Department of
Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

December 22, 1999

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Ricardo Lima, Vice President and General Manager
Okeelanta Power L.P.
P.O. Box 86
South Bay, FL 33493

Re: DEP File No. 0990332-012-AC, Request to Install Pre-Control Equipment
Okeelanta Power L.P. - Cogeneration Plant
(PSD Permit No. PSD-FL-196)
ARMS Facility ID No. 0990332

Dear Mr. Lima:

Okeelanta Power L.P. operates a biomass cogeneration plant located near South Bay in Palm Beach County, Florida. On September 7, 1999, Okeelanta Power L.P. applied to the Department for a minor permit modification to install cyclone dust collectors as pre-control devices prior to the electrostatic precipitators (ESPs). The proposed equipment is intended to remove large particulate matter, which will reduce particulate loading to the electrostatic precipitator and enhance the overall control efficiency. The Department received the final design information on December 16, 1999 and approves the request. In consideration of improving the performance of the existing electrostatic precipitators and because the proposed equipment is expected to reduce particulate emissions, the Department authorizes the applicant to immediately install the following equipment (or equivalent) prior to the electrostatic precipitator for each biomass cogeneration boiler:

Manufacturer: Barron Industries
Model: 460 Tube Barron Base III 9K15-2023-AU
Description: Four module, large diameter, multitube mechanical dust collector with airfoil vanes
Tube Specifications: Cast hard gray iron Base III tube with 9 inch diameter, 460 tubes
Casing, Hopper, and Tube Sheet Materials: Carbon steel
Hoppers: Four through hoppers with internal screw conveyor
Design Flue Gas Conditions: 450°F; 359,506 acfm; dust specific gravity is between 1.00 and 2.00
Design Pressure Drop: 2.8 inches of water column
Overall Design Collection Efficiency: > 85% efficiency for particles greater than PM_{10} (SG = 2.00)

The Department is also processing a request from Okeelanta Power L.P. to extend standby operation of the bagasse boilers at Okeelanta Corporation's existing sugar mill (DEP File No. 0990332-011-AC). As previously discussed, the Department will include requirements to install, operate, and maintain the mechanical dust collectors as part of this proposed modification, which will require the publishing of a

Public Notice making these federally enforceable. Please file a copy of this letter authorizing construction with the referenced permit.

Sincerely,

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

Mr. Ricardo Lima, Okeelanta Power L.P.*
Mr. James Meriwether, Okeelanta Power L.P.
Mr. David Buff, Golder Associates
Mr. James Stormer, Palm Beach County Health Department
Mr. David Knowles, South District Office DEP
Gregg Worley, EPA Region 4

Z 031 391 908

US Postal Service

Receipt for Certified Mail

No Insurance Coverage Provided.
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Sent to Ricardo Luna	
Street & Number Okeelanta Power	
Post Office, State, & ZIP Code South Bay Fl	
Postage	$
Certified Fee	
Special Delivery Fee	
Restricted Delivery Fee	
Return Receipt Showing to Whom & Date Delivered	
Return Receipt Showing to Whom, Date, & Addressee's Address	
TOTAL Postage & Fees	$
Postmark or Date 12-22-99 0990332-012-AC PSD-FI-196	

PS Form **3800**, April 1995

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1. ☐ Addressee's Address
2. ☐ Restricted Delivery

Consult postmaster for fee.

3. Article Addressed to:
Ricardo Luna, VP & GM
Okeelanta Power, LP
PO Box 86
South Bay, Fl
33493

4a. Article Number
Z 031 391 908

4b. Service Type
☐ Registered ☒ Certified
☐ Express Mail ☐ Insured
☐ Return Receipt for Merchandise ☐ COD

7. Date of Delivery
12.27.99

5. Received By: *(Print Name)*

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6. Signature: *(Addressee or Agent)*
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PS Form **3811,** December 1994 102595-98-B-0229 Domestic Return Receipt

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Department of
Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

September 20, 1999

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

James Meriwether, Environmental Manager
Okeelanta Cogeneration Facility
P.O. Box 9
South Bay, FL 33493

Re: Request for Additional Information
Permit No. PSD-FL-196
Okeelanta Cogeneration Facility
Modification to Original PSD Construction Permit

0990332-012-AC

Dear Mr. Meriwether:

On September 7, 1999, the Department's South District Office received a check for $250 and your letter requesting a minor source construction permit modification to add several mechanical dust collectors as pre-control devices prior to the electrostatic precipitators. The Bureau of Air Regulation considers this potentially to be a modification of the original PSD permit. As such, the South District Office has forwarded this request to the New Source Review Section in Tallahassee.

The Department considers this application to be incomplete. In order to continue processing your application, the Department will need the additional information requested below. Should your response to any of the below items require new calculations, please submit the new calculations, assumptions, reference material and appropriate revised pages of the application form.

1. Please submit the appropriate pages of the Department's application form, signed and certified by both the Responsible Official and a Professional Engineer registered in Florida.
2. Please identify the particulate emissions control expected with a corresponding particle size range.
3. What is the expected pressure drop across the duct collector? Will it be necessary to modify or replace the I.D. fan? What will be the new or modified parameters for the I.D. fan including volumetric flow rate?
4. Of what materials are the mechanical collectors made? Due to the known corrosive nature of the exhaust stream, what is the expected life of the duct collectors?

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

5. Please specify the model number, quantity, arrangement, and key design parameters for sizing the Baron Industries' dust collectors.
6. Please provide an updated process flow diagram of the cogeneration process and control equipment including: fuel storage, fuel feeds, boilers, dust collectors, electrostatic precipitators, I.D. fans, activated carbon silo and injection points, urea injection system, exhaust gas continuous monitoring systems and points, and stacks. On this process flow diagram, indicate the temperatures and flow rates of the exhaust gases as they pass through the various points in the system, as well as the associated pressure drops for each significant point.
7. Please include a full description of the ongoing stack modifications, new stack heights, and materials being used to line the stack. Will the addition of the dust collectors or modified stacks result in any changes in previous air dispersion modeling analyses performed for this facility?

The Department will resume processing your application after receipt of the requested information. Rule 62-4.050(3), F.A.C. requires that all applications for a Department permit must be certified by a professional engineer registered in the State of Florida. This requirement also applies to responses to Department requests for additional information of an engineering nature. A new certification statement by the authorized representative or responsible official must accompany material changes to the application. Rule 62-4.055(1), F.A.C. now requires applicants to respond to requests for information within 90 days. If there are any questions, please call me at 850/414-7268.

Sincerely,

Jeffery F. Koerner, P.E.
New Source Review Section

AAL/jfk

cc: Mr. Phil Barbaccia, SW District - DEP
Mr. Jim Stormer, PBCHD

P 265 659 434

US Postal Service

Receipt for Certified Mail

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Sent to	James Meriwether
Street & Number	Okeelanta Cogen
Post Office, State, & ZIP Code	South Bay Fl
Postage	$
Certified Fee	
Special Delivery Fee	
Restricted Delivery Fee	
Return Receipt Showing to Whom & Date Delivered	
Return Receipt Showing to Whom, Date, & Addressee's Address	
TOTAL Postage & Fees	$
Postmark or Date	PSD-FL-196 9-20-99

PS Form **3800**, April 1995

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- Write *"Return Receipt Requested"* on the mailpiece below the article number.
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I also wish to receive the following services (for an extra fee):

1. ☐ Addressee's Address
2. ☐ Restricted Delivery

Consult postmaster for fee.

3. Article Addressed to:

James Meriwether
Okeelanta Cogen Fac.
P O Box 9
South Bay, Fl
33493

4a. Article Number
P 265 659 434

4b. Service Type
☐ Registered ☒ Certified
☐ Express Mail ☐ Insured
☐ Return Receipt for Merchandise ☐ COD

7. Date of Delivery
9/23/99

5. Received By: *(Print Name)*

8. Addressee's Address *(Only if requested and fee is paid)*

6. Signature *(Addressee or Agent)*
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PS Form **3811**, December 1994 102595-98-B-0229 Domestic Return Receipt

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CHECK PAYMENT NBR. DATE

4591 THE DEPARTMENT OF 13672 09/22/99

INVOICE	DESCRIPTION	DATE	P.O. NO.	GROSS AMT.	DISCOUNT	NET AMOUN
92099	PERMIT FEE	09/20/99		250.00	0.00	250.0
OKEELANT CO-GEN						

FLORIDA CRYSTALS CORPORATION

TOTALS	250.00	0.00	250.0

FLORIDA CRYSTALS CORPORATION
316 ROYAL POINCIANA PLAZA
PALM BEACH, FLORIDA 33480-4099

FIRST UNION *First Union National of Florida*
PENSACOLA, FL 32634

63-1012
632

NO. 013672

DATE 09/22/99 13672

AMOUNT
$ *******250.00

PAY
TWO HUNDRED FIFTY AND 00/100--DOLLAR

TO THE ORDER OF
THE DEPARTMENT OF
ENIVRONMENTAL PROTECTION
SOUTH DISTRICT
2295 VICTORIA AVENUE
FORT MEYERS FL 33902-2549

[redacted] [redacted] [redacted]

PS Form 3811, July 1983 447-845

DOMESTIC RETURN RECEIPT

● **SENDER: Complete items 1, 2, 3 and 4.**

Put your address in the "RETURN TO" space on the reverse side. Failure to do this will prevent this card from being returned to you. The return receipt fee will provide you the name of the person delivered to and the date of delivery. For additional fees the following services are available. Consult postmaster for fees and check box(es) for service(s) requested.

1. ☑ Show to whom, date and address of delivery.
2. ☐ Restricted Delivery.

3. Article Addressed to:
Mr. Gus Cepero, VP
P.O. Box 86
South Bay, Fla 33493

4. Type of Service:
☐ Registered ☐ Insured
☑ Certified ☐ COD
☐ Express Mail

Article Number

Always obtain signature of addressee or agent and DATE DELIVERED.

5. Signature – Addressee
X

6. Signature – Agent
X

7. Date of Delivery 11/9/92

8. Addressee's Address (ONLY if requested and fee paid)

P 062 921 916

UNITED STATES POSTAL SERVICE

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(See Reverse)

Sent to Mr Gus Cepero
Street and No. P.O. Box 86
P.O., State and ZIP Code South Bay, Fl 33493

Postage	$
Certified Fee	
Special Delivery Fee	
Restricted Delivery Fee	
Return Receipt Showing to Whom & Date Delivered	
Return Receipt Showing to Whom, Date, and Addressee's Address	
TOTAL Postage & Fees	$

Postmark or Date

PS Form 3800, June 1991

9/15/92

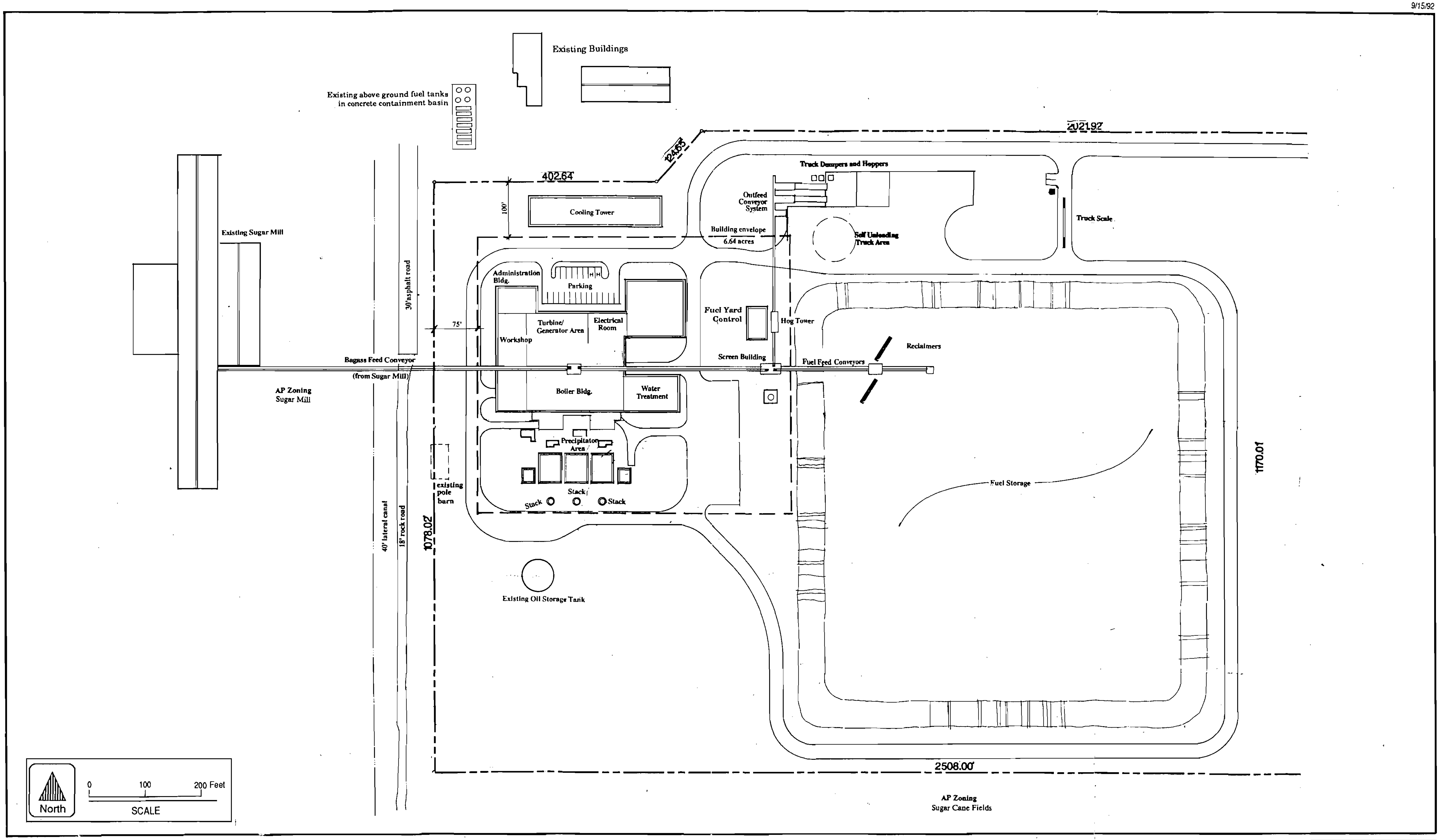


Figure 2-6 CONCEPTUAL PLOT PLAN OF PROPOSED COGENERATION FACILITY

KBN

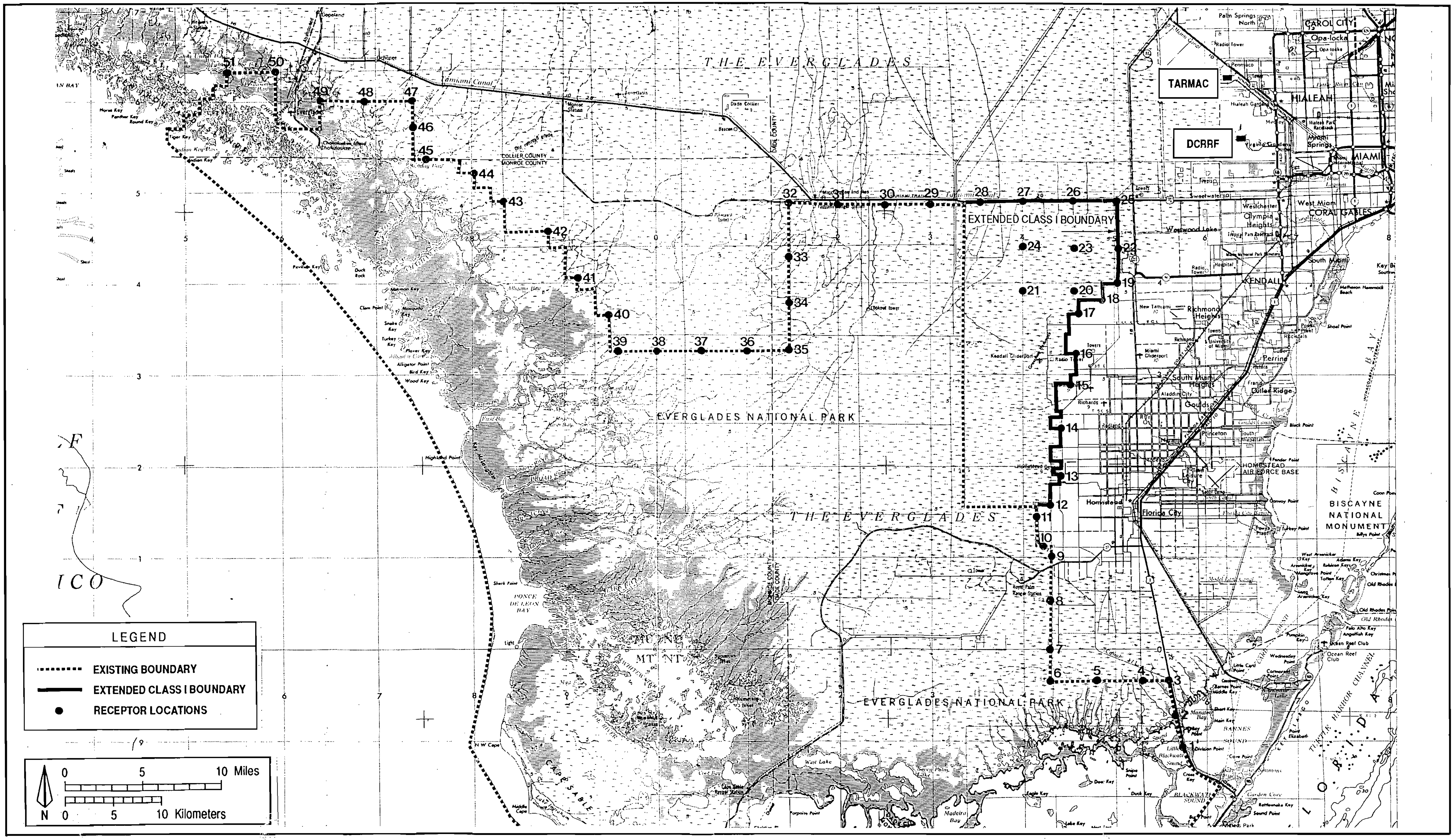


Figure 6-1 RECEPTOR LOCATIONS USED FOR THE EVERGLADES NATIONAL PARK PSD CLASS I SCREENING ANALYSES

KBN

KBN

December 4, 1992

Mr. John Brown, Jr., P.E.
Air Permitting and Standards
Florida Department of Environmental Regulation
2600 Blair Stone Road
Tallahassee, FL 32399-2400

RECEIVED
DEC 7 1992
Bureau of
Air Regulation

Re: AC50-219413/PSD-FL-196, Flo-Energy, Inc.

Dear Mr. Brown:

This correspondence contains the responses to the Florida Department of Environmental Regulation (FDER) letter dated November 3, 1992, concerning the above-referenced permit application. Responses for the Flo-Energy application are presented in Attachment A. In the attachment, each response is referenced in numerical order according to the Department's letter.

In addition to the responses to FDER comments, Flo-Energy is providing the following additional information concerning the facility.

Ammonia Slip

The vendors have indicated that a higher ammonia slip than originally proposed may be required to meet the proposed NO_x limit when burning coal. This is due to the higher levels of uncontrolled NO_x when burning coal and the higher ammonia (or urea) injection rate required for control. The proposed revised ammonia slip emission rate is based on 65 ppmv slip in the exhaust gases. We recognize that the PG&E/Bechtel Indiantown PSD permit, issued in March 1992, limited ammonia slip to 50 ppmv, but this permit was for a pulverized coal-fired boiler. The Flo-Energy boilers will be of the spreader stoker type, which have a somewhat higher uncontrolled NO_x emission rate. Thus, a higher rate of ammonia slip is expected for Flo-Energy's spreader stoker boilers.

Attached are revised tables from the PSD permit application reflecting the changes in the ammonia emissions. The ammonia emission calculation is also presented. Based on the ammonia impacts, which are well below the FDER no-threat level, no adverse environmental impacts are expected from the higher ammonia emissions.

Mercury Testing for Existing Facilities

In response to the suggestions made during our meeting with FDER on September 17, 1992, Okeelanta developed a proposed plan for investigating actual mercury emissions from the existing bagasse fired boilers at Okeelanta and Osceola. These investigations would be for the purpose of better quantifying actual baseline mercury emissions. As we discussed, the county zoning conditions and our proposed PSD permit conditions for the Flo-Energy and Sol-Energy facilities require that future mercury emissions not exceed the emissions from the existing facilities (in tons per year).

Okeelanta has conducted only one in-house mercury emission test on one boiler at their facility. This test was conducted during the past crop season using EPA Method 101A. The results of the tests are shown in the attached Table 1. The boiler was fired with bagasse and No. 6 fuel oil, with the fuel oil ranging from 15-20 percent of the total heat input. The average mercury emission rate for the boiler was 0.0020 lb/hr or $6.5x10^{-6}$ lb/MM Btu. The range of emissions was from $0.6x10^{-6}$ to $14.9x10^{-6}$ lb/MMBtu.

KBN ENGINEERING AND APPLIED SCIENCES, INC.
1034 Northwest 57th Street Gainesville, Florida 32605 904/331-9000 FAX: 904/332-4189

These test results are helpful for establishing a range of approximate emission rates, but they are much too limited to use alone for direct comparisons or for the establishment of absolute permit limits. In order to obtain more data concerning mercury emissions from bagasse boilers, Okeelanta proposes to conduct mercury emission testing on four boilers during the coming crop year. Two boilers at Okeelanta and two at Osceola Farms would be tested. Two different boiler types would be tested at each facility (i.e., fuel cell and traveling grate). In addition, bagasse, ash, and scrubber water samples will be obtained and analyzed for mercury content. Based on these data, the baseline mercury emissions for the two facilities can be determined more accurately, and the future mercury limits for the two cogeneration facilities can then be adjusted, if necessary.

In order to minimize the cost of this testing, Okeelanta may prefer to perform the mercury tests during the annual PM compliance tests run each year on the boilers. If possible, the compliance tests to be conducted in the first quarter of 1993 will be performed earlier in order to obtain the data sooner.

Due to the critical timing of obtaining the air construction permits for the facilities, it is requested that the review of the permit applications not be delayed because of Okeelanta's voluntary effort to gather additional mercury data. Flo-Energy and Sol-Energy have already proposed permit conditions which allow further testing to better quantify the baseline mercury emissions (refer to proposed Condition 26 for Flo-Energy and Condition 25 for Sol-Energy).

Construction Emissions

Little information exists concerning air emissions due to construction activities. EPA Publication AP-42, Section 11.2.4 (12/75), presents an estimate of 1.2 tons of PM per acre per month of construction activity, applicable to a medium activity level and semi-arid climate. This factor is very general, has no correction factors, and has a very high degree of uncertainty. Therefore, this emission factor is not considered appropriate for application to Flo-Energy. Actual emissions due to construction activities would be dependent upon a number of factors, including vehicle types, speeds, operating hours, rainfall, soil moisture, meteorological conditions, control measures, and the types of construction activities. In the case of Flo-Energy, emissions due to construction will be controlled as specified in proposed Specific Condition 10 contained in the application. In summary, construction emissions for Flo-Energy cannot be readily quantified, but they will be temporary in nature. Due to the remote nature of the plant site, no significant off-site impacts due to construction activities are expected.

We are confident that this information will adequately respond to your questions, allowing a determination to be made on the acceptability of the application. Please call me at (904) 331-9000 if you have any questions concerning this information.

Sincerely,

David A. Buff

David A. Buff, ME, PE
Principal Engineer
Florida Registration No. 19011

No. 19011

Enclosure
cc: Gus Cepero, Okeelanta
Don Schaberg, Okeelanta
David Dee, Carlton-Fields
Jewell Harper, EPA
H. Hanks
C. Holladay
John Bunyak, NPS
Frank Gargiulo, PBCHD
David Knowles, FDER
File (2)
I. Goldman, SE Dist

12118C4/RTC1/1

12118C4/RTC1/RAS-1
11/25/92

REVISED AMMONIA SLIP EMISSIONS FOR COAL BURNING

Maximum NH_3 slip will be 65 ppm based on vendor information.

Maximum flow rate per boiler when burning coal = 210,300 acfm

MW NH_3 = 17

$PV = mRT \qquad M = PV/RT$

$M = 2{,}116.8\ lb_f/ft^2 \times 210{,}300\ ft^3/min \times 60\ min/hr \times 17\ lb_m\text{-}^0R/1{,}545\ ft\text{-}lb_f$
$\div\ (460 + 350)^0R \times 65/10^6 = 23.6$ lb/hr each boiler

$23.6\ lb/hr \div 490x10^6\ Btu/hr = 0.048\ lb/MMBtu$

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

	Biomass				No. 2 Fuel Oil				Coal				
Non Regulated Pollutant	Emission Factor (lb/MMBtu)	Ref	Activity Factor (MMBtu/hr)	Hourly Emissions (lb/hr)	Emission Factor (lb/MMBtu)	Ref	Activity Factor (MMBtu/hr)	Hourly Emissions (lb/hr)	Emission Factor (lb/MMBtu)	Ref	Activity Factor (MMBtu/hr)	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 2-11. Maximum Annual Emissions of Non-Regulated Pollutants for the Flo-Energy Cogeneration Facility (total all boilers) (Page 1 of 2) (Revised 11/25/92)

Non Regulated Pollutant	Biomass			No. 2 Fuel Oil			Coal			Total Annual Emission (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)	
<u>Normal Operations</u>										
Ammonia	0.0148	11.500	85.1	–	–	–	–	–	–	85.1
Antimony	UD	11.500	–	–	–	–	–	–	–	–
Arsenic	5.58E-05	11.500	0.32	–	–	–	–	–	–	0.32 [a]
Barium	1.06E-04	11.500	0.61	–	–	–	–	–	–	0.61
Bromine	1.47E-03	11.500	8.45	–	–	–	–	–	–	8.5 [a]
Cadmium	5.43E-06	11.500	0.031	–	–	–	–	–	–	0.031 [a]
Chromium	5.54E-05	11.500	0.32	–	–	–	–	–	–	0.32 [a]
Chromium^{+6}	1.35E-05	11.500	0.078	–	–	–	–	–	–	0.078 [a]
Cobalt	4.98E-04	11.500	2.86	–	–	–	–	–	–	2.86 [a]
Copper	7.23E-05	11.500	0.42	–	–	–	–	–	–	0.42
Dioxin	6.93E-12	11.500	4.0E-08	–	–	–	–	–	–	4.0E-08 [a]
Furan	3.62E-10	11.500	2.1E-06	–	–	–	–	–	–	2.1E-06 [a]
Formaldehyde	6.56E-04	11.500	3.77	–	–	–	–	–	–	3.8 [a]
Hydrogen Chloride	3.70E-02	11.500	212.75	–	–	–	–	–	–	212.8
Indium	1.27E-04	11.500	0.73	–	–	–	–	–	–	0.73 [a]
Manganese	7.98E-04	11.500	4.59	–	–	–	–	–	–	4.6 [a]
Molybdenum	2.54E-04	11.500	1.46	–	–	–	–	–	–	1.5 [a]
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 [a]
Thallium	UD	11.500	–	–	–	–	–	–	–	–
Tin	1.62E-04	11.500	0.93	–	–	–	–	–	–	0.93 [a]
Zinc	4.24E-04	11.500	2.44	–	–	–	–	–	–	2.44 [a]
Zirconium	9.29E-05	11.500	0.53	–	–	–	–	–	–	0.53 [a]
<u>25% Oil Firing</u>										
Ammonia	0.0148	8.118	60.1	0.0148	2.706	10.01	–	–	–	70.1
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	8.128	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 2-11. Maximum Annual Emissions of Non-Regulated Pollutants for the Flo-Energy Cogeneration Facility (total all boilers) (Page 2 of 2) (Revised 11/25/92)

	Biomass			No. 2 Fuel Oil			Coal			
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)
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>25% Coal Firing</u>										
Ammonia	0.0148	8.118	60.1	–	–	–	0.048	2.706	64.9	125.0 [a]
Antimony	UD	8.118	–	–	–	–	3.49E-05	2.706	0.047	0.047 [a]
Arsenic	5.58E-05	8.118	0.23	–	–	–	2.64E-05	2.706	0.036	0.27
Barium	1.06E-04	8.118	0.43	–	–	–	7.44E-04	2.706	1.01	1.44 [a]
Bromine	1.47E-03	8.118	5.97	–	–	–	7.90E-04	2.706	1.069	7.04
Cadmium	5.43E-06	8.118	0.022	–	–	–	1.36E-06	2.706	0.0018	0.024
Chromium	5.54E-05	8.118	0.22	–	–	–	1.66E-05	2.706	0.022	0.24
Chromium^{+6}	1.35E-05	8.118	0.055	–	–	–	3.32E-06	2.706	0.004	0.059
Cobalt	4.98E-04	8.118	2.02	–	–	–	7.20E-05	2.706	0.097	2.1
Copper	7.23E-05	8.118	0.29	–	–	–	1.71E-04	2.706	0.23	0.52 [a]
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	–	–	–	2.20E-04	2.706	0.30	2.96
Hydrogen Chloride	3.70E-02	8.118	150.183	–	–	–	7.90E-02	2.706	106.89	257.1 [a]
Indium	1.27E-04	8.118	0.52	–	–	–	–	2.706	–	0.52
Manganese	7.98E-04	8.118	3.24	–	–	–	3.10E-05	2.706	0.042	3.3
Molybdenum	2.54E-04	8.118	1.03	–	–	–	8.83E-05	2.706	0.119	1.2
Nickel	4.41E-05	8.118	0.18	–	–	–	1.02E-03	2.706	1.38	1.56 [a]
Phosphorus	3.53E-04	8.118	1.43	–	–	–	8.60E-04	2.706	1.16	2.60 [a]
Selenium	UD	8.118	–	–	–	–	5.34E-05	2.706	0.072	0.072 [a]
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	–	–	–	8.83E-05	2.706	0.119	0.78
Zinc	4.24E-04	8.118	1.72	–	–	–	3.49E-04	2.706	0.47	2.2
Zirconium	9.29E-05	8.118	0.38	–	–	–	–	2.706	–	0.38

Note: UD = undetectable levels in gas stream.

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

Table 6-18. Maximum Impacts of Toxic Pollutants for Flo-Energy Cogeneration Facility (total all boilers) (Revised 11/25/92)

Pollutant	Maximum Hourly Emissions[a] (lb/hr)	Concentrations ($\mu g/m^3$)					
		8-Hour		24-Hour		Annual	
		Impact	NTL	Impact	NTL	Impact	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	0.0123	0.0007	0.5	0.0005	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
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).

12118C4/RTC1
11/25/92

Table 1. Results of Mercury Stack Tests at Okeelanta - Boiler No. 12

Run #		μg Hg/l	Vol. (ml)	μg Hg	DSCFM	Meter SCF	Hg (lb/hr)	Heat Input (MMBtu/hr)	Hg (lb/MMBtu)
1)	P/N/I	23.12	1,000	23.12					
	Filter	4.06	102	0.414					
	Blank	0.82	101	-0.0828	58,228	39.120	0.00462	310.45	14.9 x 10^{-6}
	Total			23.451					
2)	P/N/I	0.79	1,050	0.830					
	Filter	2.04	99	0.202					
	Blank	0.82	101	-0.0828	57,942	38.161	0.000191	315.81	0.605 x 10^{-6}
	Total			0.949					
3)	P/N/I	5.06	1,065	5.389					
	Filter	5.47	101	0.552					
	Blank	0.82	101	-0.083					
	Total			5.858	58,823	38.240	0.00119	304.49	3.91 x 10^{-6}
						Avg.	0.0020		6.47 x 10^{-6}

Note: P/N/I = Probe, Nozzle and Impingers.
EPA method 101A used for testing.

ATTACHMENT A

FLO-ENERGY, INC.

NOTE: FINAL VENDOR SELECTION HAS NOT BEEN COMPLETED FOR THE FLO-ENERGY FACILITY. INFORMATION PROVIDED REPRESENTS THE DESIGN FOR ONE OF THE TWO VENDORS BEING CONSIDERED. THE EQUIPMENT FINALLY SELECTED WILL BE OF THE DESIGN SPECIFIED, OR EQUIVALENT

__FDER Comment 1__: Please provide the make, model, drawing, brochure, or general specifications for each steam generation unit. What is the generating capacity of each plant, 74.9 or 44 MW?

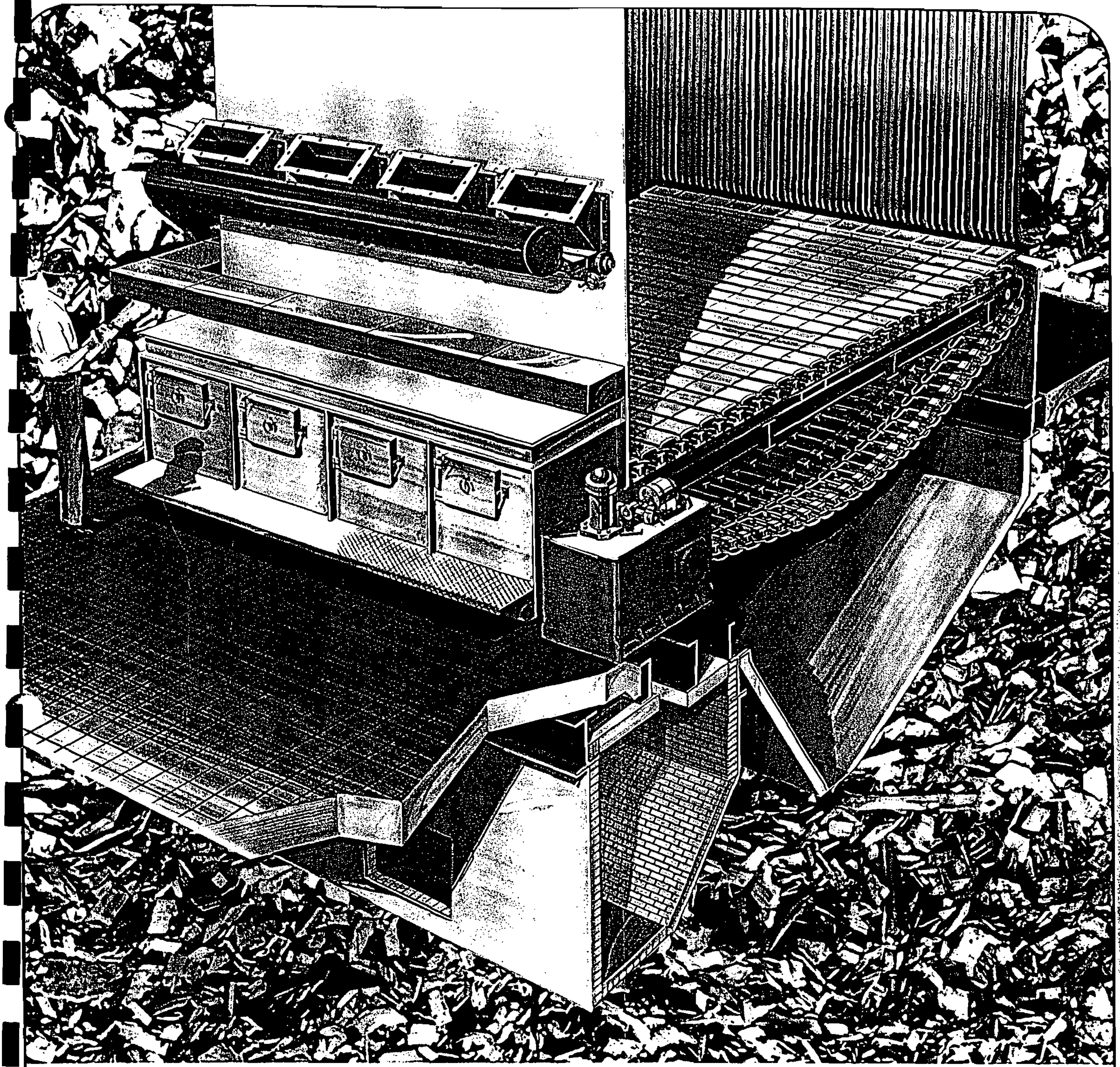
__Response 1__: The boilers will be manufactured by Zurn Industries, Inc. Design features of the boilers include the following:

- Two-drum, field erected, open pass, balanced draft steam generators
- Water cooled furnace with electrical resistance welded steel boiler tubes
- Superheater section
- Economizer section
- Primary air preheater
- Overfire air preheater
- Plenum hoppers, boiler hoppers and airheater hoppers for collection of fly ash
- Forced draft and induced draft fans
- Primary and overfire air systems
- Zurn Model SAO-32 No. 2 fuel oil burner; steam atomizing
- Spreader stoker; continuous traveling (Travagrate), front ash discharge, grate area of 585 sq. ft.

Design data for each boiler are as follows:

Furnace volume = 39,917 ft^3
Steam temperature = 975°F
Steam pressure = 1,800 psig (design); 1,500 psig (operating)
Steam output = 455,418 lb/hr
Heat input = 715 x 10^6 Btu/hr (biomass)
= 490 x 10^6 Btu/hr (coal)

The maximum electric generating capacity of the Flo-Energy facility will be 74.9 MW.

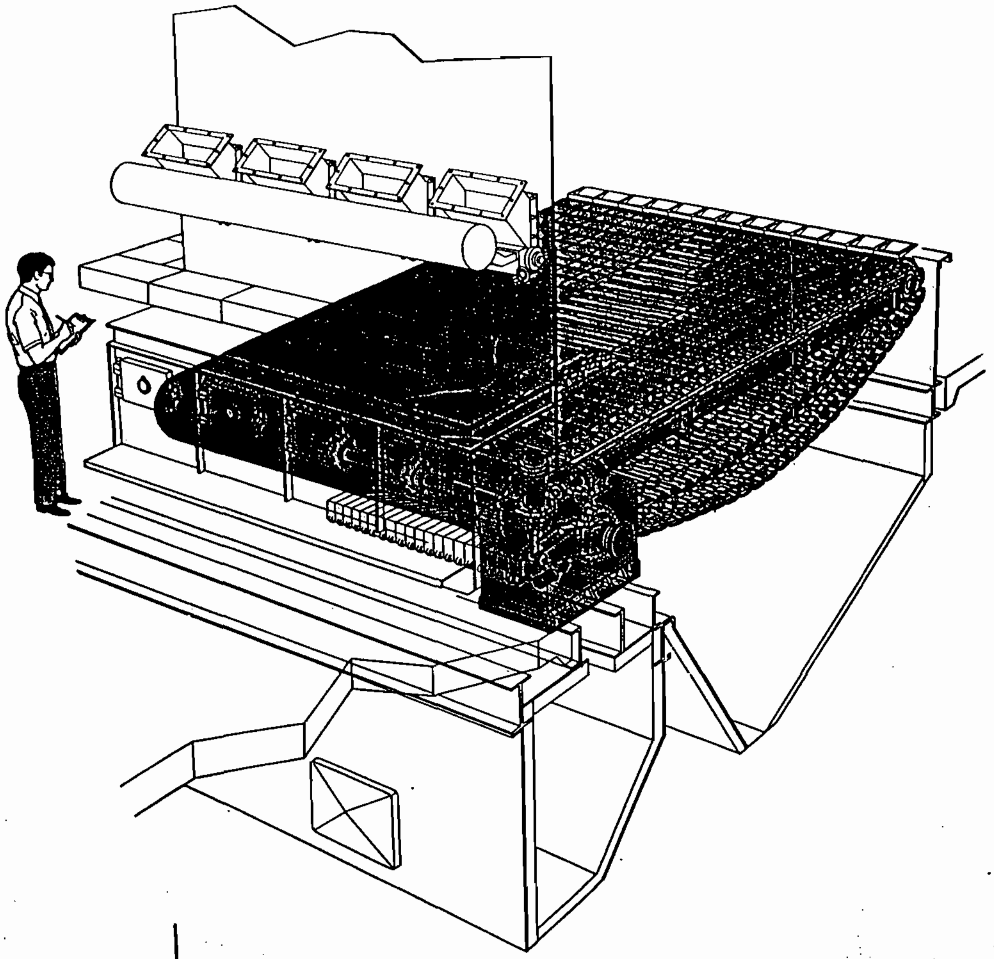


ZURN SPREADER STOKERS

FOR WOOD, WOOD WASTE, MUNICIPAL REFUSE, AND OTHER BIOMASS FUELS

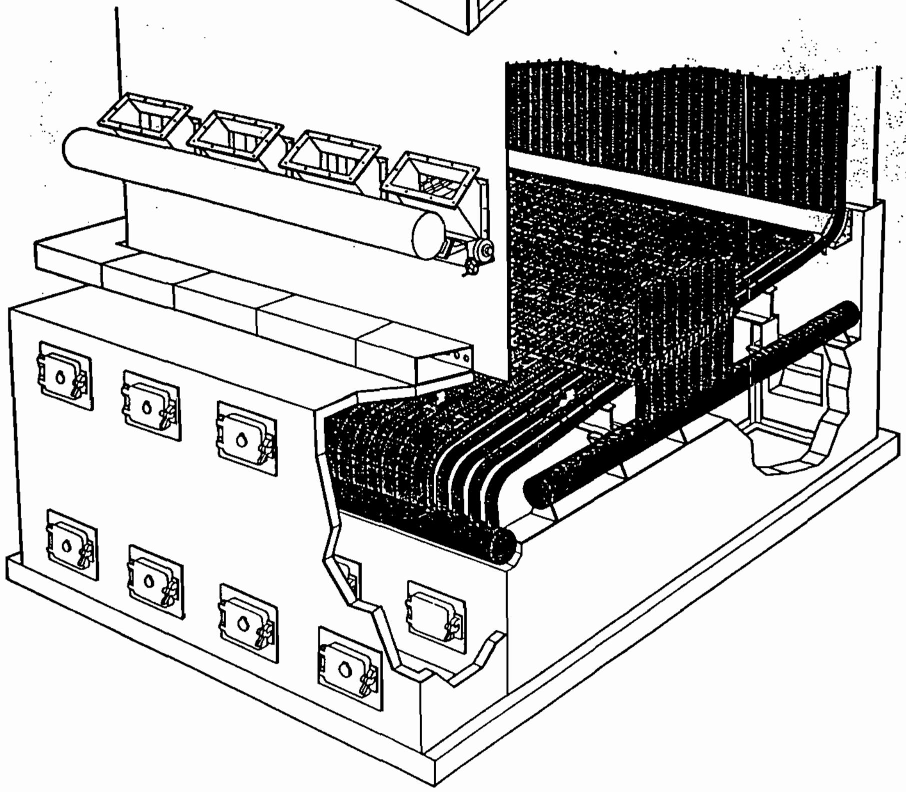
ZURN a step ahead of tomorrow

RTC-2



The Zurn TRAVAGRATE® spreader stoker is an overfeed-type stoker designed for continuous ash discharge in steam generators with capacities ranging from 10,000 to 50,000 lbs/hr factory-assembled and 30,000 to 500,000 lbs/hr field-constructed. Fuel is burned in suspension as well as on the forward-traveling grate surface.

