Florida Department of Environmental Regulation

Twin Towers Office Bldg. • 2600 Blair Stone Road • Tallahassee, Florida 32399-2400

Lawton Chiles, Governor

Virginia B. Wetherell, Secretary

June 3, 1993

CERTIFIED MAIL-RETURN RECEIPT REQUESTED

Mr. Gus Cepero, Vice President
Okeelanta Power Limited Partnership
P. O. Box 86
South Bay, Florida 33493

Dear Mr. Cepero:

Attached is one copy of the Technical Evaluation and Preliminary Determination, proposed Best Available Control Technology and Reasonable Available Control Technology Determinations, and proposed permit for the Okeelanta Power Limited Partnership cogeneration facility to be located at the Okeelanta Corporation sugar mill that is 6 miles south of South Bay off U.S. Highway 27, Palm Beach County, Florida.

Please submit any written comments you wish to have considered concerning the Department's proposed action to Mr. Preston Lewis of the Bureau of Air Regulation.

Sincerely,

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

CHF/WH/plm

Attachments

cc: David Knowles, SD
Isidore Goldman, SED
James Stormer, PBCHD
Jewell Harper, EPA
David Buff, KBN
John Bunyak, NPS

Is your RETURN ADDRESS completed on the reverse side?

SENDER:
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- Complete items 3, and 4a & b.
- Print your name and address on the reverse of this form so that we can return this card to you.
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1. ☐ Addressee's Address
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Consult postmaster for fee.

3. Article Addressed to:
Mr. Gus Cepero
Vice President
Okeelanta Power Limited Partnership
P. O. Box 86
South Bay, FL 33495

4a. Article Number
P 230 524 306

4b. Service Type
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Division of Air Resources Management

5. Signature (Addressee)

6. Signature (Agent)
[signature]

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PS Form **3811**, December 1991 ★U.S. GPO: 1992—323-402 **DOMESTIC RETURN RECEIPT**

Thank you for using Return Receipt Service.

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Receipt for Certified Mail
No Insurance Coverage Provided
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Sent to: Mr. Gus Cepero, Okeelanta ~~Power L.P.~~	
Street and No.: P. O. Bos 86	
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:t: AC 50-219413
PSD-FL-198

PS Form 3800, June 1991

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL REGULATION

CERTIFIED MAIL

In the Matter of an
Application for Permit by:

DER File No. AC50-219413
PSD-FL-196
Palm Beach County

Mr. Gus Cepero, Vice President
Okeelanta Power Limited Partnership
P. O. Box 86
South Bay, Florida 33493
__________________________________/

INTENT TO ISSUE

The Department of Environmental Regulation gives notice of its intent to issue a permit (copy attached) for the proposed project as detailed in the application specified above, for the reasons stated in the attached Technical Evaluation and Preliminary Determination.

The applicant, Okeelanta Power Limited Partnership, applied on September 30, 1992, to the Department of Environmental Regulation for a permit to construct a 71.25 MW of electricity biomass (bagasse and wood waste material), No. 2 fuel oil, and coal fired cogeneration facility at the Okeelanta Corporation sugar mill located 6 miles south of South Bay off U.S. Highway 27, Palm Beach County, Florida. The 3 boilers in the new facility will replace 8 existing bagasse/No. 6 fuel oil fired boilers at the sugar mill.

The Department has permitting jurisdiction under the provisions of Chapter 403, Florida Statutes and Florida Administrative Code (F.A.C.) Chapters 17-212 and 17-4. The project is not exempt from permitting procedures. The Department has determined that a construction permit is required for the proposed work.

Pursuant to Section 403.815, Florida Statutes and Rule 17-103.150, F.A.C., you (the applicant) are required to publish at your own expense the enclosed Notice of Intent to Issue Permit. The notice shall be published one time only within 30 days in the legal ad section of a newspaper of general circulation in the area affected. For the purpose of this rule, "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. The applicant shall provide proof of publication to the Department's Bureau of Air Regulation, 2600 Blair Stone Road, Tallahassee, Florida 32399-2400, within seven days of publication. Failure to publish the notice and provide proof of publication within the allotted time may result in the denial of the permit.

The Department will issue the permit with the attached conditions unless a petition for an administrative proceeding (hearing) is filed pursuant to the provisions of Section 120.57, F.S.

A person whose substantial interests are affected by the Department's proposed permitting decision may petition for an administrative proceeding (hearing) in accordance with Section 120.57, 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 2600 Blair Stone Road, Tallahassee, Florida 32399-2400. Petitions filed by the permit applicant and the parties listed below must be filed within 14 days of receipt of this intent. Petitions filed by other persons must be filed within 14 days of publication of the public notice or within 14 days of their receipt of this intent, whichever first occurs. Petitioner shall mail a copy of the petition to the applicant at the address indicated above at the time of filing. Failure to file a petition within this time period shall constitute a waiver of any right such person may have to request an administrative determination (hearing) under Section 120.57, Florida Statutes.

The Petition shall contain the following information;

(a) The name, address, and telephone number of each petitioner, the applicant's name and address, the Department Permit File Number and the county in which the project is proposed;
(b) A statement of how and when each petitioner received notice of the Department's action or proposed action;
(c) A statement of how each petitioner's substantial interests are affected by the Department's action or proposed action;
(d) A statement of the material facts disputed by Petitioner, if any;
(e) A statement of facts which petitioner contends warrant reversal or modification of the Department's action or proposed action;
(f) A statement of which rules or statutes petitioner contends require reversal or modification of the Department's action or proposed action; and
(g) A statement of the relief sought by petitioner, stating precisely the action petitioner wants the Department to take with respect to the Department's action or proposed action.

If a petition is filed, the administrative hearing process is designed to formulate agency action. Accordingly, the Department's final action may be different from the position taken by it in this intent. Persons whose substantial interests will be affected by any decision of the Department with regard to the application have the right to petition to become a party to the proceeding. The petition must conform to the requirements specified above and be filed (received) within 14 days of receipt of this intent in the Office of General Counsel at the above address of the Department.

Failure to petition within the allowed time frame constitutes a waiver of any right such person has to request a hearing under Section 120.57, F.S., and to participate as a party to this proceeding. Any subsequent intervention will only be at the approval of the presiding officer upon motion filed pursuant to Rule 28-5.207, F.A.C.

Executed in Tallahassee, Florida.

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL REGULATION

C. H. Fancy, P.E., Chief
Bureau of Air Regulation
2600 Blair Stone Road
Tallahassee, Florida 32399
904-488-1344

CERTIFICATE OF SERVICE

The undersigned duly designated deputy clerk hereby certifies that this INTENT TO ISSUE and all copies were mailed by certified mail before the close of business on 6-3-92 to the listed persons.

Clerk Stamp

FILING AND ACKNOWLEDGMENT
FILED, on this date, pursuant to §120.52(11), Florida Statutes, with the designated Department Clerk, receipt of which is hereby acknowledged.

Clerk 6-3-92
Date

Copies furnished to:
- David Knowles, SD
- Isidore Goldman, SED
- James Stormer, PBCHD
- Jewell Harper, EPA
- David Buff, KBN
- John Bunyak, NPS

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL REGULATION
NOTICE OF INTENT TO ISSUE PERMIT

The Department of Environmental Regulation gives notice of its intent to issue a construction permit (AC50-219413/PSD-FL-196) to Okeelanta Power Limited Partnership, P. O. Box 86, South Bay, Florida 33493. The proposed permit is for a 71.25 MW of electricity cogeneration facility that will use biomass (bagasse and wood waste material) as the primary fuel with No. 2 fuel oil and low sulfur (0.7 percent) coal as alternate fuels. The proposed facility will be constructed at the Okeelanta Corporation sugar mill located 6 miles south of South Bay, off U.S. Highway 27, Palm Beach County, Florida. The three new 715 MMBtu/hr boilers for the proposed cogeneration facility, each using an electrostatic precipitator, a selective non-catalytic reduction system, and a carbon injection system to control air pollution, will replace 8 existing bagasse/No. 6 fuel oil fired boilers at the sugar mill. Each new boiler will emit up to 21.5 lbs/hr particulate matter, 588.0 lbs/hr sulfur dioxide, 17.6 lbs/hr sulfuric acid mist, 107.3 lbs/hr nitrogen oxides, 250.3 lbs/hr carbon monoxide, 11.8 lbs/hr fluorides, 0.003 lbs/hr beryllium, 42.9 lbs/hr volatile organic compounds, and trace amounts of other criteria/non-criteria pollutants. The project (3 new cogeneration boilers replacing 8 existing bagasse/No. 6 oil fired boilers) will decrease net emissions of particulate matter (-290.4 TPY), nitrogen oxides (-26.2 TPY), carbon monoxide (-8,375.5 TPY), and volatile organic compounds (-56.9 TPY); but increase net emissions of sulfur dioxide (406.0 TPY), beryllium (+0.0048 TPY), fluorides (+21.2 TPY), and sulfuric acid mist (+6.4 TPY). The proposed increase in emissions of sulfur dioxide, beryllium, and fluorides are greater than the significant emission rates. Therefore, the project is subject to review under the Prevention of Significant Deterioration (PSD) regulations and the emission limits for these pollutants are established by a Best Available Control Technology (BACT) determination. The maximum predicted PSD Class II sulfur dioxide increments consumed after this project is constructed are the following: 8.7 ug/m^3, annual average, or 44% of the available annual increment of 20 ug/m^3; 68 ug/m^3, 24-hour average, or 75% of the available 24-hour increment of 91 ug/m^3; and 156 ug/m^3, 3-hour average, or 30% of the available 3-hour increment of 512 ug/m^3. The maximum predicted PSD Class I sulfur dioxide increments consumed are the following: 0.67 ug/m^3, annual average or 34% of the available annual increment of 2.0 ug/m^3; 4.82 ug/m^3, 24-hour average or 96% of the available 24-hour increment of 5.0 ug/m^3; and 22.8 ug/m^3, 3-hour average or 91% of the available 3-hour increment of 25 ug/m^3. The Department is issuing this Intent to Issue for the reasons stated in the Technical Evaluation and Preliminary Determination.

A person whose substantial interests are affected by the Department's proposed permitting decision may petition for an administrative proceeding (hearing) in accordance with Section 120.57, 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 2600 Blair Stone Road, Tallahassee, Florida 32399-2400, within 14 days of publication of this notice. Petitioner shall mail a copy of the petition to the applicant at the address indicated above at the time of filing. Failure to file a petition within this time period shall constitute a waiver of any right such person may have to request an administrative determination (hearing) under Section 120.57, Florida Statutes.

The Petition shall contain the following information; (a) The name, address, and telephone number of each petitioner, the applicant's name and address, the Department Permit File Number and the county in which the project is proposed; (b) A statement of how and when each petitioner received notice of the Department's action or proposed action; (c) A statement of how each petitioner's substantial interests are affected by the Department's action or proposed action; (d) A statement of the material facts disputed by Petitioner, if any; (e) A statement of facts which petitioner contends warrant reversal or modification of the Department's action or proposed action; (f) A statement of which rules or statutes petitioner contends require reversal or modification of the Department's action or proposed action; and (g) A statement of the relief sought by petitioner, stating precisely the action petitioner wants the Department to take with respect to the Department's action or proposed action.

If a petition is filed, the administrative hearing process is designed to formulate agency action. Accordingly, 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 decision of the Department with regard to the application have the right to petition to become a party to the proceeding. The petition must conform to the requirements specified above and be filed (received) within 14 days of publication of this notice in the Office of General Counsel at the above address of the Department. Failure to petition within the allowed time frame constitutes a waiver of any right such person has to request a hearing under Section 120.57, F.S., and to participate as a party to this proceeding. Any subsequent intervention will only be at the approval of the presiding officer upon motion filed pursuant to Rule 28-5.207, F.A.C.

The application 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:

Department of Environmental Regulation
Bureau of Air Regulation
111 S. Magnolia Drive, Suite 4
Tallahassee, Florida 32301

Department of Environmental Regulation
South District
2295 Victoria Ave., Suite 364
Ft. Myers, Florida 33901

Department of Environmental Regulation
Southeast District
1900 S. Congress Ave., Suite A
West Palm Beach, Florida 33406

Palm Beach County Health Dept.
Division of Environmental Science
and Engineering
901 E. Evernia Street
West Palm Beach, Florida 33406

Any person may send written comments on the proposed action to Mr. Preston Lewis at the Department's Tallahassee address. All comments received within 30 days of the publication of this notice will be considered in the Department's final determination.

Further, a public hearing can be requested by any person(s). Such requests must be submitted within 30 days of this notice.

Technical Evaluation
and
Preliminary Determination

Okeelanta Power Limited Partnership
South Bay, Palm Beach County, Florida

71.25 MW of Electricity Cogeneration Facility

File No.: AC50-219413
PSD-FL-196

Department of Environmental Regulation
Division of Air Resources Management
Bureau of Air Regulation

June 3, 1993

I. General Information

A. Applicant

Okeelanta Power Limited Partnership*
P. O. Box 86
South Bay, Florida 33493

* This facility is controlled by Okeelanta Corporation. Initial application submitted under the name of Flo-Energy, Inc.

B. Request

On September 30, 1992, Okeelanta Power submitted an application for permit to construct a 71.25 MW of electricity cogeneration facility that will use biomass (bagasse and wood waste material) as the primary fuel with No. 2 fuel oil and low sulfur (0.70 percent) coal as alternate fuels. The proposed facility will be constructed at the Okeelanta Corporation sugar mill (SIC 2061) located 6 miles south of South Bay, off U.S. Highway 27, Palm Beach County, Florida. The UTM coordinates of this site are Zone 17, 524.9 km E and 2940.1 km N. The facility will use three new 715 MMBtu/hr boilers to generate electricity and supply steam to the sugar mill. These boilers will replace 8 existing bagasse/No. 6 fuel oil fired boilers at the sugar mill once the cogeneration facility begins commercial operation. The new boilers will use electrostatic precipitators (ESP) to control particulate matter emissions, a selective non-catalytic reduction (SNCR) system to reduce nitrogen oxides emissions, and activated carbon injection to reduce mercury emissions. The application was considered complete on February 18, 1993, when the additional information requested by the Department was received. The proposal was revised in a letter dated May 25, 1993.

