6

1,063MMBtu/hr * 10^6 = [1.857 lb/hr x 10,221 Btu/lb + lb/hr x 14,000Btu/lb)]

1,063MMBtu/hr * 10^6 = 2.857 lb/hr pet coke x (10,221 Btu/lb + 14,000Btu/lb)

1,063MMBtu/hr * 10^6 /(10,221 Btu/lb + 14,000Btu/lb)= 2.857 lb/hr

2.857 lb/hr = 1,063MMBtu/hr * 10^6 /(10,221 Btu/lb + 14,000Btu/lb)

lb/hr total =	92,085			
lb/hr coal =	59,855	& heat input (MMBtu/hr) =	612	57.55%
lb/hr pet coke =	32,230	& heat input (MMBtu/hr) =	451	42.45%
Total =	92,085	& heat input (MMBtu/hr) =	1,063	

	Total:	Coal	Pet Coke
Maximum 1 units:	92,085 lb/hr	59,855 lb/hr	32,230 lb/hr
	33,151 tons/month	21,548 tons/month	11,603 tons/month
	397,808 tons/year	258,575 tons/year	139,233 tons/year
Maximum 3 Units	276,256 lb/hr	179,566 lb/hr	96,690 lb/hr
	99,452 tons/month	64,644 tons/month	34,808 tons/month
	1,109,885 tons/year	721,425 tons/year	388,460 tons/year