Zurn TRAVAGRATE spreader stokers consist of single or dual drive grate assemblies complete with hydraulic grate drive(s) and necessary pneumatic fuel distributors.



The Zurn stationary, water-cooled grate spreader stoker is also an overfeed stoker designed for intermittent zoned cleaning in steam generators with capacities ranging from 10,000 to 40,000 lbs/hr factory-assembled and 30,000 to 300,000 lbs/hr field-constructed. Fuel is burned in suspension as well as on the grate surface.

Zurn stationary, water-cooled grate spreader stokers can be automatically cleaned by intermittent air or steam by zones while maintaining full load operation. Pneumatic fuel distributors provide continuous feed of a variety of non-fossil solid fuels.

SPREADER STOKERS
A RESOURCEFUL ENERGY ALTERNATIVE

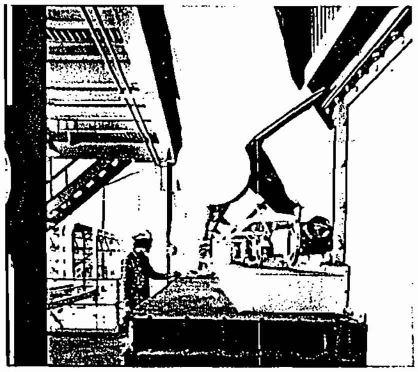
Renewable energy resources such as wood, refuse and other biomass wastes are receiving greater consideration as primary energy sources by industry and utilities.

In the early 1900's, wood was the major source of energy in the United States. Today, wood, agricultural wastes and other biomass supply almost 2% (1.5 *Quads/year) of U.S. energy, 7% of industrial energy. Government analysts estimate bioenergy resources could supply 15 to 20% (12-17 Quads/yr.) of U.S. energy by the year 2000. The combustible portion of municipal solid waste, now generated at 135 million tons/year has the potential of providing another 2%.

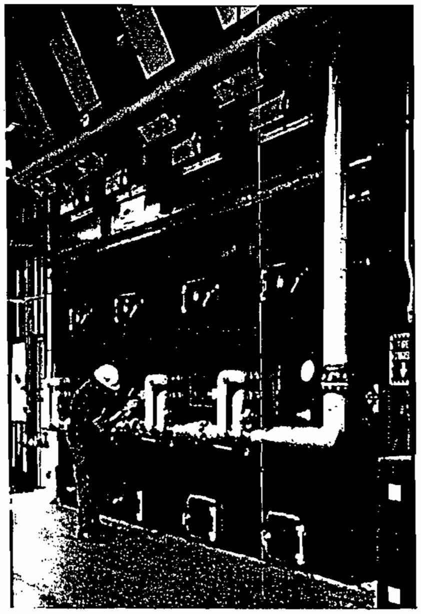
Higher costs for basic fossil fuels coupled with favorable legislation have greatly increased the financial viability of using alternate fuels. Stoker-fired systems are an excellent way to capitalize on these valuable energy resources.

The Energy Division of Zurn Industries, Inc. designs, engineers, manufactures and installs spreader stokers for burning a wide variety of wood, refuse and biomass fuels in boilers produced by Zurn or by any other boiler manufacturer.

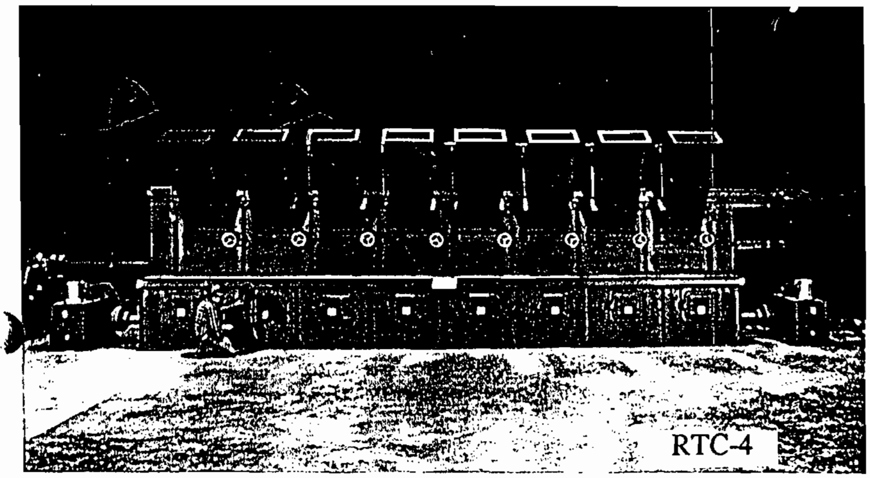
*A Quad equals 1 quadrillion (10^{15}) Btu. It equals the energy of approximately 464,000 bbl/d of oil for 1 year, 50 million tons of coal, or the typical annual energy output of eighteen 1,000 Mw power plants. Energy consumption in the U.S. totalled 70.45 Quads in 1983.



◀ *Zurn TRAVAGRATE spreader stoker provides continuous-ash-discharge for a 140,000 lb/hr wood-fired unit in a Texas forest-products producing plant. System was designed for future lignite firing and future cogeneration.*



◀ *Zurn stationary water-cooled-grate spreader stoker allows intermittent zoned cleaning of grates in a 120,000 lbs/hr unit at a Georgia paper plant.*



◀ *Zurn pneumatic fuel distributor assembly, TRAVAGRATE spreader stoker and hydraulic grate drives were pre-assembled at Zurn Energy Div. fabrication facility to assure component fit and alignment. System is installed and providing 480,000 lbs/hr steam to produce electricity for a 50 Mw wood-fired municipal power plant.*

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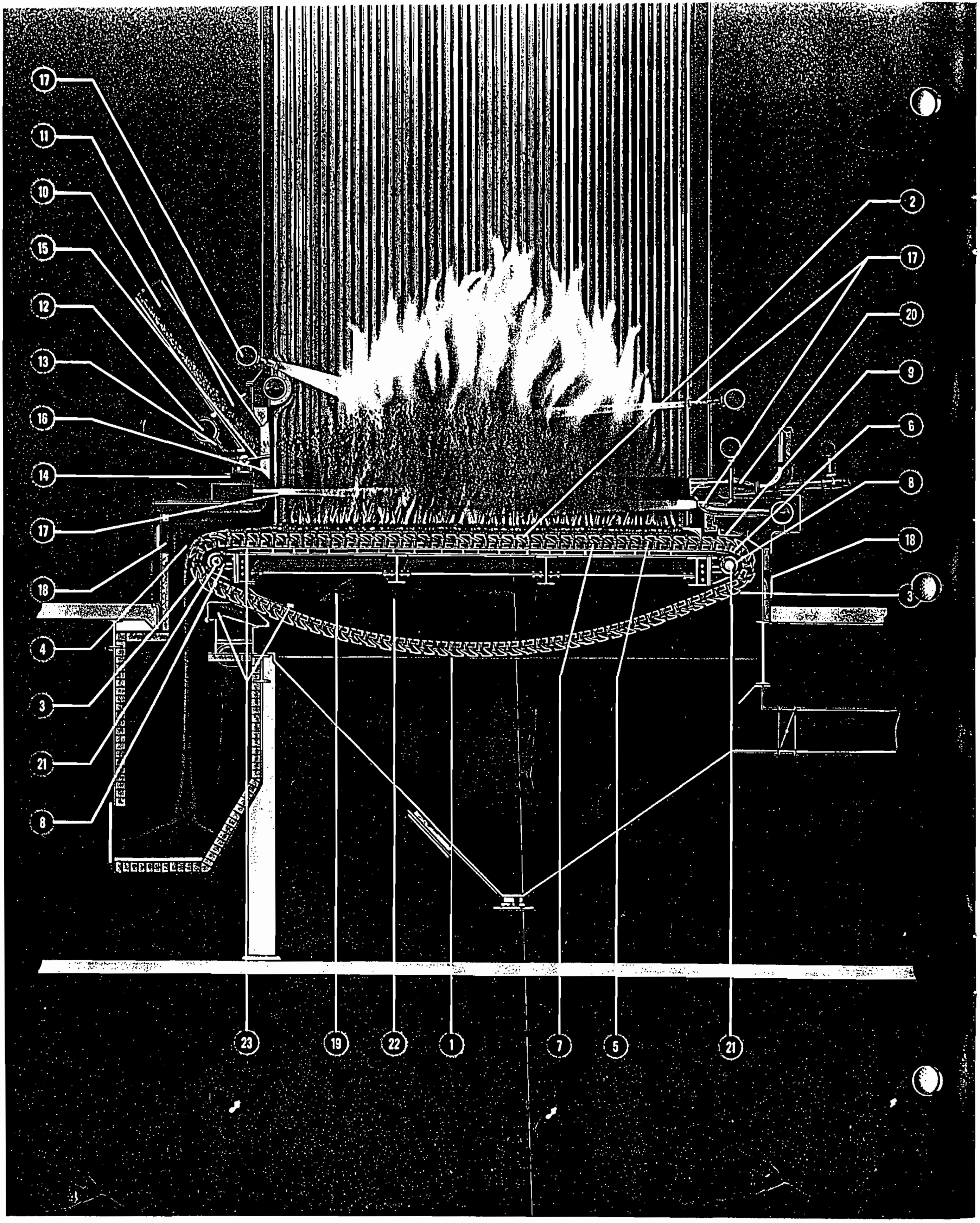


ZURN TRAVAGRATE SPREADER STOKER FOR CONTINUOUS OPERATION

FEATURES

① **Catenary design** provides for automatic take-up or tensioning of grate chains to prevent jamming. Effective catenary is maintained by gravity, thus making external shaft adjustments unnecessary.

② **Grate surface** consists of a series of grates specifically designed for spreader stoker firing. The grates are constructed of high-quality, heat-resistant, ductile iron.

③ **Grate curvature** design keeps the grates closed without the aid of auxiliary weights when making the turn around the sprockets.

④ **Grate removal** is easily achieved via a grate access door. On removal of one bolt, any grate section can be replaced while the stoker is in operation.

⑤ **The chain grate assembly** consists of forged-steel chain clips and hardened link pins and rollers. The chain clips avoid chain breakage while the hardened link pins and rollers reduce stress and wear on shaft bearings and sprockets.

⑥ **Hardened link pins** that make up the grate chain assembly are held in place by the grate carrier bars, thereby eliminating cotter pins and assuring locked pin position.

⑦ **Grates are full-bearing-supported** the entire width of the grate on carrier bars, avoiding possible grate damage from falling slag and grate warpage from too little ash on the grate.

⑧ **Oversize split sleeve bronze bearings** are strategically located for both drive and idler shaft support. Bearing sleeves can be reversed for additional life.

⑨ **Rear fuel and air seal** enables the rear water wall to expand while maintaining tightness, thus reducing air leakage and preventing fuel carry-over into the stoker plenum.

⑩ **The refuse feeding chute** for the fuel distributor is constructed for large capacity, continuous flow.

⑪ **Air-swept fuel distributors** direct the volume of fuel being fired.

⑫ **A high pressure air duct** continually supplies transport air to the solid fuel being fed.

⑬ **A metering damper** allows adjustment of air flow for proper front-to-rear fuel distribution.

⑭ **A distributor setting device** determines the positioning of the fuel trajectory plate.

⑮ **The distributor deflector plate** allows for lateral and longitudinal fuel distribution into the furnace.

⑯ **The fuel distributor opening** located adjacent to the boiler front, is completely air-cooled.

⑰ **An overfire air system** is strategically located to provide turbulence and thorough mixing of the volatile gases, thus enhancing the combustion process. Two rows are located in the front wall and two rows in the rear wall.

⑱ **Front and rear access doors,** normally a pair for each distributor, provide for stoker inspection at the ash discharge extension housing (front) and at the rear stoker housing.

⑲ **Undergrate access doors,** located on each side of the stoker housing, provide inspection of and access to grate assembly.

⑳ **A char recovery system** of the straight-through, pneumatic type is furnished with all necessary inner-hardened steel pipe and reinjection nozzles.

㉑ **Front and rear grate shafts** carry the grate chains on hardened sprockets. Bearings and sprockets are strategically located along the shafts for maximum load-bearing efficiency.

㉒ **The air pressure chamber,** completely sealed both front and rear to prevent air leakage, directs and distributes hot combustion air through the active grate surface.

㉓ **Three front undergrate air seals** limit air by-passing to the ash discharge end.

OPERATION

Fuel is continuously and automatically fed from the fuel chute into the air-swept fuel distributors where it is advanced across a specially-designed trajectory plate into the furnace. Fuel distribution, front-to-rear and laterally within the furnace, is controlled by combination setting of high-pressure transport air and trajectory plate angle setting.

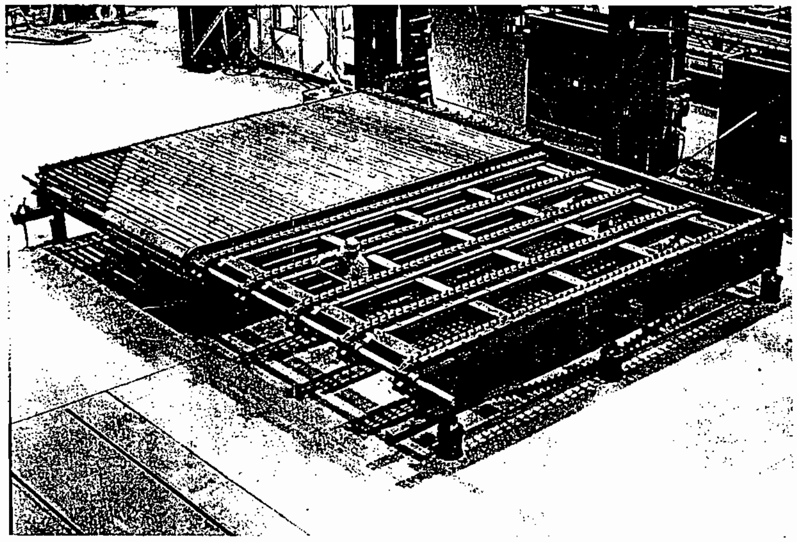
Strategically-located, high-pressure overfire air jets provide turbulence and thorough mixing of fuel/air to enhance the combustion process. As a further aid to complete combustion, hot combustion air is evenly distributed through the active grate surface. Fine particles of fuel are rapidly burned in suspension while coarser, heavier particles are spread evenly on the grate surface.

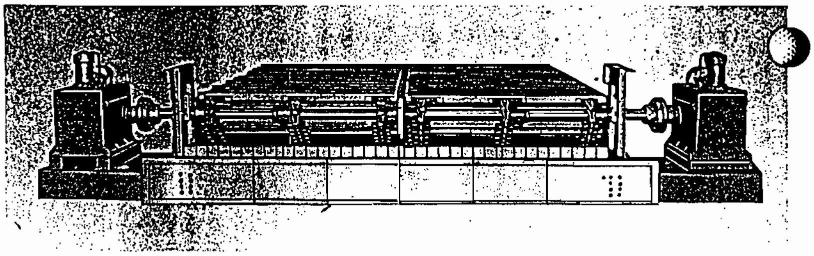
To compensate for variations in ash content, grate speed is adjustable from 0 to 24 feet per hour. The ash is continuously discharged over the front end of the grate into an ash pit or hopper.

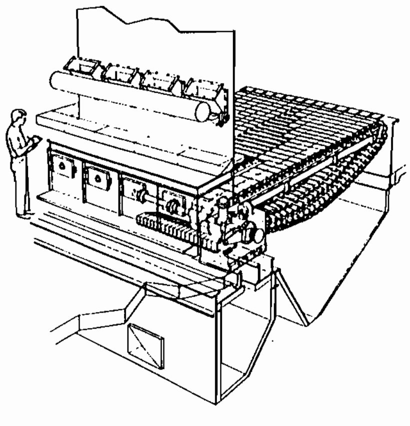
DRIVE COMPONENTS PROVIDE MAXIMUM PERFORMANCE

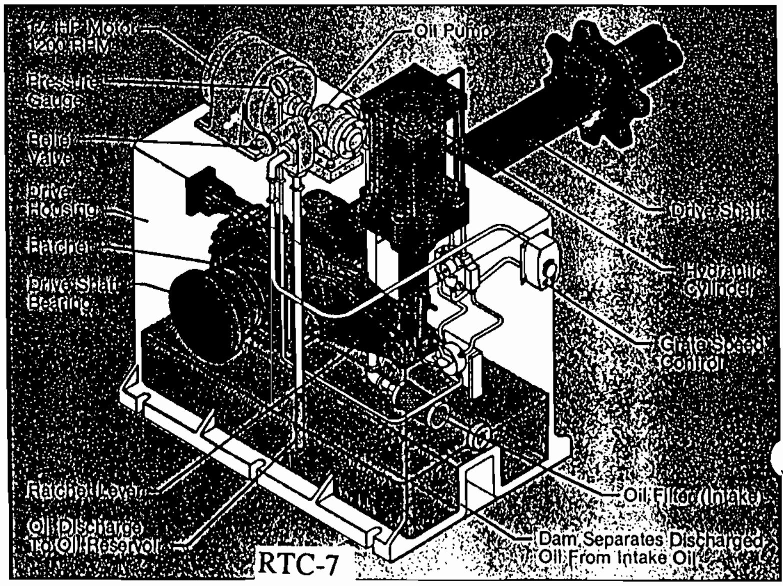
Zurn TRAVAGRATE spreader stokers are designed to provide continuous ash discharge. Grate sections mounted on carrier bars are pulled forward by forged steel chain links on skid rails. Heavy-duty, hardened sprockets specially designed for the roller chain pin design, reduce stress and provide longer life. Sprockets, located on the drive shaft, pull the chain assembly toward the front while sprockets on the idler shaft align the grate assembly at the rear.

Grates are driven by one or two hydraulic grate drives which can develop up to 30,000 ft-lbs of torque each. Grate speeds can be infinitely regulated from 0 to 24 feet per hour.









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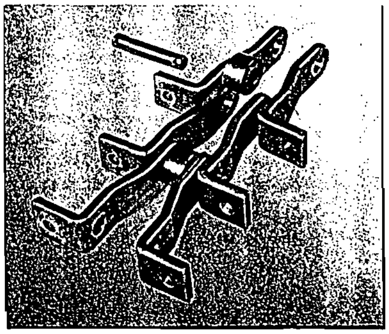
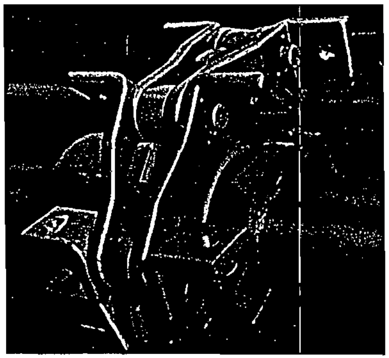
◀ *Overall view of TRAVAGRATE stoker assembly. Grate sections have been removed to show carrier bars, chains, sprockets and shaft assemblies. Shafts, bearings, sprockets and chains are pre-assembled at Zurn Energy Div. to assure component fit and alignment.*

◀ *Front view of grate assembly showing typical dual-drive application. Grate sections have been removed to show the center grate divider and dual shafts, chain sprockets, bearings and carrier bars.*

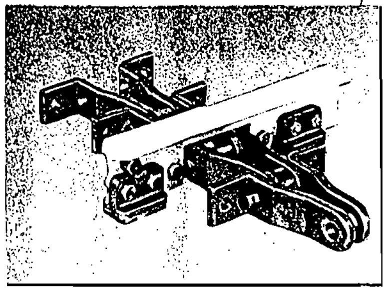
◀ *The TRAVAGRATE hydraulic grate drive is a self-contained unit in a single housing with no external piping. Hydraulic pump and control regulate the flow, and pressure to the hydraulic cylinder which is connected through linkage to a ratchet gear that drives the main shaft. The hydraulic drive and main shaft are connected by a heavy-duty flange coupling. No shear pins are used in connection with the unit drive since the hydraulic unit is equipped with a factory-set relief valve to protect the grates should the need arise. To compensate for variation of the ash content in the fuel, the drive can be infinitely regulated to control the grate speed from 0 to 24 feet per hour.*



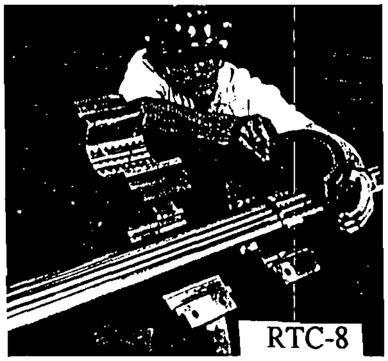
◀ *The Zurn TRAVAGRATE stoker is furnished with forged steel chain links, avoiding chain breakage and downtime. The chain is also furnished with hardened rollers and pins which reduce stress and reduce friction to the sprockets, thereby extending the sprocket life. Other manufacturers provide cast iron chain links, and use the drag-chain principle without rollers.*



◀ *Close-up view of the grate chain assembly clearly shows the rugged construction required to make a traveling grate stoker a continuous-ash-discharge stoker.*



◀ *Hardened link pins that make up the grate chain assembly are held in place by the grate carrier bars, thereby eliminating cotter pins and assuring locked pin position.*



◀ *Oversize, split-sleeve, graphite-plugged bronze bearings are strategically located for both drive and idler shaft support. Bearings can be reversed for additional life. Bearings are manually-lubricated via grease lines conveniently located on stoker side housing.*

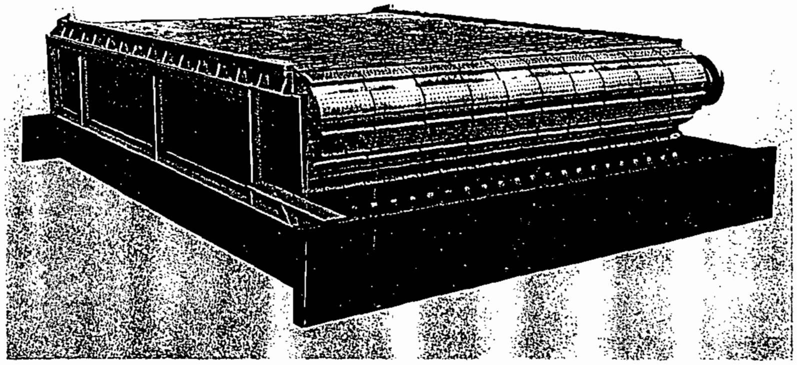
TRAVAGRATE STOK
FIT ANY BOILER, ARE EASY TO MAINTAIN

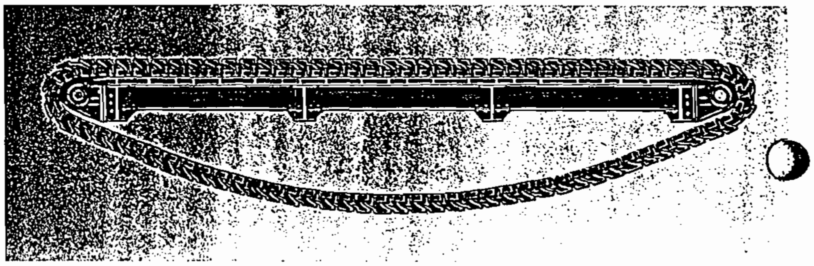
The Zurn TRAVAGRATE stoker is designed and manufactured for years of continuous operation with minimum maintenance.

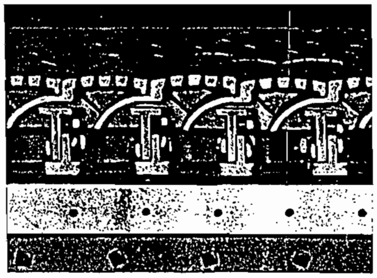
The TRAVAGRATE spreader stoker is available in various sizes to fit virtually any furnace. Stoker widths range from 7 feet to 34 feet wide, and shaft centers range from 11 feet to 25 feet.

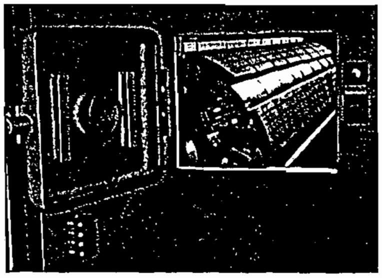
The various components are arranged for maximum efficiency and unnecessary parts have been eliminated. All sections directly exposed to the furnace are constructed of best-quality, heavy-duty, heat-resisting ductile cast iron for long service life.

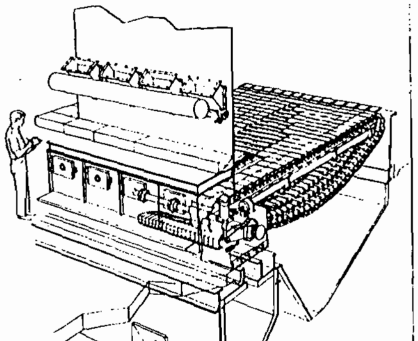
Maintenance is simplified by convenient access to all areas and external grease fittings.

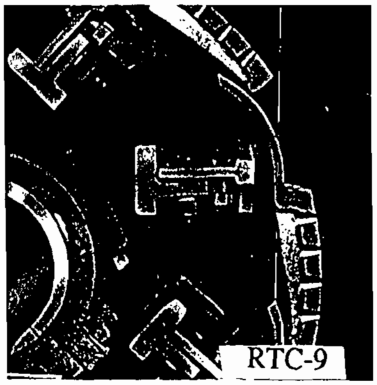


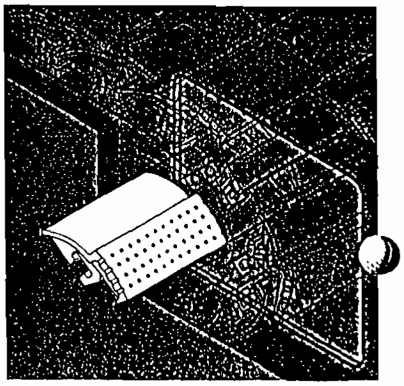












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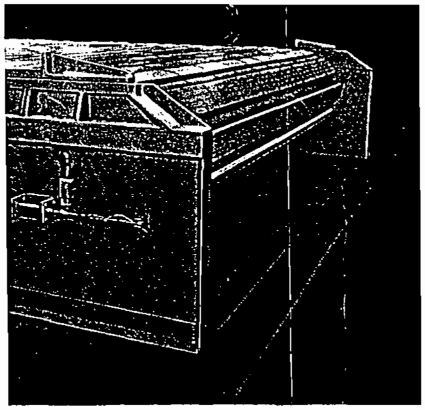
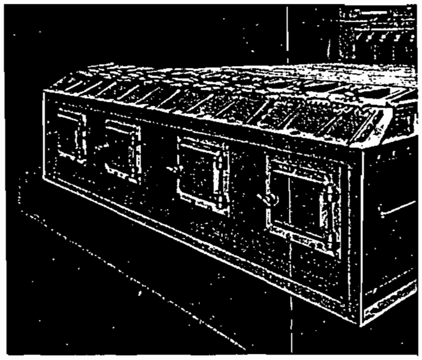
◀ *The stoker front has been removed to show the grate assembly and supporting structures. Curvature design of the grates keeps the grates closed without the aid of auxiliary weights when making the turn around the sprockets. With this design, no gaps appear between the grates, thereby directing all foreign materials into the ash pit and not into the driven shaft mechanism.*



◀ *A grate alarm system, built into the rear end of the grate assembly, is designed so that any foreign material or obstruction in the grates will come in contact with the alarm and immediately stop the stoker. An alarm is usually connected to an annunciator in the control room to alert the operator.*

◀ *Zurn catenary design provides for automatic take-up or tensioning of grate chains to prevent jamming. Effective catenary is automatically maintained by gravity thus making external shaft adjustments unnecessary.*



◀ *TRAVAGRATE stoker from the rear clearly shows convenient location of access doors for ease of inspection.*

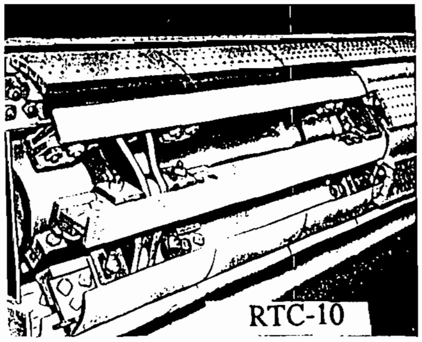
◀ *(Far left) Side view of grate assembly showing the level and uniform grate support, hardened skids and skid rails. Note that each grate section is individually supported by its own series of skid shoes.*

◀ *(Near left) A view through the side access door at the ash discharge end of the grate assembly shows how easily grates can be removed.*

◀ *To reduce maintenance costs, grate surface is made in short sections (12" to 15" long) of best quality, heavy-duty, heat-resisting ductile iron with uniformly-spaced, tapered, self-cleaning, air-metering openings, and with close-fitting, overlapping edges to reduce air leakage at the joints.*

◀ *(Far left) Close-up view through the side access door of the grate assembly as it makes its gapless turn around the ash discharge end (front). View clearly shows single bolt, nut and washer for grate removal.*

◀ *(Near left) Any grate section can be replaced without taking the steam generator or stoker out of service. Simply remove a single bolt, nut and washer and slide the grate off the carrier bar.*

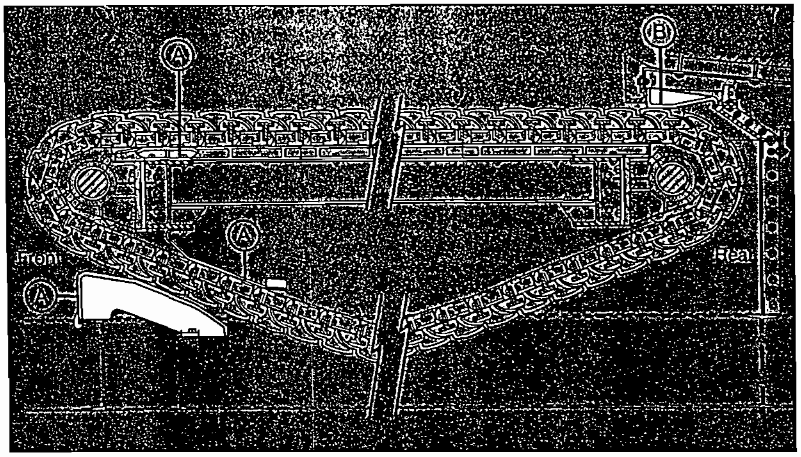


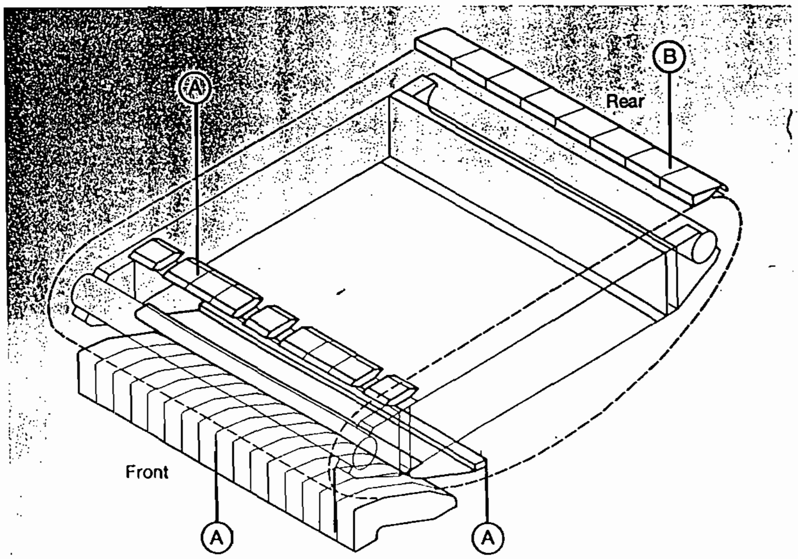
◀ *Close-up view of grate assembly as it makes the turn around the ash discharge end. Grates are completely supported the full width of the stoker by carrier bars, thereby avoiding possible grate damage from falling slag and grate warpage due to too little ash on the grate surface.*

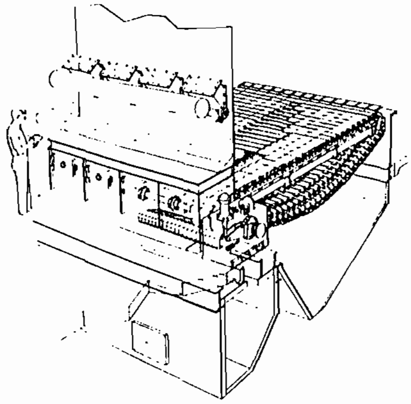
DESIGNED FOR INTEGRAL BOILER/STOKER EFFICIENCY

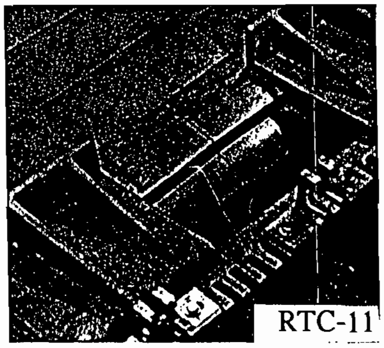
Zurn TRAVAGRATE spreader stokers are designed to operate within a variety of boiler designs. Every effort is made to merge the stoker operation and the boiler operation into an integrated system.

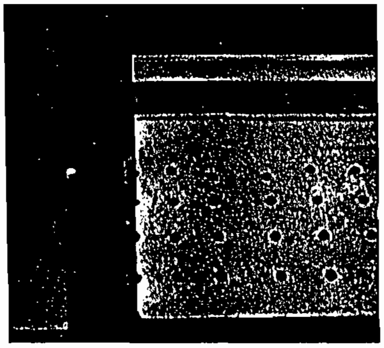
TRAVAGRATE stoker front and rear air seals automatically keep excess air to a minimum within the furnace. These front and rear seals are ruggedly constructed for long service and are automatically self-adjusting to maintain continuous close sealing contact.











◀ TRAVAGRATE stoker air/fuel seals —

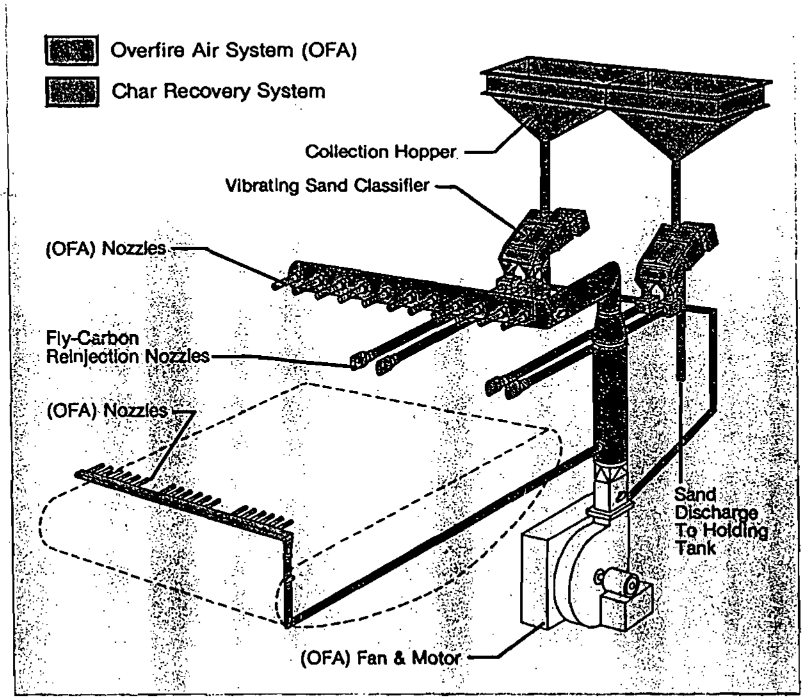
A. Three front undergrate seals limit air by-pass to the ash-discharge section and reduce excess air to a minimum within the furnace.

B. Rear fuel and air seal enables the rear water wall to expand while maintaining tightness, thus reducing air leakage and preventing fuel carryover into the stoker plenum.

◀ Location of air/fuel seals relative to grate assembly.

◀ (Far left) Close-up view of rear air/fuel seal.

◀ (Near left) The side fuel seals enable the grates to expand while preventing fuel carryover into the stoker plenum.



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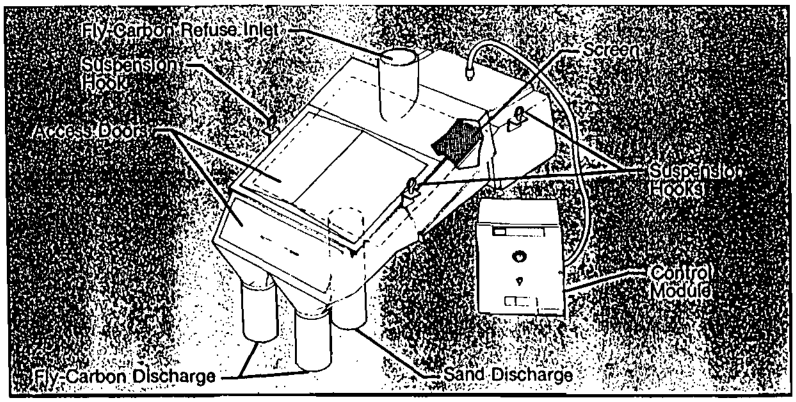
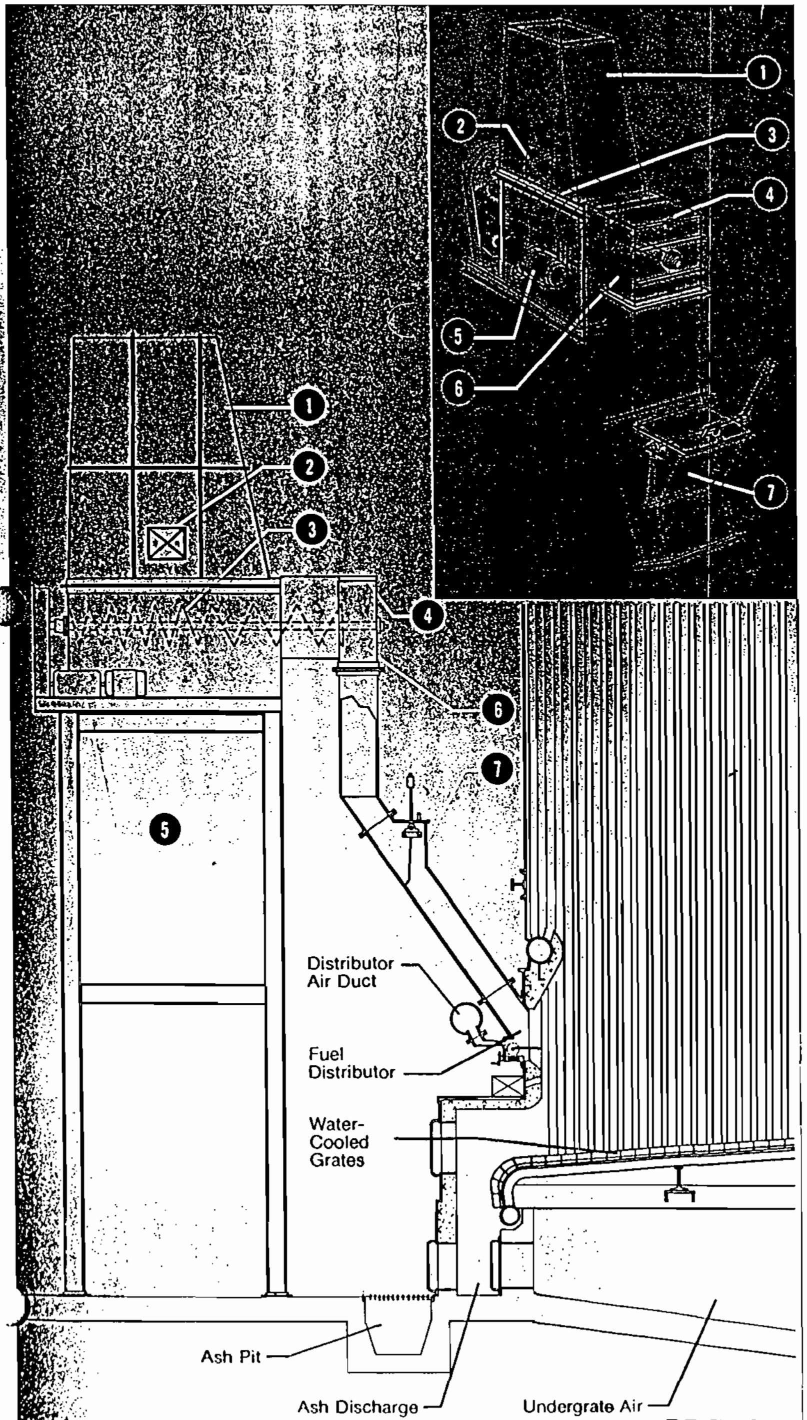
Each Zurn TRAVAGRATE spreader stoker is provided with an overfire air and char recovery system. The overfire air system must be located to provide turbulence and thorough mixing of the volatile gases, thus enhancing the combustion process. Zurn overfire air systems are designed for 30% of the total air for combustion at 80°F and 30 inches W.C. of static pressure for successful combustion of the fuel. The high pressure overfire air fan, in addition to supplying air to the overfire system, also provides the air supply for the char recovery system. Reinjection of the fly-carbon into the furnace in the high temperature zone just above the fuel bed results in an increase in boiler efficiency.

Wood bark in some regions is impregnated with sand. When reinjected with the fly-carbon, damage to the convection surface may occur. To reduce this erosion, the sand is effectively separated from the fly-carbon by vibrating sand classifiers shown below. Each sand classifier is furnished with a control module.

▼



ZURN HOGGED WOOD FUEL FEEDERS PROVIDE A CONTINUOUS, CONTROLLED SUPPLY OF FUEL



Zurn fuel feeders are designed to meter hogged wood and other waste fuels to the distributor and into a stoker-fired steam generator. Fuel metering is achieved by driving the auger screw with a direct-current motor, the speed of which is regulated by combustion control signals. Both double and single-screw designs are available in a variety of sizes and drive-motor capacities according to feed requirements.

Features of the Zurn fuel feeder include:

❶ **A large storage hopper,** sized to site conditions, incorporates expanding sides and ends to avoid fuel hangup.

❷ **Access doors** and observation ports are provided for inspection.

❸ **A variable-pitch screw auger** virtually eliminates jamming.

❹ **An inspection door** allows viewing and access to the feeder discharge chute.