C. Emissions

The emissions from the facility are a direct function of the type fuel being burned. Biomass is the primary fuel. No. 2 fuel oil is a supplementary fuel. Low sulfur coal (0.70 percent) is an alternate fuel that may be burned when biomass is unavailable. The applicant requested that, fossil fuel consumption (No. 2 fuel oil and coal) be limited by permit restriction to a total of 25 percent of the annual heat input to the cogeneration boilers. Use of the fossil fuel coal is further limited to burning a total for all 3 boilers of 73,714 tons during any 12-month period. Annual sulfur dioxide emissions due to all fuel will be limited to 1,154.3 TPY.

The following tables from the application summarizes the proposed emissions for the three cogeneration boilers:

Table 2-2. Maximum Fuel Usage and Heat Input Rates, Okeelanta Power Limited Partnership Facility (Revised 05/18/93)

Fuel	Heat Input	Heat Transfer Efficiency (%)	Heat Output	Fuel Firing Rate
	Maximum Short-Term (per boiler)			
	(MMBtu/hr)		(MMBtu/hr)	
Biomass	715	68	486	168,236 lb/hr[a]
No. 2 Oil	490	85	417	3,551 gal/hr
Coal	490	85	417	40,833 lb/hr
	Annual Average (total all three boilers)			
	(Btu/yr)		(Btu/yr)	
NORMAL OPERATIONS				
Biomass	1.150E+13	68	7.820E+12	1,352,941 TPY[a]
No. 2 Oil	0	85	0	0 gal/yr
Coal	0	85	0	0 TPY
TOTAL	1.150E+13		7.820E+12	
25% OIL FIRING				
Biomass	8.118E+12	68	5.520E+12	955,059 TPY[a]
No. 2 Oil	2.706E+12	85	2.300E+12	19,608,696 gal/yr
Coal	0	85	0	0 TPY
TOTAL	1.082E+13		7.820E+12	
16% COAL FIRING				
Biomass	9.288E+12	68	6.316E+12	1,092,706 TPY[a]
No. 2 Oil	0	85	0	0 gal/yr
Coal	1.769E+12	85	1.504E+12	73,714 TPY
TOTAL	1.106E+13		7.820E+12	

Note: Total heat output required = 486 MMBtu/hr each boiler, and 7.820E+12 Btu/yr total all boilers. Fuels may be burned in combination, not to exceed indicated total heat outputs.

[a] Based on heating value for bagasse of 4,250 Btu/lb, wet basis.

Table 2-4: Proposed Emission Limits.

Table 2-5: Maximum Short-Term Emissions (per boiler).

Table 2-6: Maximum Annual Emissions (total of all boilers).

Table 2-8: Maximum Annual PM Emissions Rates for Fugitive Dust Sources.

Table 2-10: Maximum Hourly Emissions of Non-Regulated Pollutants (per boiler).

Table 2-11: Maximum Annual Emissions of Non-Regulated Pollutants (total all boilers).

Table 3-3: PSD Source Applicability Analysis.

From Table 3-3, it can be seen that the net contemporaneous emissions of particulate matter, nitrogen oxides, carbon monoxide, volatile organic compounds, and lead will decrease as a result of this project. Also, the net contemporaneous emissions of sulfur dioxide, beryllium, and fluorides will increase by more than the significant emission rates.

II. Rule Applicability

The proposed project, construction of a 71.25 MW cogeneration facility at an existing sugar mill (SIC 2061) in Palm Beach County, is subject to the preconstruction review requirements under the provisions of Chapter 403, Florida Statutes, and Chapters 17-4, 17-210, 17-212, 17-272, 17-275, 17-296, and 17-297, Florida Administrative Code (F.A.C.).

The facility will be located in an area designated nonattainment for ozone (F.A.C. Rule 17-275.410) and attainment for the other criteria pollutants (F.A.C. Rule 17-275.400).

The facility is a major source of particulate matter (PM), sulfur dioxide (SO_2), nitrogen oxides (NO_X), carbon monoxide (CO), and volatile organic compounds (VOC) because the potential emissions of each of these air pollutants exceed 100 TPY (F.A.C. Rule 17-212.200). The proposed facility is subject to the Prevention of Significant Deterioration (PSD) regulations (F.A.C. Rule 17-212.400) because the requested increase in sulfur dioxide, beryllium, and fluoride emissions will exceed the significant emission rates (F.A.C. Rule Table 212.400-2). Therefore, the project is subject to the Preconstruction Review Requirements of F.A.C. Rule 17-212.400. The allowable emissions of the pollutants with significant emissions rate increases will be established by a Best Available Control Technology (BACT) determination (F.A.C. Rule

Table 2-5. Maximum Short-Term Emissions for the Okeelanta Power Cogeneration Facility (per boiler) (Revised 05/18/93)

Regulated Pollutant	Biomass				No. 2 Fuel Oil				Coal				Maximum Emissions for any fuel (lb/hr)
	Emission Factor (lb/MMBtu)	Ref.	Activity Factor (MMBtu/hr)	Maximum Emissions (lb/hr)	Emission Factor (lb/MMBtu)	Ref.	Activity Factor (MMBtu/hr)	Maximum Emissions (lb/hr)	Emission Factor (lb/MMBtu)	Ref.	Activity Factor (MMBtu/hr)	Maximum Emissions (lb/hr)	
Particulate (TSP)	0.03	1	715	21.5	0.03	1	490	14.7	0.03	1	490	14.7	21.5
Particulate (PM10)	0.03	1	715	21.5	0.03	1	490	14.7	0.03	1	490	14.7	21.5
Sulfur dioxide	0.10[a]	2	715	71.5[a]	0.05[a]	9	490	24.5[a]	1.2[a]	1	490	588.0[a]	588.0[a]
Nitrogen oxides	0.15[b]	3	715	107.3[b]	0.15[b]	3	490	73.5[b]	0.17[b]	3	490	83.3[b]	107.3[b]
Carbon monoxide	0.35[c]	4	715	250.3[c]	0.2[c]	4	490	98.0[c]	0.2[c]	4	490	98.0[c]	250.3[c]
VOC	0.06	4	715	42.9	0.03	4	490	14.7	0.03	4	490	14.7	42.9
Lead	2.5E-05	5	715	0.018	8.9E-07	10	490	0.0004	6.4E-05	12	490	0.031	0.031
Mercury	6.3E-06	6	715	0.0045	2.4E-06	11	490	0.00118	8.4E-06	13	490	0.0041	0.0045
Beryllium	--	7	715	--	3.5E-07	12	490	0.00017	5.9E-06	12	490	0.0029	0.0029
Fluorides	--	--	--	--	6.3E-06	14	490	0.003	0.024	14	490	11.8	11.8
Sulfuric acid mist	0.003	8	715	2.15	0.0015	8	490	0.74	0.036	8	490	17.6	17.6
Total reduced sulfur	--	--	--	--	--	--	--	--	--	--	--	--	--
Asbestos	--	--	--	--	--	--	--	--	--	--	--	--	--
Vinyl Chloride	--	--	--	--	--	--	--	--	--	--	--	--	--

[a] 24-hour average.
[b] 30-day rolling average.
[c] 8-hour average.

References:

1. Emission Factor based on NSPS 40CFR 60 Subpart Da.
2. Based upon maximum sulfur content of bagasse of 0.1%, dry basis (0.048%, wet basis).
3. Based on NO_x control system.
4. Based on boiler design.
5. No data available for bagasse; based on testing on wood fired boilers in California (Sassenrath, 1991).
6. Based on source testing at Okeelanta and Osceola, and 30% removal for mercury control system.
7. Emission Tests for Seminole Kraft (1990) and TAPPI Proceedings (1991).
8. Based on AP-42; 3% of SO_2 emissions.
9. Based on maximum sulfur content of No. 2 fuel oil.
10. Toxic Air Emission Factors, EPA, 1988 (EPA-450/2-88-006a).
11. Toxic Air Emission Factors, EPA, 1988 (EPA-450/2-88-006a), using 30% removal from mercury control system.
12. Estimating Air Toxic Emissions from Coal and Oil Combustion Sources (EPA -450/2-89-001) (1989).
13. Based on "Mercury Emissions to the Atmosphere in Florida" (KBN, 1992), and 30% removal from mercury and ESP control system.
14. Based on "Emissions Assessment of Conventional Stationary Combustion Sources: Volume V: Industrial Combustion Sources (EPA-600/7-81-003c).

Table 2-4. Proposed Emission Limits for the Okeelanta Power Facility (revised 05/18/93)

Pollutant	Emission Limit (lb/MMBtu)		
	Biomass	No.2 Oil	Bit. Coal
Particulate (TSP)	0.03	0.03	0.03
Particulate (PM10)	0.03	0.03	0.03
Sulfur Dioxide			
24-hour average	0.10	0.05	1.2
Annual average[a]	0.02	0.05	1.2
Nitrogen Oxides			
Annual average[a]	0.15	0.15	0.17
Carbon Monoxide			
8-hour average	0.35	0.2	0.2
Volatile Organic Compounds	0.06	0.03	0.03
Lead	2.5E-05	8.9E-07	6.4E-05
Mercury	[b]	2.4E-06	8.4E-06
Beryllium	--	3.5E-07	5.9E-06
Fluorides	--	6.3E-06	0.024
Sulfuric Acid Mist	0.003	0.0015	0.036

[a] Compliance based on 30-day rolling average, per 40 CFR 60, Subpart Da.
[b] Limits are 6.3×10^{-6} lb/MM Btu for bagasse and 0.29×10^{-6} lb/MM Btu for wood waste materials.

Table 2-8. Okeelanta Power Cogeneration Facility Maximum Annual PM Emission Rates for Fugitive Dust Sources (Revised 05/18/93)

Source	Uncontrolled Emission Factor (lb/ton)	Control	Control Efficiency (%)	Controlled Emission Factor (lb/ton)	Maximum Annual Thruput (tons/yr)	Maximum Annual PM(TSP) Emissions (tons/yr)	PM10 Size Mult.	Maximum Annual PM10 Emissions (tons/yr)
<u>Coal Handling</u>								
Railcar Unloading	0.00234	Enclosure	70	0.00070	73,714	0.026	0.35	0.009
Conveyor-to-Coal Pile	0.00234	None	0	0.00234	73,714	0.086	0.35	0.030
Reclaim Hopper	0.00234	Enclosure	90	0.00023	73,714	0.009	0.35	0.003
Conveyor-to-Crusher	0.00234	None	0	0.00234	73,714	0.086	0.35	0.030
Coal Crusher	0.02	Enclosure	70	0.00600	73,714	0.221	0.45	0.100
Crusher-to-Conveyor	0.00234	None	0	0.00234	73,714	0.086	0.35	0.030
Conveyor-to-Boiler Silo	0.00234	None	0	0.00234	73,714	0.086	0.35	0.030
Storage Pile	--	None	0	--	--	0.211 [a]	0.5	0.105 a
Coal Storage Pile Maintenance	0.90328	Watering	50	0.45164 b	14,600 [c]	3.297	0.35	1.154
<u>Biomass Handling</u>								
Truck Dump	0.00012	None	0	0.00012	1,352,941	0.083	0.35	0.029
Conveyor-to-Conveyor	0.00012	None	0	0.00012	1,352,941	0.083	0.35	0.029
Conveyor-to-Hog Tower	0.00012	None	0	0.00012	1,352,941	0.083	0.35	0.029
Hogger	0.02	Enclosed	95	0.00100	1,352,941	0.676	0.35	0.237
Hogger-to-Conveyor	0.00012	None	0	0.00012	1,352,941	0.083	0.35	0.029
Transfer Tower	0.00012	None	0	0.00012	1,352,941	0.083	0.35	0.029
Conveyor-to-Stacker	0.00012	None	0	0.00012	1,352,941	0.083	0.35	0.029
Stacking	0.00012	None	0	0.00012	1,352,941	0.083	0.35	0.029
Underpile Reclaim	0.00012	Enclosed	90	0.00001	1,352,941	0.008	0.35	0.003
Reclaimer-to-Conveyor	0.00012	None	0	0.00012	1,352,941	0.083	0.35	0.029
Transfer Tower	0.00012	None	0	0.00012	1,352,941	0.083	0.35	0.029
Conveyor-to-Boiler Feeders	0.00012	None	0	0.00012	1,352,941	0.083	0.35	0.029
Biomass Storage Pile	--	None	0	--	--	0.160	0.5	0.080
Biomass Storage Pile Maintenance	0.90328[b]	Watering	50	0.45164[b]	21,900[c]	4.945	0.35	1.731
<u>Fly Ash Handling</u>								
Fly Ash Transfer	0.00727	Enclosure or Watering	50	0.00364	43,294[d]	0.079	0.35	0.028
	TOTAL					10.804		3.859

[a] Refer to Appendix A and text for derivation.
[b] lb/VMT.
[c] Vehicle miles traveled per year.
[d] 1,352,941 TPY biomass at 3.20 percent ash; assumes all ash is flyash.

