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 km E; km N. This site is approximately 54 kilometers from the Okefenokee National Wildlife Refuge and 98 kilometers from the Wolf Island National Wildlife Refuge, both Class I PSD Areas.

2.2 STANDARD INDUSTRIAL CLASSIFICATION CODES (SIC)

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

2.3 FACILITY CATEGORY

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

This facility is classified as a Major or Title V Source of air pollution because emissions of at least one regulated air pollutant, such as particulate matter (PM/PM_{10}), sulfur dioxide (SO_2), nitrogen oxides (NO_X), carbon monoxide (CO) or volatile organic compounds (VOC) exceeds 100 tons per year (TPY).

This facility is within an industry included in the list of the 28 Major Facility Categories per Table 62-212.400-1, F.A.C. Because emissions are greater than 100 TPY for at least one criteria pollutant, the facility is also a Major Facility with respect to Rule 62-212.400, Prevention of Significant Deterioration (PSD). Based upon the Title V permit, this facility is a major source of hazardous air pollutants (HAPs). See Figures 1 and 2 below.

3. PROJECT DESCRIPTION

This project primarily addresses the following emissions unit(s):

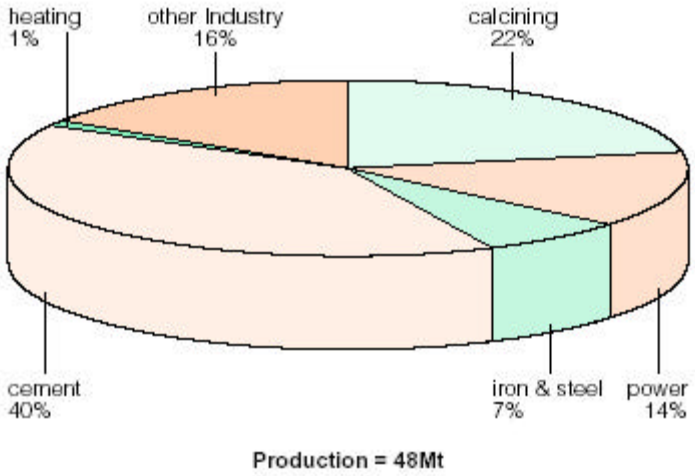
Emissions Unit No.	Emissions Unit Description
001	Pyroflow® Circulating Fluidized Bed (CFB) dry bottom boiler designated as "CFB Boiler A"
002	Pyroflow® Circulating Fluidized Bed (CFB) dry bottom boiler designated as "CFB Boiler B"
003	Pyroflow® Circulating Fluidized Bed (CFB) dry bottom boiler designated as "CFB Boiler C"

The applicant proposes to combust up to 35% of its fuel (on a weight basis) as petroleum coke (petcoke). The facility currently combusts coal as its primary fuel. The applicant indicates that this permit modification can be made in such a way that air emissions will not increase beyond historical levels, thus a PSD Review will not be triggered. The applicant further proposes to maintain and submit to the Department (FDEP) and the Regulatory and Environmental Services Department of Jacksonville (RESD) on an annual basis for a period of 5-years from the date each emission unit begins firing petroleum coke, data demonstrating in accordance with 40 CFR 52.21(b)(21)(v) and 40 CFR 52.21(b)(33) that the operational change associated with the use of petroleum coke did not result in significant emission increases for CO, NO_X, PM, SO_2, SAM and VOC. A general review of petcoke, CFB Boilers, a review of the future actual emissions and related emission analyses follow.

3.1 PETCOKE DISCUSSION

Much of this review was obtained from The Clean Coal Centre of the United Kingdom, in an article entitled "*The use of petroleum coke in a coal-fired plant*". Petroleum coke is a by-product from oil refineries and is composed mainly of carbon though it also contains high levels of sulfur and some heavy metals such as vanadium and nickel. There has been considerable interest in petcoke for several years, where it is available, as it is generally significantly cheaper than coal. The price does vary depending on the volumes produced and worldwide demand. The world production of petcoke grew by 50% from 1987 to 1998. It reached nearly 50 Million Tons (Mt) in 1999 and is expected to reach 100 Mt by 2010. The USA is the world's largest producer, producing three-quarters of world supplies. There are three types of petroleum coke, which can be produced depending on the process of production. The three processes are delayed, fluid and flexicoking with delayed coking producing over 90%. All three types of petcoke have higher calorific values than coal and contain less volatile matter and ash. The main uses of petcoke are as an energy source for power generation, in cement production and iron and steel production (which account for about two thirds of production) and the remainder is used mainly as a carbon source.