❺ **A variable-speed drive unit,** also sized to feed requirements, provides fuel metered in response to boiler demand.

❻ **The feeder discharge chute** is sized for maximum feed, minimum hangup.

❼ **A back-draft, shutoff damper** protects the fuel supply if the furnace should go positive. An access door is provided for inspection.

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ZURN WOOD/REFUSE/BIOMASS-FIRED STOKER INSTALLATIONS: THE LARGE AND SMALL OF IT

Zurn TRAVAGRATE spreader stokers . . . and Zurn water-cooled grate spreader stokers . . . can be installed in a variety of steam generating systems. They are applicable to new or retrofit installations for heat, process, electric power or cogeneration in Zurn or non-Zurn boiler designs.

Zurn also designs, engineers and constructs a complete line of non-fossil fuel steam generators ideally suited for utilizing Zurn spreader stoker designs. Typical Zurn boiler/stoker combinations (illustrated at right) include:

Ⓐ Zurn 2DR-OP watertube steam generator with TRAVAGRATE spreader stoker for wood firing only. Steam capacities range from 50,000 through 500,000 lbs/hr.

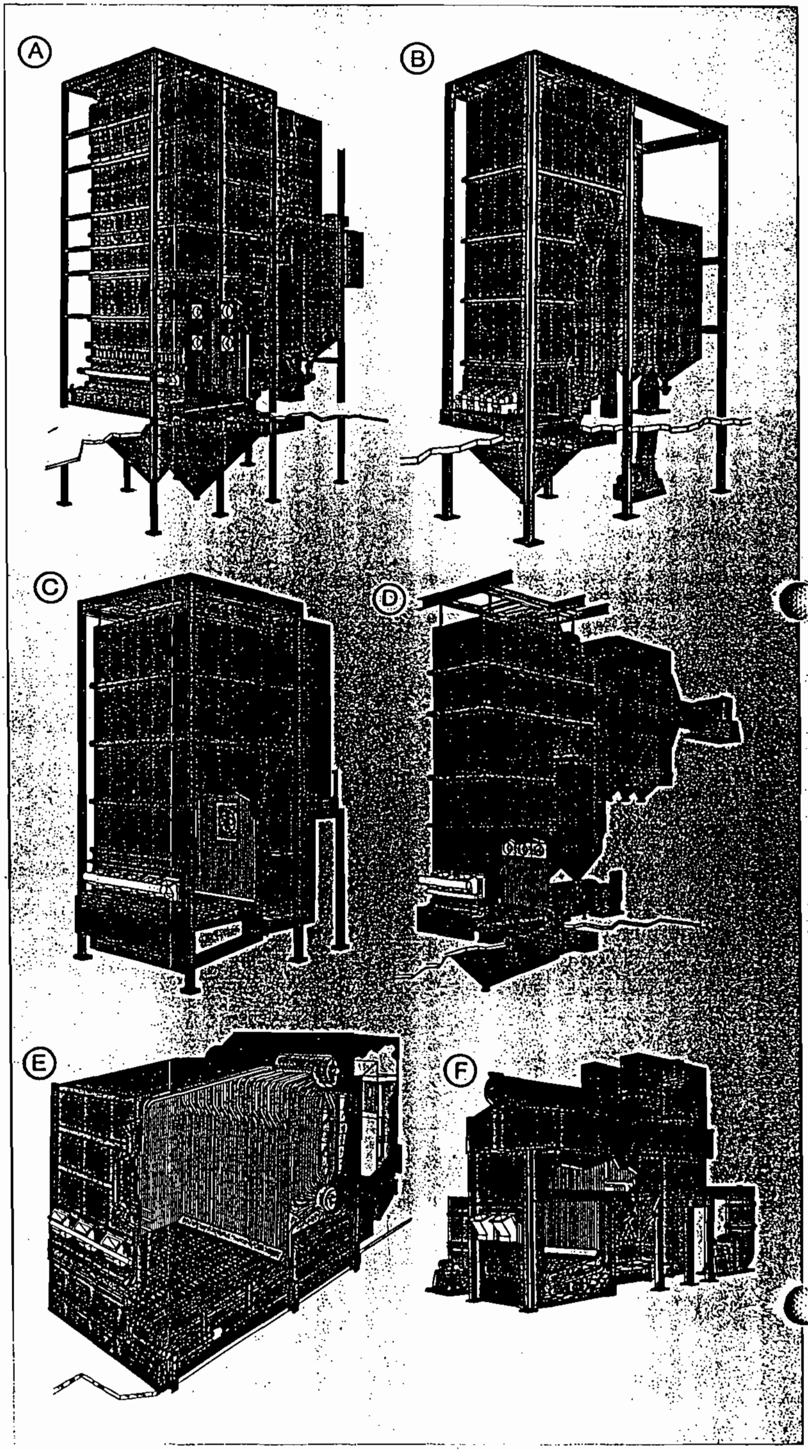
Ⓑ Zurn 2DR-OP watertube steam generator with TRAVAGRATE spreader stoker for combination firing of wood and coal. Steam capacities range from 50,000 through 500,000 lbs/hr.

Ⓒ Zurn 2DR-OP watertube steam generator with water-cooled grate spreader stoker for wood firing. Steam capacities range from 50,000 through 300,000 lbs/hr.

Ⓓ Zurn 2DR-OP watertube steam generator with TRAVAGRATE spreader stoker for refuse-derived-fuel (RDF) firing. Steam capacities range from 50,000 through 250,000 lbs/hr.

Ⓔ Zurn VC-MP watertube steam generator with water-cooled grate spreader stoker for wood firing. Steam capacities range from 30,000 through 150,000 lbs/hr.

Ⓕ Zurn VL-MP watertube steam generator with water-cooled grate spreader stoker for wood firing. Units are modularly factory-assembled for steam capacities ranging from 10,000 through 50,000 lbs/hr.



ZURN *a step ahead of tomorrow*

ZURN INDUSTRIES, INC.
ENERGY DIV.
1422 EAST AVE.
ERIE, PA, U.S.A. 16503-1592
PHONE: 814/452-6421
TELEX: 91-4473

Form No. [illegible]

<u>FDER Comment 2</u>: Will these boilers operate under negative pressure?

<u>Response 2</u>: The boilers are balanced draft boilers and will operate under a slight negative pressure (about 0.15 inches H_2O). A balanced draft furnace prevents leakage of flue gas out of the unit. Any air movement through the boiler walls will be in the form of air in-leakage.

FDER Comment 3: What is the range in temperature, pressure, and steam production for the 350 psig/650°F and 20 psig/280°F steam sources?

Response 3: The boilers are designed for a pressure of 1,800 psig. The actual operating pressure will be approximately 1,500 psig with a steam temperature of approximately 975°F. Maximum steam production for each boiler will be 455,418 lb/hr. The lower pressure and temperature steam production figures presented in the application represent the steam extracted from the steam turbine and sent to the sugar mill for use in the process. The process steam conditions will normally be controlled within a ±10 percent range. During normal operating conditions, the process steam flow can be expected to fluctuate within a ±25 percent range from flows stated in the application. During startup, shutdown, upset, or transient conditions, steam flow could diminish to zero.

FDER Comment 4: How will the heat input by the various fuels to the boilers be monitored? What parameters of the fuels will be monitored and at what frequency? What test methods will be used? Where will the samples be collected? How often will a sample be collected on each fuel used at the proposed facilities. How will this data be used to show compliance with the various sulfur dioxide standards?

Response 4: The heat input to the boilers will be measured in two separate ways. The first method is by continuously monitoring steam production, pressure and temperature and using the design heat transfer efficiencies (refer to Table 2-2 of the application). Using this information and the enthalpies of the steam, the heat input can be calculated. The second method will consist of the continuous measurement of the fuel input to each boiler. Each boiler will be fitted with belt scales which will measure the weight of biomass and coal and provide an integrated hourly total. Separate metering devices will be provided for coal so that the heat input due to coal can be determined even when burning a combination of coal and biomass fuels. Utilizing fuel quality data (i.e., heating value), the heat input to each boiler can be calculated.

Fuel quality measurements will be made on all fuels in order to provide information for heat input and emission calculations. Biomass fuels (bagasse and wood waste) are very low in sulfur content, and the heating value of these fuels are well established. Therefore, a rigorous sampling program is not necessary. It is proposed to collect daily biomass samples at a location along the conveying system, prior to the boiler, whenever biomass fuels are fired during a day. These daily samples will be composited into one weekly sample each calendar week. This composite sample will be analyzed for sulfur, moisture, ash and heating value. These data will be used to calculate heat input and SO_2 emissions due to biomass fuels. This sampling program is proposed to be conducted for 1-year duration in order to develop a database for biomass fuels. After the initial 1-year period, the sampling frequency will be reduced to a reasonable level agreeable to FDER. Flo-Energy will present the data to FDER in order to justify the reduced sampling frequency.

For coal, each coal shipment, which will typically consist of a 50 to 60 car unit train, will be accompanied by a coal analysis representative of the shipment. The analysis will include heating value and sulfur content.

Flo-Energy has determined that the most accurate, cost-effective method to determine SO_2 emissions from the facility is to install a continuous SO_2 emission monitor (that meets EPA reference method specifications). This will allow the direct determination of hourly SO_2

emissions on a continuous basis, for determining compliance with the hourly, 24-hour average, and annual average emission limits for the facility.

FDER Comment 5: Please provide plans, drawings, brochures, or specifications for all air pollution control equipment that will be used in these projects. Include base line operating parameters such as temperatures, feed rates, pressure drops, flow rates, voltages, etc., as well as an operation and maintenance plan for the recommended air pollution control equipment.

Response 5:

Electrostatic Precipitator

The electrostatic precipitator (ESP) for the Flo-Energy facility will be manufactured by Research-Cottrell. A drawing of the proposed ESP and stack is attached. Design specifications for the ESP (one per boiler) are provided below:

Chambers = 1
Gas Passages/Chamber = 18
Plate Spacing = 16 inches
Collecting Plate = 10.8 ft L x 36.0 ft H
Fields/Chamber = 3
Collecting Electrode Area = 44,323 ft^2
Specific Collection Area = 145 ft^2/1,000 acfm (minimum)
Pressure Drop = less than 2.0 inches H_2O
Operating Temperature = 350°F
Aspect Ratio = 0.90
Discharge Electrode = Dura-Trade, 18 gauge
Rapping System = Microprocessor controlled
Transformer Rectifier = 2 @ 105 kVp/500 mA
= 1 @ 105 kVp/750 mA
= microprocessor control
Ash Handling = Trough hopper with screw conveyor

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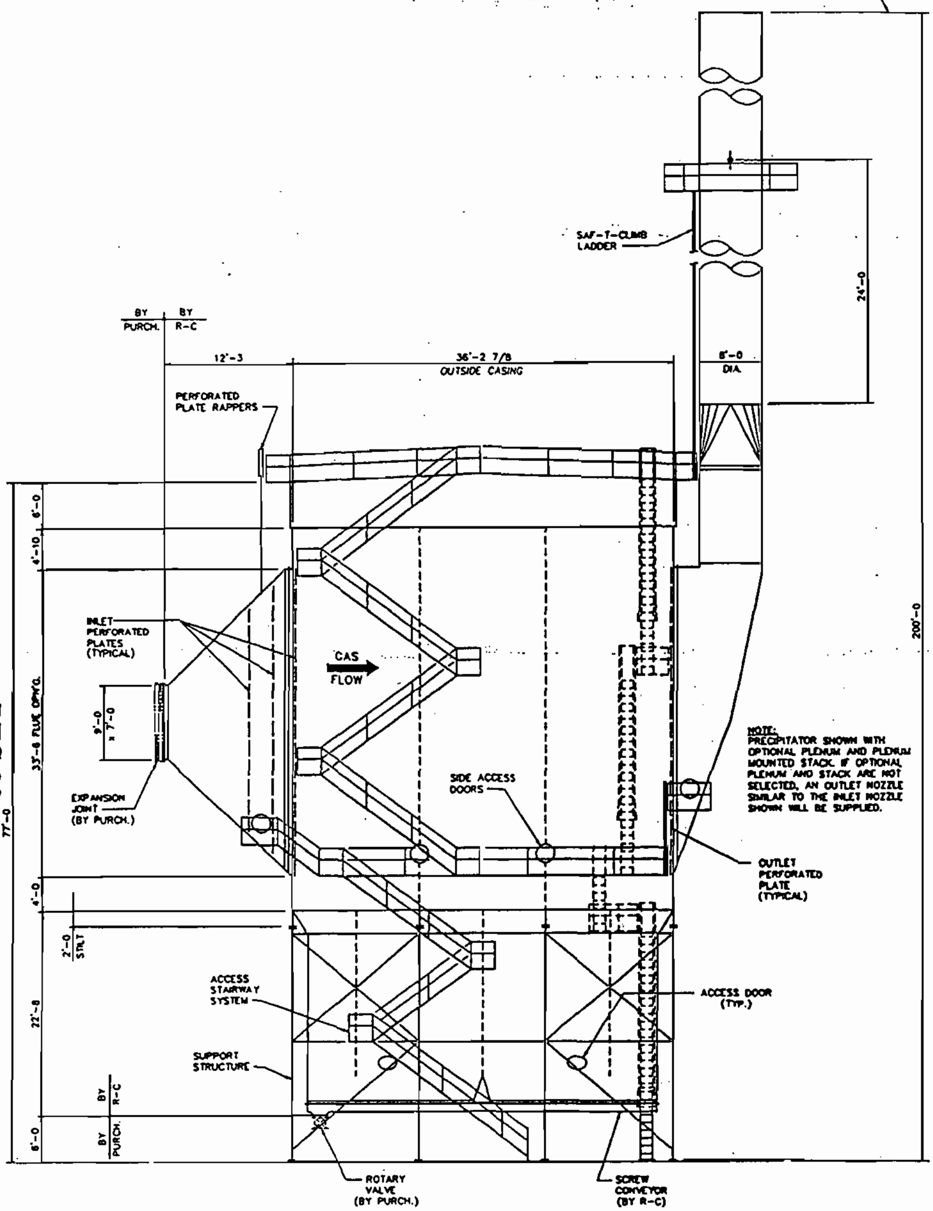
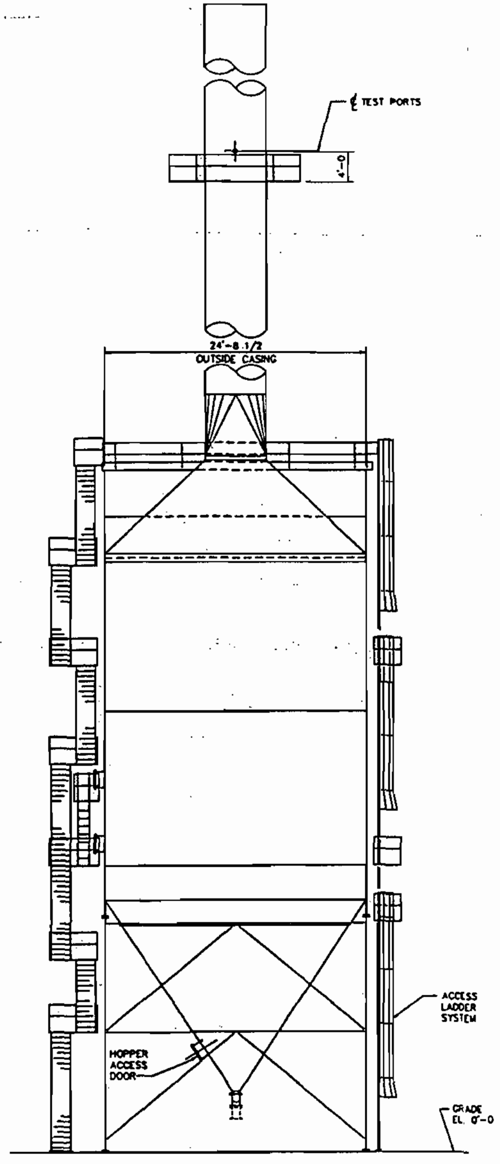
RTC-20



NOTE:
PRECIPITATOR SHOWN WITH OPTIONAL PLENUM AND PLENUM MOUNTED STACK. IF OPTIONAL PLENUM AND STACK ARE NOT SELECTED, AN OUTLET NOZZLE SIMILAR TO THE INLET NOZZLE SHOWN WILL BE SUPPLIED.

SIDE ELEVATION



OUTLET END ELEVATION

NOTES:
ALL DETAILS AND DIMENSIONS ARE SUBJECT TO CHANGE PENDING FINAL ENGINEERING.
ONE PRECIPITATOR SHOWN, OTHER TWO ARE SIMILAR.

ZURN NEPCO
OKEELANTA COGEN
SOUTH BAY, FLORIDA
PRECIPITATOR

RESEARCH-COTTRELL
EXPERIENCED ENVIRONMENTAL PEOPLE
P. O. BOX 1500 SOMERVILLE NEW JERSEY 08876

Research-Cottrell Hi-R ESP Installations
Partial Listing - Woodwaste Applications

CUSTOMER	LOCATION	APPLICATION	DATE SOLD	NO. ESP	GAS VOLUME (ACFM)	EFF. (%)
Alternative Energy	Ashland, ME	Woodwaste	Mar-92	1	296,334	98.77
Alternative Energy	Cadillac, MI	Woodwaste	Mar-92	1	305,225	98.77
Alternative Energy	Livermore Falls, ME	Woodwaste	Jun-91	1	296,334	98.77
Willamette Ind.	Campti, LA	Woodwaste	Sep-90	1	392,750	98.87
James River Corp.	Camas, WA	Woodwaste	Jul-90	1	202,000	99.33
Smurfit Newsprint	Newberg, OR	Woodwaste/Tires	Jun-90	1	354,000	99.50
Tasman Pulp #3	Kawerau, N.Z.	Woodwaste	Jan-90	1	135,610	93.30
Celgar Pulp	Castlgar, B.C.	Woodwaste	Jan-90	1	148,300	95.50
Tasman Pulp #2	Kawerau, N.Z.	Woodwaste	Jan-90	1	115,590	93.30
Simpson Tacoma Kraft	Tacoma, WA	Woodwaste	Sep-89	1	260,000	99.50
Alberta Pacific Forest Ind.	Alberta, Canada	Woodwaste	Jun-89	1	464,040	97.77
Zurn/Nepco	New Bern, NC	Woodwaste	May-89	1	282,350	99.00
S.D.Warren	Skowhegan, ME	Woodwaste	Apr-89	2	310,730	99.43
Tracy Constructors	Tracy CA	Woodwaste	Feb-89	1	140,000	99.60
Yanke Energy Inc.	Soledad, CA	Woodwaste	Sep-88	1	100,000	98.18
Honey Lake Power	Susanville, CA	Woodwaste	Mar-88	1	285,012	99.00
P.H.Glatfelter	Spring Grove, PA	CFB-Wood,Coal	Mar-87	1	236,000	99.91
Yanke Energy Inc.	North Fork, CA	Woodwaste	Jan-87	1	82,000	98.19
Ultrasystems	Fresno, CA	CFB Woodwaste	Sep-86	1	171,600	99.65
Ultrasystems	Rocklin, CA	CFB Woodwaste	Sep-86	1	171,600	99.65
Whitefield Power & Light	Whitefield, N. H.	Woodwaste	May-86	1	95,390	98.26
Gorbell Power & Light	Athens, ME	Woodwaste	Mar-86	1	101,730	98.26
Hemphill Power & Light	Springfield, NH	Woodwaste	Mar-86	1	95,390	98.26
Duluth, City of	Duluth, MN	Wood/Coal Stoke	Feb-86	2	257,870	99.00
Georgia Pacific	Palatka, FL	Woodwaste	Aug-85	1	230,000	98.30
Container Corp.	Fernandia Beach, FL	Woodwaste	Jun-85	1	282,000	94.33
Georgia Pacific	Palatka, FL	Woodwaste	Jun-85	1	230,000	96.00
Yanke Energy Inc.	Auberry, CA	FFB Woodwaste	Apr-85	1	82,000	98.19
Union Camp Corp.	Franklin, Va	Wood/Coal Stoke	Apr-85	1	95,500	98.86
Atlantic Gulf Co.	Martell, CA	Woodwaste	Jan-85	1	153,300	98.75
Yanke Energy Inc.	Dinuba Station, CA	Woodwaste	Nov-84	1	103,000	95.08
Ultrapower #4	Chinese Sta., CA	FFB Woodwaste	Jul-84	1	193,750	96.44
Ultrapower #3	Blud Lake, CA	Woodwaste	May-84	1	78,000	98.00
Appleton Power	Combined Locks, WI	Woodwaste,Coal	Jun-83	1	175,000	98.00
Union Camp Corp.	Savannah, GA	Comb.(Bark,Coal)	Oct-80	2	441,360	99.59
Weyerhauser Corp.	Plymouth, NC	Woodwaste,Coal	May-79	1	318,000	99.00

Dura-Trode™ Rigid Discharge Electrodes

The Dura-Trode rigid discharge electrode is comprised of two roll-formed steel sections welded together along their emitting edges with provisions for rigid attachment to the high voltage structural framework. The configuration provides uniform corona distribution while maximizing equipment reliability. Completely shop fabricated, no field assembly of the electrode is required.

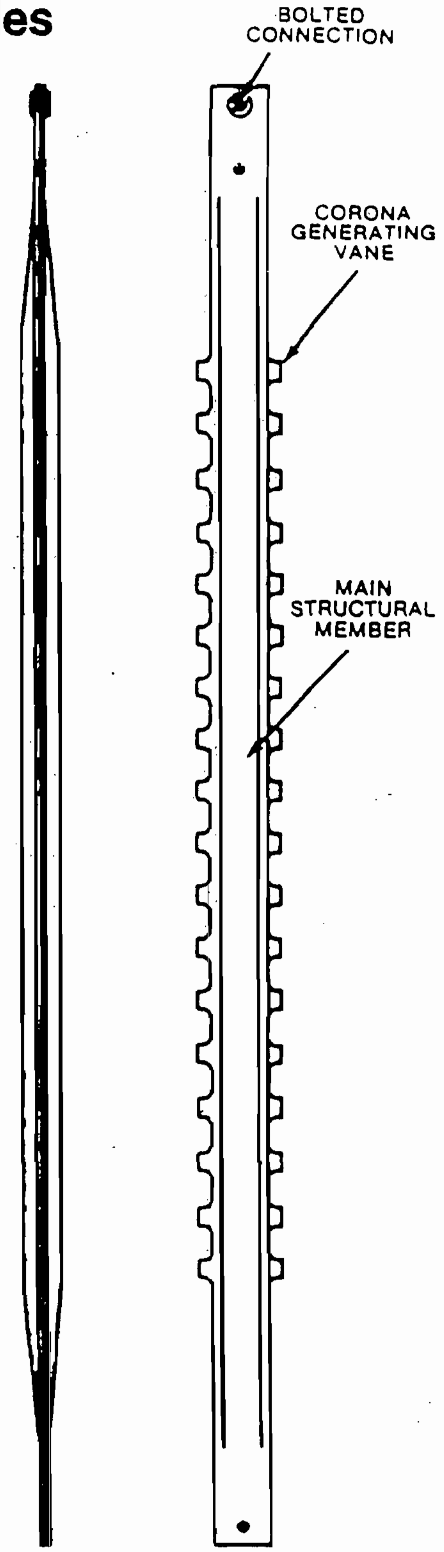
Principal design features:

Inherently rigid—No wires, thin metal strips or framework; the design incorporates electrical energization and mechanical integrity into a single member.

Self-aligning—Each electrode is individually supported from a single bolt, and guided at the bottom by a lower alignment frame.

Maintenance-free—The electrode is virtually unbreakable, and is resilient to operational upsets.

Uniform corona—The scalloped vanes, which tend to force corona to form at the sharpest points, combined with the flattened ellipsoidal shape, simultaneously provide well distributed corona and high field strength.



G-Opzel™ Collecting Surfaces

Research-Cottrell's G-Opzel collecting surfaces are designed to provide maximum accelerations normal to the collecting surface with minimum rapper energy input. The surfaces have aerodynamically designed baffles which provide quiescent zones to aid particulate collection and reduce re-entrainment. These baffles also provide the necessary structural rigidity to prevent bellying and bowing of the collecting surface.

Principal design features:

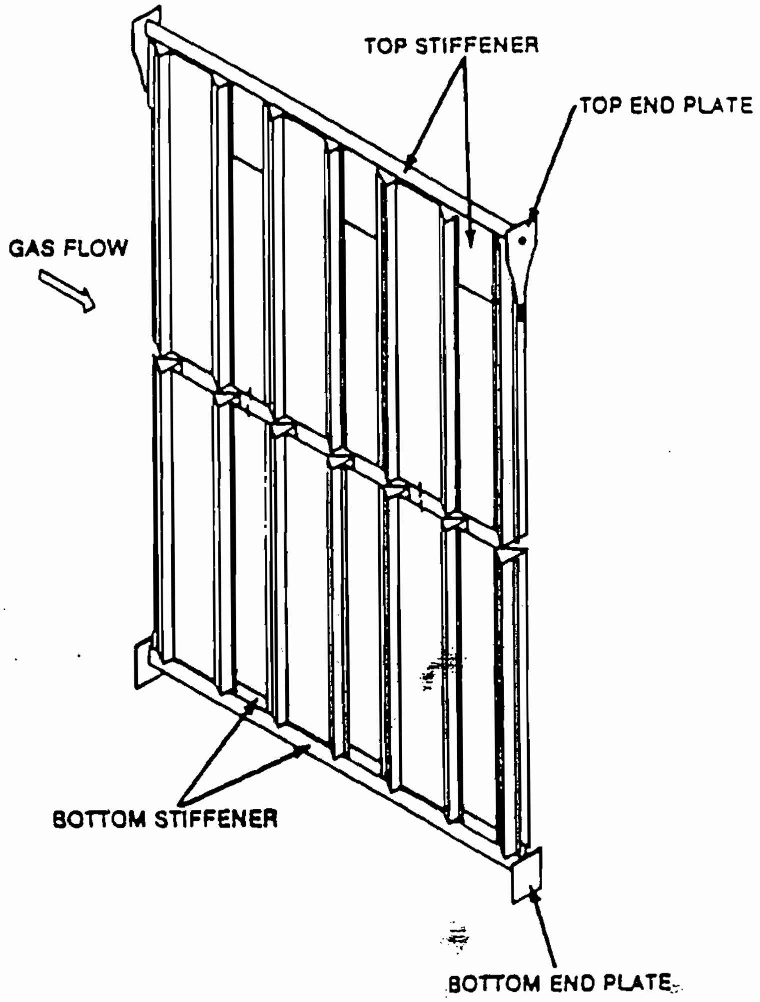
Shop assembly—Cold-rolled sheet steel is roll-formed into panel plates. Panels are then shop-welded together into full field assemblies.

Gas baffles—Vertical, triangular baffles provide plate rigidity and quiescent zones.

Top suspension—Bolted and welded to collecting surface hanger channel.

Alignment—Alignment guides provided at all four corners.

Spark suppression—The rolled tubes, attached to the top and bottom edges of the collecting surface, provide increased rigidity and suppress sparking at these edges by eliminating sharp corners.



MIGI™ Drop-hammer Rappers for Collecting Surfaces and Discharge Electrodes

The Magnetic Impulse Gravity Impact (MIGI) rapper is an electromagnetic device utilizing only one moving part. Intensity, sequence and cycle time of the rapping blows are electrically controlled from a central cabinet, enabling adjustment while the precipitator is in operation.

Principal design features:

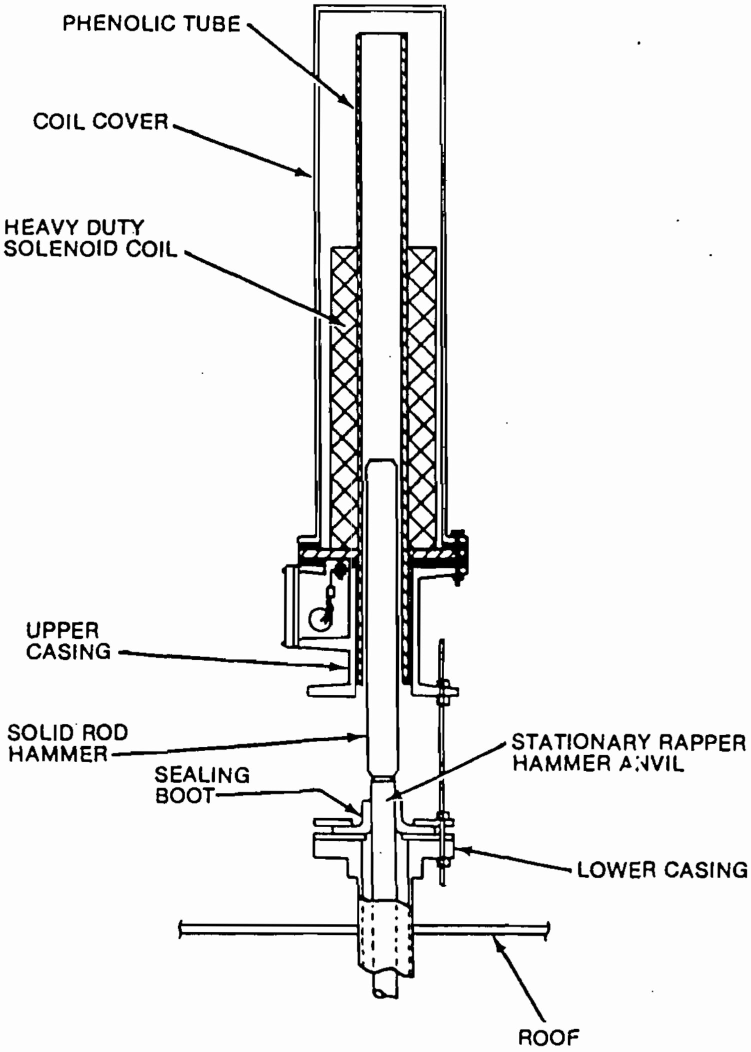
Operation—Controlled single impact; electromagnetic lift by heavy duty solenoid, gravity drop.

Accessibility—Located outside of gas stream, on precipitator roof. Inspection, maintenance and adjustments can be made during on-line operation.

Mounting—vertically mounted on three adjustable studs for easy and rapid maintenance.

Operating temperature—60°C maximum continuous ambient temperature.

Lubrication—Not required.



CONTENTS (Continued) Page

TABLES

FDER Comment 9: One application currently being processed by the Bureau is proposing 0.05% sulfur in No. 2 fuel oil. What is the lowest percent sulfur in No. 2 fuel oil available in your area?

Response 9: Many suppliers of diesel and fuel oil in southeast Florida were contacted to obtain the latest information on fuel oil availability and price. All of these suppliers, including the fuel oil supplier for Okeelanta (Star Enterprises/Texaco; Gene Tauches, 404-903-1559), stated that they were aware of the EPA mandate of 0.05 percent sulfur maximum in over-the-road diesel fuel by October 1993. However, the Department of Energy has not made a determination on the sulfur limit for off-road No. 2 fuel oil, which would also be sold as home heating oil. Fuel oil suppliers believe there may be two different fuels, with one identified with a dye. It is impossible to predict at this time what the sulfur content of the off-road diesel might be. It also is impossible to state what the cost of such a new fuel would be, or whether it will be available in sufficient quantity to be used for industrial purposes. Given these significant uncertainties, at this time Flo-Energy cannot commit to a lower sulfur No. 2 fuel oil than is currently available (i.e., 0.5 percent maximum).

<u>FDER Comment 10</u>: What are the specifications for the wood waste and biomass? Will either contain asphalt shingles, tar paper, or plastics?

<u>Response 10</u>: The specifications for the wood waste and biomass are those contained in the proposed Specific Condition 12 described in Section 8.0 of the Flo-Energy application (pg 8-3 of the application). This condition states "any wood waste materials burned as fuel shall be substantially free from painted wood, chemically treated wood, household garbage, toxic or hazardous materials or waste, and special waste." All contracts for biomass issued by Flo-Energy will contain this wording. Asphalt shingles, tar paper, and plastics, will not knowingly be accepted by Flo-Energy.

FDER Comment 11: Will the existing boiler No. 16, designated for standby service at the Flo-Energy facility, be used when all 3 of the proposed boilers are in operation?

Response 11: Boiler No. 16 will only be operated when one or more of the cogeneration boilers is shutdown (refer to proposed Specific Condition 18 on page 8-3 of the application).

FDER Comment 12: Please explain why only 30% of the mercury but 90% of the other metals will be removed from the emissions. Will the presence of ammonia in the flue gas effect the mercury removal?

Response 12: Nearly all the metals in the flue gas just prior to the ESP (temperature approximately 350°F) will be in the solid phase. The ESP will be designed for 98% removal of particulate matter; thus these metals will be controlled to approximately 98% or greater. Mercury, however, exists primarily in the vapor phase at 350°F. Research has shown that as the flue gas temperature is reduced downstream of the boiler, some mercury will be condensed and/or adsorbed onto carbon-containing particulate in the gas stream. At certain MSW resource recovery facilities, it has been demonstrated that mercury control of 30% and greater may be achievable by injection of additional carbon into the gas stream ahead of the particulate control device. The level of control is dependent upon a number of factors, including mercury concentration in the flue gas, flue gas temperature, carbon injection rate, and type of particulate control device. For a biomass/coal fueled facility, the initial mercury concentration is very low. As a result, the removal efficiency achievable in this case is not certain; however Flo-Energy's proposed mercury emission limits are based on a conservative assumption of 30 percent control efficiency.

FDER Comment 13: What is the basis of assuming that 20% of the chromium is Cr+6 in Appendix A?

Response 13: No data was found in the literature regarding the form of chromium (Cr) emissions from biomass/coal combustion sources. The estimate of 20 percent of total chromium emissions existing as hexavalent chromium is based in part on actual source testing of the Dade County Resources Recovery (DCRR) facility. The data are shown in the attached table. As shown, the results are somewhat inconclusive due to many of the measurements being below the detectable limit of the measurement method. The 20 percent factor was derived using a value equal to one-half the detectable limit for measurements which were below the detectable limit.

Data regarding Cr^{+6} emissions are available from a few other sources. Test data from an MSW combustion unit equipped with ESP control only (city of Baltimore) showed a Cr^{+6} concentration of 0.5 μg/g particulate at the inlet to the ESP, and 465 μg/g of total chromium (Municipal Waste Combustion Study, EPA, 1988). This would result in a Cr^{+6}/Cr ratio of 0.001, or 0.1 percent.

A summary of medical waste incinerator test data was recently published in the Journal of Air and Waste Management (Walker and Cooper, Vol. 42, No. 6, June 1992). The compilation showed the following for uncontrolled emissions from general medical waste:

Cr (total) - 422 μg/g waste input (average of 27 tests)
Cr^{+6} - 32 μg/g waste input (average of 9 tests)
Ratio = 32/422 = 0.076 = 7.6%

For pathological waste, the test data were as follows:

Cr (total) - 3,900 μg/g waste (average of 6 tests)
Cr^{+6} - 680 μg/g waste (average of 4 tests)
Ratio = 680/3,900 = 0.174 = 17.4%

A recent study of municipal wastewater sludge incinerator emissions (EPA, 1992) in the U.S. investigated both total Cr and Cr^{+6} emissions. At five test sites, all equipped with wet venturi scrubbers, the Cr^{+6}/Cr ratio was found to range from <1.8 percent to 11.9 percent.

Based on the limited data available, the factor of 20 percent Cr^{+6} used in the permit application appears to be very conservative.

Hexavalent Chromium Emissions from Dade County Resources Recovery Facility

Unit	Date	Total Chromium (lb/hr)	Hexavalent Chromium (lb/hr)	Cr^{+6}/Cr (%)
1	11/15/88	<0.00134	<0.000437	--
		0.00146	<0.000531	<36.4
		<0.00131	<0.000434	--
2	05/10/89	0.00244	<0.000671	<27.5
		0.00243	<0.00108	<44.4
		0.00181	<0.00054	<29.8
3	11/16/89	<0.00360	<0.00111	--
		<0.00351	<0.00115	--
		<0.00354	<0.00112	--
4	11/07/89	<0.00330	<0.00102	--
		<0.00328	<0.00092	--
		<0.00348	<0.000747	--
			Average =	<34.5

Source: Entropy, Inc.

FDER Comment 14: What does the term "black start purposes" mean (page 2-5)?

Response 14: A "Black Start" refers to the situation where the facility has electricity, but all equipment (i.e., boilers, pumps, turbine generators, etc.) are shutdown. Boiler No. 16 may be used in this situation to provide steam to operating equipment until such time as one or more of the cogeneration boilers is brought on line. As stated previously, Boiler No. 16 will not be operated when all three of the cogeneration boilers are operating.

FDER Comment 15: What is "special waste" that was referred to in proposed Specific Condition No. 12?

Response 15: The term special waste is used to describe toxic or hazardous non-biomass and non-combustible waste materials.

FDER Comment 16: Please respond to the National Park Service FAX dated October 8, 1992.

Response 16: The NPS comment concerns the ownership of the Flo-Energy facility and its relationship to the Okeelanta sugar mill. This relationship will determine if the emission reductions from the existing Okeelanta facility will be creditable reductions for PSD purposes. KBN has discussed this issue with EPA through correspondence (attached) and during a recent meeting at EPA Region IV in Atlanta. The two factors which will render the reductions creditable are as follows:

1. Okeelanta owns the existing facility, and will own 50% or more of the voting rights in Flo-Energy. Thus, both facilities will be under "common control" and constitute a single "facility" under the PSD regulations.
2. The Okeelanta sugar mill will be totally dependent upon the cogeneration facility for steam; thus the cogeneration facility and sugar mill will be considered as the same facility (i.e., same primary SIC code) for PSD purposes.

EPA has indicated in the attached correspondence and in our recent meeting that the emission reductions will be creditable for PSD purposes.

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

4APT-AEB

OCT 9 1991

Mr. David A. Buff, P.E.
KBN Engineering and Applied Sciences, Inc.
1034 Northwest 57th Street
Gainesville, FL 32605

Dear Mr. Buff:

This letter is in response to your letter dated July 18, 1991, concerning several questions related to Prevention of Significant Deterioration (PSD) source applicability for cogeneration facilities. The answers to your questions are as follows:

-- What criteria must be met for the cogeneration facility to use the emission reductions from the industrial facility in determining PSD source applicability?

The pertinent PSD criteria for emissions increases and <u>decreases</u> to be creditable for netting transactions is outlined in CFR 40 Part 52.21 (b)(3) or Part 51.166 (b)(3). Referring to (b)(3)(iii), emissions increases and decreases are creditable:

> "...if the Administrator has not relied on it (e.g., an emissions decrease) in issuing a permit for the source under regulations approved pursuant to this section, which permit is in effect when the increase in actual emissions from the particular change occurs." (NOTE: EPA's policy is to interpret the permit to be a PSD permit).

In order to be creditable, a decrease in actual emissions must meet three criteria. These criteria are stated in (b)(3)(vi)(a), (b), and (c):

> (a) The old level of actual emissions or the old level of allowable emissions, whichever is lower, exceeds the new level of actual emissions;
> (b) It is federally enforceable at and after the time that actual construction on the particular change begins; and
> (c) It has approximately the same qualitative significance for public health and welfare as that attributed to the increase from the particular change.

It is important to note that the proposed source shutdowns, as well as all other decreases, must be federally enforceable in order to be creditable. If the source nets out of review, no PSD permit is issued. Where a source is not able to net out of review, any emissions increase or decrease used in the netting equation to determine source applicability must also be used in its entirety in the subsequent air quality impact analysis. In this manner, a reviewing authority relies on the full emissions increase or decrease in determining whether the proposed project would or would not cause, or contribute to, a violation of an increment or ambient standard. At this point, these increases and decreases are no longer creditable.

-- What if the industrial facility is a joint owner of the power plant, but not the operator? Is there a certain percent ownership in the power plant necessary to qualify as "persons under common control?"

Common control or ownership has been defined by precedent in previous EPA applicability determinations. In a memorandum dated March 16, 1979, from the Director of Stationary Source Enforcement to the Director of the Enforcement Division of Region VI, the following assertion was made:

> If the International Paper Company has 50% voting interest in the Arizona Chemical Company, it can be considered "in control" for PSD (and IR*) purposes, and the International Paper mill and Arizona Chemical plant, both located at the Springhill, Louisiana complex, can be considered a single source. *(Interpretative Ruling, see Federal Register, December 21, 1976, pages 55524-55530)

-- For the power plant to be included in the same SIC code as the industrial facility, must it supply a certain portion of its total steam capacity to the industrial facility? Must the power plant not sell more than 33% of its electrical generating capacity to the electric grid, or else it would automatically be classified under SIC Major Group 49, Electric Services?

This is addressed in comments and responses on proposed PSD regulations published in the Federal Register, dated August 7, 1980, page 52695. Where a single unit is used to support two otherwise distinct sets of activities, the unit is to be included within the source which relies most heavily on its support. In this case, as long as the industrial facility required over 50% of the total steam capacity, then the power plant could be included in the same SIC group, and the remainder of its steam capacity could be sold to other users (in this instance, the electric grid).

-- What if essentially all of the steam needed by the industrial facility comes from the power plant, i.e., the industrial facility is totally dependent upon the power plant for steam?

The power plant and industrial facility would be classified as under the same source because one source classification encompasses both primary and support facilities, even when the latter includes units with a different two-digit SIC Code (reference <u>Federal Register</u>, August 7, 1980, page 52695).

-- Must both the "common control" criteria and SIC code criteria be met before any offsets from the industrial facility are available to the power plant?

Yes, and in addition a third basic test must be met. In order for offsets to be available, the affected facilities must be located on adjacent or contiguous property.

Thank you for the opportunity to respond to your questions regarding PSD applicability and netting. If you have any questions or comments, please contact Mr. Scott Davis of my staff at (404) 347-5014.

Sincerely yours,

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

KBN

July 18, 1991

Mr. Jewell A. Harper, Chief
Air Enforcement Branch
U.S. Environmental Protection Agency
345 Courtland Street, N.E.
Atlanta, GA 30365

Re: PSD Source Applicability for Cogeneration Facilities

Dear Mr. Harper:

In November 1989 the EPA issued a letter response to questions regarding PSD source applicability and emissions netting for cogeneration facilities (copy of letter attached). The letter stated that for an independently owned and operated power plant located at the same site as an industrial facility (such as a paper mill), the power plant could not use any offsets from the industrial source in its source applicability determination. The power plant and industrial source would have different SIC codes and would not be under common control, and therefore would not meet the definition of "facility" contained in the federal PSD rules.

KBN is now performing a feasibility study for locating a cogeneration facility adjacent to an industrial facility. The industrial facility will be shutting down all of its steam boilers and would receive all of its steam needs from the cogeneration facility. This cogeneration facility would also produce excess steam and electric power for sale to the grid.