Table 2-6. Maximum Annual Emissions for the Okeelanta Power Limited Partnership Facility (total all three boilers) (Revised 05/18/93)

Regulated Pollutant	Biomass			No. 2 Fuel Oil			Coal			Total Annual Emissions (TPY)
	Emission Factor (lb/MMBtu)	Activity Factor (E12 Btu/yr)	Annual Emissions (TPY)	Emission Factor (lb/MMBtu)	Activity Factor (E12 Btu/yr)	Annual Emissions (TPY)	Emission Factor (lb/MMBtu)	Activity Factor (E12 Btu/yr)	Annual Emissions (TPY)	
Normal Operations										
Particulate (TSP)	0.03	11.500	172.50	–	–	–	–	–	–	172.50 [a]
Particulate (PM10)	0.03	11.500	172.50	–	–	–	–	–	–	172.50 [a]
Sulfur dioxide	0.02	11.500	115.00	–	–	–	–	–	–	115.00
Nitrogen oxides	0.15	11.500	862.50	–	–	–	–	–	–	862.50 [a]
Carbon monoxide	0.35	11.500	2,012.50	–	–	–	–	–	–	2,012.50 [a]
VOC	0.06	11.500	345.00	–	–	–	–	–	–	345.00 [a]
Lead	2.5E-05	11.500	0.14	–	–	–	–	–	–	0.14
Mercury	[b]	11.500	[b]	–	–	–	–	–	–	0.0300
Beryllium	–	–	–	–	–	–	–	–	–	–
Fluorides	–	–	–	–	–	–	–	–	–	–
Sulfuric acid mist	0.00060	11.500	3.45	–	–	–	–	–	–	3.45
Total reduced sulfur	–	–	–	–	–	–	–	–	–	–
Asbestos	–	–	–	–	–	–	–	–	–	–
Vinyl Chloride	–	–	–	–	–	–	–	–	–	–
25% Oil Firing										
Particulate (TSP)	0.03	8.118	121.77	0.03	2.706	40.59	–	–	–	162.36
Particulate (PM10)	0.03	8.118	121.77	0.03	2.706	40.59	–	–	–	162.36
Sulfur dioxide	0.02	8.118	81.18	0.05	2.706	67.65	–	–	–	148.83
Nitrogen oxides	0.15	8.118	608.85	0.15	2.706	202.95	–	–	–	811.80
Carbon monoxide	0.35	8.118	1,420.65	0.2	2.706	270.60	–	–	–	1,691.25
VOC	0.06	8.118	243.54	0.03	2.706	40.59	–	–	–	284.13
Lead	2.5E-05	8.118	0.10	8.9E-07	2.706	0.001	–	–	–	0.10
Mercury	[b]	8.118	[b]	b	2.706	[b]	–	–	–	0.0300
Beryllium	–	–	–	3.5E-07	2.706	0.0005	–	–	–	0.00047
Fluorides	–	–	–	6.27E-06	2.706	0.0085	–	–	–	0.0085
Sulfuric acid mist	0.00060	8.118	2.44	0.0015	2.706	2.03	–	–	–	4.46
Total reduced sulfur	–	–	–	–	–	–	–	–	–	–
Asbestos	–	–	–	–	–	–	–	–	–	–
Vinyl Chloride	–	–	–	–	–	–	–	–	–	–
16% Coal Firing										
Particulate (TSP)	0.03	9.288	139.32	–	–	–	0.03	1.769	26.54	165.86
Particulate (PM10)	0.03	9.288	139.32	–	–	–	0.03	1.769	26.54	165.86
Sulfur dioxide	0.02	9.288	92.88	–	–	–	1.2	1.769	1,061.40	1,154.28 [a]
Nitrogen oxides	0.15	9.288	696.60	–	–	–	0.17	1.769	150.37	846.97
Carbon monoxide	0.35	9.288	1,625.40	–	–	–	0.2	1.769	176.90	1,802.30
VOC	0.06	9.288	278.64	–	–	–	0.03	1.769	26.54	305.18
Lead	2.5E-05	9.288	0.12	–	–	–	6.4E-05	1.769	0.06	0.17 [a]
Mercury	[b]	9.288	[b]	–	–	–	b	1.769	b	0.0300 [a]
Beryllium	–	–	–	–	–	–	5.9E-06	1.769	0.0052	0.0052 [a]
Fluorides	–	–	–	–	–	–	0.024	1.769	21.23	21.23 [a]
Sulfuric acid mist	0.00060	9.288	2.79	–	–	–	0.036	1.769	31.84	34.63 [a]
Total reduced sulfur	–	–	–	–	–	–	–	–	–	–
Asbestos	–	–	–	–	–	–	–	–	–	–
Vinyl Chloride	–	–	–	–	–	–	–	–	–	–

[a] Indicates maximum annual emission rate.
[b] Refer to text for explanation.

Table 2-11. Maximum Annual Emissions of Non-Regulated Pollutants for the Okeelanta Power Cogeneration Facility (total all boilers) (Page 1 of 2) (Revised 05/18/93)

	Biomass			No. 2 Fuel Oil			Coal			Total
Non Regulated Pollutant	Emission Factor (lb/MMBtu)	Activity Factor (E12 Btu/yr)	Annual Emissions (TPY)	Emission Factor (lb/MMBtu)	Activity Factor (E12 Btu/yr)	Annual Emissions (TPY)	Emission Factor (lb/MMBtu)	Activity Factor (E12 Btu/yr)	Annual Emissions (TPY)	Total Annual Emission (TPY)
Normal Operations										
Ammonia	0.0148	11.500	85.1	–	–	–	–	–	–	85.1
Antimony	UD	11.500	–	–	–	–	–	–	–	–
Arsenic	5.58E-05	11.500	0.32	–	–	–	–	–	–	0.32 *
Barium	1.06E-04	11.500	0.61	–	–	–	–	–	–	0.61
Bromine	1.47E-03	11.500	8.45	–	–	–	–	–	–	8.5 *
Cadmium	5.43E-06	11.500	0.031	–	–	–	–	–	–	0.031 *
Chromium	5.54E-05	11.500	0.32	–	–	–	–	–	–	0.32 *
Chromium +6	1.35E-05	11.500	0.078	–	–	–	–	–	–	0.078 *
Cobalt	4.98E-04	11.500	2.86	–	–	–	–	–	–	2.86 *
Copper	7.23E-05	11.500	0.42	–	–	–	–	–	–	0.42
Dioxin	6.93E-12	11.500	4.0E-08	–	–	–	–	–	–	4.0E-08 *
Furan	3.62E-10	11.500	2.1E-06	–	–	–	–	–	–	2.1E-06 *
Formaldehyde	6.56E-04	11.500	3.77	–	–	–	–	–	–	3.8 *
Hydrogen Chloride	3.70E-02	11.500	212.75	–	–	–	–	–	–	212.8
Indium	1.27E-04	11.500	0.73	–	–	–	–	–	–	0.73 *
Manganese	7.98E-04	11.500	4.59	–	–	–	–	–	–	4.6 *
Molybdenum	2.54E-04	11.500	1.46	–	–	–	–	–	–	1.5 *
Nickel	4.41E-05	11.500	0.25	–	–	–	–	–	–	0.25
Phosphorus	3.53E-04	11.500	2.03	–	–	–	–	–	–	2.03
Selenium	UD	11.500	–	–	–	–	–	–	–	–
Silver	2.94E-05	11.500	0.169	–	–	–	–	–	–	0.169 *
Thallium	UD	11.500	–	–	–	–	–	–	–	–
Tin	1.62E-04	11.500	0.93	–	–	–	–	–	–	0.93 *
Zinc	4.24E-04	11.500	2.44	–	–	–	–	–	–	2.44 *
Zirconium	9.29E-05	11.500	0.53	–	–	–	–	–	–	0.53 *
25% Oil Firing										
Ammonia	0.0148	8.118	60.1	0.0148	2.706	20.02	–	–	–	80.10
Antimony	UD	8.118	–	2.32E-06	2.706	0.0031	–	–	–	0.0031
Arsenic	5.58E-05	8.118	0.23	5.00E-07	2.706	0.0007	–	–	–	0.23
Barium	1.06E-04	8.118	0.43	6.69E-06	2.706	0.0091	–	–	–	0.44
Bromine	1.47E-03	8.118	5.967	6.97E-06	2.706	0.0094	–	–	–	5.976
Cadmium	5.43E-06	8.118	0.022	1.58E-06	2.706	0.0021	–	–	–	0.024
Chromium	5.54E-05	8.118	0.22	1.39E-05	2.706	0.0188	–	–	–	0.24
Chromium + 6	1.35E-05	8.118	0.055	2.78E-06	2.706	0.0038	–	–	–	0.059
Cobalt	4.98E-04	8.118	2.02	1.17E-05	2.706	0.0159	–	–	–	2.04
Copper	7.23E-05	8.118	0.29	4.20E-05	2.706	0.0568	–	–	–	0.35
Dioxin	6.93E-12	8.118	2.8E-08	–	2.706	–	–	–	–	2.8E-08
Furan	3.62E-10	8.118	1.5E-06	–	2.706	–	–	–	–	1.5E-06
Formaldehyde	6.56E-04	8.118	2.7	4.05E-04	2.706	0.55	–	–	–	3.21
Hydrogen Chloride	3.70E-02	8.118	150.18	6.37E-04	2.706	0.8616	–	–	–	151.04

Table 2-10. Maximum Hourly Emissions of Non-Regulated Pollutants for the Okeelanta Power Cogeneration Facility (per boiler) (Revised 11/25/92)

Non Regulated Pollutant	Biomass Emission Factor (lb/MMBtu)	Ref	Biomass Activity Factor (MMBtu/hr)	Biomass Hourly Emissions (lb/hr)	No. 2 Fuel Oil Emission Factor (lb/MMBtu)	Ref	No. 2 Fuel Oil Activity Factor (MMBtu/hr)	No. 2 Fuel Oil Hourly Emissions (lb/hr)	Coal Emission Factor (lb/MMBtu)	Ref	Coal Activity Factor (MMBtu/hr)	Coal Hourly Emissions (lb/hr)	Maximum Hourly Emission[a] (lb/hr)
Ammonia	0.0148	8	715	10.6	0.0148	8	490	7.3	0.048	8	490	23.6	23.6
Antimony	UD	3	715	–	2.32E-06	5	490	0.0011	3.49E-05	5	490	0.017	0.017
Arsenic	1.62E-04	10	715	0.116	5.00E-07	1	490	0.0002	2.64E-05	4	490	0.013	0.116
Barium	1.06E-04	3	715	0.076	6.69E-06	5	490	0.0033	7.44E-04	5	490	0.36	0.36
Bromine	1.47E-03	7	715	1.05	6.97E-06	5	490	0.00342	7.90E-04	5	490	0.387	1.05
Cadmium	5.43E-06	2	715	0.0039	1.58E-06	1	490	0.0008	1.36E-06	4	490	0.001	0.0039
Chromium	1.54E-04	10	715	0.110	1.39E-05	1	490	0.0068	1.66E-05	4	490	0.008	0.110
Chromium^{+6}	3.81E-05	9	715	0.027	2.78E-06	9	490	0.0014	3.32E-06	9	490	0.002	0.027
Cobalt	4.98E-04	7	715	0.356	1.17E-05	5	490	0.0058	7.20E-05	5	490	0.035	0.356
Copper	1.45E-04	10	715	0.104	4.20E-05	1	490	0.021	1.71E-04	4	490	0.084	0.104
Dioxin	6.93E-12	2	715	5.0E-09	–		490	–	–		490	–	5.5E-09
Furan	3.62E-10	2	715	2.6E-07	–		490	–	–		490	–	2.6E-07
Formaldehyde	6.56E-04	2	715	0.469	4.05E-04	1	490	0.20	2.20E-04	4	490	0.108	0.47
Hydrogen Chloride	3.70E-02	3	715	26.5	6.37E-04	6	490	0.312	7.90E-02	6	490	38.7	38.7
Indium	1.27E-04	7	715	0.091	–		490	–	–		490	–	0.091
Manganese	7.98E-04	2	715	0.57	3.08E-06	1	490	0.0015	3.10E-05	4	490	0.015	0.57
Molybdenum	2.54E-04	7	715	0.18	4.88E-06	5	490	0.0024	8.83E-05	5	490	0.043	0.18
Nickel	4.41E-05	2	715	0.032	4.76E-05	1	490	0.023	1.02E-03	4	490	0.50	0.50
Phosphorus	3.53E-04	3	715	0.25	5.81E-06	5	490	0.0028	8.60E-04	5	490	0.42	0.42
Selenium	UD	3	715	–	4.60E-06	1	490	0.0023	5.34E-05	5	490	0.026	0.026
Silver	2.94E-05	3	715	0.021	–		490	–	–		490	–	0.021
Thallium	UD	3	715	–	–		490	–	–		490	–	–
Tin	1.62E-04	7	715	0.12	3.30E-05	5	490	0.016	8.83E-05	5	490	0.043	0.12
Zinc	4.24E-04	2	715	0.30	6.69E-06	5	490	0.0033	3.49E-04	5	490	0.17	0.30
Zirconium	9.29E-05	7	715	0.066	–		490	–	–		490	–	0.066

Note: UD = undetectable levels in gas stream.

[a] Denotes maximum for any fuel.

References
1: Toxic Air Pollutant Emission Factors - A Compilation for Selected Air Toxic Compounds and Sources, Second Edition EPA-450/2-90-011 (1990).
2: Based on "Air Toxic Emissions from Wood Fired Boilers", C. Sassenrath, 1991 TAPPI Proceedings.
3: Based on stack test results of wood fired boilers and fuel analysis at Seminole Kraft Corporation (1990) equipped with wet scrubbers.
4: Estimating Emissions from Oil and Coal Combustion Sources EPA-450/2-89-001 (1989).
5: Emissions Assessment of Conventional Stationary Combustion Systems Volume V, 1981. Based on an uncontrolled spreader stoker design and then assuming 90% control from ESP.
6: Emissions Assessment of Conventional Stationary Combustion Systems Volume V, 1981. Based on an uncontrolled spreader stoker design.
7: EPA PM/VOC Speciation Database, updated October, 1989.
8: Based on maximum 20 ppm NH_3 in exhaust gases for biomass and No. 2 fuel oil; 65 ppm for coal.
9: Based upon stack test data at Dade County RRF, 1992, which indicated less than 20% of total chromium was chromium^{+6}.
10: Same as reference 2; includes 3% treated wood burning.