FIGURE 3 - 1999 WORLD PETROLEUM COKE MARKET PROFILE



The following additional information was compiled for the Year 2000. The source of this data is FERC Form 423, although the Energy Information Administration (EIA) summarized it in a report entitled "*Cost and Quality of Fuels for Electric Utility Plants 2000 Tables*", dated August 2001. This data was accumulated for electric generating plants with nameplate capacity of 50 megawatts or more. Tables 25 and 28 from that report are shown below:

Table 25. The Top 20 Electric Utilities, Ranked by Receipts of Coal, 2000

Electric Utility	Receipts (thousand short tons)	Average Delivered Cost		Total Coal Bill (million dollars)
		(cents per million Btu)	(dollars per short ton)	
1. Tennessee Valley Authority	41,992	110.2	25.44	1,068.1
2. Georgia Power Co.	34,743	154.5	35.65	1,238.7
3. TXU Electric Co	32,508	105.5	14.11	458.8
4. PacifiCorp	28,068	85.5	16.80	471.6
5. Alabama Power Co	25,634	147.0	31.37	804.2
6. Detroit Edison Co	19,582	129.6	26.90	526.8
7. Reliant HL&P	18,350	143.4	22.17	406.9
8. Basin Electric Power Coop.	15,981	59.2	8.70	139.0
9. Ameren UE	15,675	93.6	16.46	258.0
10. Duke Power Co.	15,089	135.9	33.78	509.7
11. PSI Energy Inc	14,643	109.6	24.52	359.0
12. Ohio Power Co	14,618	213.1	50.70	741.1
13 Virginia Electric & Power	13,945	126.5	32.05	447.0
14. Northern States Power Co	13,147	108.6	19.22	252.7
15. Arkansas Power & Light Co.	12,383	142.9	24.88	308.1
16. Appalachian Power Co.	11,868	132.2	32.25	382.8
17. Southwestern Electric Power	11,705	140.5	22.40	262.1
18. Salt River Proj Ag I & P Dist	11,556	116.8	24.54	283.5
19. Wisconsin Electric Power	11,362	100.0	18.96	215.4
20. Cincinnati Gas & Electric Co.	11,210	105.9	25.66	287.7

Note: Data are for electric generating plants with a total steam-electric and combined-cycle nameplate capacity of 50 or more megawatts.
Source: Federal Energy Regulatory Commission, FERC Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants."

Table 28. Receipts of Petroleum Coke by Electric Utility, 2000

Electric Utility	Receipts (thousand short tons)	Average Quality			Average Delivered Cost	
		Btu (per pound)	Sulfur (percent by weight)	Ash (percent by weight)	(cents per million Btu)	(dollars per short ton)
Central Illinois Pub Serv Co	26	14,419	3.44	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.	69	14,213	5.62	.48	46.7	13.28
Total	**1,683**	**14,214**	**5.14**	**.39**	**58.5**	**16.62**

Notes: • Totals may not equal sum of components because of independent rounding. • Data are for electric generating plants with a total steam-electric and combined-cycle nameplate capacity of 50 or more megawatts.
Source: Federal Energy Regulatory Commission, FERC Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants."

Of interest, no Florida utilities show up in the top 20 listing of coal users, even though Florida is one of the most populous states. It is observed that the cost of petroleum coke in year 2000 was approximately ¼ 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.