What criteria must be met for the cogeneration facility to use the emission reductions from the industrial facility in determining PSD source applicability?

What if the industrial facility is a joint owner of the power plant, but not the operator? Is there a certain percent ownership in the power plant necessary to qualify as "persons under common control?"

Obviously, many industrial facilities utilize steam and power. For the power plant to be included in the same SIC code as the industrial facility, must it supply a certain portion of its total steam capacity to the industrial facility? Must the power plant not sell more than 33% of its electrical generating capacity to the electric grid, or else it would automatically be classified under SIC Major Group 49, Electric Services?

What if essentially all of the steam needed by the industrial facility comes from the power plant, i.e., the industrial facility is totally dependent upon the power plant for steam?

Must both the "common control" criteria and SIC code criteria be met before any offsets from the industrial facility are available to the power plant?

KBN ENGINEERING AN D SCIENCES, INC.
1034 Northwest 57th Street Gainesville, 904/331-9000 FAX: 904/332-4189
EQUAL EMPLOYMENT OPPORTU IVE ACTION EMPLOYER

I would like to obtain EPA's current policy on these questions. If you have any questions concerning this request, please call. If possible, I would greatly appreciate a response within the next two weeks.

Sincerely,

David A. Buff

David A. Buff, M.E., P.E.
Principal Engineer

cc: Mike Sewell, EPA/RTP

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

NOV 3 1989

4APT-APB-cdw

Mr. David A. Buff, M.E., P.E.
Principal Engineer
KBN Engineering and Applied
Sciences, Inc.
Post Office Box 14288
5700 S.W. 34th Street
Gainesville, Florida 32604

Dear Mr. Buff:

We have received your October 2, 1989, letter in which you requested our position regarding the use of leftover netting credits from a modification at Seminole Kraft's pulp mill located in Jacksonville, Florida. To fully address your questions, we have requested the assistance of the New Source Review Section at our Headquarters Office of the Environmental Protection Agency (EPA). Enclosed with this letter, please find a copy of our October 27, 1989, memorandum to EPA Headquarters. Also note that we have requested Headquarters to answer other related questions in addition to the ones raised in your October 2 letter.

On a related issue, we would like to express our concerns with the proposed modification in general. As our information indicates, Seminole Kraft has jointly applied with AES Cedar Bay, Inc., (Cedar Bay) to perform several modifications: Namely, to construct a new kraft recovery boiler and smelt tank (while simultaneously shutting down three old recovery boilers and smelt tanks) and also to construct a new power facility using circulating fluidized bed (CFB) boilers. The new recovery boiler/smelt tank would be owned and operated by Seminole Kraft while the new power facility would be owned and operated by Cedar Bay. Our review of the application for the Site Certification submitted jointly by Seminole kraft and Cedar Bay indicates that netting credits from the shutdown of existing pulp mill sources are being used for both the new recovery boiler/smelt tank and the new power facility modifications. EPA Region IV disagrees with this action because netting credits can only be applied within a "facility", which is defined under federal regulations as: "all of the pollutant-emitting activities which belong to the same industrial grouping, are located on one or more contiguous or adjacent properties, and are under the control of the same person (or persons under common control) except the activities of any vessel. Pollutant-emitting activities shall be considered as part of the same industrial grouping if they belong to the same "Major Group" (i.e., which have the same first two digit code) as described in the Standard Industrial Classification Manual, 1972, as amended by the 1977 Supplement (U.S. Government Printing Office stock numbers 4101-0066 and 003-005-00176-0, respectively.)"

The modifications to the Seminole Kraft pulp mill are categorized under the "Major Group" 26-Paper and Allied Products. The cogeneration project is categorized under the "Major Group" 49-Electric, Gas, and Sanitary Services. Moreover, it is clearly stated in the Site Certification Application that the new recovery boiler/smelt tank will be owned and operated by Seminole Kraft, and the new power facility will be owned and operated by Cedar Bay. Based on these facts, we have concluded that Seminole Kraft and Cedar Bay are two separate and distinct facilities and may not "net" interchangeably under the Prevention of Significant Deterioration (PSD) rules. However, for purposes of nonattainment new source review (NSR) requirements, offset credit may be used by either facility as long as the reductions in volatile organic compound (VOC) emissions are made federally enforceable. Offset credit should not be confused with "netting" as defined under both sets of regulations, i.e., in determining applicability.)"

In summary, please be advised that we are attempting to obtain a written determination from our Headquarters Office in answering your question. We will transmit a copy of their response to you upon our receipt.

If you have any questions concerning this matter, please call Mark Armentrout of my staff at (404) 347-2864.

Sincerely yours,

Bruce P. Miller

Bruce P. Miller, Chief
Air Programs Branch
Air, Pesticides, and Toxics
  Management Division

Enclosure

cc: Clair Fancy
    Florida DER

FDER Comment 17: Please note which information for the following sources used for the modeling analysis is correct.

a. Source 50PMB500086 Glades Corr Institute:

	Qs	Hs	Ts	Vs	Ds	Xs	Ys
Table 6-4:	2.82	9.8	389	11.28	0.40	8400	15800
Model:	2.82	9.1	477	1.22	1.04	8400	15800

b. Source 50PMB500021 Pratt & Whitney:

Table 6-4:	34.2 (km)	38.9 (km)
Model:	35800 (m)	-23100 (m)

c. Source 52FTM500061 US Sugar-Bryant

	Unit 5 PSD (3hr)	Unit 1,2,3 (3hr)	Unit 5 PSD (24hr)	Unit 1,2,3 (24hr)
FOL: Table 6-4 & Model:	81.36	204.53	79.97	79.69
SOL: Table 6-4 & Model:	68.07	174.36	67.38	63.66

d. OKCOGEN Stack Height

OKCOGEN Stack Height	60.66 in Maximum Impact Analysis, PSD Class I and II Analysis
	65.2 in AAQS Analysis

Response 17:

a. For Glades Correctional Institute, the source information used in the modeling runs is correct. The source information provided in Table 6-4 has been revised to match the model input for this facility. A revised table is attached.

b. The location for Pratt & Whitney as presented in Table 6-4 is the correct location. The modeling location for this facility is not correct. This facility was modeled only in the AAQS analysis. Therefore, the AAQS impacts were remodeled with the correct information, and Tables 6-8, 6-9, and 6-10 were revised (attached). Re-modeling with this change does not significantly change any of the maximum impacts shown in the application (i.e., Table 6-11 of the application is not affected).

c. The facility information for US Sugar-Bryant, as presented in the Sol-Energy PSD application is the more accurate information. The source information for US Sugar-Bryant, as presented in the Flo-Energy application reflects higher SO_2 emissions and therefore, re-modeling for the Flo-Energy application is not necessary.

d. The OKCOGEN stack height should be 60.66 meters. The stack height of 65.2 meters, as presented in the AAQS analysis, was in error. As a result, the AAQS impacts have been revised (attached Tables 6-8, 6-9, and 6-10). As shown, this error does not have a discernable affect on maximum predicted concentrations. The maximum AAQS impacts as shown in Table 6-11 of the application are not affected.

Table 6-4. Summary of Non-Okeelanta Source Data Used in Modeling Analysis (Page 1 of 2) (Revised 11/25/92)

APIS Number	Facility	Stack		Temp (K)	Velocity (m/s)	SO_2 3-Hour Emission Rate (g/s)	PSD Source? (EXP/CON)	Modeled in		
		Height (m)	Diameter (m)					AAQS	Class II	Class I
52FTM500016	Atlantic Sugar									
	Unit 1[a]	18.9	1.92	346	12.7	17.24		Yes	No	No
	Unit 2[a]	18.9	1.92	342	10.9	22.50		Yes	No	No
	Unit 3[a]	21.9	1.83	341	17.5	16.88		Yes	No	No
	Unit 4[a]	18.3	1.83	344	15	16.88		Yes	No	No
	Unit 5[a] PSD	27.4	1.68	339	15.7	11.80	CON	Yes	Yes	Yes
50WPB43????	Bechtel Indiantown PSD	150.9	4.88	333.2	30.5	75.64	CON	Yes	Yes	Yes
50DAD130348	Dade County RRF PSD									
	Units 1&2 proposed mod.	64.9	3.66	405.4	15.86	12.30	CON	No	No	Yes
	Units 3&4 proposed mod.	64.9	3.66	405.4	15.86	12.30	CON	No	No	Yes
	Units 5&6 proposed	76.2	4.2	399.8	15.74	17.20	CON	No	No	Yes
52FTM260001	Everglades Sugar[a]	21.9	1.1	477	10.1	11.80		Yes	No	No
50BRO060037	FPL - Lauderdale									
	CTs 1-4 PSD	45.7	4.88	411	10.97	271.10	CON	Yes	Yes	Yes
	4&5 PSD Baseline	46	4.27	422	14.63	-457.00	EXP	No	Yes	Yes
50WPB430001	FPL Martin									
	Units 1&2	152.1	7.99	420.9	21.03	1743.79		Yes	No	No
	Aux Blr PSD	18.3	1.1	535.4	15.24	12.90	CON	Yes	Yes	Yes
	Diesl Gens PSD	7.6	0.3	785.9	39.62	0.51	CON	Yes	Yes	Yes
	Units 3&4 PSD	64.9	6.1	410.9	18.9	470.40	CON	Yes	Yes	Yes
50BRO060036	FPL - Port Everglades									
	GT 1-2	15.5	5.49	733	21.34	488.39		Yes	No	No
	Units 1&2	104.9	4.27	416	18.59	637.54		Yes	No	No
	Units 3&4	104.5	5.52	108	19.2	1067.16		Yes	No	No
50PMB500042	FPL - Riviera Beach									
	Unit 2	45.7	4.57	430.2	7.62	124.86		Yes	No	No
	3&4	90.8	4.88	408	18.9	846.33		Yes	No	No
50PMB500086	Glades Corr Institute	9.1	1.04	477	1.22	2.82		Yes	No	No
50PMB500045	Lake Worth									
	Units 1&2	18.23	1.52	434.1	6.19	72.58		Yes	No	No
	Units 3&4	38.1	2.29	408	9.69	237.90		Yes	No	No
	Unit 5	22.9	0.95	450.2	18.29	11.59		Yes	No	No
NA	Lee County RRF PSD	83.8	1.88	388.5	19.81	14.00	CON	No	No	Yes
NA	North Broward RRF PSD	58.5	3.96	381	18.01	35.40	CON	Yes	Yes	Yes
52FTM500019	Osceola Farms									
	Unit 1 PSD Baseline[a]	22	1.52	342	8.18	-5.07	EXP	No	No	Yes
	Unit 2 PSD Baseline[a]	22	1.52	341	18.1	-16.32	EXP	No	No	Yes
	Unit 3 PSD Baseline[a]	22	1.93	341	14.5	-7.26	EXP	No	No	Yes

Table 6-4. Summary of Non-Okeelanta Source Data Used in Modeling Analysis (Page 2 of 2) (Revised 11/25/92)

APIS Number	Facility	Stack Height (m)	Stack Diameter (m)	Temp (K)	Velocity (m/s)	SO_2 3-Hour Emission Rate (g/s)	PSD Source? (EXP/CON)	Modeled in AAQS	Modeled in Class II	Modeled in Class I
	Unit 4 PSD Baseline[a]	22	1.83	341	18.8	-13.61	EXP	No	No	Yes
	Cogenerator Units 1&2	54.9	2.13	449	26.05	139.20	CON	Yes	Yes	Yes
50WPB500234	Palm Beach RRF 1&2 PSD	76.2	2.04	505.2	24.9	85.05	CON	Yes	Yes	No
50PMB500021	Pratt & Whitney									
	ACHR-1	1.8	0.91	500	40.23	16.02		Yes	No	No
	ACHR-2	15.2	0.91	500	40.23	47.92		Yes	No	No
	ACHR-3	4.6	3.38	700	13.44	23.46		Yes	No	No
	BO-12	4.6	0.76	500	6.92	9.08		Yes	No	No
	LI-1 MW	8.2	0.67	2000	8.35	6.18		Yes	No	No
NA	South Broward RRF PSD	59.4	3.96	381	18.01	37.91	CON	Yes	Yes	Yes
52FTM260015	Southern Gardens PSD	22	0.64	479.8	17.48	4.99	CON	Yes	Yes	Yes
52FTM500026	Sugar Cane Growers									
	Unit 3[a]	24.4	1.6	344	15.6	4.40		Yes	No	No
	Unit 4 PSD[a]	33.5	1.63	344	10.6	24.20	CON	Yes	Yes	Yes
	Unit 4 PSD Baseline[a]	25.9	2.82	344	10.6	-24.20	EXP	No	Yes	Yes
	Unit 5[a]	24.4	1.4	344	15.2	16.20		Yes	No	No
	Unit 8 PSD[a]	47.2	3.05	344	10.6	26.70	CON	Yes	Yes	Yes
	Unit 1&2[a]	24.4	1.4	344	11.4	24.20		Yes	No	No
	Unit 6&7[a]	12.2	2.13	606	11.2	51.00		Yes	No	No
50DAD130020	Tarmac									
	Kiln 2 PSD Baseline	61	2.44	465	12.84	-5.71	EXP	No	No	Yes
	Kiln 3 PSD Baseline	61	4.57	472	10.78	-2.76	EXP	No	No	Yes
	Kiln 2 PSD	61	2.44	422	9.1	24.50	CON	No	No	Yes
	Kiln 3 PSD	61	4.57	450	11.04	51.40	CON	No	No	Yes
52FTM260003	US Sugar Clewiston									
	Unit 3[a]	27.4	2.29	340	14.54	28.16[b]		Yes	No	No
	Unit 4 PSD[a]	45.7	2.51	334	19.66	16.26[b]	CON	Yes	Yes	Yes
	Units 1&2[a]	22.9	1.86	339	35.54	95.22[b]		Yes	No	No
	Units 5&6[a]	19.8	1.83	340	9.78	4.48		Yes	No	No
52FTM500061	US Sugar-Bryant									
	Unit 5 PSD[a]	42.7	2.9	345	11.49	81.36[b]	CON	Yes	Yes	Yes
	Unit 1,2&3[a]	19.8	1.64	342	36.4	204.54[b]		Yes	No	No
50BRO062094	Waste Management PSD	11.3	1.22	721.9	36.82	5.39	CON	Yes	Yes	No

[a] These sources operate only during the crop season, October 1 through April 30.

[b] The following sources were modeled under 24 hour and annual averaging times with the following emission rates (g/s):
US Sugar Clewiston Unit 3: 22.99
US Sugar Clewiston Unit 4: 14.78
US Sugar Clewiston Unit 1&2: 80.68
US Sugar Bryant Unit 5 PSD: 79.97
US Sugar Bryant Unit 1,2&3: 79.69

Table 6-8. Maximum Predicted SO_2 Concentrations for the AAQS Screening Analysis, Near-Field Receptors (Revised 11/25/92)

Averaging Time	Concentration ($\mu g/m^3$)	Receptor Location[a] Direction (degrees)	Receptor Location[a] Distance (m)	Period Ending (YYMMDDHH)
Annual	36	30.	17000.	82------
	30	30.	17000.	83------
	31	30.	17000.	84------
	28	30.	17000.	85------
	28	30.	17000.	86------
24-Hour[b]	162	30.	17000.	82070824
	183	30.	17000.	83040624
	176	30.	17000.	84041224
	181	30.	17000.	85010124
	173	30.	17000.	86081224
3-Hour[b]	446	30.	17000.	82070909
	381	30.	17000.	83040609
	424	30.	17000.	84072015
	442	30.	17000.	85060318
	360	30.	17000.	86080909

Note: YY=Year, MM=Month, DD=Day, HH=Hour

[a] All receptor coordinates are reported with respect to the Boiler No. 16 stack location.

[b] All short-term concentrations indicate highest, second-highest concentrations.

Table 6-9. Maximum Predicted SO_2 Concentrations for the AAQS Screening Analysis, Far-Field Receptors (Revised 11/25/92)

Averaging Time	Concentration ($\mu g/m^3$)	Receptor Location[a] Direction (degrees)	Receptor Location[a] Distance (m)	Period Ending (YYMMDDHH)
Annual	23	40.	50000.	82------
	20	40.	50000.	83------
	24	40.	50000.	84------
	23	40.	50000.	85------
	21	20.	30000.	86------
24-Hour[b]	146	130.	80000.	82011824
	153	130.	80000.	83081024
	213	130.	80000.	84050224
	188	130.	80000.	85052124
	124	90.	70000.	86032124
3-Hour[b]	631	130.	80000.	82011815
	613	130.	80000.	83081018
	634	130.	80000.	84063015
	835	130.	80000.	85101112
	622	130.	80000.	86010212

Note: YY=Year, MM=Month, DD=Day, HH=Hour

[a] All receptor coordinates are reported with respect to the Boiler No. 16 stack location.

[b] All short-term concentrations indicate highest, second-highest concentrations.

Table 6-10. Maximum Predicted SO_2 Concentrations for the AAQS Detailed Screening Analysis Grid[a], Annual and 24-Hour Averaging Time Only (Revised 11/25/92)

Averaging Time	Concentration ($\mu g/m^3$)	Receptor Location[b] Direction (degrees)	Receptor Location[b] Distance (m)	Period Ending (YYMMDDHH)
Annual	35	30.	17000.	82------
	30	30.	17000.	83------
	33	30.	16000.	84------
	31	30.	16000.	85------
	33	30.	16000.	86------
24-Hour[c]	168	30.	16000.	82112624
	183	30.	17000.	83040624
	199	35.	16000.	84092624
	181	30.	17000.	85010124
	205	30.	16000.	86110724

Note: YY=Year, MM=Month, DD=Day, HH=Hour

[a] Centered on screening grid receptor location (17,000 m, 30°).

[b] All receptor coordinates are reported with respect to the Boiler No. 16 stack location.

[c] All short-term concentrations indicate highest, second-highest concentrations.

FDER Comment 18: What is the worst case total maximum hourly sulfur dioxide emission rate for all three boilers when they are running concurrently? Modeling for maximum short-term impacts is based on worst case maximum hourly emissions.

Response 18: The worst-case maximum hourly SO_2 emission rate for each boiler, as shown in Table 2-5 and on page 8-4 of the application, will be 588.0 lb/hr. This emission rate was used in the modeling analysis for all averaging times.

<u>FDER Comment 19</u>: Please explain the last three footnotes (a, b, c in the Sol-Energy application and b, c, d in the Flo-Energy application) in Table 6-18 of both applications. The annual impact values due to arsenic, chromium VI and nickel emissions appear to exceed the annual no threat levels (NTL) when the impact values are computed by multiplying the hourly emissions in column 1 by the highest predicted annual concentration given in the information below the table.

<u>Response 19</u>: The maximum estimated hourly emissions for all non-regulated pollutants were initially used to conservatively estimate the maximum 8-hour, 24-hour and annual air quality impacts. Based on this analysis, the annual NTL level for arsenic, hexavalent chromium, and nickel were predicted to be exceeded. Therefore, the estimated maximum annual emissions for each of these pollutants were used to more realistically predict impacts, as indicated in the footnotes to Table 6-18 of the application. The maximum annual emissions for each of these pollutants is shown in Table 2-11 of the application, and the derivation of the emissions is presented in Appendix A of the application. The annual emissions in tons per year were converted to lb/hr based on 8,760 hr/yr operation.

REFERENCES

Entropy Environmentalists Inc. 1989. Stationary Source Sampling Final Report, Reference No. 6488. Research Triangle Park, NC.

U.S. Environmental Protection Agency (EPA). 1988. Municipal Waste Combustion Study. Washington, DC. EPA/530-SW-87-021b.

U.S. Environmental Protection Agency (EPA). 1992. Emissions of Metals, Chromium and Nickel Species, and Organics from Municipal Wastewater Sludge Incinerators. Cincinnati, OH. EPA/600/R-92/003a.

Walker, B.L. and C.D. Cooper. 1992. Air Pollution Emission Factors for Medical Waste Incinerators. Journal of the Air & Waste Management Association, Vol. 42, No. 6:784-791.

Table 2-8. Flo-Energy Cogeneration Facility Maximum Annual PM Emission Rates for Fugitive Dust Sources (Revised 11/25/92)

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	112,750	0.040	0.35	0.014
Conveyor-to-Coal Pile	0.00234	None	0	0.00234	112,750	0.132	0.35	0.046
Underpile Reclaim Hopper	0.00234	Enclosure	90	0.00023	112,750	0.013	0.35	0.005
Conveyor-to-Crusher	0.00234	None	0	0.00234	112,750	0.132	0.35	0.046
Coal Crusher	0.02	Enclosure	70	0.00600	112,750	0.338	0.45	0.152
Crusher-to-Conveyor	0.00234	None	0	0.00234	112,750	0.132	0.35	0.046
Conveyor-to-Boiler Feeders	0.00234	None	0	0.00234	112,750	0.132	0.35	0.046
Storage Pile	–	None	0	–	–	0.211[a]	0.5	0.105[a]
Coal Storage Pile Maintenance	0.90328[b]	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					11.122		3.982

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[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.

BIOMASS STORAGE PILE EMISSIONS DUE TO WIND EROSION

Inventory area: Okeelanta Cogenerati
Source ID: Bagasse Pile Filename: A:\BagsPil.epc

Emissions estimate year: 91
Based on wind data year: 91
Fastest mile filename: WESTP91.MET
System of units: English
Source life (inclusive days of year)
  Start day: 1
   End day: 365
F=flat area, PC=conical pile, PO=oval pile: PC
 Pile height (ft) : 30
 Pile diameter (ft) : 767
 Area (sq ft): 463217.7
Material description: Bagasse/WW
Percent moisture content: 37
Percent silt content: 2.2
Threshold friction velocity, U*t, (cm/sec): 112
Roughness height (cm): .3
Mode (mm) of size distribution 3.533677# (# denotes calculated value)
Lc value (cf. Fig. 6-3 of reference manual):

Frequency of disturbance information :
 Us/Ur = .9 -- subarea # 1 -- 20 % of regime disturbed every 1 day(s)
 Us/Ur = .6 -- subarea # 1 -- 20 % of regime disturbed every 1 day(s)
 Us/Ur = .2 -- subarea # 1 -- 20 % of regime disturbed every 1 day(s)

Total emissions emitted over the period: 145150.4 g

Table 3-3. PSD Source Applicability Analysis for the Flo-Energy Cogeneration Facility (revised 12/1/92)

Regulated Pollutant	Baseline Emissions (TPY)	Cogeneration Facility Emissions (TPY)	Net Change (TPY)	Significant Emission Rate (TPY)	PSD Applies ?
Particulate (TSP)	473.7	183.6[b]	-290.1	25	No
Particulate (PM10)	426.3	176.4[c]	-249.9	15	No
Sulfur Dioxide	748.3	1,700	951.7	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	0.19	-0.09	0.6	No
Mercury	0.0256[d]	0.0262	0.0006	0.1	No
Beryllium	0.0004	0.0080	0.0076	0.0004	Yes
Fluorides	0.04	32.5	32.5	3	Yes
Sulfuric Acid Mist	22.4	51.2	28.8	7	Yes
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 11.1 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 most recent 2 years is 0.0256 TPY. The highest annual emission rate for either of the last 2 years is 0.0262 TPY.

<u>FDER Comment 7</u>: Gypsum recovered from the lime/limestone injection FGD system may be of value to the sugar cane industry as a soil conditioner. FGD should also reduce fluoride and sulfuric acid emissions. Please revise your BACT determination by eliminating the cost of the disposal of the material captured by the ESP and calculate the cost per ton of air pollutant removed. Also address the use of other emerging sulfur dioxide control technologies for the BACT determination such as furnace sorbent or duct sorbent injection.

<u>Response 7</u>: Gypsum ($CaSO_4{\cdot}2H_20$) is a source of elemental calcium (Ca) for plant nutrition and could potentially be a benefit to crop growers. However, organic soils and surface waters in the sugar cane growing area are Ca dominated. Thus, enough plant available Ca is already present, making additional gypsum unnecessary. Hypothetically, gypsum amendments to sugar cane soils may require additional phosphorous (P) fertilizer to compensate for the P fixation by the gypsum supplied Ca. Thus, adding gypsum to the sugar cane fields as a soil conditioner may actually have detrimental effects. Therefore, Flo-Energy cannot consider the use of FGD waste products as a soil conditioner.

<u>Emerging Sulfur Dioxide Control Technologies</u>

<u>INTRODUCTION</u>

This discussion focuses on dry sorbent injection (DSI) processes as an emerging technology for SO_2 control. The DSI process for SO_2 removal was first investigated in England in the 1930's, and was experimented with in the U.S. in the early 1960's with little success and low removal rates. With the development of the low NO_x burner technology in the 1970's, better SO_2 removal rates were obtained compared to experiments performed with conventional burners. However, little interest was shown in this technology in the U.S. until the early 1980's when concerns over acid rain in the eastern region of the U.S. prompted the need for more practical and economical alternatives for reducing SO_2 emissions from existing coal-fired power plants. Standard flue gas desulfurization (FGD) processes such as wet limestone scrubbing or spray dryer scrubbing are well-proven for controlling SO_2 emissions; however, many existing power plants are not able to apply these FGD processes because of physical constraints or the high cost associated with these technologies. A number of technologies based on DSI have been developed as low-cost SO_2 control alternatives to the standard FGD processes for retrofitting purposes.

The DSI process involves the injection of dry sorbents into a gas stream upstream from the particulate collection system. Typical sorbents include finely ground limestone, hydrated lime, sodium carbonate, and sodium sesquicarbonate. The sorbent reacts with the SO_2 emissions to form a solid material such as calcium sulfate or sodium sulfate which are then captured by the particulate control system, typically an electrostatic precipitator (ESP) or baghouse.

The DSI process includes two basic configurations which differ based on the point of injection of the sorbent into the flue gases. Initial developments concentrated on the injection of calcium sorbent directly into the furnace equipped with a low NO_x burner system (i.e., the limestone injection multistage burner or LIMB process). This process can utilize either limestone or lime as the sorbent. The second process, developed more recently, injections sorbent into the duct between the boiler and the downstream particulate collection device, termed duct injection. This latter process is designed to utilize either lime or sodium-based sorbent materials.

Both furnace DSI and duct injection DSI processes are considered demonstration technologies because their application is not yet commercially demonstrated on a long-term basis. Also, the achievable SO_2 emission reduction levels range from 30 to 70 percent, which are modest when compared to the well proven wet and dry FGD processes which can achieve over 90 percent SO_2 removal.

Since mid-1987, U.S. EPA's Clean Coal program has been conducting full-scale demonstrations of furnace injection technology in different boiler configurations. These are EPA-sponsored demonstrations at Ohio Edison's Edgewater Station in Lorrain, Ohio, using Babcock & Wilcox's front wall-fired boiler; Richmond Power and Light's Whitewater Valley Generating Station in Richmond, Indiana; and Virginia Power's Yorktown Power Station in Yorktown, Virginia. The latter two units are tangentially-fired pulverized coal boilers manufactured by ABB-Combustion Engineering.

Lime duct injection has also been studied at the Ohio Edison Edgewater power plant. Sodium sorbent duct injection has been investigated by Colorado Springs Department of Utilities (CSDU) at its R.D. Nixon Unit 2 and by Public Service Company of Colorado (PSCC) at the Cherokee power station in Denver.

TECHNICAL DESCRIPTIONS OF THE DSI PROCESS

Brief descriptions of the three different DSI processes (i.e., lime furnace injection, lime duct injection, and sodium duct injection) are described in this section.

Lime Furnace Injection-- In the lime furnace injection process, lime is injected as a sorbent directly into the upper part of the boiler where it is calcined into active calcium oxide, and then reacts with SO_2 and oxygen in the flue gas to produce calcium sulfate. The by-product is a solid placed in the upper furnace section where the temperature is in the range of 1,600 to 2,300°F. At Edgewater, a flexible sorbent injection scheme has been installed consisting of three injection grids placed 4 feet apart vertically on the front wall. Hydrated lime is fed through two sets of feeders to either one or two levels of injectors at a time.

This furnace injection design was first tested in July 1987, and by August 1988 the demonstration included a downstream flue gas humidification process for the purpose of restoring lost efficiency of the electrostatic precipitator (ESP) due to the dry sorbent injection. The humidification step also increased SO_2 removal. Without the humidification process, the dry condition of the flue gas may produce back corona in the ESP due to the high resistivity of the carbon ash, thus resulting in increased stack opacity beyond allowable levels. The humidifier was designed to quench the flue gas to within 20°F above the adiabatic saturation temperature.

The lime furnace injection process requires a Ca/S ratio of at least 2 to 1, which results in a 40 to 60 percent utilization rate. Although limestone was first proposed as sorbent, only quick lime has been used because limestone could only achieve up to 25 percent SO_2 removal. An oversize ESP was used in the demonstration project in order to handle the increased particulate loading. Particulate loading was expected to increase by a factor of two to three for the LIMB process. Changes in the particulate properties have also made the ash more difficult to collect by the ESP, potentially increasing particulate emissions. For new applications, the ESP for particulate control would have to be sized larger to account for these concerns.

Lime Duct Injection-- The lime duct injection process uses a sorbent injection system and auxiliary equipment similar to the furnace injection process. In the duct injection process, however, the hydrated lime is injected at a point that is downstream from the boiler air preheater unit. The humidifier is arranged upstream from the point of injection. The flue gas temperature entering the humidifier is about 300°F and is quenched down to approximately 20° above the adiabatic saturation condition (about 145°F). Here, humidification activates the sorbent to enhance SO_2 removal and conditions the ash for removal by the ESP.

At Edgewater, a sodium hydroxide solution was added to the humidification water to enhance SO_2 removal. An ash recycle system is used to reinject unspent sorbent into the duct for improved sorbent reactivity. To prevent condensation in the ESP and stack, the flue gas is reheated using a steam reheater unit prior to entering the stack. The lime duct injection process at Edgewater was able to achieve a SO_2 removal efficiency of up to 70 percent.

Dry-Sodium Duct Injection-- Sodium-based sorbents are also used for the duct injection process pioneered by EPRI, PSCC, and CSDU. These initial studies were performed with sodium sesquicarbonate and sodium bicarbonate supplied from the main U.S. sodium mine in the Wyoming area. Of these two sorbents, sodium bicarbonate provides slightly higher reactivity at the same normal stoichiometric ratio since it is a refined chemical. In general, sodium-based sorbents are much more reactive in nature than calcium-based (lime or limestone) sorbents, and perform best when injected in the 285-300°F flue gas temperature range. Similar to the lime duct injection process, the sodium powder is injected between the air preheater unit and the particulate collection device. In all of the dry sodium injection process demonstrations, a fabric filter has been used as the particulate control device.

Demonstrations of the dry sodium injection process on utility boilers, conducted mainly in Colorado, demonstrated that up to 70 percent SO_2 emission reduction is achievable. However, an existing unit at the PSCC's Cherokee power station has been limited to 30 percent SO_2 removal due to a brown plume effect associated with higher removal efficiencies. The reagent utilization is about 80 percent. The dry sodium utilization was shown to be insensitive to minor fluctuations in the flue gas temperature during normal boiler operation, but declined significantly when flue gas temperatures dropped below approximately 260°F. Applications of the dry sodium injection process to date has been mainly confined to the Rocky Mountain region because of the readily available sodium sorbent, and only in cases where a low level of SO_2 removal is required on low-sulfur coal (less than 0.5 percent sulfur coal).

In terms of SO_2 removal efficiency, the most consistent data indicate that the lime furnace injection process is capable of achieving 40 percent removal. Both lime and dry sodium duct injection processes can achieve between 40 to 70 percent SO_2 removal. As in the case of furnace injection, new applications would require a larger ESP to account for the increased particulate loading to the ESP.

BACT EVALUATION OF THE DSI PROCESS

Technical Issues-- The furnace injection process has been developed mainly for the retrofit of existing pulverized-coal-fired utility boilers. Thus far all furnace injection demonstration projects have been performed on pulverized-coal (PC) boilers only, with none being applied to stoker boilers. However, performance test results for PC boilers may be applicable to stoker boilers because the dry sorbent injection takes place at the upper furnace section, and thus is relatively independent of the firing mechanism in newly designed boiler systems.

The critical parameters for the furnace injection process lie in the flow pattern of the flue gas inside the furnace. The rate of SO_2 removal is directly related to the reactivity of lime, which in turn is a function of temperature, humidity, flow distribution, residence time, and contact surface area. Potential problems encountered due to lime injection result from the tendency of the sorbent to take up moisture in the flue gas. The wet sorbent may then form deposits on the outer surfaces of steam tubes, superheaters, and air preheaters. Therefore, more frequent soot blowing is required to prevent a build up of material on these components. On the average, lime furnace injection systems have about a 1 percent steam penalty.

The lime furnace injection process results in additional particulate loading to the control device. If an ESP is used, increasing the size of the ESP will be required in order to maintain the same level of particulate emissions. The dry condition of the flue gases at temperatures above 300°F also degrades the performance of the ESP unit; therefore, a humidification process is usually required to cool the flue gas temperature to approximately 275°F to enhance the ESP performance.

The lime duct injection process shares similar technical issues as the lime furnace injection process. Duct injection can achieve somewhat better SO_2 removal efficiency than the furnace injection process. The higher SO_2 removal efficiency is achieved by adding a sodium additive to the humidification water. Sodium hydroxide solution is generally recommended for use as an additive. At the Edgewater demonstration project, the Babcock & Wilcox process operated at a reduced temperature of approximately 20° above the adiabatic temperature of the flue gas, or about 145°F. The result was that additional heating was required to raise the temperature of the stack gas to above 200°F to prevent condensation in the ESP and the stack. A larger ESP is also required to handle the increased particulate loading.

Both lime furnace and duct injection processes have low reagent utilization. Approximately 40 to 60 percent of the lime injected is utilized; therefore, both processes produce large amounts of free lime in the solid waste.

For the dry-sodium duct injection process, a larger ESP unit will also be required to handle the additional particulate loading. This process has only been demonstrated on very low-sulfur coal of less than 0.4 percent sulfur by PSCC at the Cherokee power station in Denver.

As for the availability of the sodium-based sorbents, most of the sodium chemicals are being mined exclusively in sodium mines in Wyoming and processed mainly for the glass manufacturing industry. Approximately 90 percent of the sodium is converted into soda ash for this purpose, and historically sodium suppliers have not sold their products in alternative markets. Therefore, availability and pricing of sodium-based sorbents are considered to be uncertain in the future.

The DSI process has been used in several demonstration projects, but there are no commercially operating systems in the U.S. Based on the demonstration projects, the DSI process is considered technically feasible. However, the lack of long-term commercial operating experience with systems achieving greater than 30 percent SO_2 control efficiency introduces significant uncertainties concerning the economics and effectiveness of the DSI system.

Environmental Effects-- While the waste materials from the sorbent injection technologies differ from conventional pulverized coal combustion, they are similar to wastes generated by spray dryers or fluidized bed combustors. The lime furnace injection process tends to form calcium sulfate and substantial quantities of unreacted free lime (up to 50 percent); the reactivity and exothermicity of the free lime require special handling because of the associated safety hazards. On the other hand, waste from the lime duct injection process contains less free lime, but large amounts of calcium sulfite, which can cause compaction problems during disposal. If the lime duct injection process uses a sodium additive such as sodium hydroxide, the ash has to be handled as hazardous solid waste.

The sodium-containing wastes from the dry sodium injection process are a concern with respect to surface runoff and leachate entering the groundwater. The wastes must be disposed of in a landfill with a liner. In addition, a brownish plume may be produced when the injection system is operated at higher than 30 percent SO_2 removal efficiency. Through a complex chemical reaction, NO_2 is produced by the oxidation of NO which occurs at a high level of depletion of SO_2 from the flue gas. Therefore, visible emissions will be expected to increase when a sodium-based DSI process is operated at above 30 percent SO_2 removal efficiency.

Energy Requirements and Impacts-- Both the furnace and duct injection processes require additional electricity to drive various mechanical equipment, including conveyor belts, feeder systems, pulverizers, and air pumps. Additional energy is required for operating a larger ESP unit as well as larger ash handling equipment. The estimated energy requirement is approximately 1,765 megawatt-hours per year (MW-hr/yr) for both the furnace and duct injection processes. These estimated energy requirements are calculated assuming the maximum allowable coal-firing for the Flo-Energy facility, and that the DSI system would be operating only during coal firing.

In the furnace injection process, the sorbent is injected into the flue gas prior to the superheater section of the boiler. Some of the sorbent will undergo pozzolanic reactions with the fly ash and may deposit on boiler internal components, forming a coating and resulting in a small steam penalty (approximately 1 percent of the total steam production).

In the lime duct injection process, reheat of the flue gas may be required prior to discharge at the stack. More electricity will be required for a larger ESP unit, and for the operation of auxiliary equipment. Additional water usage is required for the humidification system for both lime injection processes.

The dry sodium process will also require additional electricity to operate a larger ESP unit and the auxiliary equipment associated with the injection system and ash handling system.

Economic Analysis-- The capital cost factors for the DSI system were developed from vendor information and published literature. The estimated factors are $4,000/MMBtu heat input for the lime furnace injection system, $3,500/MMBtu for the lime duct injection system, and $3,000/MMBtu for the dry sodium duct injection process. The capital, operating and annualized cost estimates for the DSI systems are presented in the attached Table A. The estimates include the costs of upsizing the ESP units and the ash handling systems.

The total capital investment for the three DSI processes are estimated at $7.08 million, $6.00 million, and $4.98 million for the lime furnace injection process, the lime duct injection process, and the dry sodium duct injection process, respectively. The annualized costs for these three DSI processes are approximately $3.06 million, $2.76 million, and $2.56 millon, respectively. The cost effectiveness values for these DSI processes are $4,709 per ton of SO_2 removed for the lime furnace injection process, \$3,396 per ton of SO_2 removed for the lime duct injection process, and \$3,155 for the dry sodium duct injection process.

A review of the cost tables presented in the Flo-Energy application for the spray dryer SO_2 control system revealed that ESP upsizing was not included in the costs. Therefore, Tables 5-3 and 5-4 from the original application have been revised and are attached.

A revised BACT summary table (Table 5-5 from the original permit application) is attached which incorporates all of the FGD technologies considered. The dry-sodium duct injection process is used to represent all DSI processes in the revised BACT summary table because this process has the lowest cost effectiveness, reflected in the lowest annualized cost at 50 percent SO_2 removal efficiency as shown in Table A.

BACT CONCLUSIONS

In conclusion, the three DSI processes (lime furnace injection, lime duct injection, and dry-sodium injection) are considered technically feasible for application to Flo-Energy. However, the lack of any long-term operating experience renders these DSI processes uncertain in terms of economics and SO_2 removal efficiency. In actual operations, all SO_2 removal efficiencies have been reported at lower rates than those projected thus far in all existing demonstration projects in the U.S. Other concerns related to lime injection DSI systems include solids buildup on heat transfer surfaces, increased particulate emissions and/or solid waste disposal, and increased water and energy usage. The dry-sodium injection process has several areas of concern that include:

- Brown plume visible emissions,
- Disposal of highly soluble sodium ash, and
- Long-term cost and availability of sodium-based sorbent for the proposed project.

The total cost effectiveness for the lime furnace injection, the lime duct injection, and the dry sodium duct injection processes are \$4,709; \$3,396; and \$3,155 per ton of SO_2 removed, respectively. Thus, the dry sodium process is the most effective of these three emerging control technologies.

With the addition of the DSI process to the revised BACT summary table (Table 5-5) for the Flo-Energy facility, the total cost effectiveness for the wet limestone scrubber, the spray dryer, and the dry-sodium duct injection process are \$3,155, \$2,794, and \$4,698 per ton of SO_2 removed, respectively, based on the worst-case annual emissions. The total cost effectiveness for these same options for the combined Flo-Energy and Sol-Energy facilities is at least two times higher for each option (i.e., \$8,342; \$6,912; and \$12,666 per ton for the wet limestone scrubber, the spray dryer, and the dry-sodium duct injection process, respectively) based on the combined average SO_2 emissions from the two facilities of 1,000 TPY.

The incremental cost effectiveness of the dry sodium injection process, above the baseline case of low sulfur coal firing, is \$3,155/ton SO_2 removed. This value is far above the incremental cost effectiveness considered to be unreasonable in previous BACT determinations for SO_2, i.e., greater than \$2,000/ton. The incremental cost of the spray dryer, over the DSI process, is \$2,365/ton, and the incremental cost of the wet scrubber option, above the spray dryer process cost, is \$63,090/ton. In the case of the combined Flo-Energy and Sol-Energy projects, these incremental costs are more than doubled.

These high costs render all SO_2 control alternatives considered as economically infeasible. Therefore, the firing of low sulfur coal is BACT for the proposed Flo-Energy Cogeneration facility.

Table A. Capital, Operating, and Annualized Cost Estimates for Sorbent Injection Systems, Flo–Energy Cogenration.

Cost Items	Basis	Furnace Injection Lime Sorbent	Duct Injection Lime Sorbent	Duct Injection Sodium Sorbent
TOTAL CAPITAL INVESTMENT (TCI)				
(1) Dry Sorbent Injection System	See Note 1	$5,880,000	$4,704,000	$4,410,000
(a) Flue Gas Humidification System		Included	Included	--
(2) Upsizing ESP for Particulate Control				
(a) Percent Increase in Size	Based on ESP's Vendor Estimate	55%	60%	25%
(b) Cost of Upsizing for 3 Boilers	$7,000 per 1% Increase per boiler	$1,155,000	$1,260,000	$525,000
(3) Upsizing Ash Handling System				
(a) Cost of Upsizing for 3 Boilers	10% of current system cost. See Note 2.	$40,000	$40,000	$40,000
Subtotal of TCI	(1) + (2b) + (3a)	$7,075,000	$6,004,000	$4,975,000
DIRECT OPERATING COSTS (DOC):				
(1) Labor				
Operator[2]	$22/hr; 4,706 hr/yr total	$129,425	$129,425	$129,425
Supervisor[1]	15% of operator cost	$19,414	$19,414	$19,414
(2) Maintenance[2]	5% of direct capital cost	$237,013	$201,134	$166,663
(3) Replacement Parts	3% of direct capital cost	$142,208	$120,680	$99,998
(4) Utilities				
(a) Electricity for ESP	$85 per MW–hr	$159,115	$164,247	$128,318
for Auxiliary Equipment	$85 per MW–hr	$42,431	$43,799	$34,218
(b) Water	$0.27 / 1,000 gal	$10,726	$10,726	--
(c) Steam Lost or Reheat	$6.19/$10^3$ lb	$32,749	--	--
(5) Raw Chemicals				
(a) Limestone (97% purity)	$32 / ton including freight	--	--	--
(b) Hydrated Lime (74% purity)	$140 / ton including freight	$568,874	$568,874	--
(c) Sodium Bicarbonate	$230 / ton including freight	--	--	$602,762
(6) Solid Disposal	$27 / ton for Lime; $50 /ton for Sodium	$98,721	$123,402	$204,979
Total DOC		$1,440,674	$1,381,701	$1,385,776
INDIRECT OPERATING COSTS (IOC):				
(7) Overhead[1]	60% of operating labor & maintenance	$231,511	$209,983	$189,301
(8) Property Taxes[1]	1% of total capital investment	$58,800	$47,040	$44,100
(9) Insurance[1]	1% of total capital investment	$58,800	$47,040	$44,100
(10) Administration[1]	2% of total capital investment	$117,600	$94,080	$88,200
Total IOC		$466,711	$398,143	$365,701
CAPITAL RECOVERY COST (CRC)	CRF of 0.1627 times TCI	$1,151,103	$976,851	$809,433
ANNUALIZED COST (AC):	DOC + IOC + CRC	$3,058,487	$2,756,696	$2,560,909
TOTAL SO2 REMOVED, TPY [3]	40% for Furnace Inj.; 50% for Duct Inj.	649	812	812
COST EFFECTIVENESS		$4,709	$3,396	$3,155

[1] Based on catalytic incinerators, from OAQPS Control Cost Manual, Fourth Edition.