Source: KBN, 1992.

Table 3-3. PSD Source Applicability Analysis for the Okeelanta Power Limited Partnership Facility (revised 05/18/93)

Regulated Pollutant	Baseline Emissions (TPY)	Cogeneration Facility Annual Emissions (TPY)	Net Change (TPY)	Significant Emission Rate (TPY)	PSD Applies ?
Particulate (TSP)	473.7	183.3[b]	-290.4	25	No
Particulate (PM10)	426.3	176.4[c]	-249.9	15	No
Sulfur Dioxide	748.3	1,154.3	406.0	40	Yes
Nitrogen Oxides	888.7	862.5	-26.2	40	No
Carbon Monoxide	10,388.0	2,012.5	-8,375.5	100	No
VOC	401.9	345.0	-56.9	40	No[a]
Lead	0.28	0.17	-0.11	0.6	No
Mercury	0.0292[d]	0.0300	0.0008	0.1	No
Beryllium	0.0004	0.0052	0.0048	0.0004	Yes
Fluorides	0.04	21.2	21.2	3	Yes
Sulfuric Acid Mist	22.4	34.6	6.4	7	No
Total Reduced Sulfur	–	–	0	10	No
Asbestos	–	–	0	0.007	No
Vinyl Chloride	–	–	0	0	No

[a] Nonattainment review does not apply since there is no increase in VOC emissions.

[b] Includes 172.5 TPY from boilers and 10.8 TPY from fugitive dust sources.

[c] Includes 172.5 TPY from boilers and 3.9 TPY from fugitive dust sources.

[d] The estimated average annual emission rate for the 1990-1991 and 1991-1992 crop years is 0.0292 TPY. The highest annual emission rate for either of these years is 0.0300 TPY.

Table 2-11. Maximum Annual Emissions of Non-Regulated Pollutants for the Okeelanta Power Cogeneration Facility (total all boilers) (Page 2 of 2) (Revised 05/18/93)

Non Regulated Pollutant	Biomass Emission Factor (lb/MMBtu)	Biomass Activity Factor (E12 Btu/yr)	Biomass Annual Emissions (TPY)	No. 2 Fuel Oil Emission Factor (lb/MMBtu)	No. 2 Fuel Oil Activity Factor (E12 Btu/yr)	No. 2 Fuel Oil Annual Emissions (TPY)	Coal Emission Factor (lb/MMBtu)	Coal Activity Factor (E12 Btu/yr)	Coal Annual Emissions (TPY)	Total Annual Emission (TPY)
Indium	1.27E-04	8.118	0.52	–	2.706	–	–	–	–	0.52
Manganese	7.98E-04	8.118	3.24	3.08E-06	2.706	0.0042	–	–	–	3.2
Molybdenum	2.54E-04	8.118	1.03	4.88E-06	2.706	0.0066	–	–	–	1.0
Nickel	4.41E-05	8.118	0.18	4.76E-05	2.706	0.0644	–	–	–	0.24
Phosphorus	3.53E-04	8.118	1.43	5.81E-06	2.706	0.0079	–	–	–	1.44
Selenium	UD	8.118	–	4.60E-06	2.706	0.0062	–	–	–	0.0062
Silver	2.94E-05	8.118	0.119	–	2.706	–	–	–	–	0.119
Thallium	UD	8.118	–	–	2.706	–	–	–	–	–
Tin	1.62E-04	8.118	0.66	3.30E-05	2.706	0.045	–	–	–	0.70
Zinc	4.24E-04	8.118	1.72	6.69E-06	2.706	0.0091	–	–	–	1.7
Zirconium	9.29E-05	8.118	0.38	–	2.706	–	–	–	–	0.38
<u>16% Coal Firing</u>										
Ammonia	1.48E-02	9.288	68.73	–	–	–	0.048	1.769	42.46	111.19 [a]
Antimony	UD	9.288	–	–	–	–	3.49E-05	1.769	0.031	0.031 [a]
Arsenic	5.58E-05	9.288	0.26	–	–	–	2.64E-05	1.769	0.023	0.28
Barium	1.06E-04	9.288	0.49	–	–	–	7.44E-04	1.769	0.66	1.15 [a]
Bromine	1.47E-03	9.288	6.83	–	–	–	7.90E-04	1.769	0.699	7.53
Cadmium	5.43E-06	9.288	0.025	–	–	–	1.36E-06	1.769	0.0012	0.026
Chromium	5.54E-05	9.288	0.257	–	–	–	1.66E-05	1.769	0.015	0.272
Chromium +6	1.35E-05	9.288	0.063	–	–	–	3.32E-06	1.769	0.003	0.066
Cobalt	4.98E-04	9.288	2.31	–	–	–	7.20E-05	1.769	0.064	2.4
Copper	7.23E-05	9.288	0.34	–	–	–	1.71E-04	1.769	0.15	0.49 [a]
Dioxin	6.93E-12	9.288	3.2E-08	–	–	–	–	1.769	–	3.2E-08
Furan	3.62E-10	9.288	1.7E-06	–	–	–	–	1.769	–	1.7E-06
Formaldehyde	6.56E-04	9.288	3.0	–	–	–	2.20E-04	1.769	0.19	3.24
Hydrogen Chloride	3.70E-02	9.288	171.828	–	–	–	7.90E-02	1.769	69.88	241.7 [a]
Indium	1.27E-04	9.288	0.59	–	–	–	–	1.769	–	0.59
Manganese	7.98E-04	9.288	3.71	–	–	–	3.10E-05	1.769	0.027	3.7
Molybdenum	2.54E-04	9.288	1.18	–	–	–	8.83E-05	1.769	0.078	1.3
Nickel	4.41E-05	9.288	0.21	–	–	–	1.02E-03	1.769	0.90	1.11 [a]
Phosphorus	3.53E-04	9.288	1.64	–	–	–	8.60E-04	1.769	0.76	2.40 [a]
Selenium	UD	9.288	–	–	–	–	5.34E-05	1.769	0.047	0.047 [a]
Silver	2.94E-05	9.288	0.137	–	–	–	–	1.769	–	0.137
Thallium	UD	9.288	–	–	–	–	–	1.769	–	–
Tin	1.62E-04	9.288	0.75	–	–	–	8.83E-05	1.769	0.078	0.83
Zinc	4.24E-04	9.288	1.97	–	–	–	3.49E-04	1.769	0.31	2.3
Zirconium	9.29E-05	9.288	0.43	–	–	–	–	1.769	–	0.43

Note: UD = undetectable levels in gas stream.

[a] Denotes maximum annual emissions for any fuel scenario.

17-212.410). The proposed facility is also subject to the federal new source performance standards (NSPS) for electric utility steam generating units (40 CFR 60, Subpart Da). The emission limits and monitoring requirements of this rule will be applied to the proposed facility.

The proposed facility will not be subject to new source review for nonattainment areas (F.A.C. Rule 17-212.500) because the contemporaneous VOCs and NO_x emissions will not increase above the significant emission rates. The facility is subject to F.A.C. Rule 17-296.570, Reasonable Available Control Technology, for VOC and NO_x because the proposed sources are major emitters of these pollutants.

III. Technical Evaluation

The proposed 71.25 megawatt of electricity (maximum) cogeneration facility will contain three boilers capable of burning biomass, No. 2 fuel oil, and coal. The emissions from each boiler will be controlled by an electrostatic precipitator (ESP) for PM and acid mist control, selective non-catalytic reduction system (SNCR) for NO_x control, and a carbon injection system for mercury control. The three new boilers in the cogeneration system will replace eight existing bagasse/No. 6 fuel oil fired boilers at the Okeelanta Corporation sugar mill.

The primary fuel to the cogeneration facility will be bagasse (2/3 of the heat input) and wood waste material (1/3 of the heat input). No. 2 fuel oil and coal are used as alternate fuels. Heat input from No. 2 fuel oil will be restricted by permit conditions to 25 percent of the total annual heat input to the cogeneration facility. The maximum amount of coal that can be burned at this facility is further limited to 73,714 tons during any 12-month period (16 percent of total annual heat input). The combined use of coal and fuel oil cannot exceed 25 percent of the total annual heat input to the cogeneration facility. In addition, the total sulfur dioxide emissions will be limited to 1,154.3 TPY (12-month rolling average). Particulate matter (PM/PM_{10}) emissions from the new boilers will be controlled by an ESP that has a design efficiency in excess of 98 percent. The ESP will be capable of meeting the NSPS PM standard of 0.03 lbs/MMBtu heat input. The NSPS visible emissions standard is 20 percent opacity (6-minute average), except for one 6-minute period per hour of not more than 27 percent opacity. Compliance will be determined by periodic stack tests and the visible emissions will be continuously monitored. The proposed facility is not subject to the PSD regulations for particulate matter.

SO_2 emissions will be controlled by the use of low sulfur fuels. Biomass (bagasse and wood waste material), the primary fuel, averages about 0.009 percent sulfur. The No. 2 fuel oil, which may be used as a supplementary or auxiliary fuel, will have a

Table 6-18. Maximum Impacts of Toxic Pollutants for Okeelanta Power Cogeneration Facility (total all boilers) (Revised 05/18/93)

Pollutant	Maximum Hourly Emissions[a] (lb/hr)	Concentrations ($\mu g/m^3$) 8-Hour Impact	8-Hour NTL	24-Hour Impact	24-Hour NTL	Annual Impact	Annual NTL
Ammonia	70.8	3.9	180	3.0	43.2	–	–
Antimony	0.051	0.0028	5	0.002	1.2	0.0002	0.3
Arsenic	0.35	0.0163	2	0.01	0.48	0.000226 [b]	0.000230
Barium	1.08	0.0594	5	0.05	1.2	0.0033	50
Beryllium	0.0087	0.0005	0.02	0.0004	0.0048	0.00003	0.00042
Bromine	3.15	0.15	7	0.11	1.68	–	–
Cadmium	0.012	0.0005	0.5	0.0004	0.12	0.00003	0.00056
Chromium metals	0.33	0.0154	5	0.012	1.2	0.00087	1000
Chromium+6	0.081	0.0041	0.5	0.003	0.12	0.000059 [c]	0.000083
Cobalt	1.07	0.05	0.5	0.04	0.12	–	–
Copper	0.31	0.01	10	0.01	2.4	–	–
Dioxins/Furans	8.0E-07	–	–	–	–	2.1E-09	2.2E-08
Fluoride	35.4	1.95	25	1.48	6	–	–
Formaldehyde	1.41	0.07	4.5	0.05	1.08	0.004	0.077
Hydrogen Chloride	116.1	6.39	70	4.84	16.8	0.360	7.0
Indium	0.27	0.01	1	0.01	0.24	–	–
Manganese	1.71	0.08	50	0.06	12	–	–
Mercury	0.0135	0.0007	0.5	0.0006	0.12	0.00004	0.3
Molybdenum	0.54	0.03	50	0.02	12	–	–
Nickel	1.50	0.08	0.5	0.06	0.12	0.0011 [d]	0.0042
Phosphorus	1.26	0.07	1	0.05	0.24	–	–
Selenium	0.08	0.004	2	0.003	0.48	–	–
Silver	0.06	0.003	0.1	0.002	0.024	0.0002	3
Sulfuric Acid Mist	52.8	2.9	10.0	2.2	2.4	–	–
Thallium	–	–	–	–	–	–	–
Tin	0.36	0.02	1	0.01	0.24	–	–
Zinc	0.90	0.04	10	0.03	2.4	–	–
Zirconium	0.20	0.009	50	0.01	12	–	–

Note: NTL = no-threat level.
Maximum concentrations determined with ISCST2 model and West Palm Beach meteorological data for 1982 to 1986.
Highest predicted concentration ($\mu g/m^3$) for a 10 g/s (79.365 lb/hr) emission rate:
8-hour = 4.369
24-hour = 3.310
Annual = 0.2459

[a] Total all three boilers.
[b] Based on maximum annual average emission rate of 0.32 TPY total all three boilers (avg. of 0.073 lb/hr).
[c] Based on maximum annual average emission rate of 0.078 TPY total all three boilers (avg. of 0.018 lb/hr).
[d] Based on maximum annual average emission rate of 1.56 TPY total all three boilers (avg. of 0.356 lb/hr).

Net Contemporaneous Emission Change Analysis Okeelanta Power Limited Partnership Based on the use of coal fuel being limited to 73,714 tons during any 12-month period heat input.					
	TPY Emissions				
Pollutants	Biomass (BM)	BM+Oil (O)	BM+Coal (C)	BM+O+C	Net Contemporaneous Change
Sulfur Dioxide	115.0	148.9	1,154.3	1,154.3	+406.0
Nitrogen Oxides	862.5	811.8	847.0	847.0	-26.2
Beryllium	--	0.0005	0.0052	0.0052	+0.0048
Fluorides	--	0.0085	21.2	21.2	+21.2
Sulfuric Acid Mist	3.45	4.46	34.6	34.6	+6.4

The applicant is committed to not increasing the mercury emissions from this facility. An activated carbon injection system will be used on the new boilers to reduce mercury emissions. Stack tests will be used to establish the actual emissions of mercury, estimated to be 0.0300 TPY, and to confirm compliance with the mercury emission standard.

Reasonable precautions will be required to control fugitive particulate matter emissions from the fuels (biomass and coal), ash (boilers and ESP), and activated carbon injection system. Control will be accomplished through wetting and/or containment, and the use of dust filters on the activated carbon system silos.