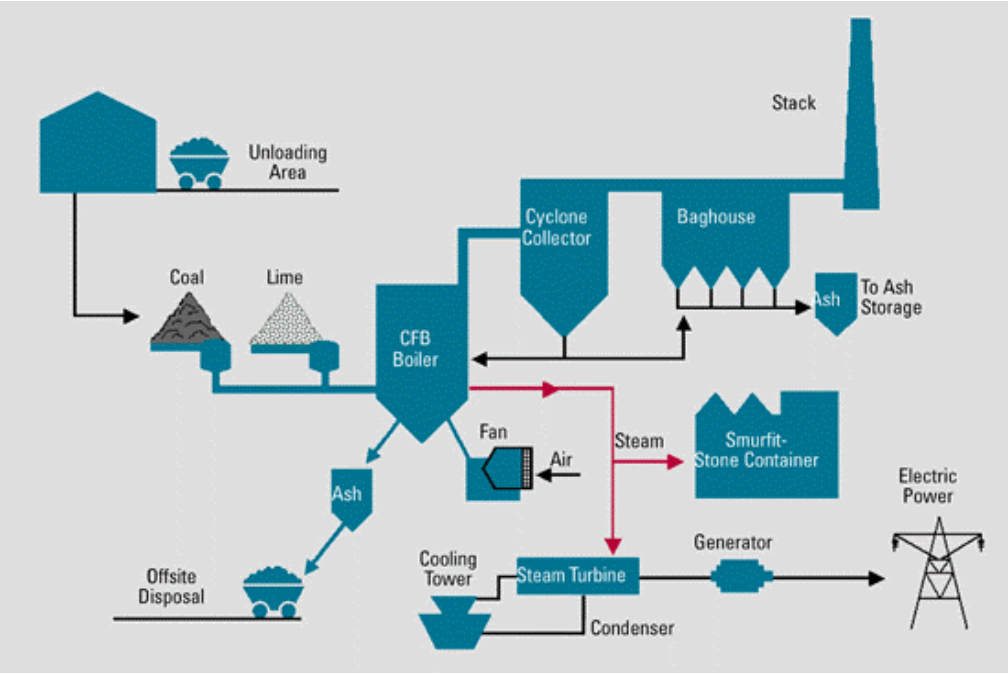
3.2 FLUIDIZED BED COMBUSTION

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 bumout. 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

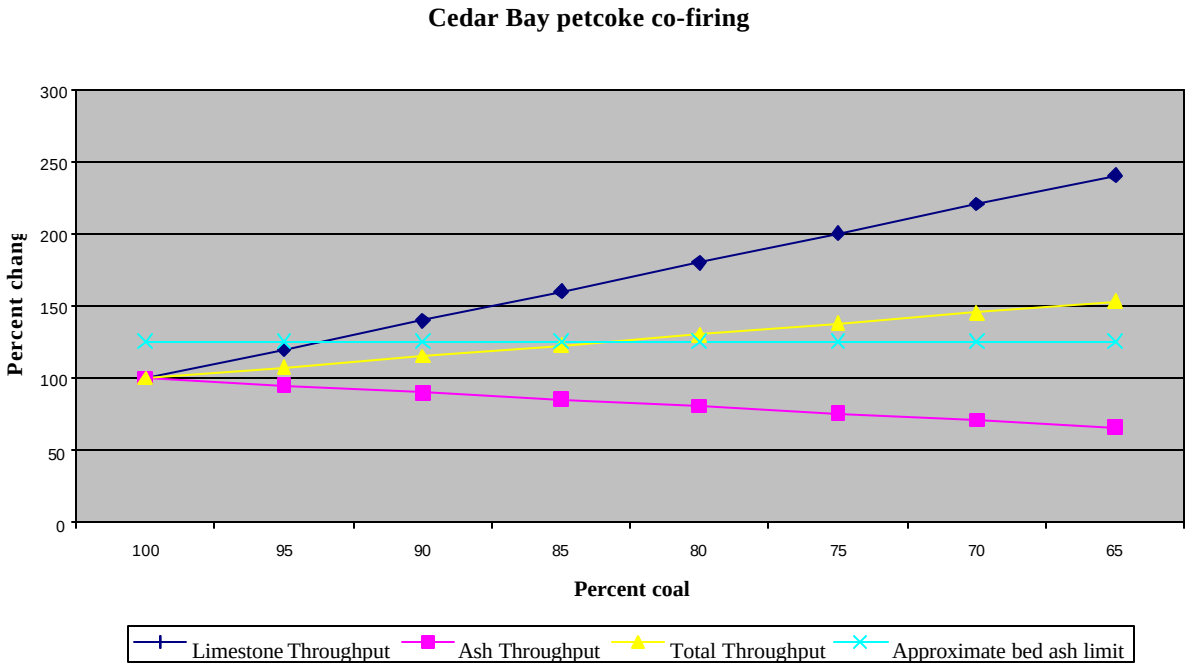
Concerning limestone, the Department estimates that the facility will need to (approximately) double the throughput, in order to achieve the necessary SO_2 scrubbing required to ensure that the PSD significance level is not exceeded. As can be seen from the above table, limestone throughputs can nearly 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).



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