[2] Based on maximum of 25% coal firing for the Flo–Energy cogeneration facility.

[3] Uncontrolled SO2 emissions from coal firing for the worst–case year are 1,623.6 TPY.

Note 1: Capital cost factors are $4,000/MMBtu of heat input for Furnace Injection and $3,500/MMBtu of heat input for Duct Injection (both using lime) projecting from Babcock and Wilcox's cost analysis summary for Ohio's Edison Power Plant located at Edgewater, Ohio. The capital cost factor for the sodium sorbent injection process is $3,000/MMBtu of heat input based on estimations from Colorado Springs Utilities Company and Publlic Service Company of Colorado. Total Capital Investment for the dry sorbent injection process was calculated using these cost factors for a total of three 490–MMBtu boilers for the proposed Flo–Energy facility.

Note 2: Capital cost estimates of the ash handling system prior to the upsizing in order to handle the additional ash generated from the DSI process are approximately $400,000.

Table 5-3. Capital Cost Estimates for Alternative SO2 Control Systems for Flo-Energy (Revised 11/30/92).

Cost Items	Cost Factors	Spray Dryer	Wet FGD
DIRECT CAPITAL COSTS (DCC):			
(1) Purchased Equipment			
(a) Basic Equipment*	Vendor Quote	$3,990,000	$8,618,400
(b) Auxiliary Equipment	included	included	included
(c) Structure Support	0.10 x (1a)	$399,000	$861,840
(d) Instrumentation & Controls	0.10 x (1a)	$399,000	$861,840
(e) Freight[1]	0.05 x (1a-1d)	$239,400	$430,920
(f) Sales Tax (Florida)	0.06 x (1a-1d)	$287,280	$517,104
(g) Subtotal	(1a-1f)	$5,314,680	$11,290,104
(2) Direct Installation[1]	0.30 x (1g)	$1,594,404	$3,387,031
(3) Upsizing ESP for Particulate Control			
(a) Percent Increase in Size	Based on ESP's Vendor Estimate	40%	--
(b) Cost of Upsizing for 3 Boilers	$7,000 per 1% Increase per boiler	$840,000	--
(4) Upsizing Ash Handling System			
(a) Cost of Upsizing for 3 Boilers	See Note 1.	$40,000	--
Total DCC:	(1) + (2) + (3) + (4)	$7,789,084	$14,677,135
INDIRECT CAPITAL COSTS (ICC):			
(3) Indirect Installation			
(a) Engineering & Supervision[1]	0.10 x (DCC)	$778,908	$1,467,714
(b) Construction & Field Expenses[1]	0.10 x (DCC)	$778,908	$1,467,714
(c) Contruction Contractor Fee[1]	0.05 x (DCC)	$389,454	$733,857
(d) Contigencies[1]	0.20 x (DCC)	$1,557,817	$2,935,427
(4) Other Indirect Costs			
(a) Startup & Testing[1]	0.03 x (DCC)	$233,673	$440,314
(b) Working Capital	30-day DOC**	$125,642	$188,150
Total ICC:	(3) + (4)	$3,864,403	$7,233,175
TOTAL CAPITAL INVESTMENT (TCI):	DCC + ICC	$11,653,487	$21,910,311

* For the spray dryer, the basic equipment cost is the average of budgetary quotations from ABB-Flakt, Joy Environmental Systems, and United McGill. The basic equipment cost for the wet limestone scrubbers were estimated as 2.16 times the cost for the spray dryer scrubbers. The cost factor was determined from vendor estimates and comparative costs between the wet scrubber and the dry scrubber processes as as presented in similar analysis.

** 30 days of direct operating costs, calculated from the annualized cost Table 5-4 (i.e., total DOC/12 months).

[1] Based on catalytic incinerators, from OAQPS Control Cost Manual, Fourth Edition (1990).

Note 1: Capital cost estimates of the ash handling system prior to the upsizing in order to handle the additional ash generated from the spray dryer process are approximately $400,000. The upsizing of the ash handling system will add an additional 10% cost or approximately $40,000 to the spray dryer option. The wet FDG option does not involve any upsizing of the ESP ash handling system.

Table 5–4. Annualized Cost Estimates for the Alternative SO2 Control Systems for Flo–Energy (Revised 11/30/92).

Cost Items	Basis	Spray Dryer	Wet FGD
DIRECT OPERATING COSTS (DOC):			
(1) Labor			
Operator[2]	\$22/hr; 4,706 and 7,087 hr/yr total	\$103,540	\$155,905
Supervisor[1]	15% of operator cost	\$15,531	\$23,386
(2) Maintenance[2]	5% of direct capital cost	\$389,454	\$733,857
(3) Replacement Parts	3% of direct capital cost	\$233,673	\$440,314
(4) Utilities			
(a) Electricity	\$85 per MW–hr	\$320,901	\$670,312
(b) Water	\$0.27 / 1,000 gal	\$6,129	\$15,323
(5) Raw Chemicals			
(a) Limestone (97% purity)	\$32 / ton including freight	--	\$101,313
(b) Hydrated Lime (74% purity)	\$140 / ton including freight	\$329,591	--
(6) Solid Disposal	\$27 / ton	\$108,892	--
(7) Sludge Disposal	\$27 / ton	--	\$117,397
Total DOC		\$1,507,709	\$2,257,806
INDIRECT OPERATING COSTS (IOC):			
(7) Overhead[1]	60% of operating labor & maintenance	\$305,115	\$547,888
(8) Property Taxes[1]	1% of total capital investment	\$116,498	\$219,103
(9) Insurance[1]	1% of total capital investment	\$116,498	\$219,103
(10) Administration[1]	2% of total capital investment	\$232,995	\$438,206
Total IOC		\$771,105	\$1,424,301
CAPITAL RECOVERY COST (CRC)	CRF of 0.1627 times TCI	\$1,895,415	\$3,564,808
ANNUALIZED COST (AC):	DOC + IOC + CRC	\$4,174,230	\$7,246,914

[1] Based on catalytic incinerators, from OAQPS Control Cost Manual, Fourth Edition.

[2] Based on maximum of 25% coal firing for the Flo–Energy cogeneration facility.

Table 5–5. Summary Results of the Top–Down BACT Analysis for SO2 for Flo–Energy Cogeneration Facility (Revised 11/30/92).

				Environmental Impacts		Energy Impacts	Economic Impacts			
Control Alternative	Total SO2 Emissions (TPY)	Total Emission Reduction (TPY)*	Incremental Emission Reduction (TPY)	Potential toxic air impact?	Potential adverse enviromental impacts?	Additional Energy Requirements Electricity (MW–hr/yr)	Total Annualized Cost ($/yr)*	Incremental Annualized Cost ($/yr)	Total Cost Effectiveness ($/ton)*	Incremental Cost Effectiveness ($/ton)
Flo–Energy Facility Only– Worst Case Year										
Wet Limestone Scrubber	81.2	1,542.4	48.7	No	Yes	7,900	$7,247,000	$3,073,000	$4,698	$63,090
Spray Dryer	129.9	1,493.7	681.9	No	Yes	3,800	$4,174,000	$1,613,000	$2,794	$2,365
Dry–Sodium Duct Injection	811.8	811.8	811.8	No	Yes	2,000	$2,561,000	$2,561,000	$3,155	$3,155
Baseline (0.7 Wt% S Coal Uncontrolled)	1,623.6	––	––	––	––	––	–––	–––	–––	–––
Flo–Energy and Sol–Energy Facilities Combined– Average SO2 Emissions										
Wet Limestone Scrubber	50	950	30	No	Yes	12,900	$12,033,000	$5,674,000	$12,666	$189,133
Spray Dryer	80	920	420	No	Yes	6,200	$6,359,000	$2,188,000	$6,912	$5,210
Dry–Sodium Duct Injection	500	500	500	No	Yes	3,300	$4,171,000	$4,171,000	$8,342	$8,342
Baseline (0.7 Wt% S Coal Uncontrolled)	1,000	––	––	––	––	––	–––	–––	–––	–––

* Total emission reduction, total annualized cost, and total cost effectiveness are based on comparison to the baseline case.

FDER Comment 8: Please provide an operation and maintenance plan to minimize emissions during filling and storage of ammonia. What controls will be used to capture any ammonia escaping from the storage tank's pressure relief valve?

Response 8: The filling and storage of ammonia will be performed according to the American National Standards Institute (ANSI) K-61.1-1989 guideline (title page and table of contents attached). This document contains safety procedures and basic rules for the storage and handling of anhydrous ammonia. Minimum construction specifications are included for the tank, piping, tubing, fittings, and the pressure relief valve. Safety procedures for filling and handling are included. Safety procedures for a spill, rupture or relief valve opening are also specified.

The pressure relief valve on the ammonia storage tank will open only during emergency conditions when the pressure in the tank exceeds specified levels. Under such conditions, the ANSI guideline recommends the use of water spray directed at the vapor cloud. The water spray can be applied via a fire hose.

Since ammonia is not considered a toxic or health related air pollutant, no further controls on the pressure relief valve are proposed. The potential for any emergency ammonia releases to cause nuisance odors is extremely low due to the remote location of the Flo-Energy site in regard to any residences or commercial development. Water sprays can adequately control any emergency ammonia releases.

ANSI
K-61.1-1989
Revision of
K61.1-1981

American National Standard Safety Requirements for the Storage and Handling of Anhydrous Ammonia

Secretariat
Compressed Gas Association, Inc.
1235 Jefferson Davis Highway
Arlington, VA 22202

CGA Pamphlet G-2.1 — 1989

Approved March 17, 1989
American National Standards Institute, Inc.

RTC-67

CONTENTS Page

Improved
ER&E THERMAL DeNO$_X$ Process

Exxon Research and Engineering Company (ER&E) has developed, and is offering for license, a non-catalytic process called THERMAL DeNO$_X$ for removing oxides of nitrogen (NO$_X$) from flue gas in stationary combustion sources. Recent improvements in the process now permit the attainment of higher deNO$_X$, better load following and lower equipment cost.

U.S. patents covering the THERMAL DeNO$_X$ process have been granted to ER&E. Applications for counterparts of these patents have been filed in a number of foreign countries and additional patents on related technology are pending.

	Completed	Under Construction
Japanese Industrial Boilers	4	
Japanese Utility Boilers	5	
Japanese Petroleum Heaters	4	
California Oil Field Steamers	5	
California Flat Glass Melting Furnace	1	2
California Petroleum Heaters	30	
California Utility Boiler	1	
California Industrial Boilers	3	
California Incinerators	3	11
California Wood-Fired Boilers	3	
German Coal-Fired Boilers	2	

Table I—THERMAL DeNO$_X$ Experience Summary

Table I summarizes the commercial-scale field experience that has been acquired to date with this process. NO$_X$ reductions of up to 90% have been demonstrated on an oil field steamer where favorable process conditions exist. DeNO$_X$ performance using earlier technology ranges from 50% to 70% for most oil- and gas-fired process heaters and steam boilers. Successful results have also been obtained on a municipal incinerator, a glass furnace and coal-fired utility boilers.

Development of an accurate kinetic model of the process chemistry has significantly expanded the understanding of the interaction of all parameters affecting performance, and permits accurate calculation of NO$_X$ reduction and unreacted ammonia. Substantially greater performance is now achieved through the use of an inexpensive wall injection system. These advances have resulted in deNO$_X$ performance of 70% to over 80% and better load following capability without the use of hydrogen. Lower cost installations are being accomplished by replacement of grid injectors with the new injection system design. In effect, THERMAL DeNO$_X$ now offers performance approaching that of competing flue gas treatment processes for many types of fired equipment, at lower cost and with reduced space requirements.

This brochure is intended to provide an overview of THERMAL DeNO$_X$, to assist those companies that may be concerned with their present or projected NO$_X$ emission levels, in the evaluation of NO$_X$ reduction options currently available commercially. A list of relevant publications is appended for those seeking additional background information on this general subject. Readers desiring specific technical assistance, or those interested in exploring the possibility of licensing ER&E THERMAL DeNO$_X$ technology, are invited to contact ER&E either by mail or phone as follows:

Technology Sales Division
Exxon Research and Engineering Company
P.O. Box 390, Florham Park, N.J. 07932 Phone: (201) 765-2615

Process Description

THERMAL DeNO$_X$ is a non-catalytic process based on the gas phase homogeneous reaction between NO$_X$ in flue gas and ammonia (NH$_3$) which produces nitrogen and water. In general, NH$_3$ is injected into the hot flue gas by means of either air or steam carrier gas at a point in the flue specifically selected to provide optimum reaction temperature and residence time. The following two equations describe the reactions which govern the overall process:

$$NO_X + NH_3 + O_2 + H_2O + (H_2) \rightarrow N_2 + H_2O \qquad (1)$$

$$NH_3 + O_2 \rightarrow NO_X + H_2O \qquad (2)$$

Equation (1) is the deNO$_X$ reaction. In the temperature range of 1600F (870C) to 2200F (1200C), the reaction occurs through the injection of NH$_3$ alone. Hydrogen (H$_2$) can also be injected along with NH$_3$ to extend the effectiveness of the deNO$_X$ reaction down to the range of 1300F (700C). As indicated by equation (2), NH$_3$ injected into high temperature flue gas above the range of the deNO$_X$ reaction, results in increased NO$_X$ and is thus counterproductive.

Detailed laboratory experiments have shown that there are no reactions between the THERMAL DeNO$_X$ process components and sulfur compounds in high temperature flue gas regions. Also, the injection of NH$_3$ does not cause SO$_2$ to undergo additional oxidation to SO$_3$.

Ammonia breakthrough in the THERMAL DeNO$_X$ process is extremely complicated because it depends upon the interaction of numerous factors. Because of its complexity, ammonia breakthrough must be evaluated for a particular fired equipment apparatus, and there are very few generalizations which can be made. Since breakthrough is linked to a certain degree to deNO$_X$ performance, fired equipment in which the time-temperature relationship is favorable to achieving high deNO$_X$ performance will also typically exhibit low NH$_3$ breakthrough. In cases where favorable conditions exist, it has been possible for ER&E to predict NH$_3$ breakthrough as low as 5 ppm. In any case, the placement of the injectors for a given time-temperature relationship and their mixing effectiveness are of prime importance in minimizing NH$_3$ breakthrough, and this is within the control of the deNO$_X$ system design which can be prepared by ER&E.

In practice, some of the injected NH$_3$ escapes reaction with the NO$_X$ and, as it cools with the combustion gases, it reacts with SO$_3$ and H$_2$O to form NH$_4$HSO$_4$, and (NH$_4$)$_2$SO$_4$. Laboratory as well as full-scale commercial test results show these sulfates to be harmless with respect to both corrosion and preheater fouling when the THERMAL DeNO$_X$ process is operated within the prescribed design specifications. Long-term tests conducted in two oil-fired boilers in Japan showed that these sulfate deposits are readily removed by periodic water washing.

Tests to determine the THERMAL DeNO$_X$ process applicability to coal burning boilers gave performance similar to oil and gas burning boilers. These tests were made on a 3M Btu/hr (0.9 MW) combustion system under the joint sponsorship of EPRI and ER&E and represented the first development step in the application of THERMAL DeNO$_X$ to coal-fired utility boilers. Subsequent installation of the process in two coal fired utility boilers in Germany have substantiated the application to coal fired units.

Process Modeling

Equations (1) and (2) summarize the overall effect of the deNO$_X$ reaction, but they do not reveal the complexity of interaction of numerous intermediate chain branching reactions involving certain key free radicals. A recently developed kinetic model has been successful in assessing the process chemistry and reaction rate constants for each of the intermediate chain branching reactions. The model has been verified by an extensive laboratory data bank and also agrees well with pilot plant data and commercial plant performance. This technology has enabled extension of the temperature window using NH$_3$ alone from under 1600F (870C) to over 2200F (1200C) under certain conditions of the other kinetic parameters. The model is being used to pinpoint the optimum flue gas temperature zone and ammonia injection rate for specific applications. The model also permits accurate prediction of unreacted ammonia.

The kinetic model calculations represent the maximum possible deNO$_X$ performance for the process under a given set of flue gas conditions. Performance may be lowered in a real system due to one or more of the engineering design or unit specific parameters including mixing, carrier rate, flue gas temperature and velocity gradients, and staged injection. The influence of each of these parameters has been the subject of considerable research and development. Mixing effectiveness of grid injectors has been increased such that it is possible to achieve 95-100% of the kinetic limit performance. Wall injector mixing can now be optimized for a specific geometry by utilizing a recently field-validated three-dimensional flow modeling technique.

Application Engineering

The original THERMAL DeNO$_X$ applications involved positioning an injection grid within the flue gas stream at the proper flue gas temperature for injecting a mixture of NH$_3$ and carrier steam or air. Sometimes, multiple grids and/or hydrogen were employed to achieve some load following, but this increased the complexity and cost of the installation. Also, there was concern over the long term operability of the grid, particularly in corrosive, erosive or heavy fouling flue gas streams such as occur with coal-firing. In most applications today, the injection grids are being superseded by wall injectors consisting of large jets located at or near the boundary walls of the injection zone. The advantages of wall injectors are listed in Table II.

- Higher Performance
- Lower Investment Cost
- Better Load Following
- Lower Fouling Tendency
- No Cooling Requirement
- Simple Installation
- Easily Retrofitted
- Greater Cost Effectiveness

Table II—Advantages of Wall Injectors

The wall injectors are simple and relatively inexpensive, but require careful design and placement in order to achieve optimum process results. They are not subject to overheating upon loss of carrier, corrosive attack, or collection of fuel ash deposits such as may result with a grid injector design when firing heavy fuel oil, coal or refuse. These factors permit location of the injectors at the optimum flue gas temperature, even within the combustion zone of fired equipment. To accommodate turndown operation, two sets of injectors may be used with little impact on overall cost. Through proper location of the injectors to cover the load range, the need for hydrogen injection to promote low temperature performance is eliminated. In addition, if flue gas temperatures during operation of a unit are substantially different from those anticipated in the design, the wall injectors may be relocated during a short outage. Wall injectors may be retrofitted to an existing boiler without relocating ducting, air preheaters, stacks, etc. and with minimal impact on the boiler structure. All of these factors contribute to a THERMAL DeNO$_X$ technology which is practical, highly efficient and cost effective.

While the wall jet injectors do offer substantial benefits over injection grids, they also pose a challenging problem in achieving adequate mixing, especially in very large fired equipment. This has spurred development of a three-dimensional, turbulent flow modeling technique. Use of this tool, coupled mathematically with the kinetic model, permits the direct calculation of deNO$_X$ performance for any geometry, flow condition and temperature profile.

The modeling technique has been validated by field testing of a boiler located in Kawasaki, Japan. The test unit is a 440,000 lb/hr (200 ton/hr) oil- and gas-fired power boiler. This is a typical front-fired, waterwall boiler where flue gases exit the burners in the lower part of the combustion chamber, pass upward over a small arch and into the superheater zone. Flue gases then turn downward through the steam generating tube bank and exit to the air preheater.

The ammonia injectors are arranged in three zones. Zone 1 enters through the roof upstream of the primary superheater. Zone 2 enters through the roof in the cavity between the primary and secondary superheater. Zone 3 enters the lower part of this same cavity through the sidewalls.

Field data and calculated performance results for this boiler are illustrated in Figures 1, 2, 3 and 4. In Figure 1 performance results are provided for 80, 90 and 100% load. Performance results were obtained by first testing individual injection zones and then testing combinations of zones to determine which operating conditions yield optimum performance. Zone settings for NH$_3$ and carrier rates were guided by performance calculations and modeling results.

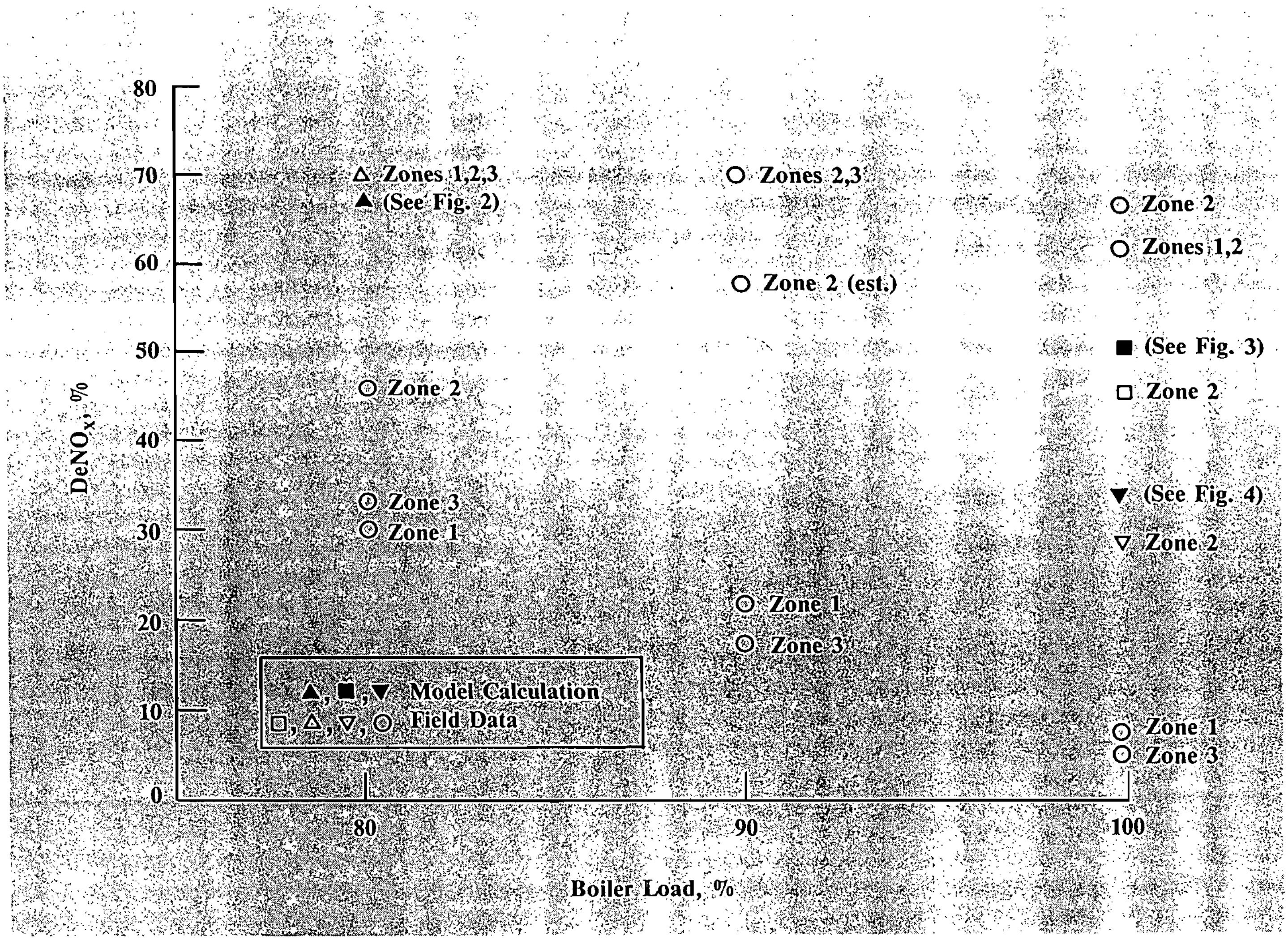

Figure 1. THERMAL DeNO$_x$ Test Results for Kawasaki Boiler

Optimized performance for the three test loads of 80, 90 and 100% are 70, 70 and 65% deNO$_x$, respectively. At 100% load optimized performance is achieved by operating Zone 2 alone. At 90% load optimized performance is achieved by simultaneously operating Zones 2 and 3, and at 80% load optimized performance is obtained by operating all three zones. The individual zone data show that Zone 2 achieves its maximum effectiveness at full load and decreases in effectiveness as load is reduced. On the other hand, Zones 1 and 3 are ineffective at full load, but increase in effectiveness as load is reduced. This multizone design technique can be utilized to achieve essentially constant performance over a wide load range. Figure 2 is a modeling result for the 3-zone operation at 80% load which predicts 67.5% deNO$_x$ vs. the 70% indicated by field data.

It was desirable to optimize performance in the range of 30-50% deNO$_x$ since it is unnecessary to achieve high NO$_x$ reduction except during pollution emergencies. Figures 3 and 4 illustrate modeling results at 100% load for 50% and 30% deNO$_x$ respectively, utilizing only the Zone 2 injectors. The Figure 3 results are for a relatively high injection velocity which yields an outlet NO$_x$ concentration of 92 vppm (184 mg/m^3). In Figure 4 the jection velocity is relatively low and the indicated outlet conc tration is 126 vppm (252 mg/m^3). These modeling results w verified by field testing with a maximum variation betw calculated results and field data of ±7%. Thus, in the 80-10 load range, this boiler may operate with a single zone of inj tors making adjustments to carrier and NH$_3$ rate as required meet emission targets.

Generally, the first step in determining the feasibility of a pot tial THERMAL DeNO$_x$ installation is the preliminary estin tion of overall applicability, cost and NO$_x$ reducing capabili ER&E's application engineers can provide these prelimin estimates from a review of the original equipment design specifi tions. More accurate estimates can be obtained on the basis measured temperature profiles and other field data. Individual p cess designs are also derived from such data. ER&E person can provide recommendations for designing new equipment well as for modifying existing equipment in order to maxim overall process efficiency.

Cost Effectiveness

In order to illustrate the cost effectiveness of the THERMAL $DeNO_X$ process, a 200,000 lb/hr (91 ton/hr) oil- or gas-fired industrial boiler has been selected for detailed analysis. Figure 5 shows the corresponding flow schematic of the THERMAL $DeNO_X$ supply system, which is sized on the basis of the values presented in Table III. It is assumed that the boiler has an uncontrolled NO_X effluent of 200 vppm (400 mg/m^3) corrected to 3% O_2 dry and that it will be equipped with two sets of injectors for injecting NH_3 via a steam carrier. Provision for a one-month NH_3 supply storage facility is also assumed in this analysis.

The total erected capital investment for these facilities is estimated to be \$470k as outlined in Table IV. Direct costs include the material and labor for equipment outlined in Table III plus interconnecting piping. Indirect costs include field labor overheads, construction supervision and equipment, labor wage taxes, erection fee and engineering costs. Costs are expressed on 3Q86 basis at Southern California location. Excluded from these costs are such items as land, owners' charges and licensing royalty.

Cost effectiveness for the sample boiler installation is also shown in Table IV for three different bases. Annualized costs are obtained by assuming a five-year payout on investment plus annual operating costs. On a heat-fired basis, cost effectiveness of the process is \$0.13 per MBtu (0.44 \$/MWh). The cost effectiveness based on NO_x removed is 1.22k\$/US ton (1.34 \$/kg) NO_2 for a $deNO_X$ efficiency of 70% and 1.06k\$/US ton (1.17 \$/kg) NO_2 for 80% $deNO_X$. This cost compares favorably with some combustion modification techniques, such as burners out of service and flue gas recirculation, and is substantially lower than selective catalytic reduction.

Annual operating costs are shown in Table V. These costs are based on a 65% annual load factor and include values for NH_3, power and steam consumption, and maintenance material and labor.

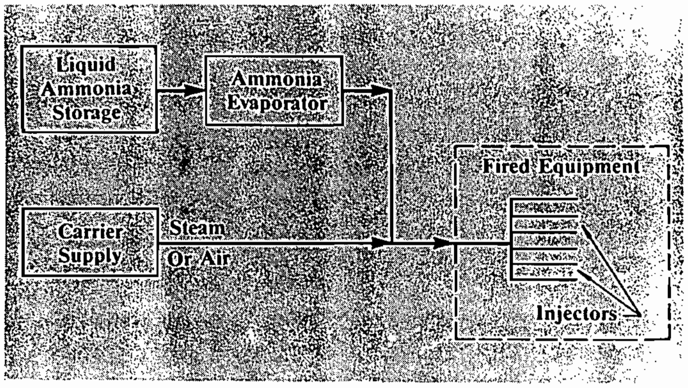

Figure 5—Simplified THERMAL $DeNO_X$ Supply System Flow Diagram

Capital Investment[(1)]	
Material and Labor[(2)]	\$190k
Indirect Costs[(3)]	\$280k
	\$470k
Cost Effectiveness:	
\$/MBTU Fired (\$/MWh)	0.13 (0.44)
k\$/US Ton (\$/kg) NO_X Removed @ 70% $DeNO_X$	1.22 (1.34)
k\$/US Ton (\$/kg) NO_X Removed @ 80% $DeNO_X$	1.06 (1.17)

Notes:
(1) Investment costs are expressed at 3Q84 Southern California level
(2) Includes equipment items listed in Table III plus interconnecting piping
(3) Includes field labor overheads, construction supervision and equipment, labor wage taxes, erection fee, contractor engineering and Exxon Research and Engineering Co. charges. Excluded are such items as land, owners charges and licensing royalty.

Table IV—THERMAL $DeNO_X$ Investment Cost and Cost Effectiveness for Sample Industrial Boiler

Boiler Design Conditions
200,000 lb/hr, 615 PSIG, 700F

Fuel	Oil or Gas
Initial NO_X	200 vppm (400 mg/m^3)
NH_3/NO_X	2.0 = 0.174 lb NH_3/lb NO_x
Carrier Requirement	Steam, 1500 lb/hr (680 kg/hr)
NH_3 Storage Tank	30 Day Storage Capacity (8000 US gallons = 30.3 m^3)
NH_3 Vaporizor	(1) Electric Element, Direct Contact
Injectors	Two Locations
Instrumentation	As Required

Table III—Equipment Sizing Basis for Permanent THERMAL $DeNO_X$ Facilities For Sample Industrial Boiler

Item	Annual Consumption(1)	Unit Cost	Annual Cost
Ammonia(2)	181 US Tons	\$250/Ton	\$45,250
Electric Power(3)	55 MWh	\$75/MWh	4,125
Steam(4)	4290 US Tons	\$12/Ton	51,480
Maintenance Material and Labor(5)			13,300
		Total	\$114,155

Notes:
(1) Assumes 65% load factor
(2) Includes ammonia for direct injection
(3) Includes power requirement for ammonia vaporizer
(4) Low pressure steam (15 psig = 1 barg minimum) for carrier
(5) Assumed to be 7% of direct investment cost

Table V—THERMAL $DeNO_X$ Annual Operating Cost for Sample Industrial Boiler

Summary

In summary, the THERMAL $DeNO_x$ process offers one of the most practical and cost-effective approaches to significant NO_x reduction from stationary fired equipment of any post-combustion NO_x removal process currently on the market. This is due to the fact that the process is far less capital intensive and its NO_x reduction capability approaches that of other, more costly processes.

Recent technological advances have resulted in significant increases in THERMAL $DeNO_x$ performance along with decreases in equipment cost, thus further improving its cost effectiveness. No technological difficulties are foreseen in applying the THERMAL $DeNO_x$ process to all types of fired equipment, including those that are coal-fired. ER&E stands ready to work with potential users of this technology and/or their consultants to evaluate specific application situations.

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Basic Chemistry

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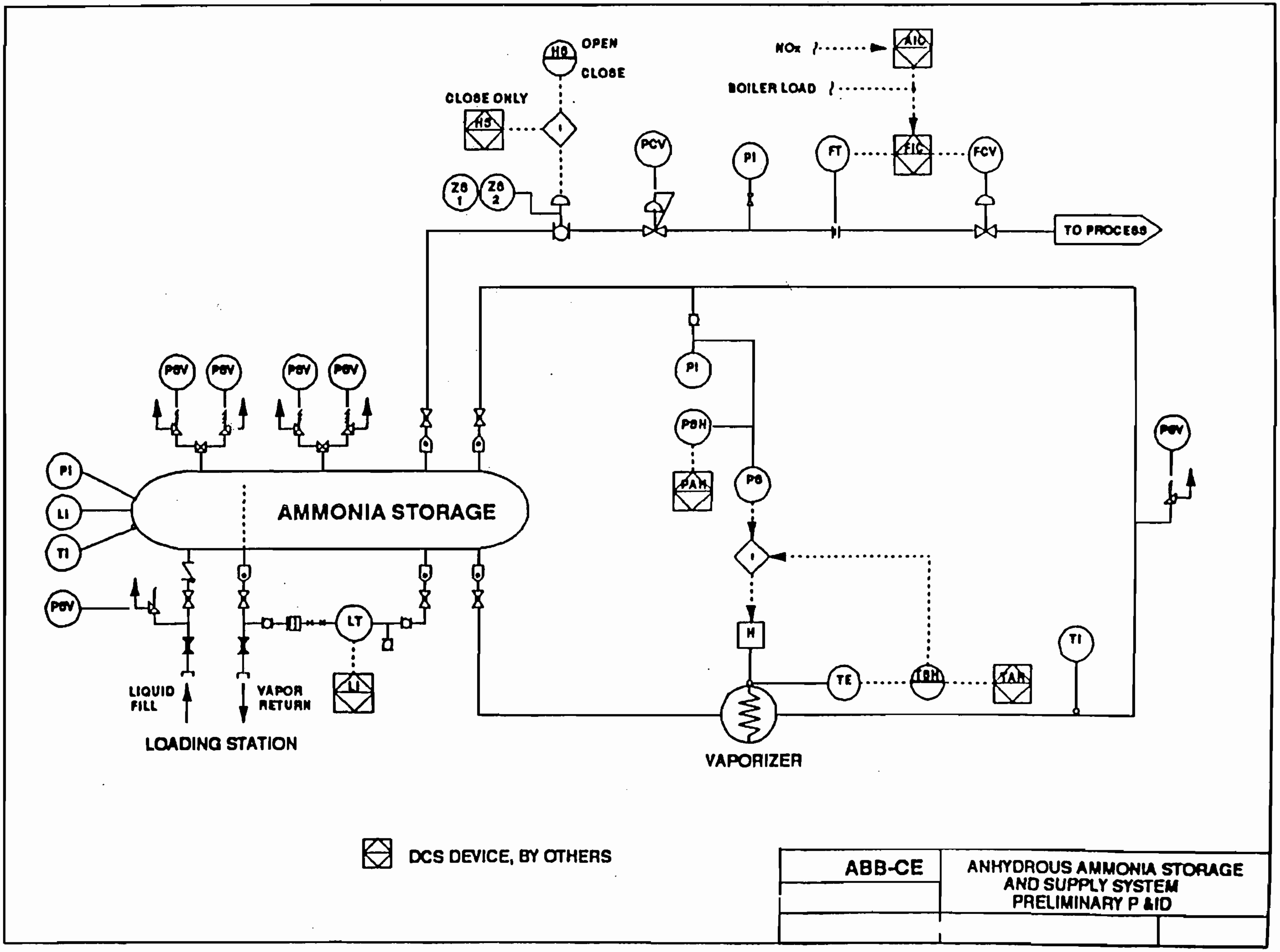
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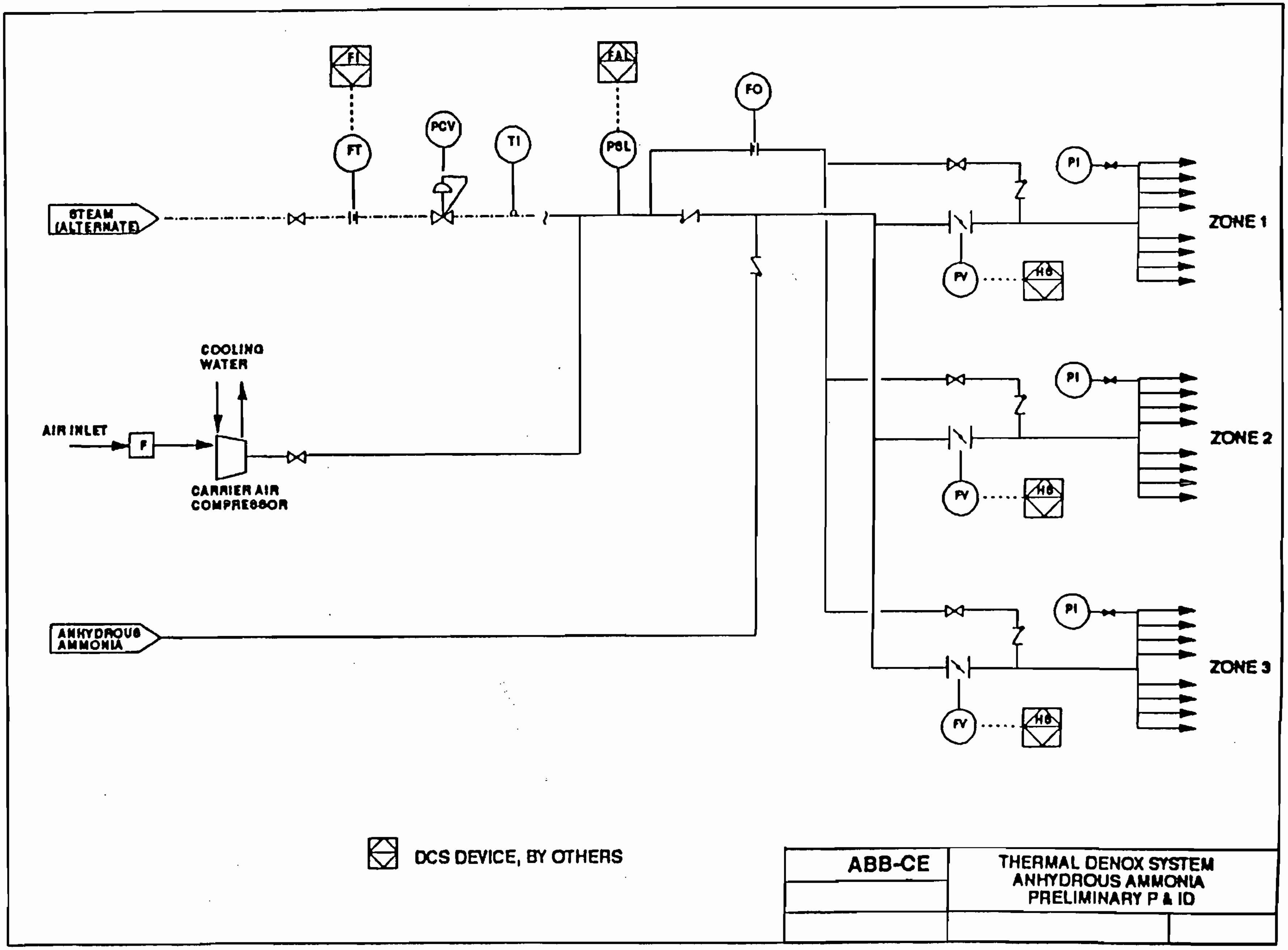
VAPORIZER
DCS DEVICE, BY OTHERS
ABB-CE
ANHYDROUS AMMONIA STORAGE AND SUPPLY SYSTEM PRELIMINARY P &ID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PSL
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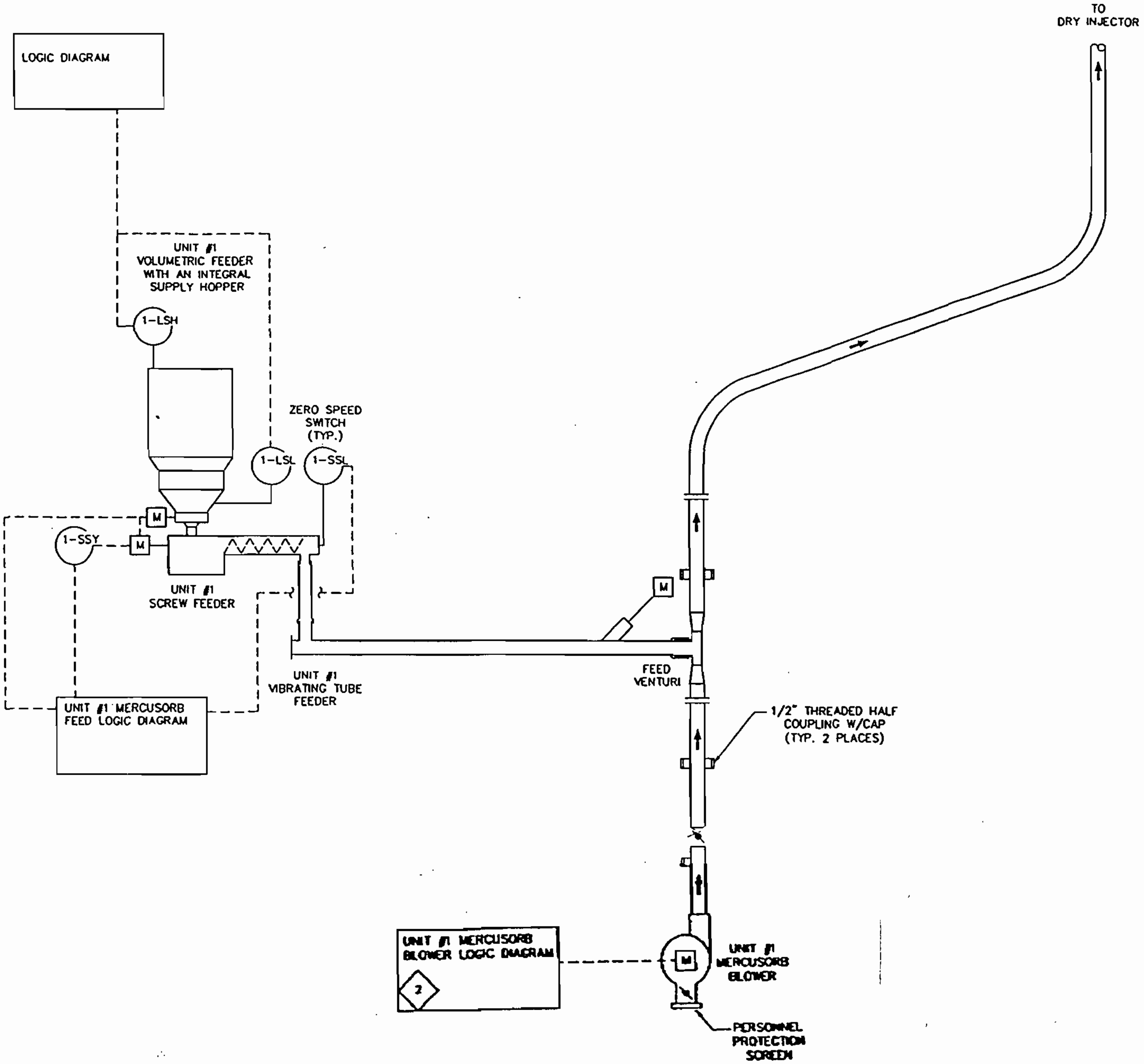
STEAM (ALTERNATE)
ZONE 1
FV
HS
COOLING WATER
AIR INLET
F
CARRIER AIR COMPRESSOR
PI
ZONE 2
FV
HS
ANHYDROUS AMMONIA
PI
ZONE 3
FV
HS
DCS DEVICE, BY OTHERS
ABB-CE
THERMAL DENOX SYSTEM
ANHYDROUS AMMONIA
PRELIMINARY P & ID

Mercury Control System

A schematic of a proposed mercury control system from Research-Cottrell is attached. The system would be similar to that installed on municipal waste incinerators. A volumetric feeder with integral supply hopper would meter activated carbon for injection at a point upstream of the ESP and ID fan to promote turbulent mixing and provide adequate residence time. A blower system would transport the carbon to the injection point. The ESP will effectively capture the activated carbon particles along with the boiler flyash (which also contains some carbon). No adjustment to the size of the ESP is envisioned since the activated carbon particles will be relatively large in size and small in amount compared to the flyash. No increase in stack particulate emissions is expected.