IV. Air Quality Report

a. Introduction

The Okeelanta Power cogeneration project as proposed by the applicant will emit three pollutants in PSD significant amounts. These pollutants include the criteria pollutant sulfur dioxide (SO_2) and the non-criteria pollutants beryllium (Be), and fluoride (Fl). (Table 1) maximum sulfur content of 0.05 percent (lower than the 0.5 percent requested by the applicant) which will produce 0.05 lbs SO_2/MMBtu when burned. Coal, an alternate fuel to be used only when adequate quantities of biomass are not available, will be allowed a maximum sulfur content of 0.7 percent which will produce 1.2 lbs SO_2/MMBtu when burned. This emission will meet the applicable NSPS for SO_2. Compliance with the SO_2 emission standards will be demonstrated by fuel analysis, stack testing, and/or continuous emission monitoring. The facility is subject to PSD and BACT for sulfur dioxide emissions because the increase in annual SO_2 emissions can exceed the significant emission rate.

NO_x emissions will be controlled by a SNCR system. The system will be designed to reduce NO_x emissions by at least 40 percent. The proposed NO_x emission limit of 0.15 lbs/MMBtu for biomass and No. 2 fuel oil, and 0.17 lbs/MMBtu for coal are below the NSPS for this type of facility. Compliance with the emission standards will be determined by stack tests and the NO_x emissions will be monitored continuously. The project will result in the net contemporaneous NO_x emissions decrease of 26.2 TPY. Therefore, the project is not subject to PSD for NO_x. The proposed NO_x limit, less than the applicable NSPS, are acceptable to the Department as meeting or exceeding the applicable RACT for these sources.

CO and VOC emissions will be controlled through boiler design and good combustion practices. The requested emissions, shown in Table 2-4 of the application, will depend on the fuel being burned. The project is expected to result in a net reduction of 8,375.5 TPY CO and a decrease of 56.9 TPY VOC. Thus, the project is not subject to PSD for these pollutants. Compliance with the emission standards will be determined by stack tests. Carbon monoxide and oxygen emissions will be monitored continuously to comply with the NSPS. Good operation practices, based on the guidance in the document titled "Use of Flue Gas Oxygen Meter as BACT for Combustion Controls" is acceptable as the RACT determination to control VOC emissions.

The project is subject to the PSD regulations for sulfur dioxide, beryllium, and fluorides. These pollutants are caused primarily by the contaminants in the fossil fuels. Emissions will be controlled by limiting both the sulfur content in the fossil fuels (0.05 percent sulfur in the No. 2 fuel oil and 0.70 percent sulfur in the coal) and the quantity of fossil fuel that can be burned to 25 percent of the annual heat input. The ESP may remove some particulate matter containing these pollutants. Compliance for all three pollutants shall be determined by stack tests.

The following table summarizes the emissions of air pollutants subject to PSD review.

For non-criteria pollutants, such as Be and Fl, EPA's general position is to not require monitoring data, but to base the analysis of existing air quality on modeled impacts. Even though the maximum predicted impact of Fl is greater than the significant monitoring concentration, the Department is not requiring preconstruction monitoring for this project because there are no EPA-approved monitoring methods for Fl.

The Florida Sugar Cane League (FSCL) has operated an ambient monitoring network in the sugar cane growing area for several years. The network contains one continuous ambient SO_2 monitor, located at the Florida Celery Exchange in Belle Glade. This site is about 15 km northeast of the Okeelanta sugar mill and the data from this site satisfy the preconstruction monitoring requirements for SO_2.

The second highest 3-hour and 24-hour and highest annual average SO_2 concentrations measured at the Belle Glade monitor during period 1989-1991 were used. Based on this analysis, the background SO_2 concentrations were determined to be 53 and 21 ug/m^3 for the 3- and 24-hour averaging periods, respectively, and 8 ug/m^3 for the annual averaging period.

c. Modeling Methodology

The EPA-approved Industrial Source Complex Short-Term (ISCST2) dispersion model was used to evaluate the pollutant emissions from the proposed facility and other existing major facilities. The model determines ground-level concentrations of inert gases or small particles emitted into the atmosphere by point, area and volume sources. The model incorporates elements for plume rise, transport by the mean wind, Gaussian dispersion, and pollutant removal mechanisms such as deposition. The ISCST2 model allows for the separation of sources, building wake downwash, and various other input and output features. A series of specific model features, recommended by the EPA, are referred to as the regulatory options. The applicant used the EPA recommended regulatory options in each modeling scenario. Direction-specific downwash parameters were used because the stacks were less than the good engineering practice (GEP) stack height.

For the PSD Class I analysis, the ISCST2 model is used initially as a screening model for estimating impacts on the Everglades National Park since the increment-consuming source inventory used in the modeling analysis has sources over 50 km in it. If a more refined analysis is needed, the MESOPUFF II long-range transport model is used. This model is more appropriate for long-range transport applications where receptors are located more than 50 km from a source. However, no MESOPUFF II modeling was necessary for this application.

The air quality impact analysis required by the PSD regulations for these pollutants includes:

* An analysis of existing air quality;
* A PSD increment analysis (SO_2);
* An Ambient Air Quality Standards (AAQS) analysis;
* An analysis of impacts on soils, vegetation, and visibility and of growth-related air quality modeling impacts; and
* A "Good Engineering Practice" (GEP) stack height determination.

The applicant submitted the air quality analysis required by the PSD regulations for these three pollutants; this analysis is presented in this section.

The analysis of existing air quality generally relies on preconstruction monitoring data collected with EPA-approved methods. The PSD increment and AAQS analysis depends on air quality dispersion modeling carried out in accordance with EPA guidelines.

Based on the required analyses, the Department has reasonable assurance that the proposed Okeelanta Power cogeneration project, as described in this report and subject to the conditions of approval proposed herein, will not cause or contribute to a violation of any AAQS or PSD increment. A discussion of the modeling methodology and required analysis follows.

b. Analysis of Existing Air Quality

Preconstruction ambient air quality monitoring is required for all pollutants subject to PSD review.

An exemption to the monitoring requirement can be obtained if the maximum air quality impact, as determined by air quality modeling, is less than a pollutant-specific "de minimus" concentration. In addition, if an acceptable ambient monitoring method for the pollutant has not been established by EPA, monitoring is not required.

The predicted impacts of the proposed project for those pollutants subject to PSD review are listed in Table 2.

The maximum 24-hour average SO_2 concentration due to the proposed cogeneration units is predicted to be 74 ug/m^3. The de minimus concentration level for SO_2 is 13 ug/m^3, 24-hour average. Therefore, an ambient monitoring analysis is required for SO_2.

e. PSD Increment Analysis

1. Class II Area

The PSD increment represents the amount that new sources in an area may increase ambient ground level concentrations of a pollutant. Atmospheric dispersion modeling, as previously described, was performed to quantify the amount of PSD increment consumed. Based on the screening results, a refined modeling analysis was performed for each averaging time. The results, summarized in Table 4, show that the maximum SO_2 PSD increment consumption will not exceed the allowable Class II PSD increments.

2. Class I Area

A proposed source subject to PSD review must conduct a dispersion modeling analysis of its impacts on any PSD Class I area located near the source. The northeastern corner of the Class I Everglades National Park is approximately 94 km south of the Okeelanta Power site. Modeling was performed and the modeling results are summarized in Table 5. Based on these results, the proposed facility along with all other increment consuming sources in the area will meet the allowable annual and 3-hour PSD increments in the Class I area. However, the ISCST2 modeling, which is initially used for screening purposes at distances greater than 50 km, indicates that the 24-hour Class I increment of 5 ug/m^3 will be exceeded in the Class I area on one day and at one receptor. Source contributions to this maximum show that the proposed Okeelanta Power cogeneration project will contribute only 0.04 ug/m^3 to this HSH concentration of 5.42 ug/m^3. This contribution is less than the National Park Service's recommended 24-hour SO2 Class I significant impact level of 0.07 ug/m^3. Therefore, the Okeelanta Power project does not significantly contribute to the predicted 24-hour exceedance in the Class I area and no refined modeling using MESOPUFF II is necessary. However, refined modeling was done using MESOPUFF II for the Osceola Power cogeneration project, a concurrent project located 120 km from the Everglades National Park. Refined modeling was done by Osceola Power since ISCST2 modeling predicted that this project had a significant impact on the exceedance mentioned above. This refined modeling, performed according to National Park Service recommendations, showed that the maximum predicted impacts for all increment-consuming sources is 4.21 ug/m^3 instead of 5.42 ug/m^3. With the screening value of 5.42 ug/m^3 reduced to 4.21 ug/m^3, the next HSH predicted by ISCST2 is 4.82 ug/m^3. This value was not refined since it is less than 5.0 ug/m^3. This is the value for the 24-hour SO_2 increment given in Table 5.

Initially, for the significant impact analysis, concentrations were predicted at 288 receptors located in a radial grid centered on the proposed stacks for the new cogeneration units. Receptors were located in "rings", with 36 receptors per ring spaced at 10-degree intervals at distances of 11, 20, 30, 40, 50, 60, 70, and 80 km. For the AAQS and PSD Class II analyses, both near- and far- field receptor grids were used. The near-field screening grids included 36 receptors for each 10 degree sector located on the following rings: at the plant property; 5,7, and 9 km in the directions outside plant property (distance to property boundary varies greatly by sector); and 10, 12, 14, 17, and 20 km. The far-field screening grid included six rings of receptors at distances of 25, 30, 40, 50, 60, and 80 km.

The Everglades National Park is a PSD Class I area that is located within 100 km of the Okeelanta Power plant site. In the screening analysis, Everglades National Park is represented by 51 discrete receptors, including 47 receptors covering the eastern and northern boundaries of the park from the Florida Keys to the Gulf of Mexico and 4 receptors inside the northeast corner of the Park.

Meteorological data used in the ISCST2 model to determine air quality impacts consisted of a concurrent 5-year period of hourly surface weather observations and twice-daily upper air soundings from the National Weather Service (NWS) station at West Palm Beach. The 5-year period of meteorological data was from 1982 through 1986. The NWS station at West Palm Beach, located approximately 60 km east of the Okeelanta Power site, was selected for use in the study because it is the closest primary weather station to the study area and is most representative of the plant site. The surface observations included wind direction, wind speed, temperature, cloud cover and cloud ceiling.

Since five years of data were used, the highest-second-high (HSH) short-term predicted concentrations were compared with the appropriate ambient air quality standards or PSD increments. For the annual averages, the highest predicted yearly average was compared with the standards.

d. Significant Impact Analysis

The maximum air quality impacts due to SO_2 emissions from the proposed Okeelanta Power facility only are presented in Table 3. As shown, the facility's maximum annual, 24-hour, and 3-hour predicted SO_2 concentrations are 0.8, 74, and 164 ug/m^3, respectively. These maximum impacts are greater than the respective SO_2 significant impact levels of 1, 5, and 25 ug/m^3. Therefore, a full impact assessment was performed for SO_2.

f. AAQS Analysis

For the pollutants subject to an AAQS review, the total impact on ambient air is obtained by adding a "background" concentration to the maximum modeled concentration. This "background" concentration takes into account all sources of a particular pollutant that are not explicitly modeled. The 1989 -1991 monitoring results from Belle Glade were used to determine the background SO_2 concentrations. The results of the AAQS analysis for SO_2 are summarized in Table 6. Emissions from the proposed facility are not expected to cause or contribute to a violation of an AAQS.

g. Air Toxics Analysis

H_2SO_4 mist is a non-criteria pollutant, which means that neither a national ambient air quality standard nor a PSD significant impact has been defined for this pollutant. However, the Department does have a draft Air Toxics Reference Concentration of 2.4 ug/m^3, 24-hour average for H_2SO_4 mist. The Department used the same modeling procedure described above to predict the maximum ground level concentration of H_2SO_4 mist due to the project. The result was 2.2 ug/m^3, 24-hour average, which is below the reference concentration for H_2SO_4 mist.

The maximum impacts of regulated and non-regulated toxic air pollutants that will be emitted by the Okeelanta Power facility project are presented in Table 7. Each pollutant's maximum 8-hour, 24-hour, and annual impact is compared to Department's Air Toxics Reference Concentrations. The table shows that all toxic pollutant impacts will be below their respective reference concentrations.

V. Additional Impacts Analysis

a. Impacts on Soils, Vegetation, and Wildlife

The maximum ground-level concentration predicted to occur for SO_2 as a result of the proposed project, including a background concentration and all other nearby sources, will be below the national secondary standard which was developed to protect public welfare-related values. As such, this project is not expected to have a harmful impact on soils and vegetation in the PSD Class II area. An air quality related values (AQRV) analysis was done by the applicant for the Class I area. No significant impacts on this area are expected.

b. Impact on Visibility

Visual Impact Screening and Analysis (VISCREEN), the EPA-approved Level I visibility computer model was used to estimate the impact of proposed facility's stack emissions on visibility in the Everglades National Park.

The results indicate that the maximum visibility impacts caused by the facility do not exceed the screening criteria inside or outside the Everglades National Park Class I area. As a result, there is no significant impact on visibility predicted for the Class I area.

c. Growth-Related Air Quality Impacts

There will be a small number of temporary construction workers during construction. There will be about 30 permanent employees at Okeelanta Power associated with the operation of the cogeneration facility. These increases are minor, and there will be no significant impacts on air quality caused by associated population growth.

d. GEP Stack Height Determination

Good Engineering Practice (GEP) stack height means the greater of: (1) 65 meters (213 feet) or (2) the maximum nearby building height plus 1.5 times the building height or width, whichever is less.

The boiler building is the significant structure associated with the proposed cogeneration facility. The building has a height of 128 feet and a total combined width of 180 feet. From the above formula, the GEP stack height is 128+(1.5x128)=320 feet. The three stacks for the proposed facility will be 199 feet high and therefore do not exceed the GEP stack height. The potential for downwash of the emissions from the facility due to the presence of nearby structures was considered in the modeling study.