Given that the inlet mercury concentration on a biomass and coal-fired boiler would be very low, it is difficult to estimate carbon requirements. At the Stanislaus County MSW incineration facility, EPA has conducted one of the most extensive studies to date on the injection of activated carbon for mercury control. Carbon feed rates were varied between 2.8 lb/hr and 12.1 lb/hr, which equated to approximately 25 to 110 pounds of carbon per pound of mercury in the incoming flue gas. Mercury removal rates ranged from 53 to 85 percent at the lower injection rate, and from 88 to 98 percent at the higher injection rate. Inlet mercury flue gas concentrations ranged from 300 to 1,300 μg/dscm at 7 percent O_2.

To conservatively estimate carbon injection design rates for the proposed facility, the maximum indicated carbon injection rate of 110 lb/lb of mercury from Stanislaus was used. For each boiler, the maximum mercury emissions occur when burning coal at 490 MMBtu/hr, and maximum mercury emissions based on 30 percent control are 0.0041 lb/hr. Therefore, uncontrolled mercury emissions would be 0.0059 lb/hr. The calculated carbon injection requirement would then be 0.6 lb/hr. Based on this calculation, the proposed system will be designed to inject at least 1.0 lb/hr of carbon into each boiler. Flo-Energy will continue to evaluate the status of research concerning carbon injection for mercury control. A larger injection system will be implemented if final engineering demonstrates higher carbon injection rates are needed.


TO
DRY INJECTOR
LOGIC DIAGRAM
UNIT #1
VOLUMETRIC FEEDER
WITH AN INTEGRAL
SUPPLY HOPPER
1-LSH
ZERO SPEED
SWITCH
(TYP.)
1-LSL
1-SSL
M
1-SSY
M
UNIT #1
SCREW FEEDER
M
UNIT #1
VIBRATING TUBE
FEEDER
FEED
VENTURI
1/2" THREADED HALF
COUPLING W/CAP
(TYP. 2 PLACES)
UNIT #1 MERCUSORB
FEED LOGIC DIAGRAM
UNIT #1 MERCUSORB
BLOWER LOGIC DIAGRAM
2
M
UNIT #1
MERCUSORB
BLOWER
PERSONNEL
PROTECTION
SCREEN

Operation and Maintenance Plan

Since final equipment selection has not been completed, it is premature to develop an operation and maintenance (O&M) plan for the air pollution control equipment. However, Flo-Energy would be agreeable to a permit condition which would require an O&M plan to be submitted at least 90 days prior to beginning operation, or within 6 months of final equipment selection, whichever occurs first.

<u>FDER Comment 6</u>: Please provide drawings of all storage and material handling equipment (biomass, coal, bagasse, fly ash, carbon, etc.) with notations of how fugitive particulate matter emissions from hauling the material to the plant to disposing of any waste will be controlled. Include a table similar to Table 2-8 to show the fugitive emissions from these materials. Clarify how the ash for coal will be kept separate from the ash produced by the biomass.

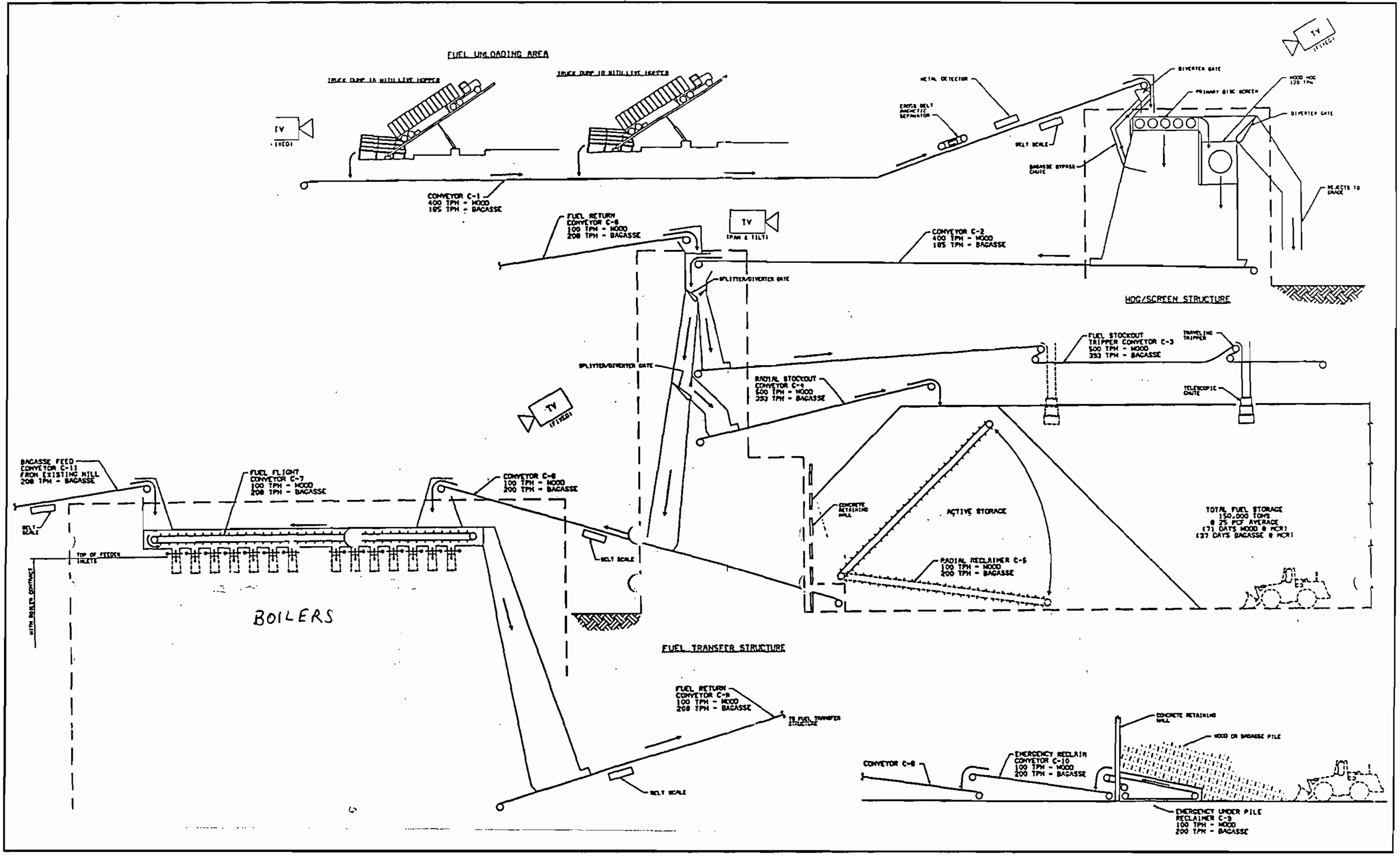
<u>Response 6</u>: A diagram of the biomass/coal handling facilities is presented in the attached figure, entitled, Schematic of Fuel Handling System. Elevation views of the conveyor belts and transfer points are shown in the second figure, entitled, Elevation View of Fuel Handling System. Biomass will be delivered to the facility by conveyor belt (directly from the sugar mill) or by truck. The trucks will discharge the material into a dump hopper. The truck dump hopper will be open, but all subsequent conveyor belts will be covered and transfer points will be partially enclosed. From the dump hoppers, the biomass will be placed on a conveyor belt, pass through the hogger (crusher), and be placed on another conveyor to the transfer tower. From the transfer tower, the material can be fed to the boilers or directed to the fuel storage yard. If directed to the boilers, the material will be transferred from a conveyor belt to the fuel flight conveyor and then to the boiler feeders. Fuel will be delivered to the fuel yard via a stacker, and reclaimed by underpile reclaimer or by an overpile reclaimer device. To estimate worst case emissions, underpile reclaiming is assumed, which maximizes vehicular traffic in the fuel yard.

Bottom ash will be handled in a wet state and therefore emissions should not occur. Fly ash will be handled in an enclosed manner and will be delivered to enclosed dumpsters via a drop tube, or, as an alternative, will be first conditioned and then stored in open bins. Since the ash will be stored in dumpsters, it is very simple to segregate the coal ash from the biomass ash. Whenever coal firing commences, any ash placed in the dumpsters from that point on will be treated as coal ash. This will continue until such time as coal firing ceases and coal ash clears the system. Once specific ash handling equipment has been selected, the maximum time for ash to clear the system can be calculated. To provide assurance that coal ash is not mixed with biomass ash, Flo-Energy will continue to handle the ash during this time, plus an additional two hours, as coal ash.

All potential fugitive dust emission points are identified in Tables 2-7 and 2-8 attached. Table 2-7 and 2-8 have been revised to include the biomass transfer points. Worst case fugitive particulate emissions have been estimated by assuming the maximum amount of biomass to be burned is brought in by truck, proceeds to the fuel storage area (storage piles), and then is reclaimed and sent to the boilers. The estimated fugitive dust emissions do not consider any enclosures on the conveyor belts or transfer points (i.e., zero control efficiency has been assumed). Pile maintenance emissions are based on one vehicle operating 12 hours per day at an average speed of 5 mph (21,9000 VMT per year). Wind erosion emissions are based on the assumption that the entire fuel storage area contains biomass.

The fugitive emissions due to biomass handling are then added to the fugitive particulate emissions due to coal handling to estimate total emissions. Based on this very conservative methodology, the maximum estimated total fugitive PM (TSP) emissions are 11.122 TPY and the fugitive PM10 emissions are 3.982 TPY. Based on these changes, Table 3-3 of the permit application has been revised and is attached.

11-26-92



RTC-47

SCHEMATIC OF FUEL HANDLING SYSTEM

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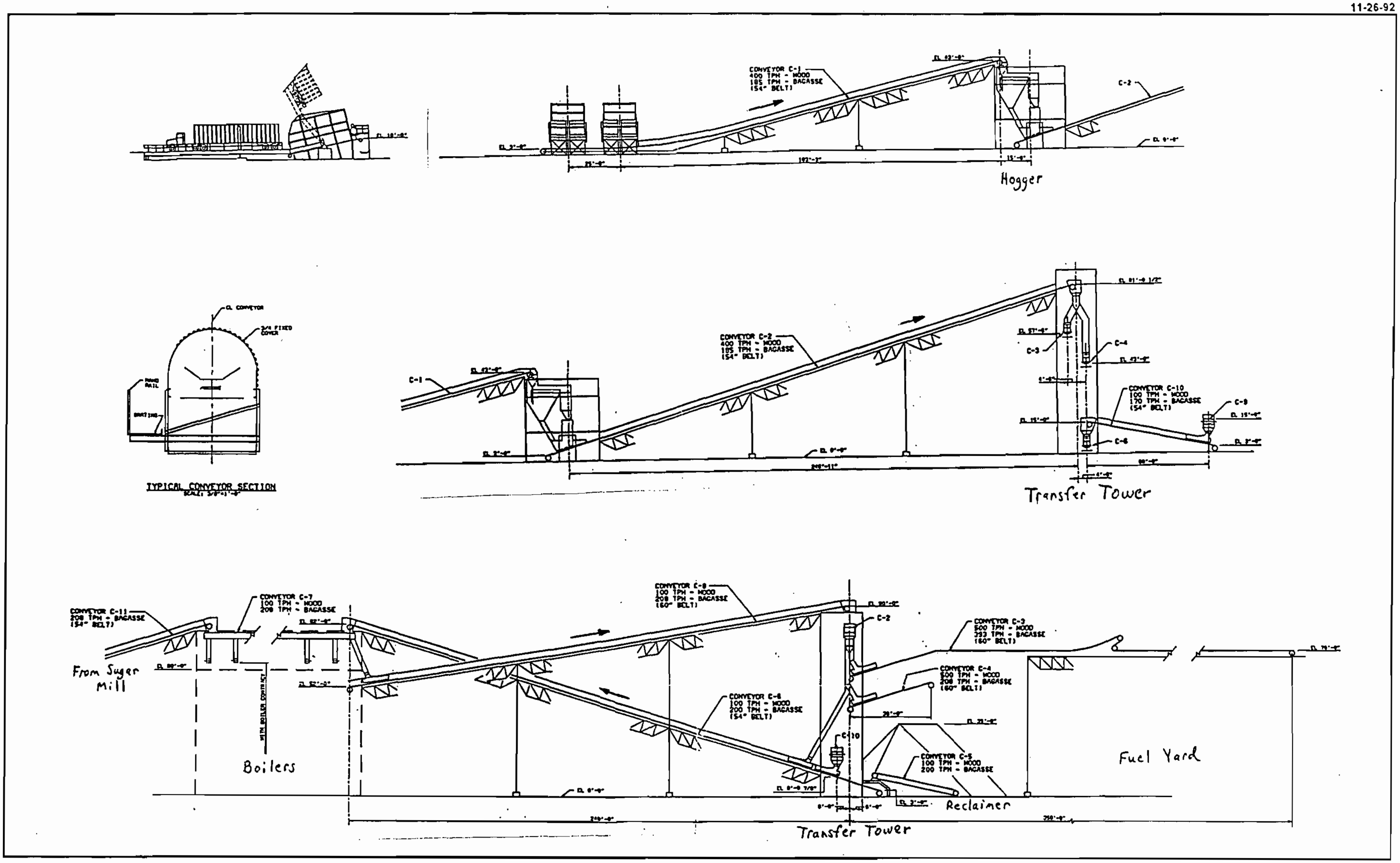


RTC-48

ELEVATION VIEW OF FUEL HANDLING SYSTEM

KBN

Table 2-7. Flo-Energy Cogeneration Facility Annual Average Uncontrolled Fugitive Emission Factors (Revised 11/17/92)

Source	Type of Operation[a]	M Moisture Content (%)	U Wind Speed (mph)	E Emission Factor (lb/ton)
Coal Handling				
Railcar Unloading	Batch Drop	4.5	9.4	0.00234
Conveyor-to-Coal Pile	Batch Drop	4.5	9.4	0.00234
Underpile Reclaim Hopper	Batch Drop	4.5	9.4	0.00234
Conveyor-to-Crusher	Batch Drop	4.5	9.4	0.00234
Coal Crusher	Coal Crushing	--	--	0.02 [b]
Crusher-to-Conveyor	Batch Drop	4.5	9.4	0.00234
Conveyor-to-Boiler Feeders	Batch Drop	4.5	9.4	0.00234
Storage Pile	Wind Erosion	--	--	-- [c]
Coal Pile Maintenance	Vehicular Traffic	--	--	0.90328 [d]
Biomass Handling				
Truck Dump	Batch Drop	37	9.4	0.00012
Hopper-to-Conveyor	Batch Drop	37	9.4	0.00012
Conveyor-to-Hog Tower	Batch Drop	37	9.4	0.00012
Hogger	Crushing	--	--	0.02
Hogger-to-Conveyor	Batch Drop	37	9.4	0.00012
Transfer Tower	Batch Drop	37	9.4	0.00012
Conveyor-to-Stacker	Batch Drop	37	9.4	0.00012
Stacking	Batch Drop	37	9.4	0.00012
Underpile Reclaim	Batch Drop	37	9.4	0.00012
Reclaimer-to-Conveyor	Batch Drop	37	9.4	0.00012
Transfer Tower	Batch Drop	37	9.4	0.00012
Conveyor-to-Boiler Feeders	Batch Drop	37	9.4	0.00012
Biomass Storage Pile	Wind Erosion	--	--	--
Biomass Storage Pile Maintenance	Vehicular Traffic	--	--	0.90328 [d]
Fly Ash Handling				
Fly Ash Transfer	Batch Drop	2.0	9.4	0.00727

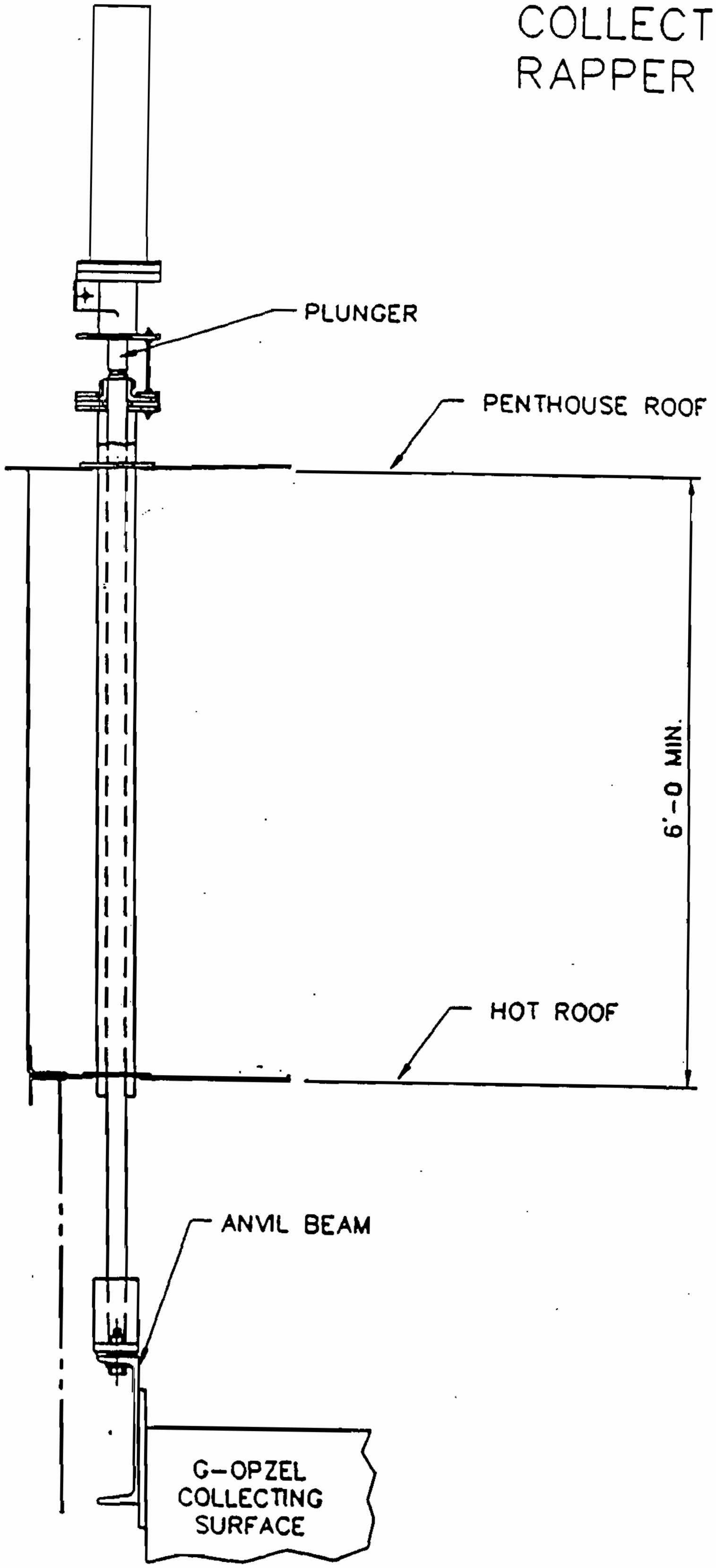
[a] Batch drop emission factors are computed from AP-42 (EPA, 1988) Section 11.2.3 $E = 0.0032 \times (U/5)^{1.3} / (M/2)^{1.4}$ lb/ton.

[b] Emission factor for coal crusher computed from AP-42 Table 8.23-1, for high moisture ore.

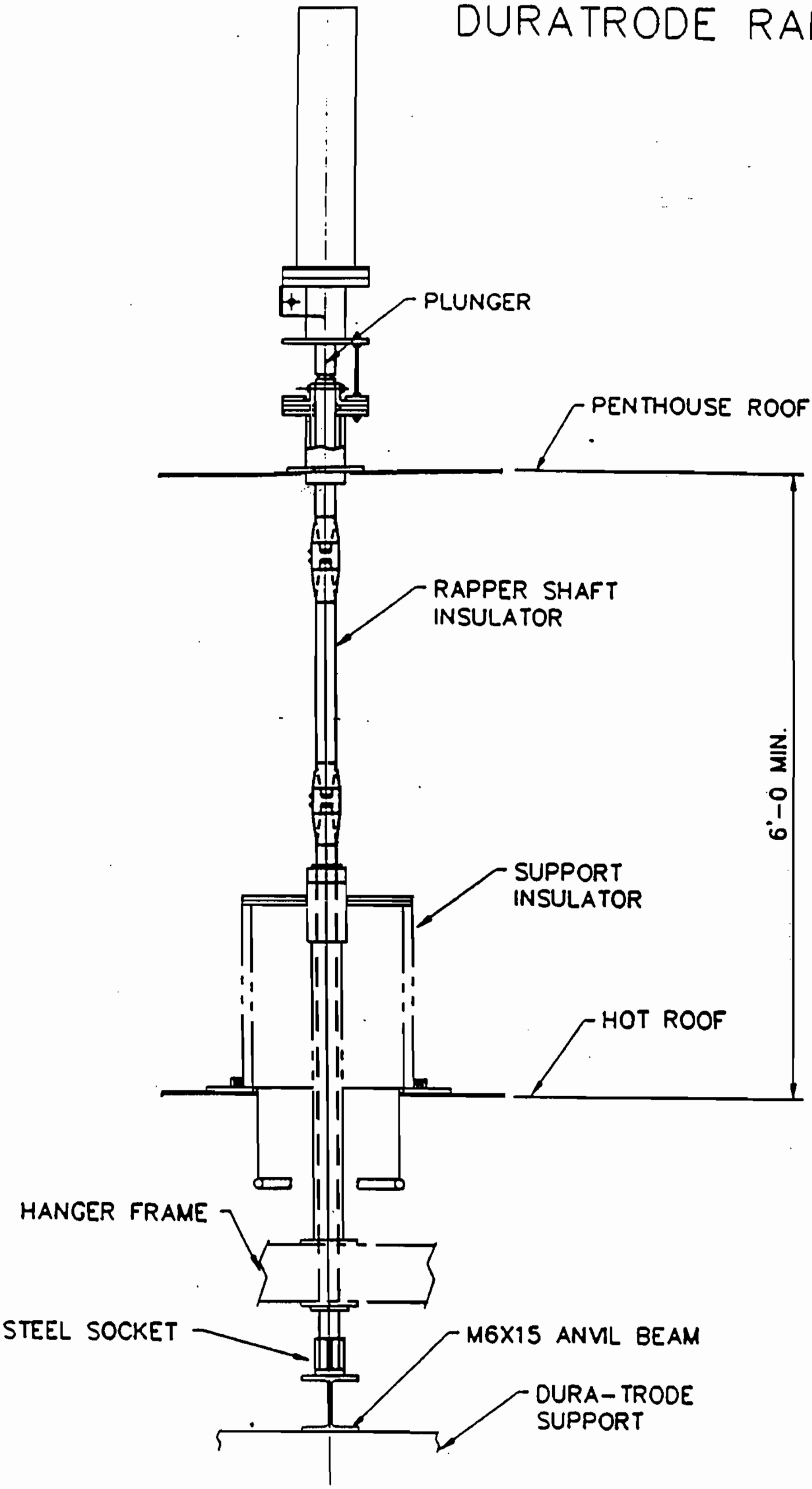
[c] Emission calculations provided in Appendix A.

[d] lb/vehicle mile traveled based on AP-42 Section 11.2.1. Silt = 2.2, W = 53.

COLLECTOR PLATE RAPPER TRAIN



DURATRODE RAPPER TRAIN



Research-Cottrell
Air Pollution Control Division

Transformer-Rectifier

Research-Cottrell manufactures transformer-rectifier units specifically designed for electrostatic precipitator applications. In-house quality control, in which all units are tested prior to shipment, and a conservative rating have produced an outstanding record of operating reliability.

Description

Transformer type—Liquid immersed, convection cooled, designed for outdoor installation.

Dielectric fluid—Mineral oil RTEmp™ or silicone fluid, with visual indicator.

Rectifier type—Silicon diode, immersed in dielectric fluid, full wave or optional double half-wave bridge configuration.

Rectifier transient protection—Rectifier stack contains transient suppression voltage equalization networks. A high frequency choke in the high voltage output leg protects all components from connected load transients.

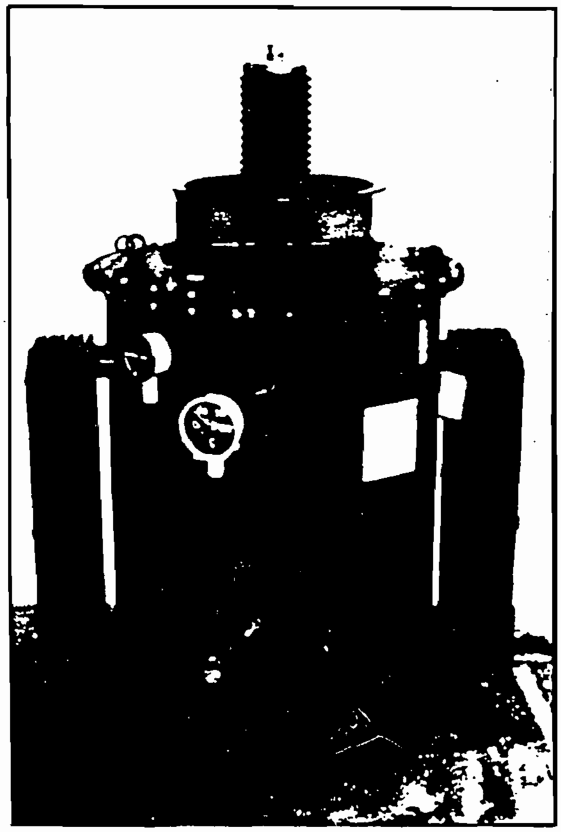
Temperature—Maximum continuous temperature range of −40 °C to +50 °C. Thermowell provided as standard.

Electrical connections—Molded epoxy low voltage and instrumentation bushings; glazed porcelain high voltage output bushing.

Inspection—Bolted hand hole provided for inspection and internal servicing.

Bushing enclosure—Steel weatherproof enclosure, with observation window. Externally mounted, key-interlocked ground switch prevents access to transformer-bushings and precipitator internals unless ground switch is in the grounded position. The transformer-rectifier is also key-interlocked with its control cabinet to prevent grounding when energized. A high voltage danger sign and a sign warning against operating without a load are provided.

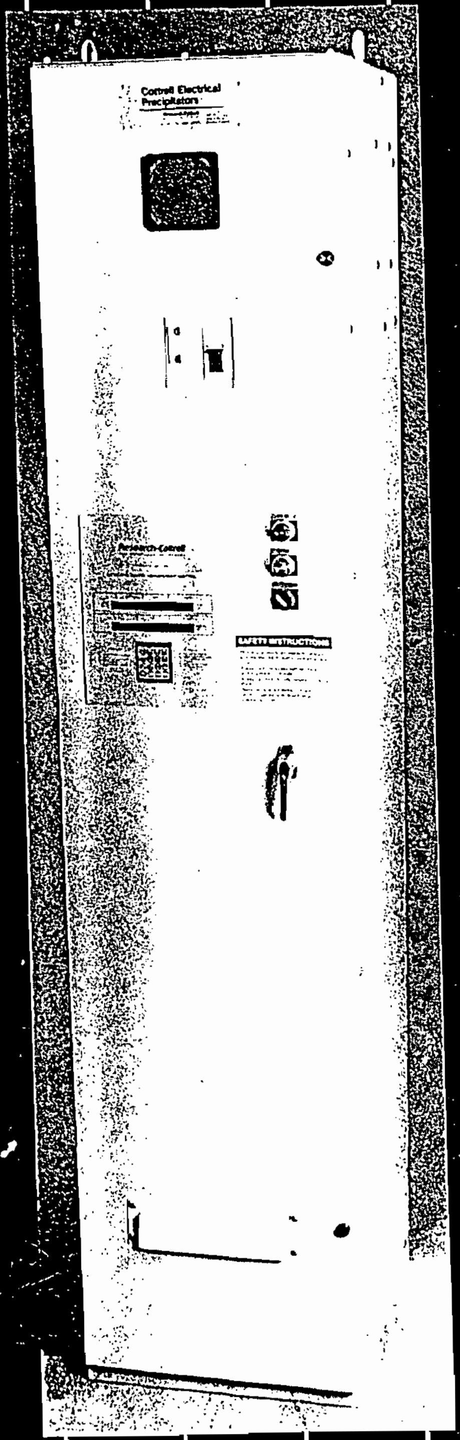
High voltage bus—Black iron pipe completely enclosed in a grounded steel tubular guard. Conductor is terminated with gastight, glazed, feed-through insulators at output end. For inspection, there is a bolted access plate at each insulator location.



March 1986

Research-Cottrell The Clean Air Company℠

Technical Bulletin



Microprocessor Transformer-rectifier Controls For Electrostatic Precipitators

Maximum precipitator collection efficiency can only be achieved if optimum levels of charging and collecting energy are provided at all times. Research-Cottrell's Microprocessor Transformer Control (MTC™) is designed to maintain maximum useable precipitator energy by monitoring and automatically controlling electrical variables.

The MTC is an advanced microprocessor energization system designed specifically for electrostatic precipitators. It continuously and automatically adjusts to conditions such as changing boiler loads, variable fuel supplies, and upset situations without readjustment.

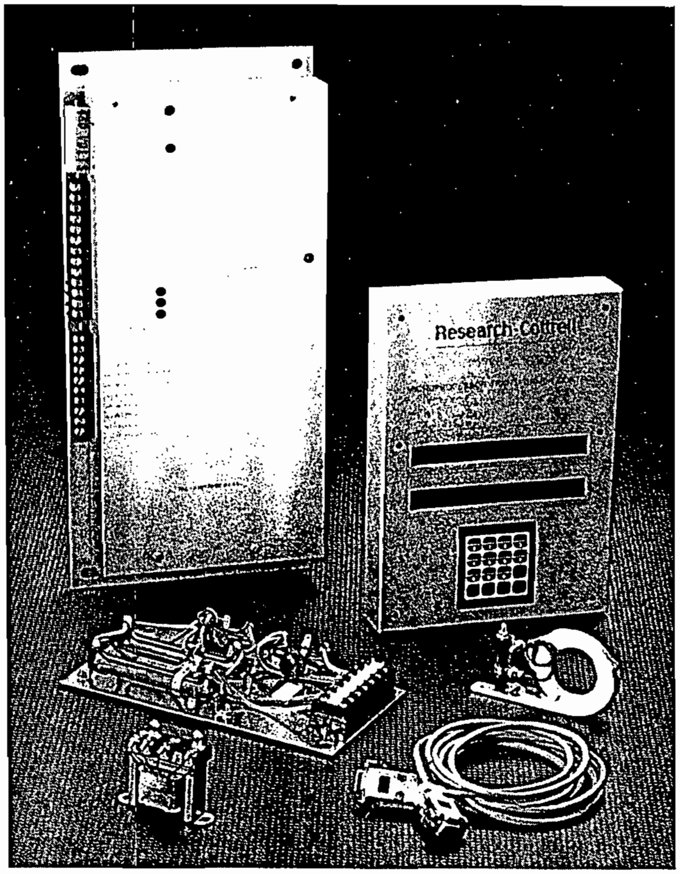
These controls are designed for field installation into existing Research-Cottrell control cabinets as well as precipitator control cabinets manufactured by others. It takes about four hours to convert SCR type cabinets to the MTC system. New control cabinets incorporating the MTC system can also be provided for adding more controls and transformers to existing precipitators.

Control Parameters

The following describes the programmable control parameters of the MTC system.

Primary voltage limit - limits the primary voltage level of the transformer preventing the transformer-rectifier from operating above its voltage rating.

Primary current limit - limits the primary current level of the transformer preventing the transformer-rectifier from operating above its primary current rating.



The two main components of the backfit package (for installing the MTC system into existing control cabinets) are the Interface Board (top left) and Microprocessor Module (top right). Also shown are the signal conditioning resistor panel, current transformer, potential transformer and interface cable.

Secondary voltage (KV) limit - prevents the transformer-rectifier from operating above its secondary voltage rating.

Secondary current limit - prevents the transformer-rectifier from operating above its secondary current rating.

Peak secondary voltage limit - limits transformer peak secondary voltage, protecting the transformer-rectifier from damage due to excessive voltages with Intermittent Energization.

Peak secondary current limit - limits transformer peak secondary current, protecting the transformer-rectifier from damage due to excessive currents with Intermittent Energization.

Undervoltage trip - de-energizes the control and transformer if the primary voltage drops below a programmed value and the current is greater than 20% of rated current. This protects precipitator internals from damage due to localized heating generated by high resistance grounds, reduces clinker formation, and reduces the chance of support insulator failure due to electrical tracking.

Phase back - controls the amount of power reduction after each spark. Since sparking is actually self-extinguishing, the power is reduced to ensure against repetitive sparking or bursting (and discharge electrode erosion).

Ramp rate - controls the rate of power recovery after a phase back. Power recovery starts at the phase back level and continues until either rated power or another spark or arc occurs.

Quench - interrupts power for a programmable time period after an arc occurrence. The control can be programmed to quench for sparks as well as arcs.

Pedestal rate - controls the rate of power recovery after each quench. This reduces the amount of arcing that occurs while maintaining a high level of useable precipitator power.

Percent power - limits maximum operating power for manual energy management or special operating conditions. Once programmed for a power limit the control will not exceed the chosen limit. In the percent power mode all automatic features remain active.

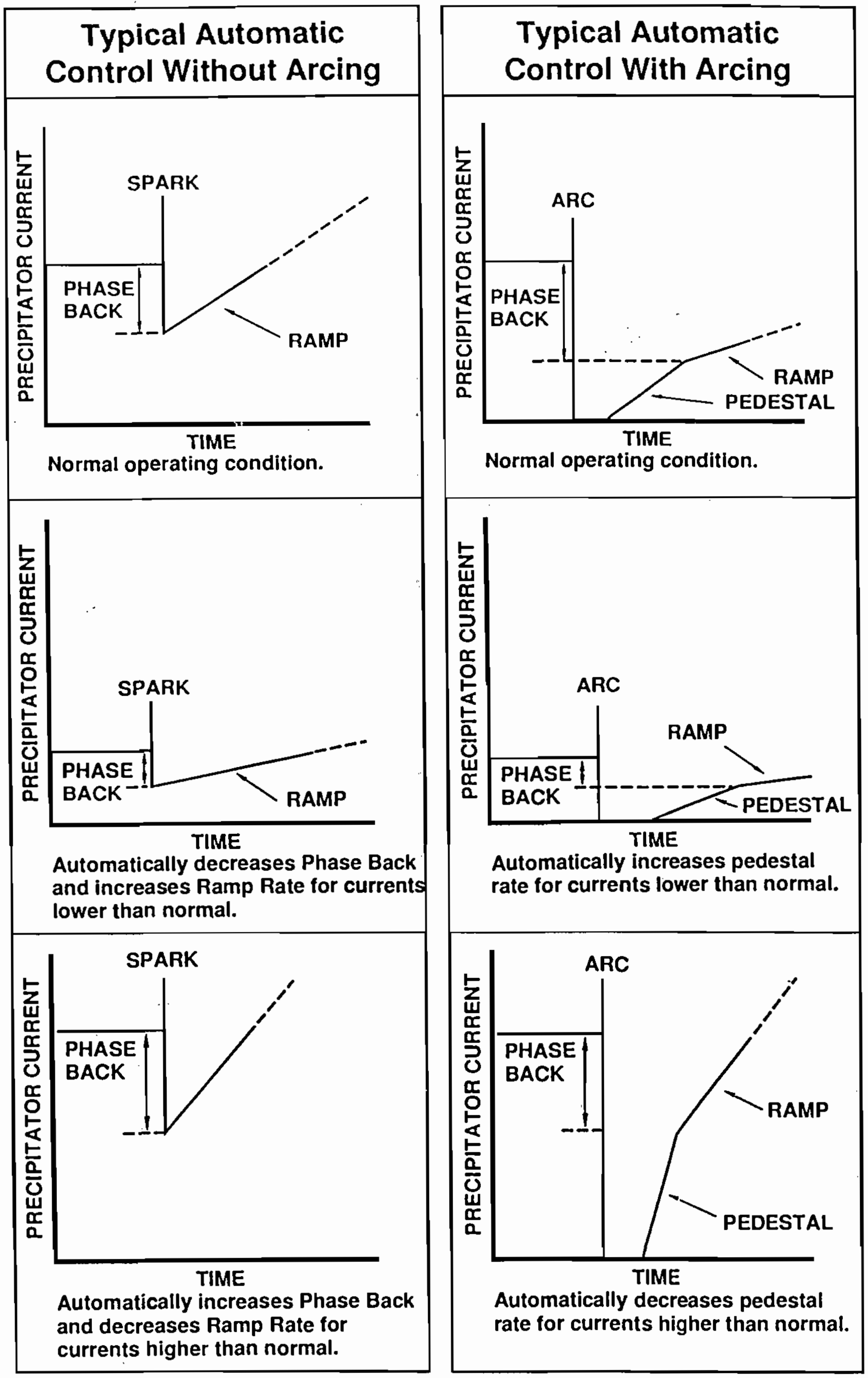
Back corona detector (BCD) - displays the detection of back corona or changes operating parameter to optimize performance under back corona conditions. A choice of operating at the knee of the curve or automatically switching to Intermittent Energization when back corona is detected.

Intermittent energization (IE) - allows the duty cycle of the transformer-rectifier to be changed to take advantage of the capacitive nature of the electrostatic precipitator. This reduces power consumption and, in high resistivity cases, improves precipitator performance.

Process sense - allows rapid power recovery if sparking does not occur within a programmable time period.

Automatic Readjustment

Once parameters are adjusted for normal operation, no further programming adjustments are necessary. As a control's power level decreases (due to increasing boiler load, boiler tube leaks, heavy carbon carry over, heavier ash loading, or other upset conditions) the programmable parameters automatically readjust to maintain optimum precipitator power. Conversely, as a control's power level increases, (due to decreasing boiler load or other improving conditions) the control again readjusts operating parameters to maintain optimum precipitator power.



Normal operating condition.

Normal operating condition.

Automatically decreases Phase Back and increases Ramp Rate for currents lower than normal.

Automatically increases pedestal rate for currents lower than normal.

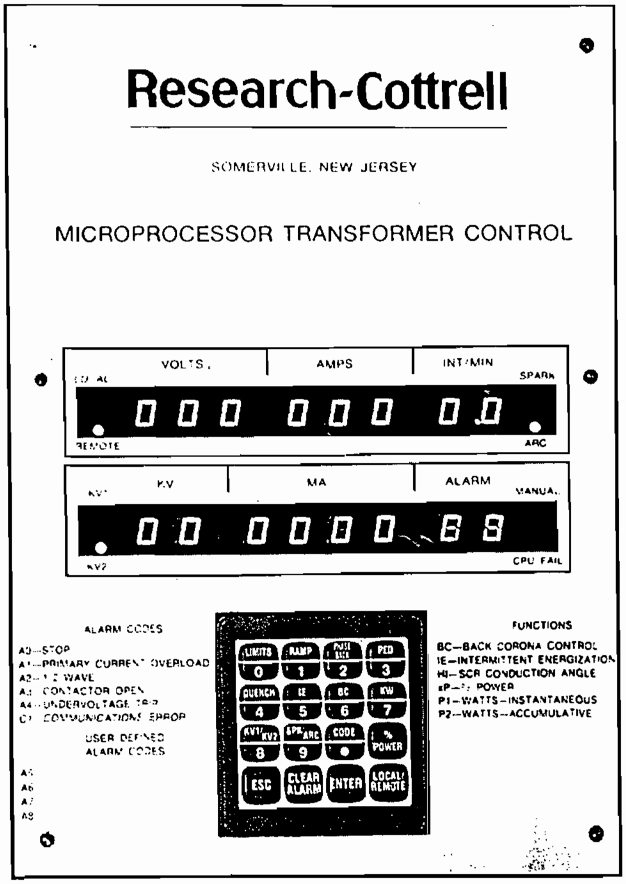
Automatically increases Phase Back and decreases Ramp Rate for currents higher than normal.

Automatically decreases pedestal rate for currents higher than normal.

The MTC automatically adjusts programmable parameters such as Phase Back, Ramp and Pedestal to optimize useable power levels based on actual precipitator operating conditions.

Programming

All programming of the control is performed through a sixteen key, double-function keypad. The keypad is a membrane, tactile feel, hermetically sealed unit, and each key is labeled by function. To prevent unauthorized programming of the control, a four digit code



All operator programming is performed through a sixteen key, double function keypad. Each key is labeled with its control function. All operating electrical values are digitally displayed.

must be entered before control parameter changes can be made.