VI. Conclusion

Based on the information provided by OPLP, the Department has reasonable assurance that the proposed construction/installation of the 71.25 MW cogeneration facility, as described in this evaluation, and subject to the conditions proposed herein, will not cause or contribute to a violation of any air quality standard, PSD increment, or any other technical provision of Chapter 17-212 of the Florida Administrative Code.

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the impact of proposed facility's stack emissions on visibility in the Everglades National Park.

The results indicate that the maximum visibility impacts caused by the facility do not exceed the screening criteria inside or outside the Everglades National Park Class I area. As a result, there is no significant impact on visibility predicted for the Class I area.

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Table 3. Maximum Air Quality Impacts for Comparison to the Significant Impact Levels.

Pollutant	Avg. Time	Predicted Impact (ug/m^3)	Significant Imapct Level (ug/m^3)
SO2	Annual	0.8	1
	24-hour	74	5
	3-hour	164	25

Table 4. PSD Class II Increment Analysis

Pollutant	Averaging Time	Max. Predicted Impact (ug/m^3)	Allowable Increment (ug/m^3)
SO_2	Annual	8.7	20
	24-hour	68	91
	3-hour	156	512

Table 5. PSD Class I Increment Analysis

Pollutant	Averaging Time	Max. Predicted Impact (ug/m^3)	Allowable Increment (ug/m^3)
SO_2	Annual	0.67	2
	24-hour	4.82	5
	3-hour	22.8	25

Table 1: Siginificant and Net Emission Rates (Tons per Year)

Pollutant	Proposed Net Emissions Increase	Significant Emission Rate	Applicable Pollutant (Yes/No)
TSP	-290.4	25	No
PM10	-249.9	15	No
SO_2	406.0	40	Yes
NO_x	-26.2	40	No
CO	-8,375.5	100	No
VOC	-56.9	40	No
Lead	-0.11	0.6	No
Mercury	0.0008	0.1	No
Beryllium	0.0048	0.0004	Yes
Fluorides	21.2	3	Yes
Sulfuric Acid Mist	6.4	7	No
TRS	0	10	No
Asbestos	0	0.007	No
Vinyl Chloride	0	0	No

Table 2. Maximum Air Quality Impacts for Comparison to the De Minimus Ambient Levels.

Pollutant	Avg. Time	Predicted Impact (ug/m^3)	De Minimus Level (ug/m^3)
SO_2	24-hour	74	13
Beryllium *	24-hour	0.0004	0.001
Fluorides *	24-hour	1.48	0.25

* non-criteria pollutant

Table 6. Ambient Air Quality Impact

Pollutant	Averaging Time	Major Sources Imapct (ug/m³)	Background Conc. (ug/m³)	Total Impact (ug/m³)	Florida AAQS (ug/m³)
SO_2	Annual	44	8	52	60
	24-hour	215	21	236	260
	3-hour	835	53	888	1,300

Table 7: Air Toxics Analysis

	8- hour		24- hour		Annual	
Pollutant	Impact (ug/m³)	ATRC (ug/m³)	Impact (ug/m³)	ATRC (ug/m³)	Impact (ug/m³)	ATRC (ug/m³)
Ammonia	3.9	180	3.0	43.2	-	-
Antimony	0.0028	5	0.002	1.2	0.0002	0.3
Arsenic	0.0163	2	0.01	0.48	0.000226	0.000230
Barium	0.0594	5	0.05	1.2	0.0033	50
Beryllium	0.0005	0.02	0.0004	0.0048	0.00003	0.00042
Bromine	0.15	7	0.11	1.68	-	-
Cadmium	0.0005	0.5	0.0004	0.12	0.00003	0.00056
Chromium metals	0.0154	5	0.012	1.2	0.00087	1000
Chromium+6	0.0041	0.5	0.003	0.12	0.000059	0.000083
Cobalt	0.05	0.5	0.04	0.12	-	-
Copper	0.01	10	0.01	2.4	-	-
Dioxines/Furans	-	-	-	-	2.1e-09	2.2e-8
Fluoride	1.95	25	1.48	6	-	-
Formaldehyde	0.07	4.5	0.05	1.08	0.004	0.0077
Hydrogen Chloride	6.39	70	4.84	16.8	0.360	7.0
Indium	0.01	1	0.01	0.24	-	-
Manganese	0.08	50	0.06	12	-	-
Mercury	0.0007	0.5	0.0006	0.12	0.00004	0.3
Molybdenum	0.03	50	0.02	12	-	-
Nickel	0.08	0.5	0.06	0.12	0.0011	0.0042
Phosphorus	0.07	1	0.05	0.24	-	-
Selenium	0.004	2	0.003	0.48	-	-
Silver	0.003	0.1	0.002	0.024	0.0002	3
Sulfuric Acid Mist	2.9	10	2.2	2.4	-	-
Tin	0.02	1	0.01	0.24	-	-
Zinc	0.04	10	0.03	2.4	-	-
Zirconium	0.009	50	0.01	12	-	-

Note: ATRC = Air Toxics Reference Concentration

Florida Department of Environmental Regulation

Twin Towers Office Bldg. • 2600 Blair Stone Road • Tallahassee, Florida 32399-2400

Lawton Chiles, Governor

Virginia B. Wetherell, Secretary

PERMITTEE:
Okeelanta Power Limited Partnership
P. O. Box 86
South Bay, FL 33493

Permit Number: AC50-219413
PSD-FL-196
Expiration Date: July 1, 1996
County: Palm Beach
Latitude/Longitude: 26°35'00"N 80°45'00"W
Project: Cogeneration Facility

This permit is issued under the provisions of Chapter 403, Florida Statutes, and Florida Administrative Code Chapters 17-210, 212, 272, 275, 296, and 297; and 17-4. The above named permittee is hereby authorized to perform the work or operate the facility shown on the application and approved drawings, plans, and other documents attached hereto or on file with the Department and made a part hereof and specifically described as follows:

A 71.25 megawatt of electricity (biomass-bagasse and wood waste material as the primary fuel, No. 2 fuel oil as a supplementary fuel, and low sulfur coal as an alternate fuel) cogeneration facility located at Okeelanta Corporation's sugar mill that is 6 miles south of South Bay, off U.S. Highway 27, Palm Beach County, Florida. The cogeneration facility contains three Zurn spreader-stroker or equivalent steam boilers with a design heat input for each boiler of 715 MMBtu/hr on biomass and 490 MMBtu/hr on fossil fuels. Each boiler will produce approximately 455,400 lbs/hr of steam at 1,500 psig and 975°F. Particulate matter, nitrogen oxides, and mercury emissions from each boiler will be controlled by Research-Cottrell (or equivalent) electrostatic precipitator, Thermal De NO_x (or equivalent) selective non-catalytic reduction system, and an activated carbon injection system, respectively (or equivalent). Auxiliary equipment includes feed and ash handling systems, steam turbines and condensers, electric generators, cooling towers, and stacks that are 8.0 ft. in diameter and a 199 ft. high.

The UTM coordinates of this facility are Zone 17, 524.9 km E and 2940.1 km N.

The source shall be constructed in accordance with the permit application, plans, documents, amendments and drawings, except as otherwise noted in the General and Specific Conditions.

<u>Attachments are listed below</u>:

1. Application received September 30, 1992.
2. DER letter dated November 3, 1992.
3. KBN letter dated December 4, 1992.
4. Carlton letter dated December 23, 1992.
5. KBN letter dated February 17, 1993.
6. KBN letter dated May 25, 1993.

GENERAL CONDITIONS:

1. The terms, conditions, requirements, limitations, and restrictions set forth in this permit are "Permit Conditions" and are binding and enforceable pursuant to Sections 403.161, 403.727, or 403.859 through 403.861, Florida Statutes. The permittee is placed on notice that the Department will review this permit periodically and may initiate enforcement action for any violation of these conditions.

2. This permit is valid only for the specific processes and operations applied for and indicated in the approved drawings or exhibits. Any unauthorized deviation from the approved drawings, exhibits, specifications, or conditions of this permit may constitute grounds for revocation and enforcement action by the Department.

3. As provided in Subsections 403.087(6) and 403.722(5), Florida Statutes, the issuance of this permit does not convey any vested rights or any exclusive privileges. Neither does it authorize any injury to public or private property or any invasion of personal rights, nor any infringement of federal, state or local laws or regulations. This permit is not a waiver of or approval of any other Department permit that may be required for other aspects of the total project which are not addressed in the permit.

4. This permit conveys no title to land or water, does not constitute State recognition or acknowledgement of title, and does not constitute authority for the use of submerged lands unless herein provided and the necessary title or leasehold interests have been obtained from the State. Only the Trustees of the Internal Improvement Trust Fund may express State opinion as to title.

5. This permit does not relieve the permittee from liability for harm or injury to human health or welfare, animal, or plant life, or property caused by the construction or operation of this permitted source, or from penalties therefore; nor does it allow the permittee to cause pollution in contravention of Florida Statutes and Department rules, unless specifically authorized by an order from the Department.

6. The permittee shall properly operate and maintain the facility and systems of treatment and control (and related appurtenances) that are installed or used by the permittee to achieve compliance with the conditions of this permit, as required by Department rules. This provision includes the operation of backup or auxiliary facilities or similar systems when necessary to achieve compliance with the conditions of the permit and when required by Department rules.

GENERAL CONDITIONS:

7. The permittee, by accepting this permit, specifically agrees to allow authorized Department personnel, upon presentation of credentials or other documents as may be required by law and at a reasonable time, access to the premises, where the permitted activity is located or conducted to:

   a. Have access to and copy any records that must be kept under the conditions of the permit;

   b. Inspect the facility, equipment, practices, or operations regulated or required under this permit; and

   c. Sample or monitor any substances or parameters at any location reasonably necessary to assure compliance with this permit or Department rules.

Reasonable time may depend on the nature of the concern being investigated.

8. If, for any reason, the permittee does not comply with or will be unable to comply with any condition or limitation specified in this permit, the permittee shall immediately provide the Department with the following information:

   a. a description of and cause of non-compliance; and

   b. the period of noncompliance, including dates and times; or, if not corrected, the anticipated time the non-compliance is expected to continue, and steps being taken to reduce, eliminate, and prevent recurrence of the non-compliance.

The permittee shall be responsible for any and all damages which may result and may be subject to enforcement action by the Department for penalties or for revocation of this permit.

9. In accepting this permit, the permittee understands and agrees that all records, notes, monitoring data and other information relating to the construction or operation of this permitted source which are submitted to the Department may be used by the Department as evidence in any enforcement case involving the permitted source arising under the Florida Statutes or Department rules, except where such use is prescribed by Sections 403.73 and 403.111, Florida Statutes. Such evidence shall only be used to the extent it is consistent with the Florida Rules of Civil Procedure and appropriate evidentiary rules.

10. The permittee agrees to comply with changes in Department rules and Florida Statutes after a reasonable time for compliance,

GENERAL CONDITIONS:

provided, however, the permittee does not waive any other rights granted by Florida Statutes or Department rules.

11. This permit is transferable only upon Department approval in accordance with Florida Administrative Code Rules 17-4.120 and 17-730.300, F.A.C., as applicable. The permittee shall be liable for any non-compliance of the permitted activity until the transfer is approved by the Department.

12. This permit or a copy thereof shall be kept at the work site of the permitted activity.

13. This permit also constitutes:

    (x) Determination of Best Available Control Technology (BACT)
    (x) Determination of Prevention of Significant Deterioration (PSD)
    (x) Compliance with New Source Performance Standards (NSPS)

14. The permittee shall comply with the following:

    a. Upon request, the permittee shall furnish all records and plans required under Department rules. During enforcement actions, the retention period for all records will be extended automatically unless otherwise stipulated by the Department.

    b. The permittee shall hold at the facility or other location designated by this permit records of all monitoring information (including all calibration and maintenance records and all original strip chart recordings for continuous monitoring instrumentation) required by the permit, copies of all reports required by this permit, and records of all data used to complete the application for this permit. These materials shall be retained at least three years from the date of the sample, measurement, report, or application unless otherwise specified by Department rule.

    c. Records of monitoring information shall include:

        - the date, exact place, and time of sampling or measurements;
        - the person responsible for performing the sampling or measurements;
        - the dates analyses were performed;
        - the person responsible for performing the analyses;

GENERAL CONDITIONS:

- the analytical techniques or methods used; and
- the results of such analyses.

15. When requested by the Department, the permittee shall within a reasonable time furnish any information required by law which is needed to determine compliance with the permit. If the permittee becomes aware that relevant facts were not submitted or were incorrect in the permit application or in any report to the Department, such facts or information shall be corrected promptly.

SPECIFIC CONDITIONS:

<u>Construction Details</u>

1. Construction of the proposed cogeneration facility shall reasonably conform to the plans described in the application. The facility shall be designed and constructed so that its generating capacity shall not exceed 71.25 MW.

The permittee shall provide detailed engineering plans, 30 days after they become available, demonstrating that the steam electric generating system is not capable of producing more than 74.9 MW as an instantaneous maximum at design maximum steam pressure plus 10% overpressure. Such demonstration may include plans for installation of a steam pressure relief valve. If the steam electric generating system is designed with a pressure relief valve, such valve shall be installed and maintained as a requirement of this permit.

2. Boilers No. 1, 2 and 3 shall be of the spreader stoker type with a maximum heat input of 715 MMBtu/hr with biomass fuel and 490 MMBtu/hr with fossil fuels.

3. Each boiler shall have an individual stack, and each stack must have a minimum height of 199 feet. The stack sampling facilities for each stack must comply with F.A.C. Rule 17-297.345.

4. Each boiler shall be equipped with instruments to measure the fuel feed rate, steam production, steam pressure, and steam temperature.

5. Each boiler shall be equipped with a:

- Electrostatic precipitator (ESP) designed for at least 98 percent removal of particulate matter;
- Selective non-catalytic reduction (SNCR) system designed for at least 40 percent removal of NO_x; and
- Carbon injection system (or equivalent) for mercury emissions control.