Display of Operating Conditions and Programmed Parameters

All operating electrical values and programmed parameters are displayed on multiple, seven-segment light emitting diode (LED) digital displays. The digital display is divided into six sections for display of: primary voltage, primary current, secondary current, secondary voltage (KV1/KV2), sparks/arcs per minute and alarms. The electrical readings are displayed continuously while the programmed parameters are displayed only when requested during programming or parameter checks.

The primary volts and amps and secondary volts and amps displays also contain an LED that illuminates when a limit has been reached.

Alarm display - for ease of troubleshooting, the alarm display will indicate an alphanumeric code for the following alarm conditions ("A" alarms will de-energize the control):

AO - Stop
A1 - Primary current overload
A2 - SCR unbalance
A3 - Open contactor
A4 - Undervoltage
A5 - SCR overtemp
A6 - TR oil level
A7 - TR overtemp
A8 - Hopper level
EE - Programmed memory loss
CX - Communication error
F1 - Communication error when used with central control

Function display - the following codes are displayed when their corresponding function is activated:

IE - Intermittent energization
H1 - SCR on-time
XP - Percent power
P1 - Wattmeter, instantaneous
P2 - Wattmeter, accumulative
BC - Back corona
PL - Peak limits

Additional Features

Overcurrent protection - an internal overcurrent protection circuit de-energizes the control at 125% of rated current in either auto or manual mode.

SCR unbalance trip - the control will trip on an SCR unbalanced condition in either auto or manual mode. This protects against transformer-rectifier primary half wave operation.

SCR indicators - two LEDs are provided to indicate SCR gate operation. These LEDs aid in troubleshooting electrical problems.

SCR firing delay - a delay of 2 seconds between control energization and firing of the SCRs is provided. This delay eliminates false firing and increases SCR life.

Research-Cottrell
Air Pollution Control Division

Technical Bulletin

Microprocessor Rapper/Vibrator Controls For Electrostatic Precipitators

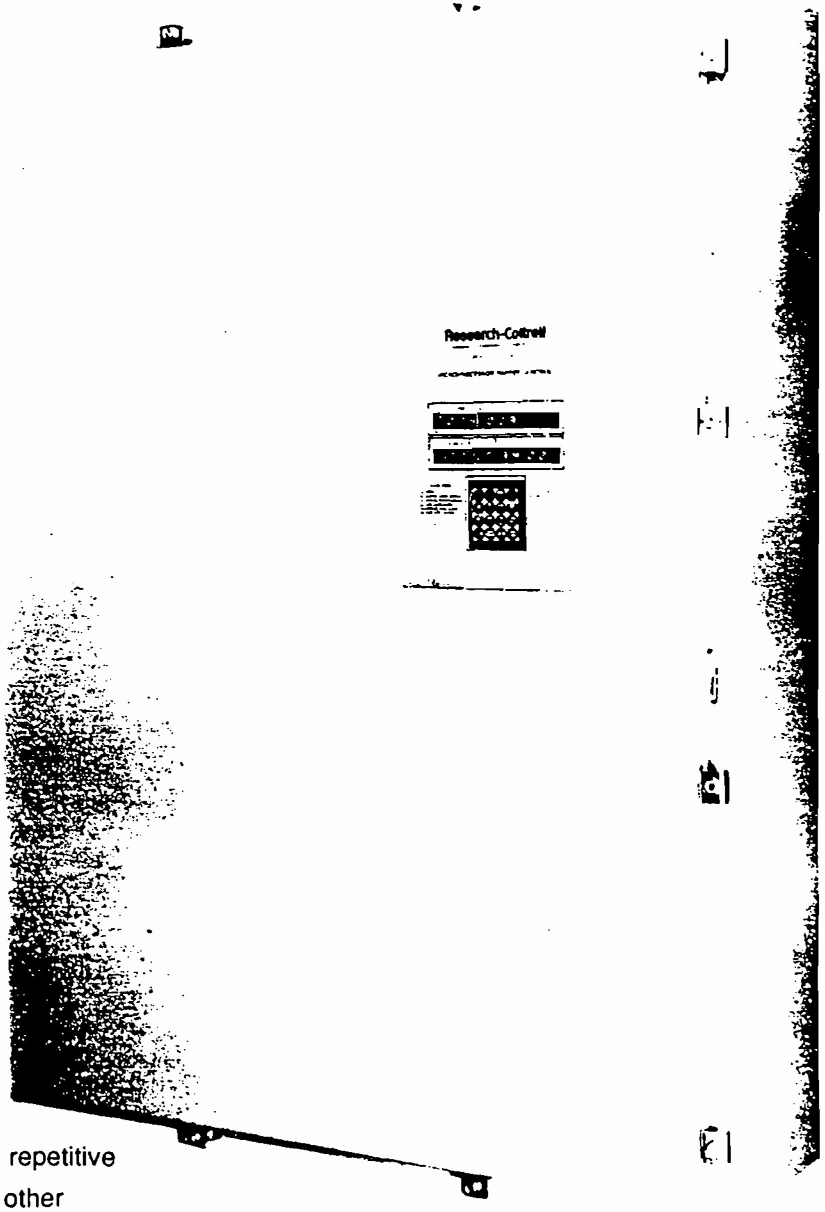
Maximum precipitator efficiency can only be achieved if discharge and collecting electrodes are kept operationally clean without unnecessary particulate reentrainment. Excessive particulate buildups on the collecting electrodes cause increased sparking and reduced precipitator operating power levels while buildups on the discharge electrodes limit corona current as well as cause excessive sparking.

Research-Cottrell's Microprocessor Rapper/Vibrator Control (MRC™) for electrostatic precipitators is designed to achieve maximum flexibility of electrode rapping and/or vibrating to ensure operationally clean electrodes with minimum reentrainment.

The central electronics are designed for compact size, long life, low power consumption and high reliability. Non-volatile EEPROM memory keeps all field programmed parameters active. Power outages of any duration have no effect on MRC operation.

The MRC offered by Research-Cottrell is an advanced microprocessor rapper/vibrator energization system designed specifically for electrostatic precipitators. The control is easily field programmed for rapper cycle time, vibrator ON/OFF time, intensity, repetitive "raps", master intensity and a host of other operating parameters. This results in an extremely high level of system flexibility with minimum user effort.

The MRC is designed for backfitting existing Research-Cottrell rapper/vibrator controls as well as backfitting controls by other manufacturers. The MRC will control low voltage, magnetic impact (solenoid



NO_x Control System

An ammonia injection system known as Thermal $DeNO_x$, or equivalent, will be provided as the method of NO_x control (manufacturer's literature attached). The Thermal $DeNO_x$ technology is a selective, non-catalytic reduction process (SNCR), which reduces NO_x emissions through chemical reaction with ammonia (NH_3). The process injects ammonia into the flue gas stream which reacts with nitrogen oxides to form nitrogen and water vapor.

The proposed NO_x system includes the following major components:

- Carrier air compressors.
- Anhydrous ammonia tank package.
- Electric vaporizers.
- Ammonia flow controls.
- Control panel (on tank skid).
- Injection manifolds and injectors.
- Valves and instrumentation.

A single storage system will supply ammonia to all the boilers. A process flow diagram is attached.

Vaporous ammonia for injection into the boiler is drawn from the tank vapor space. On warm days, tank pressure can be maintained by ambient solar heat. On cold days, tank pressure is maintained by the vaporizer, which supplies the heat of vaporization for process demand and compensates for heat losses through the tank walls. The vaporizer receives liquid ammonia from the tank by gravity and supplies ammonia vapor to the tank vapor space (see flow diagram).

At least two injection zones will be used to provide injection at full and part load conditions. Each zone will have about 20 injectors. Zone switching valves will direct the ammonia/carrier mixture to the appropriate injection zone. A third injection zone will be added if final engineering demonstrates the necessity for a third zone.

Specifications for the ammonia injection system are provided below (on a per boiler basis):

Ammonia injection rate - 185 lb/hr
Compressed air - 3,900 scfm

Power Requirements - Vaporizer - 175 kW
- Air Compressor - 350 kW

Ammonia Slip - Biomass - 20 ppm (max)
- Coal - 65 ppm (max)

CARLTON, FIELDS, WARD, EMMANUEL, SMITH & CUTLER, P. A.
ATTORNEYS AT LAW

ONE HARBOUR PLACE	FIRSTATE TOWER	HARBOURVIEW BUILDING	FIRST FLORIDA BANK BUILDING	ESPERANTE	BARNETT TOWER
P.O. BOX 3239	P.O. BOX 1171	P.O. BOX 12426	P.O. DRAWER 190	P.O. BOX 150	P.O. BOX 2861
TAMPA, FLORIDA 33601	ORLANDO, FLORIDA 32802	PENSACOLA, FLORIDA 32582	TALLAHASSEE, FLORIDA 32302	WEST PALM BEACH, FLORIDA 33402	ST PETERSBURG, FLORIDA 33731
(813) 223-7000	(407) 849-0300	(904) 434-0142	(904) 224-1585	(407) 659-7070	(813) 821-7000
FAX (813) 229-4133	FAX (407) 648-9099	FAX (904) 434-5366	FAX (904) 222-0398	FAX (407) 659-7368	FAX (813) 822-3768

PLEASE REPLY TO :

November 19, 1992 Tallahassee

Willard Hanks
Department of Environmental
Regulation
Division of Air Resources
Bureau of Air Regulation
2600 Blair Stone
Twin Towers Office Building
Tallahassee, Florida 32399-2400

Dear Mr. Hanks:

This law firm is assisting Flo-Sun Corporation with its efforts to obtain the necessary environmental permits for two proposed cogeneration facilities that will be located adjacent to the existing Okeelanta and Osceola sugar mills. On November 4, 1992, we met with representatives of the United States Environmental Protection Agency (Region IV) in Atlanta to discuss these proposed facilities. The meeting was attended by Gus Cepero, David Buff, Brian Beals, Greg Worley, Lew Nagler, Scott Davis, and myself. At your request, we have prepared this letter summarizing the pertinent issues that were discussed by Flo-Sun and EPA.

At the outset, we explained that we had requested a meeting with EPA so that we could describe the details of the projects directly to EPA and thereby minimize confusion and delays in the review process. In turn, the EPA representatives confirmed that this was an informational meeting only and they would give their comments to DER at the appropriate time.

We then provided EPA with a general description of the project and highlighted the facts that have been presented in the applications filed for Flo-Energy and Sol-Energy. We explained that the facilities normally will burn 100% biomass fuels, but must have the ability to use low sulphur oil or coal as a

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NOV 20 1992

Division of Air
Resources Management

supplemental fuel, if necessary. Since biomass fuels are not always available on the open market, the facilities need the flexibility to use an alternate fuel in the unlikely event that there is an insufficient supply of biomass fuel.

Much of the discussion at EPA focused on the determination of BACT for sulphur dioxide (SO_2). We believe the analyses in the two applications demonstrate that BACT for SO_2 is the use of low sulphur fuels. First, biomass is a very low sulphur fuel. Add-on SO_2 controls would not be necessary under normal conditions when the facilities are using biomass fuel. Consequently, add-on SO_2 control systems would rarely, if ever, be used.

Secondly, Palm Beach County imposed a long-term average SO_2 emission limitation of 1,000 tons per year on the two facilities, which would restrict future SO_2 emissions to the levels established by current operations (i.e., actual emissions). The BACT analysis based on average annual emissions of 1000 tons or less shows the cost of add-on SO_2 controls is unreasonably high--at least $6,880 per ton of SO_2 removed.

Since DER and EPA are concerned about the enforceability of the County's SO_2 limitation, we acknowledged that the PSD permits for the two facilities should impose joint and several liability on both facilities. This approach would give EPA and DER reasonable assurances that they can take appropriate enforcement action, if necessary. We also acknowledged that the facilities should be subject to other short and long-term SO_2 emission limitations that would help the agencies ensure that the facilities were consistently in compliance with applicable regulations.

The BACT regulations indicate that DER and EPA may consider the actual operating conditions at a facility when determining BACT. In this case, even if EPA and DER were to conclude that the County's long-term emission limitation is not appropriate for inclusion in the PSD permit, the agencies should recognize that the permit condition has been imposed by the County and thus will limit the actual operations at the facilities. The annual average SO_2 emissions will be limited to 1,000 tons and, therefore, this number should be used when calculating the cost effectiveness of add-on SO_2 controls. Additionally, the BACT analyses should recognize that the use of fossil fuels is a low probability event.

At EPA's request, we agreed to supplement the BACT analyses with information concerning two other add-on control systems for acid gases. We will contact Mr. Charlie Sedmon at the EPA research laboratory to obtain additional information about a dry sorbent injection system called "Advocate". We also will ask him about the "NO_x SO" system for NO_x and acid gas control.

We discussed a variety of other issues with EPA, but no significant concerns were identified. Among other things, no specific problems were identified with regard to the two applications and: (a) the use of the "net emissions" concept when evaluating the emissions from the proposed cogeneration facilities; (b) the evaluation of the facilities' potential impacts on Class I areas; (c) the use of the MESOPUFF model for the evaluation of Sol-Energy's impacts on the Class I areas; (d) the use of a 100 kilometer range for evaluating the potential impacts on Class I areas; and (e) the analysis and conclusions concerning the facilities' emissions of toxic air pollutants. Similarly, the issues raised by the Hadson Power case did not seem to significantly affect the analyses performed for Flo-Energy and Sol-Energy.

Please call us if you have any questions or need additional information about these issues.

Sincerely,

D. S. Dee

David S. Dee

cc: Gus Cepero
David Buff
Preston Lewis
Clair Fancy
Greg Worley
Scott Davis
Brian Beals
Lew Nagler
C. Holladay
D. Knowles, SW Dist
J. Brooks, SE Dist
J. Stormer, PBCHD
J. Bunyak, NPS

Florida Department of Environmental Regulation
Twin Towers Office Bldg. • 2600 Blair Stone Road • Tallahassee, Florida 32399-2400
Lawton Chiles, Governor
Carol M. Browner, Secretary

November 6, 1992

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. Gus Cepero, Vice President
Flo-Energy, Inc.
Sol-Energy, Inc.
P. O. Box 86
South Bay, Florida 33493

Dear Mr. Cepero:

Applicants for permits to construct resource recovery facilities are required to publish a Notice of Application. Your Notice of Application is enclosed. You must publish the Notice in a newspaper having circulation in the county that the facility will be located and provide the Department with proof of publication. You will also be required to publish a Notice of Intent in the same newspaper after the Department has processed your applications. The public will have an opportunity to comment on or petition for an administrative hearing in response to any Notice of Intent.

If you have any questions on this matter, please write to me or call Willard Hanks at (904) 488-1344.

Sincerely,

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

CHF/WH/plm

cc: David Knowles, SD
Isidore Goldman, SED
James Stormer, PBCHD
David Buff, P.E., KBN

Notice of Application

The Department of Environmental Regulation announces receipt of two applications for permits to construct 74.9 megawatts cogeneration facilities in Palm Beach County. The facilities will burn bagasse, wood waste, No. 2 fuel oil, and coal. One facility, Flo-Energy, Inc., will be located 6 miles south of South Bay off U.S. Highway 27. The other facility, Sol-Energy, Inc., will be located near the intersection of U.S. Highway 98 and Hatton Highway, Pahokee.

The applications are available for public inspection at the following Department offices: Bureau of Air Regulation, 2600 Blair Stone Road, Tallahassee, FL 32399-2400; South District, 2295 Victoria Avenue, Suite 364, Ft. Myers, FL 33901; Southeast District, 1900 S. Congress Avenue, Suite A, West Palm Beach, FL 33406; and at the Palm Beach County environmental office located at 901 E. Evernia Street, West Palm Beach, FL 33402.

Anyone may send written comments on these applications to Mr. Preston Lewis at the Department's office in Tallahassee.

Florida Department of Environmental Regulation

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

Lawton Chiles, Governor

Carol M. Browner, Secretary

November 3, 1992

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. Gus Cepero, Vice President
Flo-Energy, Inc.
Sol-Energy, Inc.
P. O. Box 86
South Bay, Florida 33493

Dear Mr. Cepero:

Re: File No. AC50-219413/PSD-FL-196, Flo-Energy, Inc.
File No. AC50-219795/PSD-FL-197, Sol-Energy, Inc.

The Department has reviewed your applications for permits to construct the referenced cogeneration facilities in Palm Beach County, Florida. The additional information shown below will be needed before the review of these applications can continue:

1. Please provide the make, model, drawing, brochure, or general specifications for each steam generation unit. What is the generating capacity of each plant, 74.9 or 44 MW?

2. Will these boilers operate under negative pressure?

3. What is the range in temperature, pressure, and steam production for the 350 psig/650°F and 20 psig/280°F steam sources?

4. How will the heat input by the various fuels to the boilers be monitored? What parameters of the fuels will be monitored and at what frequency? What test methods will be used? Where will the samples be collected? How often will a sample be collected on each fuel used at the proposed facilities. How will this data be used to show compliance with the various sulfur dioxide standards?

5. Please provide plans, drawings, brochures, or specifications for all air pollution control equipment that will be used in these projects. Include base line operating parameters such as temperatures, feed rates, pressure drops, flow rates, voltages, etc., as well as an operation and maintenance plan for the recommended air pollution control equipment.

6. Please provide drawings of all storage and material handling equipment (biomass, coal, bagasse, fly ash, carbon, etc.) with notations of how fugitive particulate matter emissions from hauling the material to the plant to disposing of any waste will be controlled. Include a table similar to Table 2-8 to show the fugitive emissions from these materials. Clarify how the ash for coal will be kept separate from the ash produced by the biomass.

7. Gypsum recovered from the lime/limestone injection FGD system may be of value to the sugar cane industry as a soil conditioner. FGD should also reduce fluoride and sulfuric acid emissions. Please revise your BACT determination by eliminating the cost of the disposal of the material captured by the ESP and calculate the cost per ton of air pollutant removed. Also address the use of other emerging sulfur dioxide control technologies for the BACT determination such as furnace sorbent or duct sorbent injection.

8. Please provide an operation and maintenance plan to minimize emissions during filling and storage of ammonia. What controls will be used to capture any ammonia escaping from the storage tank's pressure relief valve?

9. One application currently being processed by the Bureau is proposing 0.05% sulfur in No. 2 fuel oil. What is the lowest percent sulfur in No. 2 fuel oil available in your area?

10. What are the specifications for the wood waste and biomass? Will either contain asphalt shingles, tar paper, or plastics?

11. Will the existing boiler No. 16, designated for standby service at the Flo-Energy facility, be used when all 3 of the proposed boilers are in operation?

12. Please explain why only 30% of the mercury but 90% of the other metals will be removed from the emissions. Will the presence of ammonia in the flue gas effect the mercury removal?

13. What is the basis of assuming that 20% of the chromium is Cr+6 in Appendix A?

14. What does the term "black start purposes" mean (page 2-5)?

15. What is "special waste" that was referred to in proposed Specific Condition No. 12?

16. Please respond to the National Park Service FAX dated October 8, 1992.

17. Please note which information for the following sources used for the modeling analysis is correct.

a. Source 50PMB500086 Glades Corr Institute:

	Qs	Hs	Ts	Vs	Ds	Xs	Ys
Table 6-4:	2.82	9.8	389	11.28	0.40	8400	15800
Model:	2.82	9.1	477	1.22	1.04	8400	15800

b. Source 50PMB500021 Pratt & Whitney:

Table 6-4:	34.2(km)	38.9(km)
Model:	35800(m)	-23100(m)

c. Source 52FTM500061 US Sugar-Bryant

	Unit 5 PSD (3hr)	Unit 1,2,3 (3hr)	Unit 5 PSD (24hr)	Unit 1,2,3 (24hr)
FOL: Table 6-4 & Model:	81.36	204.53	79.97	79.69
SOL: Table 6-4 & Model:	68.07	174.36	67.38	63.66

d. OKCOGEN Stack Height 60.66 in Maximum Impact Analysis,
PSD Class I and II Analysis
65.2 in AAQS Analysis

18. What is the worst case total maximum hourly sulfur dioxide emission rate for all three boilers when they are running concurrently? Modeling for maximum short-term impacts is based on worst case maximum hourly emissions.

19. Please explain the last three footnotes (a, b, c in the Sol-Energy application and b, c, d in the Flo-Energy application) in Table 6-18 of both applications. The annual impact values due to arsenic, chromium VI and nickel emissions appear to exceed the annual no threat levels (NTL) when the impact values are computed by multiplying the hourly emissions in column 1 by the highest predicted annual concentration given in the information below the table.

Several matters make review of this application difficult. There is little information on specific equipment, drawings showing equipment layout, or fugitive dust controls for the various materials that will be handled at these plants. We suspect that you have not completed final engineering and equipment selection for these projects. Should this be the case, try to provide the information requested for some of the equipment being considered and note that it or equivalent equipment will be installed at the plants.

Should the Department conclude that the complete applications for the proposed projects can be approved, your specific conditions, with some revisions and additions, will help the Department draft the proposed permits. Prior to drafting the proposed permits, the Bureau will consult with our Office of General Counsel to see how the County's conditions can be addressed in a Department permit.

If you have any questions on this matter, please write to me or call Willard Hanks, review engineer, or Cleve Holladay, meteorologist, at (904) 488-1344. We will resume processing these applications after receipt of the requested information.

Sincerely,

John C Brown Jr

John C. Brown, Jr., P.E.
Administrator
Air Permitting and Standards

JCB/WH/plm

Enclosure: NPS October 8 FAX

cc: David Knowles, SD
Isidore Goldman, SED
James Stormer, PBCHD
Jewell Harper, EPA
David Buff, P.E., KBN
Brian Mitchell, NPS

October 7, 1992

PROJECT: Flo-Energy Cogeneration Facility Air Permit Application
National Park Service Completeness Review

NPS PERSON ON CALL: Dee Morse

PERSON: Willard Hanks

ORGANIZATION: Florida Department of Environmental Regulation,
Bureau of Air Regulation

TELEPHONE NUMBER: (904) 488-1344, FAX 922-6979

BACKGROUND: We reviewed the Air Permit Application for the Flo-Energy Cogeneration facility and found the application to be complete. However, Flo-Energy states in the permit that "based on current actual emissions from the Okeelanta Sugar Mill and Refinery and worst-case maximum emissions from the proposed cogeneration facility, the proposed project will result in significant reductions in several air pollutants, including particulate matter, nitrogen oxides, carbon monoxide, volatile organic compounds, and lead". Therefore, they conclude that PSD review is not required for these pollutants. Netting of emission decreases and increases only applies if both the proposed Flo-Energy Cogeneration facility and the Okeelanta Sugar Mill are considered the same source, i.e., owned by the same company. If not, the Flo-Energy Cogeneration facility will have to apply BACT for these pollutant emissions, and perform an air quality analysis for the pollutants, since the proposed facility will cause a significant increase in emissions. In our detailed comments on the application we will assess the adequacy of the air quality analysis and proposed BACT. Also we will review the draft permit to ensure the proposed emission reductions at the Okeelanta Sugar Mill are enforceable.

SUBJECT DISCUSSED: I called Willard Hanks and informed him that we had reviewed the air application and found it to be complete. I also asked him if both Okeelanta Sugar Mill and the proposed Flo-Energy Cogeneration facility were owned by the same company. He was not sure, but asked if I would fax to him our concern and he would put it in the State's letter to the applicant.

ACTION REQUIRED: Fax to Willard Hanks a copy of this telephone record.

COPIES TO: Willard Hanks (FDER), Brian Mitchell (AQD), John Bunyak (AQD),
John Notar (AQD), and Tom Schmidt (EVER)

PS Form 3811, July 1983 447-845

DOMESTIC RETURN RECEIPT

● **SENDER: Complete items 1, 2, 3 and 4.**

Put your address in the "RETURN TO" space on the reverse side. Failure to do this will prevent this card from being returned to you. The return receipt fee will provide you the name of the person delivered to and the date of delivery. For additional fees the following services are available. Consult postmaster for fees and check box(es) for service(s) requested.

1. ☑ Show to whom, date and address of delivery.
2. ☐ Restricted Delivery.

3. Article Addressed to:

Mr. Gus Cepero, VP
P.O. Box 86
South Bay, Fla 33493

4. Type of Service:
☐ Registered ☐ Insured
☑ Certified ☐ COD
☐ Express Mail

Article Number

Always obtain signature of addressee or agent and DATE DELIVERED.

5. Signature – Addressee
X

6. Signature – Agent
X B. M Phee

7. Date of Delivery
11/9/92

8. Addressee's Address *(ONLY if requested and fee paid)*

P 062 921 916

Receipt for Certified Mail

No Insurance Coverage Provided
Do not use for International Mail
(See Reverse)

Sent to M Gus Cepero	
Street and No. P.O. Box 86	
P.O., State and ZIP Code South Bay, Fl 33493	
Postage	$
Certified Fee	
Special Delivery Fee	
Restricted Delivery Fee	
Return Receipt Showing to Whom & Date Delivered	
Return Receipt Showing to Whom, Date, and Addressee's Address	
TOTAL Postage & Fees	$
Postmark or Date	

PS Form 3800, June 1991

HRS
STATE OF FLORIDA
DEPARTMENT OF HEALTH AND REHABILITATIVE SERVICES

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OCT 22 1992

Division of Air
Resources Management

October 16, 1992

Mr. Willard Hanks
Air Permitting Section
Bureau of Air Quality Management
Florida Department of Environmental Regulation
2600 Blair Stone Road
Tallahassee, Florida 32301-8241

Re: File No. AC50-219413/PSD-FL-196, Flo-Energy, Inc.
File No. AC50-219795/PSD-FL-197, Sol-Energy, Inc.

Dear Mr. Hanks:

Our program has completed a preliminary review of the above referenced applications for air pollution permits in Palm Beach County. We request additional information from the applicant concerning the following items:

1. Were other emerging sulfur dioxide control technologies requiring less capital expenditures (such as furnace sorbent or duct sorbent injection) considered during the BACT determination?

2. The application provides little detail with regard to the controls for particulate, NOx and mercury. More detailed technical design specifications should be submitted. In particular, we would appreciate more information on baseline operating parameters for this equipment such as: temperatures, feed rates, pressure drops, flow rates, voltages, etc., as well as an operation/maintenance plan for this equipment.

3. Please have the applicant submit a schedule for the frequency and types of the fuel analyses to be performed. It would also be helpful if the methodology for determining sulfur dioxide emissions from these analyses specifically stated.

4. The applicant states that ash resulting from coal firing will not be mixed with ash resulting from biomass burning. We request more information on the actual equipment necessary for dual ash handling.

DISTRICT IX
PALM BEACH COUNTY HEALTH UNIT • P.O. BOX 29 • WEST PALM BEACH, FLORIDA 33402
LAWTON CHILES, GOVERNOR

5. Throughout the permit application for Sol-Energy, the applicant refers to the generating capacity as 74.9 MW. During the zoning approval for Palm Beach County, the applicant stated the generating capacity as about 44 MW. Please ask the applicant to verify this figure.

As shown in the requested permit conditions, Palm Beach County has already invested a great deal of time in this project. We ask to be kept informed of any future meetings FDER may have with the applicant in order to keep abreast of these projects. As always, thank you for the opportunity to comment on these applications.

Sincerely,

For the Division Director
Environmental Science & Engineering

James E. Stormer, Administrator
Air Pollution Control Section

FJG/JES/JFK/lh

cc: Southeast District, DER
Source File

United States Department of the Interior

NATIONAL PARK SERVICE
AIR QUALITY DIVISION
P.O. BOX 25287
DENVER, CO 80225

FACSIMILE

DATE: 10/8/92 TIME: 9:35 AM

FAX PHONE NO. (303) 969-2822

NUMBER OF PAGES TO FOLLOW: 1

TO: Willard Hawks - FDER

PHONE: (904) 488-1344

FROM: Dee Morse - NPS - Air Quality Division

PHONE: (303) 969-2071

SUBJECT: Flo-Energy Cogeneration Facility Air Permit Application
National Park Service Completeness Review

REMARKS: Willard, Attached is our concern w/ the application which you asked me to FAX to you. If you have any questions please give me a call. (303) 969-2071

October 7, 1992

PROJECT: Flo-Energy Cogeneration Facility Air Permit Application
National Park Service Completeness Review

NPS PERSON ON CALL: Dee Morse

PERSON: Willard Hanks

ORGANIZATION: Florida Department of Environmental Regulation,
Bureau of Air Regulation

TELEPHONE NUMBER: (904) 488-1344, FAX 922-6979

BACKGROUND: We reviewed the Air Permit Application for the Flo-Energy Cogeneration facility and found the application to be complete. However, Flo-Energy states in the permit that "based on current actual emissions from the Okeelanta Sugar Mill and Refinery and worst-case maximum emissions from the proposed cogeneration facility, the proposed project will result in significant reductions in several air pollutants, including particulate matter, nitrogen oxides, carbon monoxide, volatile organic compounds, and lead". Therefore, they conclude that PSD review is not required for these pollutants. Netting of emission decreases and increases only applies if both the proposed Flo-Energy Cogeneration facility and the Okeelanta Sugar Mill are considered the same source, i.e., owned by the same company. If not, the Flo-Energy Cogeneration facility will have to apply BACT for these pollutant emissions, and perform an air quality analysis for the pollutants, since the proposed facility will cause a significant increase in emissions. In our detailed comments on the application we will assess the adequacy of the air quality analysis and proposed BACT. Also we will review the draft permit to ensure the proposed emission reductions at the Okeelanta Sugar Mill are enforceable.

SUBJECT DISCUSSED: I called Willard Hanks and informed him that we had reviewed the air application and found it to be complete. I also asked him if both Okeelanta Sugar Mill and the proposed Flo-Energy Cogeneration facility were owned by the same company. He was not sure, but asked if I would fax to him our concern and he would put it in the State's letter to the applicant.

ACTION REQUIRED: Fax to Willard Hanks a copy of this telephone record.

COPIES TO: Willard Hanks (FDER), Brian Mitchell (AQD), John Bunyak (AQD), John Notar (AQD), and Tom Schmidt (EVER)

KBN

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OCT 5 1992

Bureau of
Air Regulation

October 2, 1992

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

RE: Computer Printouts for the Flo-Energy Cogeneration Facility Prevention of Significant Deterioration Application

Dear Mr. Fancy:

Please find enclosed one hard and two floppy disk copies of all computer output files performed for the Flo-Energy Cogeneration Facility PSD application. The files on the disk are compressed by similar model run type with the utility PKZIP. A directory of ZIPPED files names is provided. If you need further information or have any questions, please call.

Sincerely,

Steve Marks

Steven R. Marks
Senior Meteorologist

SRM/dmpm

cc: Gus Cepero
David Dee
David Buff
File (2)

KBN ENGINEERING AND APPLIED SCIENCES, INC.
1034 Northwest 57th Street Gainesville, Florida 32605 904/331-9000 FAX: 904/332-4189

KBN

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SEP 30 1992

Bureau of
Air Regulation

September 28, 1992

Mr. Clair Fancy
Bureau of Air Management
Florida Department of Environmental Regulation
2600 Blair Stone Road
Tallahassee, FL 32399-2400

Re: PSD Class I 3-Hour Refinements for the Flo-Energy Cogeneration Facility

Dear Mr. Fancy:

I have enclosed a revised Table 6-17 (Page 6-31) of the Air Permit Application for the Flo-Energy Cogeneration Facility, which was delivered to FDER on September 17, 1992. The 3-hour PSD Class I refined concentrations in that table have been corrected. Printed and disk copies of all the modeled output files for this project will be sent to FDER as soon as possible.

Sincerely,

David A. Buff

David A. Buff, M.E., P.E.
Principal Engineer

David A. Buff
No. 19011

SRM/dmpm

cc: Gus Cepero
David Dee
Steven Marks
File (2)
H. Hanks
C. Holladay
O. Knowles, S Dist
S. Brooks, SE Dist
J. Stormer, PBCHD
J. Harper, EPA
B. Mitchell, NPS

12118C1/1

KBN ENGINEERING AND APPLIED SCIENCES, INC.
1034 Northwest 57th Street Gainesville, Florida 32605 904/331-9000 FAX: 904/332-4189

Table 6-17. Maximum Predicted SO_2 Concentrations as Compared with PSD Class I Increments - Refined Analysis

Averaging Time	Concentration ($\mu g/m^3$)	Receptor Location[a] UTM-E (m)	Receptor Location[a] UTM-N (m)	Period Ending (YYMMDDHH)	Allowable Increment ($\mu g/m^3$)
Annual	0.6	550300.	2848600.	82-----	2
24-Hour[b]	5.42[c]	550300.	2839000.	83081724	5
3-Hour[b]	22.8	497000.	2830500.	82071621	25
	21.4	547000.	2848600.	83081603	
	19.9	546000.	2845000.	85041721	

Note: YY=Year, MM=Month, DD=Day, HH=Hour

[a] All receptor coordinates are reported in Universal Transverse Mercator (UTM) coordinates.

[b] All short-term concentrations are highest, second-highest concentrations.

[c] The proposed Flo-Energy cogeneration facility contributes only 0.04 $\mu g/m^3$ to this concentration. The facility's contribution is less than the National Park Service's recommended 24-hour SO_2 Class I significance level of 0.07 $\mu g/m^3$.

Florida Department of Environmental Regulation

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

Lawton Chiles, Governor

Carol M. Browner, Secretary

September 17, 1992

Mr. Brian Mitchell, Acting Chief
Policy, Planning and Permit Review Branch
National Park Service-Air Quality Division
12795 West Alameda Parkway, Room 215
Denver, Colorado 80228

Dear Mr. Mitchell:

RE: Flo-Energy Cogeneration Facility
Palm Beach County, PSD-FL-196

The Department has received the above referenced PSD application. Please review this package for completeness and forward your comments to the Bureau of Air Regulation by October 9, 1992. The Bureau's FAX number is (904)922-6979.

If you have any questions, please call Willard Hanks or Cleve Holladay at (904)488-1344 or write to me at the above address.

Sincerely,

Patricia G. Adams

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

CHF/pa

Enclosures

Florida Department of Environmental Regulation

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

Lawton Chiles, Governor

Carol M. Browner, Secretary

September 23, 1992

Ms. Jewell A. Harper, Chief
Air Enforcement Branch
U.S. EPA, Region IV
345 Courtland Street, N.E.
Atlanta, GA 30365

Dear Ms. Harper:

RE: Flo-Energy Cogeneration Facility
Palm Beach County, PSD-FL-196

The Department has received the above referenced PSD application. Please review this package for completeness and forward your comments to the Bureau of Air Regulation by October 9, 1992. The Bureau's FAX number is (904)922-6979.

If you have any questions, please call Willard Hanks or Cleve Holladay at (904)488-1344 or write to me at the above address.

Sincerely,

Patricia G. Adams

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

CHF/pa

Enclosures

OKEELANTA CORPORATION
316 Royal Poinciana Plaza
Post Office Box 1059
Palm Beach, Florida 33480

Telephone (407) 655-6303
Telex: 803444 FAI PABH

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September 17, 1992

Mr. Clair Fancy
Bureau Chief
Bureau of Air Regulation
Department of Environmental Regulation
2600 Blair Stone Road
Twin Towers
Tallahassee, FL 32399-2400

Dear Mr. Fancy:

Enclosed please find check # 74821 in the amount of $7,500 in payment for Flo-Energy Cogen application.

Sincerely,

Gus Cepero /reg

Gus Cepero
Vice President

GRC/reg

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316 ROYAL POINCIANA PLAZA
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Your Phone Number (Very Important): (407) 655 630
Company: Okeelanta Corporation
Department/Floor No.:
Street Address: 316 Royal Poinciana Plaza
City: Palm Beach, State: FL ZIP Required: 33480

2 To (Recipient's Name) Please Print: Mr. Clair Fancy
Recipient's Phone Number (Very Important): (904) 488 1344
Company: Department of Environmental Regu
Bureau of Air Regulation
Department/Floor No.:
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SUGARMILL DIVISION

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MIAMI, FLORIDA

NUMBER	DATE	AMOUNT
74821	9/17/92	$7,500.00

PAY Seven thousand five hundred and 00/100-----------------------------------

VOID AFTER NINETY DAYS FROM DATE OF CHECK

TO THE ORDER OF
Florida Department of
Environmental Regulation

[redacted] [redacted] [redacted]

219413

Air Permit Application For FLO-ENERGY COGENERATION FACILITY
Palm Beach County, Florida

Prepared For:

Flo-Energy, Inc.
316 Royal Poinciana Plaza
Palm Beach, Florida 33480

Prepared By:

KBN Engineering and Applied Sciences, Inc.
1034 NW 57th Street
Gainesville, Florida 32605

September 1992
12118C1

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EXECUTIVE SUMMARY

Flo-Energy, Inc. is proposing to install a cogeneration facility at the site of the existing Okeelanta Corporation sugar mill and refinery located south of South Bay, Florida, in Palm Beach County. Flo-Energy, Inc. is proposing to replace the eight existing bagasse/oil-fired boilers as well as a recently constructed oil-fired boiler with a cogeneration system consisting of three new spreader stoker combustion units. The recently constructed oil-fired boiler will be retained as a standby boiler. The cogeneration facility will use primarily biomass (bagasse and wood waste materials) to generate steam and electricity. The new facility will provide enough steam energy for the needs of the existing sugar mill and refinery and will generate up to 74.9 megawatts of electricity which will be sold to Florida Power & Light Company. Further, the proposed facility will reduce total annual air emissions and water consumption compared to the existing facility while generating approximately 15 times more electric energy than the existing facility.

It is Flo-Energy's desire to burn 100 percent biomass fuels in the proposed facility. Generally, the bagasse from the sugar grinding operation will provide approximately two-thirds of the annual fuel requirements of the facility. The other one-third will be provided by wood waste materials, which could include clean construction and demolition wood debris, yard trimmings, land clearing debris, and other clean cellulose and vegetative matter. However, because wood waste materials are not commodity fuels and the supply of wood waste may fluctuate, it is necessary to have the ability to burn limited amounts of fossil fuel in the event that the supply of biomass fuel is not adequate. Therefore, the proposed facility will have the capability to burn biomass, fuel oil, and coal, either alone or in combination.

Any fossil fuels utilized at the facility will be limited to a combined 25 percent of the total annual heat input in any given year. Any fuel oil utilized will be very low sulfur No. 2 distillate fuel oil with a maximum sulfur content of 0.5 percent. Any coal fired in the facility will be low sulfur coal of approximately 0.7 percent sulfur content. It is emphasized that Flo-Energy does not ever intend to burn coal at the facility and will not burn coal if the biomass supply is adequate to meet the fuel requirements of the plant.

The proposed facility will utilize several emission control techniques to reduce emissions. The facility will incorporate a selective non-catalytic reduction system to reduce nitrogen oxide emissions. Carbon monoxide and volatile organic compound emissions will be minimized through proper furnace design and good combustion practices. Particulate emissions will be reduced by an electrostatic precipitator (ESP). Mercury emissions will be controlled through a carbon injection system (or equivalent) and the ESP system.

This report addresses the requirements of the prevention of significant deterioration (PSD) review procedures, pursuant to the rules and regulations implementing the federal Clean Air Act Amendments of 1977. Based on the current actual emissions from the Okeelanta facility and worst-case maximum emissions from the proposed cogeneration facility, the proposed project will result in significant reductions in several air pollutants, including particulate matter, nitrogen oxides, carbon monoxide, volatile organic compounds, and lead. Reductions in emissions of sulfur dioxide, beryllium, fluorides, and sulfuric acid mist will also occur under the anticipated case of 100 percent biomass firing. Under worst-case conditions of 25 percent coal firing during a year, increases in emissions of sulfur dioxide, fluoride, beryllium, and sulfuric acid mist will occur, requiring a PSD review for these pollutants.

However, on balance, there will be no increase in SO_2 emissions due to the proposed project. A similar cogeneration project is proposed for the Osceola Farms sugar mill. According to the zoning approval with the Palm Beach County Planning and Zoning Board, annual SO_2 emissions for both the Flo-Energy and Sol-Energy (i.e., Okeelanta and Osceola) cogeneration facilities combined, averaged over the life of the project (estimated at 30 years), must be limited to the current combined SO_2 emissions from the existing Okeelanta and Osceola sugar mills (i.e., 1,000 tons per year).

In the case of mercury emissions, the Palm Beach County zoning approval requires that maximum annual mercury emissions for the cogeneration facility cannot exceed current annual mercury emissions, even under worst-case conditions of 25 percent coal burning. In order to meet this requirement, Flo-Energy will install a mercury control system on each of the three new cogeneration units. This is the first facility of its type in the world to employ a mercury control system.

Flo-Energy will demonstrate compliance with pollutant emission limits by monitoring continuously such parameters as steam production; fuel input rates; and stack gas opacity, nitrogen oxides (NO_x), carbon monoxide (CO), and oxygen or carbon dioxide (CO_2) content. In addition, stack testing will be performed for particulate matter (PM), NO_x, CO, SO_2, lead, mercury, and volatile organic compounds (VOCs) every 6 months during the first 2 years of operation. If these tests show compliance with the permitted emission limits, the stack testing frequency will be reduced to that typically required by the Florida Department of Environmental Regulation (i.e., once every year or once every 5 years, depending upon pollutant).

A top-down BACT analysis for SO_2 was performed for the worst-case scenario where the proposed boilers fire 25 percent coal as an auxiliary fuel on an annual basis. The analysis concluded that both wet and dry scrubbing technologies are technically feasible for the facility. However, significant economic, environmental, and energy costs are associated with the two alternative scrubber options. The estimated costs for add-on SO_2 controls are unreasonable, particularly considering that the facility will not burn coal as its primary fuel; if burned, coal will be burned in limited amounts, and only when the supply of biomass fuels is not adequate; and coal may never be burned at the facility. A very high capital cost would be incurred for SO_2 control equipment that may never be used. No other facility in the United States has been identified as requiring add-on SO_2 controls as BACT where the heat input due to fossil fuels was less than 30 percent. Based on these considerations, using low-sulfur (approximately 0.7 percent maximum) coal as an auxiliary fuel and limiting the use of coal to a maximum of 25 percent of the total annual heat input represents BACT for SO_2 for the Flo-Energy cogeneration project.

BACT for fluorides, beryllium, and sulfuric acid mist was determined to be the firing of low-sulfur biomass, very low sulfur fuel oil, and low sulfur coal, coupled with electrostatic precipitator technology.

The air quality impact analysis for SO_2 demonstrates that the proposed facility, even when operating under worst-case conditions of coal burning, will comply with all ambient air quality standards and PSD increments. The higher stacks associated with the new cogeneration facility, compared to the shorter stacks of the existing facility, will result in a general air quality improvement for all pollutants. No adverse air quality impacts will result upon the Everglades National Park PSD Class I area.

1.0 INTRODUCTION

Flo-Energy, Inc. is proposing to install a cogeneration facility which will use primarily biomass (bagasse and wood waste materials) to generate steam and electricity. The cogeneration facility will be located at the site of the existing Okeelanta Corporation sugar mill and refinery located south of South Bay, Florida. The existing sugar mill and refinery boilers will be replaced with a cogeneration system consisting of three new combustion units.