SPECIFIC CONDITIONS:

6. The permittee shall install and operate continuous monitoring devices for each main boiler exhaust for opacity, nitrogen oxides (NO_X), sulfur dioxide (SO_2), oxygen (O_2), and carbon monoxide (CO). The monitoring devices shall meet the applicable requirements of Section 17-297.500, F.A.C., and 40 CFR 60.47a. The opacity monitor may be placed in the duct work between the electrostatic precipitator and the stack.

A oxygen meter shall be installed for each unit to continuously monitor a representative sample of the flue gas. The oxygen monitor shall be used with automatic feedback or manual controls to continuously maintain air/fuel ratio parameters at an optimum. Operating procedures shall be established based on the initial performance tests required by Specific Condition No. 21 below. The document "Use of Flue Gas Oxygen Meter as BACT for Combustion Controls" shall be used as a guide. An operating plan shall be submitted to the Department within 90 days of completion of such tests.

7. For the electrostatic precipitator, the selective non-catalytic reduction process (SNCR), and the activated carbon injection mercury control system (equivalent controls allowed):

   a. The permittee shall submit to the Department copies of technical data pertaining to the selected PM, NO_X, and mercury emission controls within thirty (30) days after it becomes available. These data should include, but not be limited to, guaranteed efficiency and emission rates and major design parameters. The Department may review these data to determine whether the selected control equipment is adequate to meet the emission limits specified in Specific Condition No. 20 below. Such review shall be completed within 30 days of receipt of the technical data.

8. For the fly ash handling and mercury control system reactant storage systems:

   a. The particulate matter filter control system for the storage silos shall be designed to achieve a 0.01 gr/acf outlet dust loading. The permittee must submit to the Department copies of technical data pertaining to the selected particulate emissions control for the mercury control system reactant storage silos within thirty (30) days after it becomes available. These data should include, but not be limited to, guaranteed efficiency and emission rates, and major design parameters. The Department may review these data to determine whether the selected control device is adequate to meet the emission limits specified in Specific Condition No. 19 below. Such

SPECIFIC CONDITIONS:

review shall be completed within 30 days of receipt of the technical data.

b. The fly ash handling system (including transfer points and storage bin) shall be enclosed. The ash shall be wetted in the ash conditioner to minimize fugitive dust prior to it being discharged into the disposal bin.

9. Prior to operation of the source, the permittee shall submit to the Department an operation and maintenance plan that will allow the permittee to monitor emission control equipment efficiency and enable the permittee to return malfunctioning equipment to proper operation as expeditiously as possible.

10. During land clearing and site preparation, wetting operations or other soil treatment techniques appropriate for controlling unconfined particulates, including grass seeding and mulching of disturbed areas, shall be undertaken and implemented. Any open burning of land clearing debris on this site shall be performed in compliance with Department regulations.

<u>Operational and Emission Restrictions</u>

11. The proposed cogeneration facility steam generating units shall be constructed and operated in accordance with the capabilities and specifications described in the application. The facility shall not exceed 71.25 (gross) megawatt generating capacity and the maximum heat input rate for each steam generator of 715 MMBtu/hr when burning 100 percent biomass and 490 MMBtu/hr when burning 100 percent No. 2 fuel oil or low sulfur coal. Maximum heat input to the entire facility (total all three boilers) shall not exceed 11.5 x 10^{12} Btu per year. Steam production of each boiler shall not exceed an average of 455,418 lbs/hr at 1,500 psig, 975°F.

12. Any wood waste materials burned as fuel shall be free from painted and chemically treated wood, household garbage, toxic or hazardous materials or waste, and special waste (toxic or hazardous non-biomass and non-combustible waste material). The permittee shall perform a daily inspection of the delivered wood waste materials. Any shipment observed to contain chemically treated wood or any of this material shall not be burned at this facility. A representative ash sample for the biomass burned during the month shall be analyzed for wood preservatives (CCA-copper, chromium, arsenic) by appropriate analytical procedures per 40 CFR 261, Appendix III, described in SW-846, Test Methods for Evaluating Solid Waste, Physical/Chemical Methods.

13. Any fuel oil burned in the facility shall be "new" No. 2 fuel

SPECIFIC CONDITIONS:

oil with a maximum sulfur content of 0.05 percent sulfur as determined by the appropriate test method listed in 40 CFR 60.7. "New" oil means an oil which has been refined from crude oil and has not been used in any manner that may contaminate it.

14. Any coal burned in the facility shall be low sulfur coal with a maximum sulfur content of 0.70 percent with a maximum potential emission equivalent to 1.2 lb SO_2/MMBtu.

15. The consumption of No. 2 fuel oil shall not exceed 25 percent of the total heat input to each boiler unit in any calendar quarter. Not more than 73,714 tons of coal shall be burned at this facility during any 12-month period (16 percent of the annual heat input). The combined heat input for coal and oil shall not exceed 25 percent of the annual heat input.

16. The permittee shall maintain a daily log of the amounts and types of fuels used. The amount, heating value, beryllium content (coal only), sulfur content, and equivalent SO_2 emission rate (in lbs/MMBtu) of each fuel oil and coal delivery shall be kept in a log for at least two years. For each calendar month, the calculated SO_2 emissions and 12-month rolling average shall be determined (in tons) and kept in a log.

17. During the first three years of cogeneration facility operation, the existing Boilers Nos. 4, 5, 6, 10, 11, 12, 14, and 15 (Permit Nos. AO50-169210, 190690, 175414, 190693, 175411, 169215, 189904, and 209094, respectively) may be retained for standby operation. These boilers may be operated only when all three cogeneration boilers are shutdown. During operation, these boilers must meet all requirements in the most recent construction and operation permits for the boilers. These boilers shall be shutdown and rendered incapable of operation within three (3) years of commercial startup of the cogeneration facility, but no later than January 1, 1999.

18. Boiler No. 16 (AC50-191876) may be retained as a standby boiler for the cogeneration facility provided its permit is amended to authorize standby use. This boiler may be operated only when one or more of the three cogeneration boilers are shutdown. During operation, this boiler must meet all requirements in the current construction or operating permit for the boiler.

19. For the biomass, coal, fly ash, and mercury control system reactant handling facilities:

a. All conveyors and conveyor transfer points shall be substantially enclosed to preclude PM emissions (except those directly associated with the stacker/reclaimers, for which enclosure is operationally infeasible).

SPECIFIC CONDITIONS:

b. Inactive coal storage piles shall be shaped, compacted, oriented to minimize wind erosion, and covered.

c. Water sprays or chemical wetting agents and stabilizers shall be applied to storage piles, handling equipment, unenclosed transfer points, etc. during dry periods and as necessary to all facilities to maintain an opacity of less than or equal to 5 percent, except when adding, moving or removing coal from the coal pile, which would be allowed no more than 20 percent opacity.

d. The mercury control system reactant storage silos shall be maintained at a negative pressure while operating with the exhaust vented to a filter control system. Particulate matter emissions from each of the three silos shall not exceed a visible emission reading of 5 percent opacity. A visible emission test is to be performed annually on each silo.

20. Based on a maximum heat input to each boiler of 715 MMBtu/hr for biomass fuels and 490 MMBtu/hr for No. 2 fuel oil and coal, stack emissions shall not exceed any limit shown in the following table:

	Emission Limit (per boiler)[d]						Total All[e] Three Boilers
	Biomass		No. 2 Oil		Bit. Coal		
Pollutant	(lb/MMBtu)	(lb/hr)	(lb/MMBtu)	(lb/hr)	(lb/MMBtu)	(lb/hr)	(TPY)
Particulate (TSP)	0.03	21.5	0.03	14.7	0.03	14.7	172.5
Particulate (PM_{10})	0.03	21.5	0.03	14.7	0.03	14.7	172.5
Sulfur Dioxide							
24-hour average	0.10	71.5	0.05	24.5	1.2	588.0	---
Annual average[a]	0.02	---	---	---	1.2	---	1,154.3[f]
Nitrogen Oxides							
Annual average[a]	0.15	107.3	0.15	73.5	0.17	83.3	873.1
Carbon Monoxide							
8-hour average	0.35	250.3	0.2	98.0	0.2	98.0	2,012.5
Volatile Organic Compounds	0.06	42.9	0.03	14.7	0.03	14.7	345.0
Lead	2.5×10^{-5}	0.018	8.9×10^{-7}	0.0004	6.4×10^{-5}	0.031	0.17
Mercury	6.3×10^{-6}[b] 0.29×10^{-6}[c]	0.0045[b] 0.00021[c]	2.4×10^{-6}	0.00118	8.4×10^{-6}	0.0041	0.0300

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Beryllium	---	---	3.5×10^{-7}	0.00017	5.9×10^{-6}	0.0029	0.0052
Fluorides	---	---	6.3×10^{-6}	0.003	0.024	11.8	21.2
Sulfuric Acid Mist	0.003	2.15	0.0015	0.74	0.036	17.6	34.6

[a]Compliance based on 30-day rolling average, per 40 CFR 60, Subpart Da.
[b]Emission limit for bagasse. Subject to revision after testing pursuant to Specific Conditions Nos. 24 and 25.
[c]Emission limit for wood waste. Subject to revision after testing pursuant to Specific Conditions Nos. 24 and 25.
[d]The emission limit shall be prorated when more than one type of fuel is burned in a boiler.
[e]Limit heat input from No. 2 fuel oil to 25% of total heat input, coal to 73,714 tons during any 12-month period, and the combination of oil and coal to 25% of the total annual heat input.
[f]Compliance based on a 12-month rolling average.

Compliance Requirements

21. Stack Testing

a. Within 60 calendar days after achieving the maximum capacity at which each unit will be operated, but no later than 180 operating days after initial startup, the permittee shall conduct performance tests for all air pollutants listed in Specific Condition No. 20, and visible emissions during normal operations near (i.e., within 10 percent) 715 MMBtu/hr heat input and furnish the Department a written report of the results of such performance tests within 45 days of completion of the tests. The performance tests will be conducted in accordance with the provisions of 40 CFR 60.46a.

b. Compliance with emission limitations for each fuel stated in Specific Condition No. 20 above shall be demonstrated using EPA Methods, as contained in 40 CFR Part 60 (Standards of Performance for New Stationary Sources), or 40 CFR Part 61 (National Emission Standards for Hazardous Air Pollutants), or any other method as approved by the Department, in accordance with F.A.C. Rule 17-297.620. A test protocol shall be submitted for approval to the Bureau of Air Regulation at least 90 days prior to testing.

EPA Method	For Determination of
1	Selection of sample site and velocity traverses.
2	Stack gas flow rate when converting concentrations to or from mass emission limits.
3	Gas analysis when needed for calculation of molecular weight or percent O_2.

SPECIFIC CONDITIONS:

4	Moisture content when converting stack velocity to dry volumetric flow rate for use in converting concentrations in dry gases to or from mass emission limits.
5	Particulate matter concentration and mass emissions.
201 or 201A	PM_{10} emissions.
6, 6C, or 19	Sulfur dioxide emissions from stationary sources.
7, 7C, or 19	Nitrogen oxide emissions from stationary sources.
8	Sulfuric acid mist.
9	Visible emission determination of opacity. - At least three one hour runs to be conducted simultaneously with particulate testing. - At least one truck unloading into the mercury reactant storage silo (from start to finish).
10	Carbon monoxide emissions from stationary sources.
12 or 101A	Lead concentration from stationary sources.
13A or 13B	Fluoride emissions from stationary sources.
18 or 25	Volatile organic compounds concentration.
101A or 108	Mercury emissions.
104	Beryllium emission rate and associated moisture content.

22. Performance tests shall be conducted under such conditions as the Department shall specify based on representative performance of the facility. The permittee shall make available to the Department such records as may be necessary to determine the conditions of the performance tests.

23. The permittee shall provide 30 days notice of the performance tests or 10 working days for stack tests in order to afford the Department the opportunity to have an observer present.

24. Stack tests for particulates, NO_x, SO_2, sulfuric acid mist, CO, VOC, lead, mercury, beryllium, fluorides and visible emissions shall be performed once every six months during the first two years of facility operation in accordance with Specific Conditions Nos. 21, 22, and 23 above. If the test results for the first two years of operation indicate the facility is operating in compliance with the terms of approval and of applicable permits and regulations,

SPECIFIC CONDITIONS:

the tests will thereafter occur according to the following schedule:

-Annually for particulates, sulfur dioxide*, sulfuric acid mist*, NO_x, CO, VOC, mercury, and visible emissions.
-Once every five years (at permit renewal time) for SO_2, sulfuric acid mist, lead, beryllium, and fluorides.

*Test required only during years coal is burned in the boilers.

In the event that the first two years of testing show non-compliance with a particular pollutant, then the frequency of testing of that pollutant shall continue to occur once every six months until the facility achieves a sustained two-year period of compliance. Any exceedance of any emission standard may subject the facility to enforcement action by the County, Department and/or EPA.

25. After conducting the initial stack tests required under Specific Condition No. 24 above, a fuel management plan shall be submitted to the Department and Palm Beach County within 90 days specifying the fuel types and fuel quantities to be burned in the facility in order to not exceed the facility annual mercury, lead, beryllium, and fluorides emission limits specified in Condition 20 above. The plan shall include mercury emission factors based on stack testing, and may include revised mercury emission factors and baseline emission estimates for the existing Okeelanta facility.

<u>Reporting Requirements</u>

26. Stack monitoring, fuel usage, and fuel analysis data shall be reported to the Department's South and Southeast District Offices and to the Palm Beach County Health Unit on a quarterly basis commencing with the start of commercial operation in accordance with 40 CFR, Part 60, Sections 60.7 and 60.49a, and in accordance with Section 17-297.500, F.A.C.

27. The permittee, for good cause, may request that this construction permit be extended. Such a request shall be submitted to the Bureau of Air Regulation prior to 60 days before the expiration of the permit (F.A.C. Rule 17-4.090).

28. An application for an operation permit must be submitted to the South District office at least 90 days prior to the expiration date of this construction permit. To properly apply for an operation permit, the applicant shall submit the appropriate application form, fee, certification that construction was

SPECIFIC CONDITIONS:

completed noting any deviations from the conditions in the construction permit, and compliance test reports as required by this permit (F.A.C. Rules 17-4.055 and 17-4.220).

Issued this ______ day
of _______________, 1993

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL REGULATION

____
Virginia B. Wetherell, Secretary
Department of Environmental Regulation

Best Available Control Technology (BACT) Determination
Okeelanta Power Limited Partnership
Palm Beach County
AC50-219413 (PSD-FL-196)

The applicant proposes to construct a 71.25 MW (net) of electricity cogeneration facility consisting of three 715 MMBtu/hr spreader-stroker boilers that will burn biomass (bagasse and wood waste material), No. 2 fuel oil, and coal. The proposed cogeneration facility will be constructed at Okeelanta Corporation's sugar mill that is located 6 miles south of South Bay, off U.S. Highway 27, Palm Beach County, Florida. Eight existing bagasse/No. 6 fuel oil fired boilers at the sugar mill will be shut down when the cogeneration facility begins commercial operation.

The cogeneration facility, as proposed, will cause a significant net emissions increase of sulfur dioxide, fluorides, and beryllium. Therefore, the project is subject to new source review pursuant to the Prevention of Significant Deterioration (PSD) regulations (F.A.C. Rule 17-212.400). This BACT determination is part of the PSD requirements.

<u>Date of Receipt of a BACT Application</u>: September 30, 1992

The BACT Determination requested by the applicant is summarized below:

<u>Sulfur Dioxide</u>: The recommended BACT is the use of low sulfur fuel: biomass, typically 0.009 percent sulfur; No. 2 fuel oil with a maximum of 0.05 percent sulfur, and coal with a maximum of 0.70 percent sulfur. Also, limiting the No.2 fuel oil burned in the boilers to 25 percent of the annual heat input, limiting the burning of coal to 73,714 tons during any 12-month period, limiting the combined heat input from coal and oil to 25 percent of the annual heat input, and limiting the annual sulfur dioxide emissions to 1,154.3 TPY is a condition of the BACT determination.

<u>Fluorides</u>: The recommended BACT is limiting the quantity of low sulfur coal burned in the facility, the primary source of fluorides, to a maximum of 16 percent of the total annual heat input and the use of an ESP to capture particulates containing the pollutant.

<u>Beryllium</u>: Same as above.

A summary of the emission limits proposed by the applicant for each pollutant subject to the BACT determination follows:

Proposed Emission Limits for the Okeelanta Power Facility

Pollutants	Emission Limits (lbs per MMBtu/lbs per hr per boiler) Fuels* Biomass	No. 2 fuel oil	Coal
SO_2	0.10/71.5	0.05/24.5	1.2/588
Beryllium	--	3.5E-7/1.7E-4	5.9E-6/2.9E-3
Fluorides	--	6.3E-6/3.0E-3	2.4E-2/11.8

* Maximum heat input per boiler

Biomass - 715 MMBtu/hr
No. 2 fuel oil - 490 MMBtu/hr
Coal - 490 MMBtu/hr

BACT Determination Procedure

In accordance with Florida Administrative Code Chapter 17-212.410, Best Available Control Technology Determination, Stationary Source-Preconstruction Review, this BACT determination is based on the maximum degree of reduction of each pollutant emitted which the Department, on a case by case basis, taking into account energy, environmental and economic impacts, and other costs, determines is achievable through application of production processes and available methods, systems, and techniques. In addition, the regulations state that in making the BACT determination the Department shall give consideration to:

(a) Any Environmental Protection Agency determination of Best Available Control Technology pursuant to 40 CFR 52.21, and any emission limitation contained in 40 CFR Part 60 (Standards of Performance for New Stationary Sources) or 40 CFR Part 61 (National Emission Standards for Hazardous Air Pollutants).

(b) All scientific, engineering, and technical material and other information available to the Department.

(c) The emission limiting standards or BACT determinations of any other state.

(d) The social and economic impact of the application of such technology.

The EPA currently stresses that BACT should be determined using the "top-down" approach. The first step in this approach is to determine for the emission source in question the most stringent control available for a similar or identical source or source category. If it is shown that this level of control is technically or economically infeasible for the source in question, then the next most stringent level of control is determined and similarly evaluated. This process continues until the BACT level under consideration cannot be eliminated by any substantial or unique technical, environmental, or economic objections.

BACT Determination by DER

Pollutant	Emission Limit (lbs/MMBtu)	Control Technology	EPA Test Method
Sulfur Dioxide	0.10 (biomass) 0.02 (30-day rolling avg. on biomass) 0.05 (No. 2 fuel oil) 1.2 (coal)	Low sulfur fuel (0.05 percent max. for No. 2 fuel oil; 0.70 percent max. for coal; max. annual heat input of 25 percent from No. 2 fuel oil, a max. of 73,714 tons coal burned during any 12-month period, a max. combined heat input for coal and oil of 25 percent of the annual heat input, and limiting sulfur dioxide emissions to 1,154.3 TPY 12-month rolling average	6, 6C, or 19 and continuous emissions monitoring.
Beryllium	3.5E-7 (No. 2 fuel oil) 5.9E-6 (coal)	Max. annual heat input of 25 percent from No. 2 fuel oil, max. annual capacity factor of 16 percent for coal, a max. combined heat input of 25 percent for coal and oil, and use of an ESP	104
Fluorides	6.3E-6 (No. 2 fuel oil) 2.4E-2 (coal)	Max. annual heat input of 25 percent from No. 2 fuel oil, max. annual capacity factor of 16 percent for coal, a max. combined heat input of 25 percent for coal and oil, and use of an ESP	13A or 13B

BACT Determination Rationale

Sulfur Dioxide: The proposed facility is subject to PSD because of the potential emissions of the alternate coal fuel. The coal will contain a maximum of 0.70 percent sulfur. The applicant proposes that the heat input from fossil fuels be limited to 25 percent of the total annual heat input for the boilers. Thus, 75 percent of the annual heat input (minimum) for the boilers will be provided by biomass -- a fuel that averages 0.009 percent sulfur. The highest proposed SO_2 emissions, 1.2 lbs/MMBtu heat input and 1,154 TPY, will occur when 16 percent of the heat input is provided by coal containing 0.7 percent sulfur. These emissions meet the applicable new source performance standards, 40 CFR 60, Subpart Da. The use of either a wet limestone scrubber or lime/sodium spray dry scrubber, controls used in other BACT determinations listed in the BACT/LAER Clearinghouse document, would reduce SO_2 emissions significantly (over 90 percent). The scrubbers would also create a contaminated liquid or dry solid waste which would have to be disposed of properly. The applicant evaluated the economic, energy and environmental impacts of wet scrubbers, dry scrubbers and dry injection system, in combination with low, medium and high sulfur coal, as technically feasible control alternatives. The economic analysis estimated the total cost effectiveness over baseline of these alternatives to range from $4,994 to $8,923 per ton of SO_2 removed. Limiting the use of low sulfur coal to a 16 percent capacity factor and total sulfur dioxide emissions from the facility, instead of requiring a flue gas desulfurization system, is consistent with recent BACT determinations for multi-fuel spreader stroker boilers. This is applicable to Okeelanta Power because the coal will be fired on an infrequent and intermittent basis. The weighted average sulfur dioxide emissions from this facility will be 0.21 lbs/MMBtu. The combined sulfur dioxide emissions from Okeelanta Power and Osceola Power, a similar proposed plant whose application is being processed at this time, is 1,507 TPY. This results in an overall sulfur dioxide emission limit of 0.168 lbs/MMBtu for both facilities. This average emission rate is close to that determined as BACT for 100 percent coal-fired power plants (i.e., 0.17 lbs/MMBtu for Bechtel Indiantown and 0.25 lbs/MMBtu for OUC Stanton Unit 2).

The ambient air impact for SO_2 at the proposed emission rate has been calculated to be 0.8, 74, and 164 ug/m^3 for the annual, 24-hour, and 3-hour time periods, respectively.

Beryllium: Traces of beryllium are present in fossil fuels. Beryllium can be vaporized and emitted as an air pollutant when these fuels are burned. At the operating temperature of the ESP, approximately 450°F, most of the beryllium should be condensed and captured by the 98 percent efficient ESP. Maximum beryllium emissions are estimated to be 8.7E-3 lbs/hr. The ambient air impact of this emission will be 5E-4, 4E-4, and 3E-5 ug/m^3 for the 8-hour, 24-hour and annual time periods, respectively. These impacts are below the Air Toxics Reference Concentration (ATRC), a concentration believed to have an acceptable health risk to the public.

Fluorides: The fluorides in the fuels can be converted to acid gases during combustion. A majority of these pollutants at Okeelanta Power will come from the coal burned at that facility. By limiting the heat input from coal to a 16% capacity factor, acid gases (fluorides) will be limited. Any acid gas existing in a liquid or solid phase can be captured by the ESP.

At a maximum emission rate per boiler of 11.8 lbs/hr fluorides, the 8-hour and 24-hour impacts are 1.95 and 1.48 ug/m^3. These impacts are below the ATRC.

The Department concluded that limitations on the amount of fossil fuel burned at this facility is BACT for these pollutants.

Conclusion

For the emission standards established as BACT, the ambient air impacts of the sulfur dioxide, beryllium, and fluorides will be below the ambient air standards and/or ATRCs for these pollutants.

Details of the Analysis May be Obtained by Contacting:

Doug Outlaw, P.E., BACT Coordinator
Department of Environmental Regulation
Bureau of Air Regulation
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Recommended by:	Approved by:
C. H. Fancy, P.E., Chief Bureau of Air Regulation	Virginia B. Wetherell, Secretary Dept. of Environmental Regulation
______________ 1993 Date	______________ 1993 Date

Reasonably Available Control Technology (RACT) Determination
Okeelanta Power Limited Partnership
Palm Beach County
AC50-219413 (PSD-FL-196)

The applicant proposed to construct a 71.25 MW (net) of electricity cogeneration facility consisting of three 715 MMBtu/hr spreader-stroker boilers that will burn biomass (bagasse and wood waste material), No. 2 fuel oil, and coal. The proposed cogeneration facility will be constructed at and its operations integrated into Okeelanta Corporation's sugar mill. This mill is located 6 miles south of South Bay, Palm Beach County, Florida. Eight existing bagasse/No. 6 fuel oil boilers at the sugar mill will be replaced by the cogeneration facility when it begins commercial operation. The cogeneration facility is a major source for volatile organic compounds (345 TPY) and nitrogen oxides (862.5 TPY). However, the net contemporaneous emission change for these pollutants resulting from the cogeneration facility project, a reduction of 56.9 TPY for VOC and a reduction of 26.2 TPY for NO_x, is less than the significant emission rates, Table 212.400-2, F.A.C. Thus, the project is subject to F.A.C. Rule 17-296.570, Reasonable Available Control Technology (RACT) Requirements for Major VOC - and NO_x - Emitting Facilities.

<u>Date of Receipt of an Application Subject to RACT</u>: Sept. 30, 1992.

The RACT Determination requested by the applicant is summarized below:

<u>Volatile Organic Compounds</u>: The recommended VOC air pollution control is efficient boiler design and good combustion practices based on the document titled "Use of Flue Gas Oxygen Meter as BACT for Combustion Controls." The estimated VOC emission rates are 0.06 lbs/MMBtu on biomass and 0.03 lbs/MMBtu on No. 2 fuel oil and coal.

<u>Nitrogen Oxides</u>: The recommended NO_x air pollution control is use of a selective non-catalytic reduction system designed to achieve at least 40 percent NO_x reduction efficiency. The estimated NO_x emission rates are 0.15 lbs/MMBtu for biomass fuels and No. 2 fuel oil and 0.17 lbs/MMBtu for coal firing.

<u>RACT Determination Procedure</u>

In accordance with F.A.C. Rule 17-296.570, Reasonably Available Control Technology (RACT) Requirements for Major VOC - and NO_x - Emitting Facilities, this RACT determination is based on the applicant's proposal, published documents, and technological feasibility.

RACT Determined by DER

Fuel	VOC lbs/MMBtu	VOC Control	NO_x lbs/MMBtu	NO_x Control
Biomass	0.06	Boiler Design, Good operation practice using the oxygen meter	0.15	Non-Catalytic reduction system
No. 2 Fuel Oil	0.03		0.15	
Coal	0.03		0.17	

RACT Determination Rationale

VOC: The applicant is committed to meeting the VOC emission limit through good design and operating practice based on a procedure that has been considered as a BACT determination for similar boilers. As a BACT determination is generally considered to establish more stringent emission standards than a RACT determination, the Department finds the applicant's proposal acceptable.

NO_x: The applicant will use a selective non-catalytic reduction system to lower NO_x emissions. The proposed NO_x emissions are lower than the limits given in the new source performance standards (NSPS) for electric utility steam generation units (40 CFR 60, Subpart Da). As a NSPS is generally considered to have a more stringent emission limit than a RACT standard, the Department finds the applicant's proposal acceptable.

There is a net reduction in the VOC and NO_x emissions from the Okeelanta Power Limited Partnership project. Therefore, the ambient air impact of these pollutants from the Okeelanta Corporation's sugar mill will decrease.

Conclusion

Good boiler design, operation practice and use of a non-catalytic reduction system meets the VOC and NO_x RACT for the proposed cogeneration facility. The emissions will not interfere with reasonable further progress in this ozone non-attainment area.

Details of the Analysis May be Obtained by Contacting:

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

Recommended by:

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

____________________ 1993
Date

Approved by:

Virginia B. Wetherell, Secretary
Dept. of Environmental Regulation

____________________ 1993
Date