The cogeneration facility will provide enough steam energy for the needs of the Okeelanta sugar mill and refinery and will generate electricity which will be sold to Florida Power & Light Company (FPL). Further, the proposed facility will reduce total annual air emissions and water consumption compared to the existing facility while generating approximately 15 times more electric energy than the existing facility.

This report addresses the requirements of the prevention of significant deterioration (PSD) review procedures, pursuant to the rules and regulations implementing the federal Clean Air Act Amendments of 1977. The Florida Department of Environmental Regulation (FDER) has PSD review and approval authority in Florida. Based on the current actual emissions from the Okeelanta facility and future maximum emissions from the proposed cogeneration facility, a PSD review is indicated for sulfur dioxide (SO_2), fluoride (F), beryllium (Be), and sulfuric acid mist.

This PSD permit application contains seven additional sections. A complete description of the project, including air emission rates and stack parameters, is found in Section 2.0. The air quality requirements for the project and new source review applicability are discussed in Section 3.0. Ambient monitoring requirements under PSD are addressed in Section 4.0. The best available control technology (BACT) analysis is presented in Section 5.0. The air quality impact (dispersion modeling) analysis is presented in Section 6.0 and additional impacts upon soils, vegetation and visibility are described in Section 7.0. Completed construction permit application forms and supportive information are contained in the appendices.

Appendix C contains the conditions and restrictions imposed on this project by Palm Beach County during the zoning process. In accordance with Palm Beach County's Condition No. 1.f., Flo-Energy requests that the County's Conditions No. 1.a. through 1.e. be included in FDER's specific permit conditions for the cogeneration facility. A complete list of specific permit conditions proposed for the facility is contained in Section 8.0 of this report.

2.0 PROJECT DESCRIPTION

2.1 EXISTING OPERATIONS

Okeelanta Corporation currently operates a sugar cane processing facility at its mill located just south of South Bay in Palm Beach county. The mill's air emission sources consist of eight boilers fired by bagasse and No. 6 fuel oil. These boilers normally operate from October through March (termed the "crop season"). During this period, the mill processes sugar cane into raw sugar.

Currently, a raw sugar refinery is operated that processes a portion of the raw sugar into refined sugar. In the past, the refinery has operated only during the crop season. A new boiler, Boiler No. 16, was recently constructed which will allow the refinery to operate during the off season. The new Boiler No. 16 will operate only during the off-season, starting in July 1992, to produce steam for raw sugar refining operations in the off-season. Fuel for this boiler is limited to low sulfur No. 2 distillate fuel oil.

The processing of the sugar cane produces a solid fuel byproduct, called bagasse, which is burned in the boilers to generate steam for the process. The boilers also burn No. 6 fuel oil during start-up and shutdown and at times when bagasse is not available to meet the total steam demands of the facility. Based on the current annual air emissions from the facility and the permitted emissions for Boiler No. 16, the facility is classified as an existing major stationary facility as defined in the Florida PSD Rules.

A regional map showing the location of the site is presented in Figure 2-1. A location map of the existing sugar mill indicating the plant property boundaries is presented in Figure 2-2. As shown, Okeelanta owns extensive sugar cane fields surrounding the mill in all directions. The nearest property boundary is approximately 1.5 miles from the existing sugar mill. A plot plan of the existing mill indicating the existing boilers, stacks, and buildings is presented in Figure 2-3.

2.2 PROPOSED COGENERATION FACILITY

A 74.9 megawatt (MW) (gross) cogeneration system is proposed which will be used to provide steam to the Okeelanta sugar mill and refining operations, and additionally will deliver a

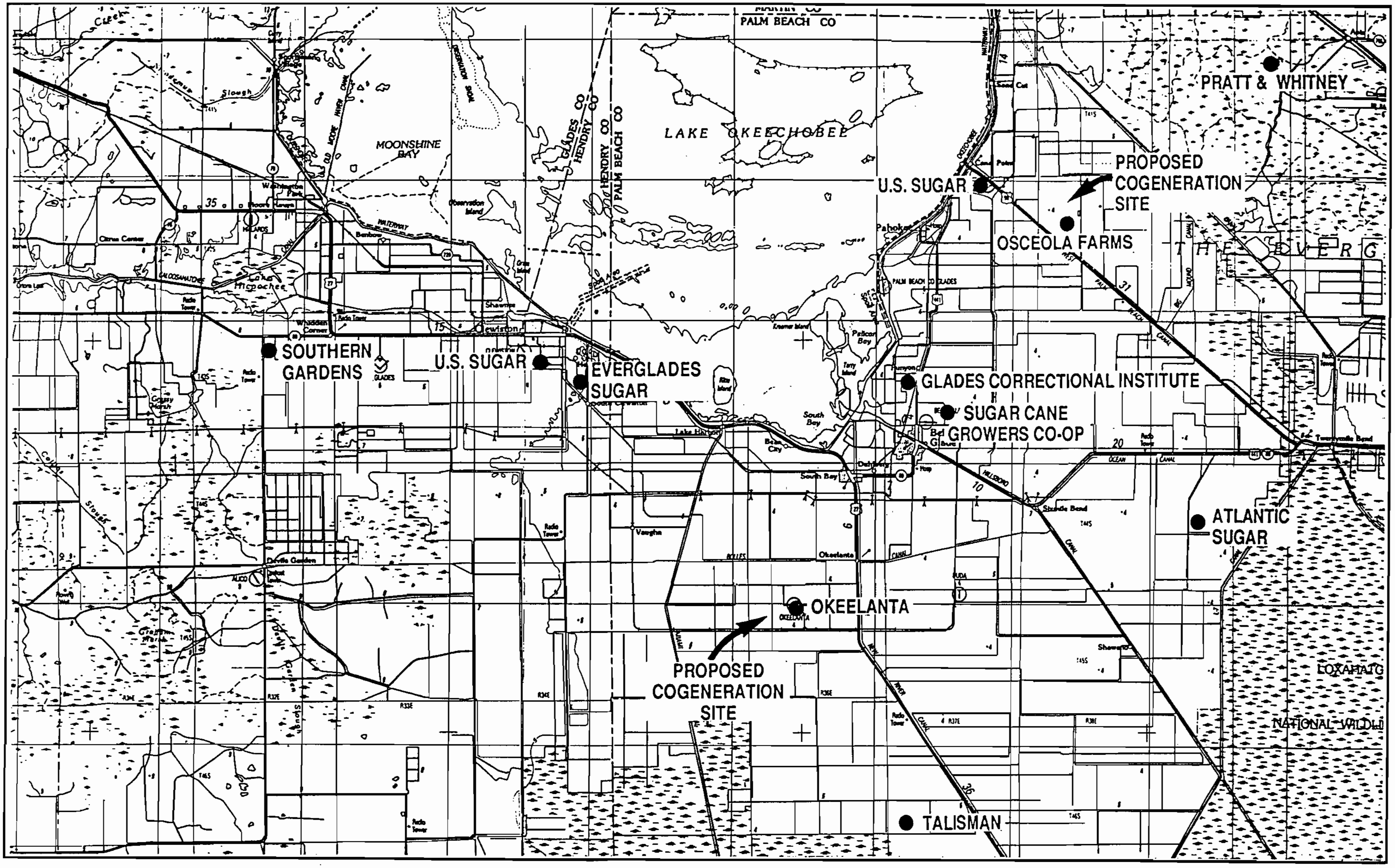

Figure 2-1 REGIONAL SITE MAP

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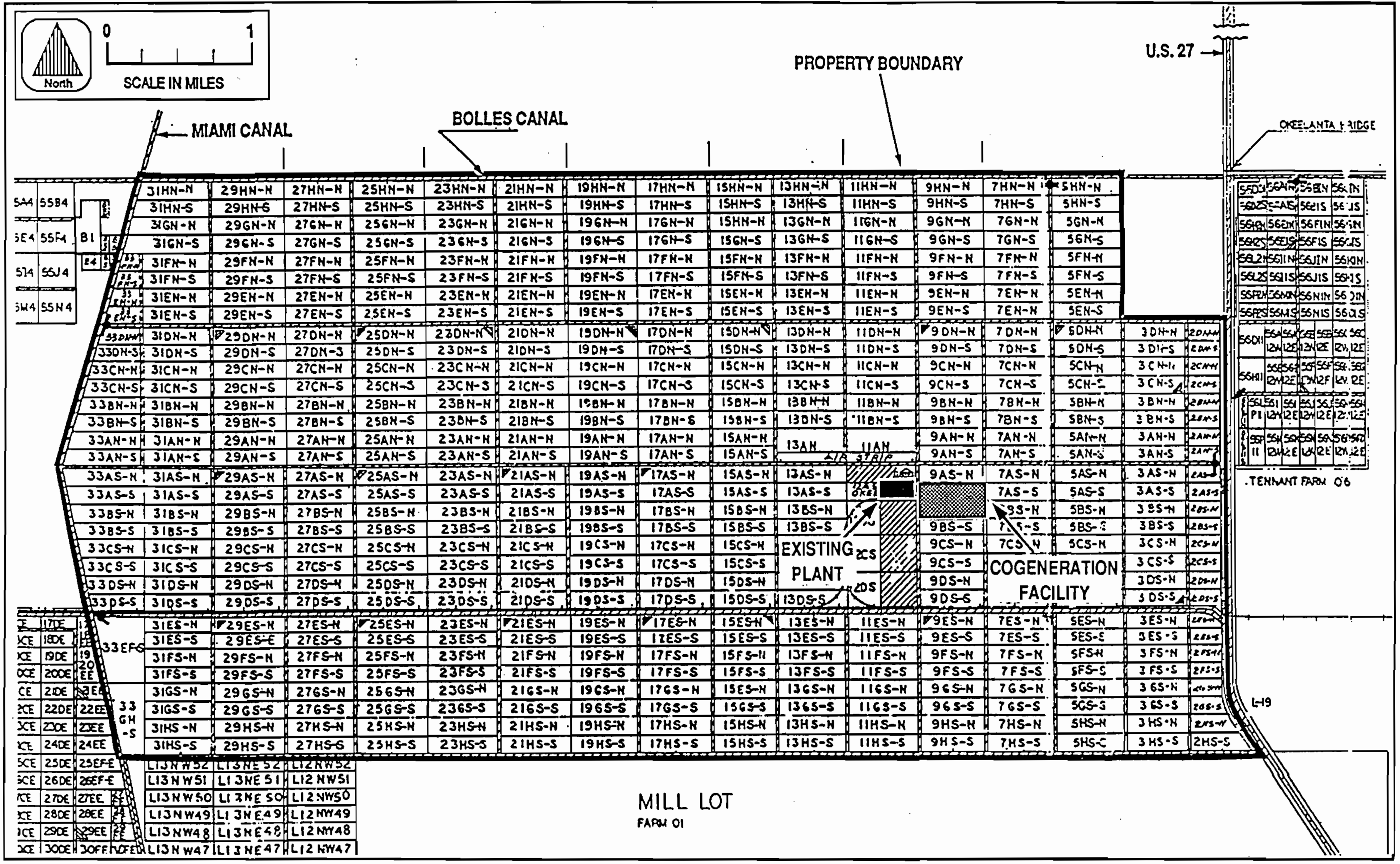

Figure 2-2 LOCATION OF EXISTING SUGAR MILL AND PROPOSED COGENERATION FACILITY

KBN

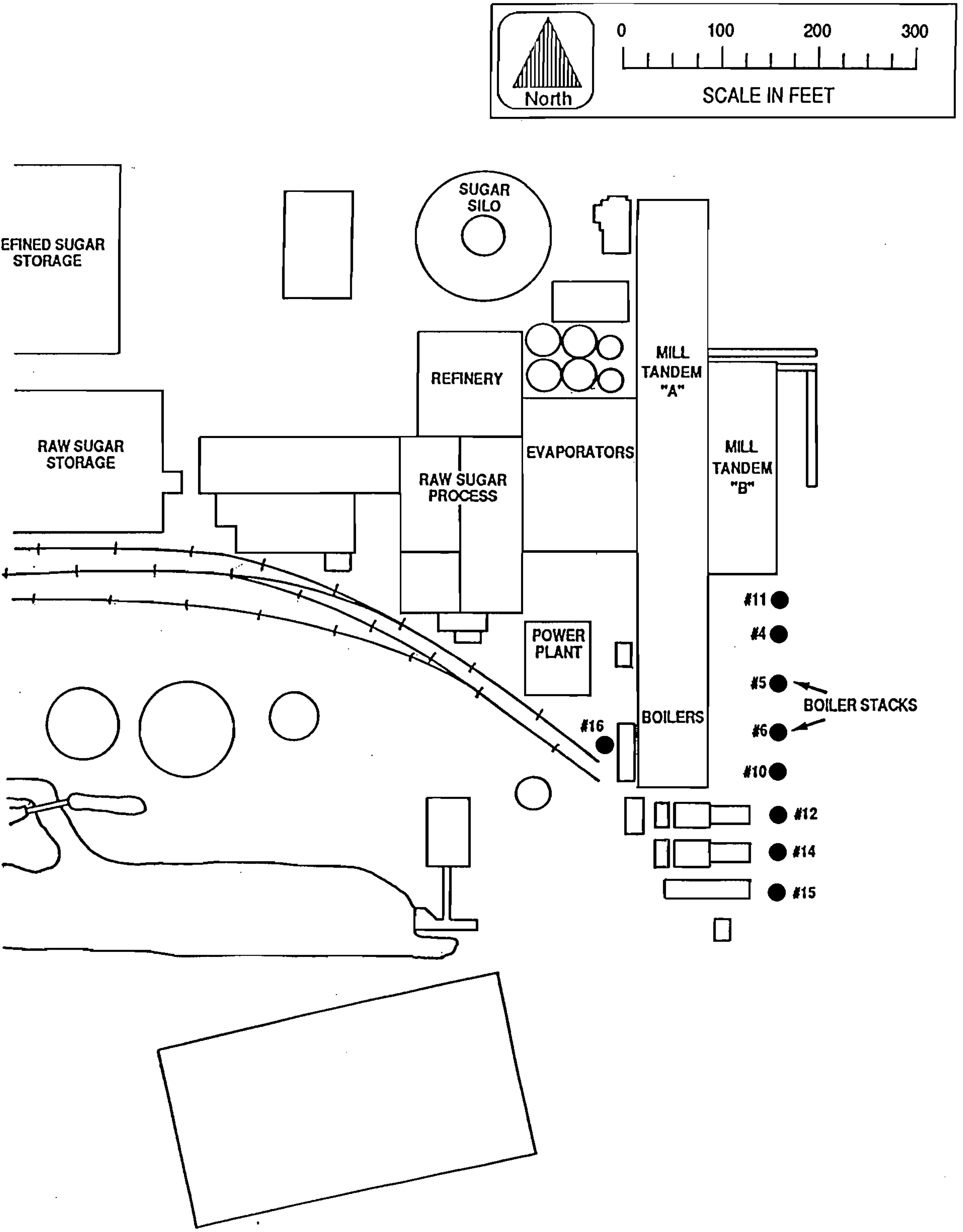

Figure 2-3 PLOT PLAN OF EXISTING OKEELANTA SUGAR MILL

substantial amount of electricity to FPL to supply its customers in south Florida. The proposed facility will be located immediately adjacent to the existing sugar mill and refinery (see Figures 2-2 and 2-4).

The proposed facility will operate with three steam boilers burning biomass (primarily bagasse and wood waste materials). The proposed facility will be designed to provide the sugar mill with an average of approximately 264,000 lb/hr of steam at 350 pounds per square inch gauge (psig) and 650°F and the sugar mill and refinery with an average of approximately 442,000 lb/hr of steam at 20 psig and 280 °F during the crop season. During the off-season, the refinery steam requirements will average approximately 120,000 lb/hr at 20 psig and 280°F. These steaming rates may vary as a function of operational conditions; equipment and process efficiencies; characteristics of the fuel, which is an agricultural product and somewhat variable; and overall sugar mill production rate. The proposed facility will produce approximately 74.9 MW (gross) of electricity year-round. A simplified flow diagram of the process is provided in Figure 2-5.

The existing boilers will be shut down upon commercial operation of the proposed cogeneration facility. During the first 3 years of cogeneration facility operation, the existing boilers may be operated only at times when all three boilers of the new cogeneration facility are shut down for repair or maintenance. After this time, the existing Boiler Nos. 4, 5, 6, 10, 11, 12, 14, and 15 will be permanently disabled and made incapable of operation. The recently constructed Boiler No. 16, which is permitted to burn only low sulfur No. 2 fuel oil, will be retained as a standby boiler for the cogeneration facility. This boiler would be operated only for black start purposes or when one of the cogeneration boilers is shut down. At 205 MMBtu/hr heat input, this boiler is much smaller than the cogeneration boilers which each have a maximum heat input of 715 MMBtu/hr.

A plot plan of the proposed facility is presented in Figure 2-6. The major structures will consist of the three boiler buildings.

It is Flo-Energy's desire to burn 100 percent biomass fuels. Generally, the bagasse from the sugar grinding operation will provide approximately two-thirds of the annual fuel requirements of the facility. The other one-third will be provided by wood waste materials, which could include

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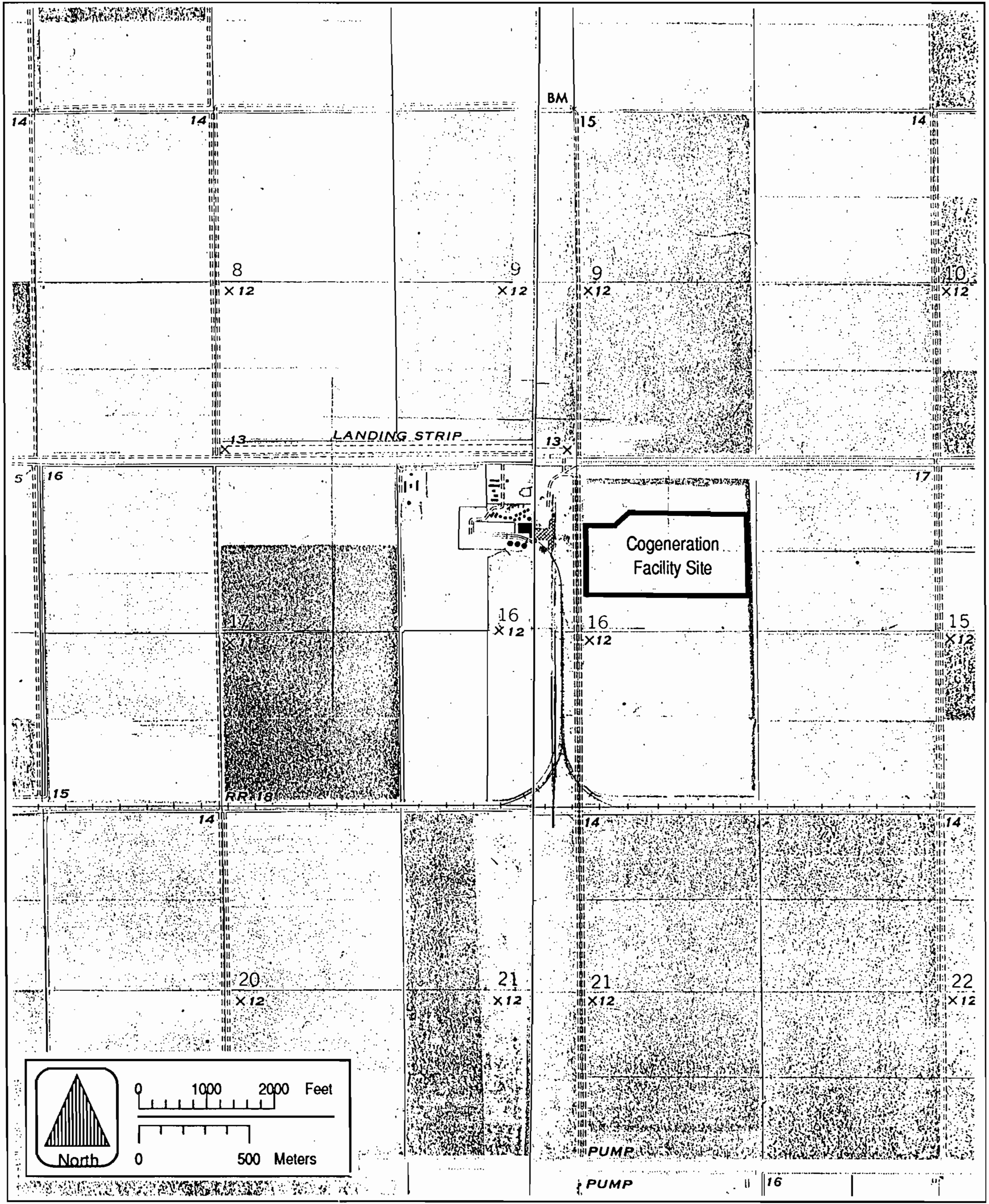

Figure 2-4 SITE LOCATION MAP

KBN

KBN.33-OKEELANTA
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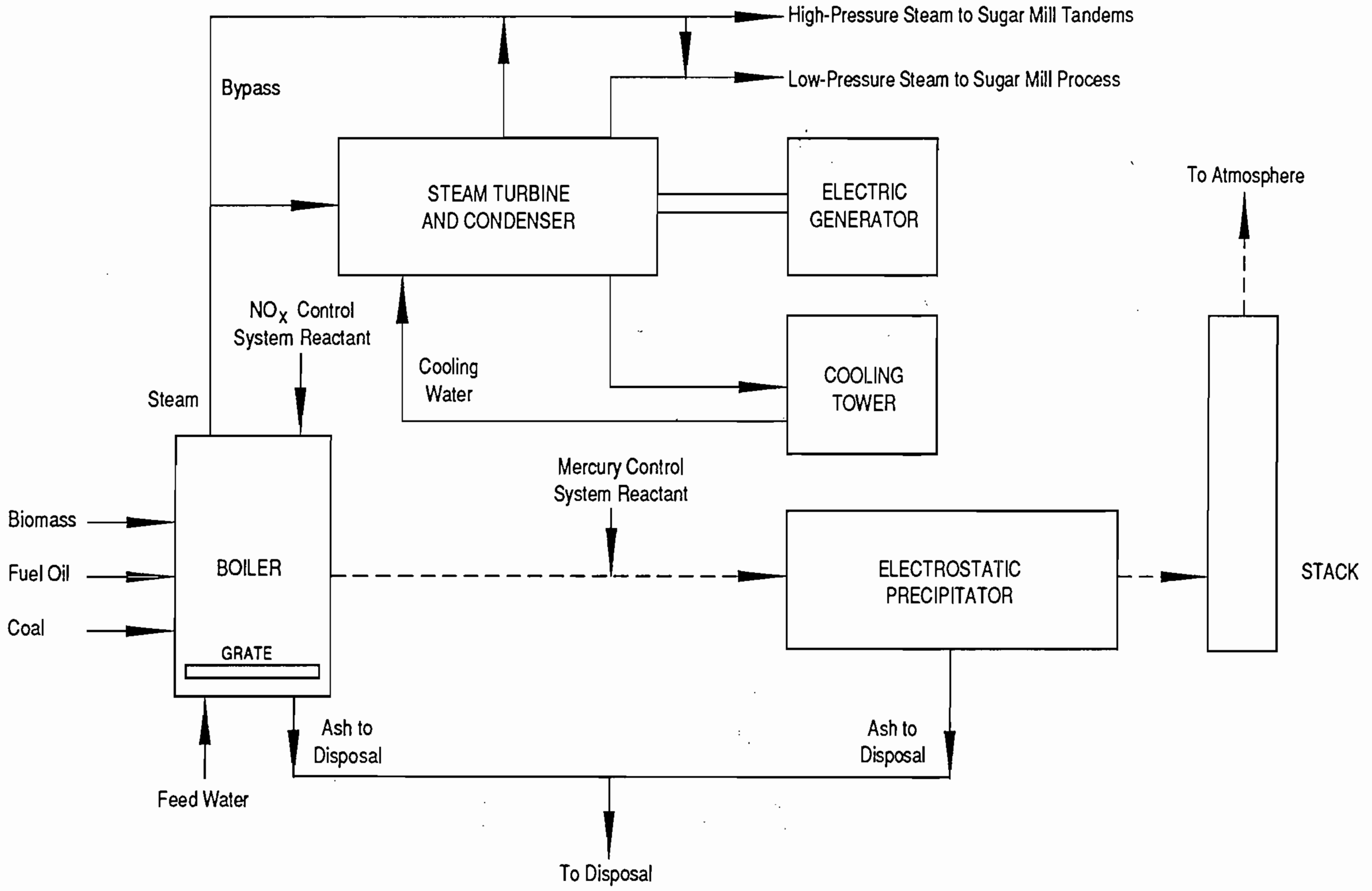

Figure 2-5 SIMPLIFIED FLOW DIAGRAM FOR FLO-ENERGY COGENERATION FACILITY

clean construction and demolition wood debris, yard trimmings, land clearing debris, and other clean cellulose and vegetative matter. However, because wood waste materials are not commodity fuels and the supply of wood waste may fluctuate, it is necessary to have the ability to burn limited amounts of fossil fuel in the event that the supply of biomass fuel is not adequate. Therefore, each combustion unit will have the capability to burn biomass, fuel oil, and coal, either alone or in combination.

The cogeneration facility will use low sulfur No. 2 fuel oil only to assist in startup or when the biomass fuel supply is not adequate. The No. 2 distillate fuel oil will have a maximum sulfur content of 0.5 percent and an equivalent maximum SO_2 emission rate of 0.5 lb/MMBtu.

Coal will be utilized only when the biomass fuel supply is not adequate. Coal fired in the facility will be low sulfur coal of approximately 0.7 percent sulfur content, with an equivalent maximum SO_2 emission rate of 1.2 lb/MMBtu.

The fuel handling system will be initially designed to handle biomass. The fuel systems are designed to feed reduced rates to the boilers to match boiler demand/use rates. Bagasse fuel can be delivered to the facility and boilers in several ways. Normally, bagasse from the sugar mill will be delivered directly to the boilers by a belt conveyor. Biomass can also be delivered by truck and conveyed to the boilers via the outfeed conveyor system. Biomass can be delivered from either of these sources to the fuel storage area for future reclaim. Biomass fuel from the reclaim system will be deposited on a conveyor and delivered to the boilers.

Biomass will be burned on a traveling or vibrating grate located within each boiler. In this design, biomass material is deposited on the grate, which moves slowly or vibrates, allowing combustion to occur in suspension or on the grate surface. Both underfire and overfire air are supplied to enhance combustion efficiency.

Coal fuel, if utilized, would also be fed to the boilers from the fuel storage area via the reclaim system. The coal will be burned on the grate in the boiler, similar to biomass firing, or by pulverized coal firing.

The proposed boilers will be equipped with fuel oil burners designed to provide maximum combustion efficiency. Associated piping will also be installed.

Fuel specifications for each fuel that may be utilized by the proposed facility are presented in Table 2-1. Based on these fuel specifications, maximum hourly firing rates are shown in Table 2-2 for each fuel when fired alone. The maximum heat input to each boiler due to biomass fuels will be 715 MMBtu/hr. Due to limitations of the boiler and firing system, maximum heat input of fossil fuels will be limited to 490 MMBtu/hr. Biomass and fossil fuels may also be burned in combination, not to exceed a total heat output of approximately 486 MMBtu/hr per boiler.

On an annual basis, all fuels may be fired alone or in combination, not to exceed a total heat output for all boilers of 7.820 x 10^{12} Btu/yr. In addition, burning of all fossil fuels will be limited to a total of 25 percent of the total annual heat input. Three cases are shown in Table 2-2 to illustrate the anticipated scenario of firing 100 percent biomass fuel and the potential cases of firing the maximum amount of fuel oil or the maximum amount of coal, with the remaining heat input due to biomass. When only biomass is fired, the annual heat input requirement is 11.5 x 10^{12} Btu/yr for the entire facility (total all three boilers). Under the worst-case of burning fossil fuels at 25 percent of the total annual heat input, the annual heat input requirement for the entire facility becomes 10.82 x 10^{12} Btu/yr, due to the different heat transfer efficiency for fossil fuels versus biomass.

Coal handling facilities will be constructed as needed prior to coal-firing. The coal handling system will consist of unloading, transfer, storage, reclaiming, and crushing operations. A railcar unloading system will utilize an enclosed bottom dumping type facility or equivalent. Coal will be delivered to the site via trains consisting of up to 75 railcars or by truck. Each railcar may hold up to 100 tons and each truck up to 25 tons. The cogeneration facility may burn up to approximately 112,075 tons of coal per year under the scenario of 25 percent of total annual heat input from coal.

Ash generated from the combustion process will consist of bottom ash, siftings ash, and fly ash. Bottom ash is ash which falls off the front of the grate onto a submerged conveyor. Siftings

Table 2-1. Design Fuel Specifications[a] for the Flo-Energy Cogeneration Facility

Parameter	Biomass Bagasse	 Wood Waste	No. 2 Fuel Oil	Bituminous Coal
Specific Gravity	--	--	0.865	--
Heating Value (Btu/lb)	4,250	5,500	19,175	12,000
Heating Value (Btu/gal)	--	--	138,000	--
Ultimate Analysis (dry basis):				
Carbon	48.93%	49.58%	87.01%	82.96%
Hydrogen	6.14%	5.87%	12.47%	5.41%
Nitrogen	0.25%	0.40%	0.02%	1.58%
Oxygen	43.84%	40.90%	0.00%	5.72%
Sulfur	0.009%	0.009%	0.50%	0.67%
Ash/Inorganic	0.83%	3.24%	0.00%	3.66%
Moisture	52%	37%	--	4.5%

[a] Represents average fuel characteristics.

Sources: Okeelanta Corp., 1992.
Combustion Engineering, 1981.

Table 2-2. Maximum Fuel Usage and Heat Input Rates, Flo-Energy Cogeneration Facility

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	÷ 2000 = 3,551 gal/hr
Coal	490	85	417	40,833 lb/hr 84.118
	Annual Average (total all three boilers) (Btu/yr)		(Btu/yr)	x 1/3 = 450,980
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	x 1/3 = 0 TPY 6,536,232
TOTAL	1.082E+13		7.820E+12	
25% COAL FIRING				
Biomass	8.118E+12	68	5.520E+12	955,059 TPY[a]
No. 2 Oil	0	85	0	0 gal/yr
Coal	2.706E+12	85	2.300E+12	112,750 TPY x 1/3 = 37,583
TOTAL	1.082E+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.

ash is ash which drops down through the grate to the bottom of the boiler. Fly ash is ash captured downstream of the boiler in the boiler bank hoppers, air preheater hoppers, and the ESP.

Bottom ash generated in the boilers will be handled wet via a submerged drag-chain conveyor. This ash will be delivered to a dumpster for subsequent disposal. The siftings ash collected at the bottom of the boiler and the fly ash collected downstream of the boiler will be conveyed via enclosed drag-chain conveyors to dumpsters. Particulate emissions from the material handling system are discussed in Section 2.4.1.

2.3 APPLICABILITY OF FEDERAL NEW SOURCE PERFORMANCE STANDARDS

Based on the maximum heat input to the cogeneration facility boilers and the type of fuel burned, the boilers will be subject to the federal NSPS for electric utility steam generating units (40 CFR 60, Subpart Da). The Subpart Da standards are summarized in Table 2-3.

For PM, the NSPS limits emissions to 0.03 lb/MMBtu when burning solid or liquid fuels. An opacity limit also applies, which limits opacity to 20 percent (6-minute average), except up to 27 percent opacity is allowed for one 6-minute period per hour.

In the case of SO_2, the proposed cogeneration units will be classified as "resource recovery units", since combustion of non-fossil fuels will be more than 75 percent on a quarterly (calendar) heat input basis. For such units, the NSPS limits SO_2 emissions to 1.2 lb/MMBtu based on a 30-day rolling average. The proposed facility will comply with the NSPS for SO_2 by burning biomass, low sulfur coal with a maximum sulfur content of approximately 0.7 percent, and very low sulfur distillate fuel oil with a maximum sulfur content of approximately 0.5 percent. Equivalent maximum SO_2 emission rates are 1.2 lb/MMBtu for coal and 0.5 lb/MMBtu for No. 2 fuel oil. Biomass has an inherently low sulfur content (i.e., average of about 0.009 percent by weight).

The NSPS for NO_x is 0.30 lb/MMBtu heat input for fuel oil firing and 0.60 lb/MMBtu for solid fuels, including bagasse, wood and coal. The proposed maximum NO_x emission rate for the facility for each fuel is lower than the NSPS. Compliance with the NO_x emissions limitation under Subpart Da is based on a 30-day rolling average.

Table 2-3. Federal NSPS for Electric Utility Steam-Generating Units Applicable to the Flo-Energy Cogeneration Facility

Pollutant	Emission Limitation
Particulate Matter	Liquid fuel--0.03 lb/10^6 Btu Solid fuel--0.03 lb/10^6 Btu
Visible Emissions	20% opacity (6-minute average), except up to 27% opacity is allowed for one 6-minute period per hour
Sulfur Dioxide[a]	Resource Recovery Units--1.20 lb/10^6 Btu
Nitrogen Oxides[a]	Fuel Oil--0.30 lb/10^6 Btu Solid fuels: Bituminous coal--0.60 lb/10^6 Btu All other fuels--0.60 lb/10^6 Btu

Note: Emission limits for PM, NO_x, and SO_2 do not apply during periods of startup, shutdown, or malfunction.

[a] Compliance determined on a 30-day, rolling average basis.

Source: 40 CFR 60, Subpart Da.

Further requirements under 40 CFR 60 Subpart Da include emission monitoring. Continuous monitoring is required for opacity, NO_x, and carbon dioxide or oxygen. Continuous monitoring is defined as "a minimum of 18 hours in at least 22 out of 30 successive boiler operating days" (40 CFR 60.47a (f)). Specifically, a continuous opacity monitor must be installed at a point free of interference from water to monitor PM emissions. NO_x emissions must also be measured at the stack. Further, at the point NO_x emissions are monitored, oxygen or carbon dioxide must be monitored. The continuous monitoring systems are to be operated and data recorded during "all periods of operation including periods of startup, shutdown, malfunction of emergency conditions, except for continuous monitoring system breakdowns, repairs, calibration checks and span adjustments" [40 CFR 60.47a (e)].

2.4 EMISSIONS OF REGULATED POLLUTANTS

2.4.1 COGENERATION FACILITY BOILERS

The proposed emission limits for all regulated pollutants emitted by the proposed boilers are presented in Table 2-4. Maximum emissions of total suspended particulate matter PM(TSP) and particulate matter less than 10 microns in diameter (PM10) are based upon an electrostatic precipitator (ESP) control device to meet New Source Performance Standards (NSPS) for electric utility steam generating units, as specified in 40 CFR 60 Subpart Da.

The maximum NO_x emissions reflect a flue-gas NO_x control system (i.e., selective non-catalytic reduction system) which will be designed to achieve at least a 40 percent NO_x reduction efficiency. The proposed emission rates are 0.15 lb/MMBtu for biomass fuels and No. 2 fuel oil, and 0.17 lb/MMBtu for coal firing, all based on a 30-day rolling average. Carbon monoxide (CO) and volatile organic compounds (VOCs) emissions reflect the proposed boiler design and good combustion practices.

Emissions of SO_2 are based on the maximum sulfur content of the fuels, subsequent SO_2 emissions, and the fuel firing rates. NSPS limits SO_2 emissions due to fossil fuel firing to 1.2 lb/MMBtu or less, based on a 30-day rolling average. Compliance with this limit will be achieved by burning biomass fuels, low sulfur (approximately 0.7 percent maximum) coal, and

Table 2-4. Proposed Emission Limits for the Flo-Energy Facility

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	0.5	1.2
Annual average[a]	0.02	0.5	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	0.015	0.036

[a] Compliance based on 30-day rolling average, per 40 CFR 60, Subpart Da.
[b] Limits are 5.5×10^{-6} lb/MM Btu for bagasse and 0.29×10^{-6} lb/MM Btu for wood waste materials.

very low sulfur (approximately 0.5 percent maximum) fuel oil. Biomass fuels are inherently low in sulfur, resulting in low emission rates. Both annual average and 24-hour limits are proposed for SO_2 (see Table 2-4).

Emissions of other regulated pollutants, including trace elements, for biomass are based on sugar industry test data, emission tests of wood-fired boilers at Seminole Kraft Corporation in 1990, fuel sampling, and EPA Publication AP-42 (EPA, 1988a). Further, for No.2 fuel oil and coal, emission factors for trace elements were obtained from Toxic Air Emission Factors: A Compilation, revised edition (EPA, 1988a) and Estimating Air Toxic Emissions from Coal and Oil Combustion Sources (EPA, 1989).

Mercury emissions from the proposed boilers are based upon the best available data concerning emissions from firing bagasse and wood. No bagasse boiler mercury test data is available. However, sugar cane dead leaves have been tested (Patrick, 1991). The dead leaves are considered to be similar to bagasse, which is dead sugar cane stalk. Numerous samples of the dead sugar cane leaves yielded an average mercury content of 0.068 ppm (dry basis). This equates to an uncontrolled mercury emission factor of 6.6×10^{-5} lb/ton of wet bagasse, or 7.8×10^{-6} lb/MMBtu. Published test data from wood-fired spreader stoker boilers indicate that uncontrolled mercury emissions for wood waste firing are 0.41×10^{-6} lb/MMBtu (see Appendix A).

Published information on the mercury content of No. 2 fuel oil allowed derivation of an emission factor for this fuel. A recent report (KBN, 1992) presented mercury emission factors for coal-fired boilers and formed the basis for mercury emissions from coal-firing.

The mercury emission factors also reflect a minimum 30 percent control efficiency resulting from a mercury control system (carbon injection or equivalent) and an ESP control device. However, due to the uncertainty related to the emission estimates (i.e., limited data on bagasse and wood waste materials as well as mercury control systems), a 30 percent control efficiency may not be necessary to achieve the proposed emission rates. It is therefore requested that only the emission limitations for mercury (i.e., lb/MMBtu and TPY limits) become permit conditions. A percent removal efficiency for mercury should not be specified as a permit condition.

Sulfuric acid mist emissions are based upon EPA AP-42 (EPA, 1988a), which indicates sulfuric acid mist is approximately 3 percent of sulfur dioxide emissions.

Maximum hourly emissions from each of three proposed boilers for each fuel are presented in Table 2-5. Each emission factor is noted with its specific reference. As shown, the maximum hourly emissions occur when burning either biomass or bituminous coal.

The total maximum annual emissions for each pollutant from all three boilers are presented in Table 2-6. These are based upon the same emission factors as described previously. The total maximum emissions for each pollutant is based upon the worst-case fuel operating scenario and is indicated in the far right column of Table 2-6. Derivations and sample calculations for the emission factors are presented in Appendix A.

The annual SO_2 emissions presented in Table 2-6 include the worst-case scenario of 25 percent coal burning in any one year, with remaining heat input from biomass. However, according to the zoning approval with the Palm Beach County Planning and Zoning Board, annual SO_2 emissions must be limited to a total of 1,000 TPY for both the Flo-Energy and Sol-Energy (i.e., Okeelanta and Osceola) cogeneration facilities combined, averaged over the life of the project (estimated at 30 years). Therefore, if fossil fuels are burned in either facility and they result in annual SO_2 emissions greater than 1,000 tons, the use of fossil fuels must be limited in other years to produce average annual SO_2 emissions of less than 1,000 tons for both facilities combined. A copy of the zoning requirements is contained in Appendix C.

In the case of mercury emissions, the Palm Beach County zoning approval requires that maximum annual mercury emissions for the cogeneration facility cannot exceed current annual mercury emissions. As presented in Appendix B, the best available estimate of current mercury emissions from the Okeelanta facility, based on limited data, is 0.0256 TPY, based on a 2-year average, or 0.0262 based upon the highest year out of the last 2 years. As a result, the proposed mercury limit for the cogeneration facility is 0.0262 TPY. It is noted that, Okeelanta may conduct testing in the future to better establish baseline emission factors and emission levels for mercury.

Table 2-5. Maximum Short-Term Emissions for the Flo-Energy Cogeneration Facility (per boiler)

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]	0.5[a]	9	490	245.0[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	5.5E-06	6	715	0.0039	2.4E-06	11	490	0.00118	8.4E-06	13	490	0.0041	0.0041
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	0.015	8	490	7.4	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 mercury content in sugar cane and 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 2-6. Maximum Annual Emissions for the Flo-Energy Cogeneration Facility (total all three boilers)

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	115.0	–	–	–	–	–	–	115.0
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]	–	–	–	–	–	–	0.0262
Beryllium	–	–	–	–	–	–	–	–	–	–
Fluorides	–	–	–	–	–	–	–	–	–	–
Sulfuric acid mist	0.0006	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	81.2	0.5	2.706	676.50	–	–	–	757.7
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]	–	–	–	0.0262
Beryllium	–	–	–	3.5E-07	2.706	0.0005	–	–	–	0.0005
Fluorides	–	–	–	6.3E-06	2.706	0.0085	–	–	–	0.0085
Sulfuric acid mist	0.0006	8.118	2.44	0.015	2.706	20.30	–	–	–	22.74
Total reduced sulfur	–	–	–	–	–	–	–	–	–	–
Asbestos	–	–	–	–	–	–	–	–	–	–
Vinyl Chloride	–	–	–	–	–	–	–	–	–	–
		25% Coal 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	80	–	–	–	1.2	2.706	1,620	1,700 [a]
Nitrogen oxides	0.15	8.118	608.85	–	–	–	0.17	2.706	230.01	838.86
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	–	–	–	6.4E-05	2.706	0.09	0.19 [a]
Mercury	[b]	8.118	[b]	–	–	–	[b]	2.706	[b]	0.0262 [a]
Beryllium	–	–	–	–	–	–	5.9E-06	2.706	0.0080	0.0080 [a]
Fluorides	–	–	–	–	–	–	0.024	2.706	32.47	32.47 [a]
Sulfuric acid mist	0.0006	8.118	2.44	–	–	–	0.036	2.706	48.71	51.15 [a]
Total reduced sulfur	–	–	–	–	–	–	–	–	–	–
Asbestos	–	–	–	–	–	–	–	–	–	–
Vinyl Chloride	–	–	–	–	–	–	–	–	–	–

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

Source: KBN, 1992.

In order to meet the proposed mercury emission limit (in TPY) under certain fuel firing scenarios, the annual firing of bagasse and/or coal may need to be limited due to the higher emission factors for bagasse and coal compared to wood waste firing. The limits on firing of different fuels will depend upon the mix of fuels, actual emission factors, and the total heat input in any given year. Once operation of the facility commences, a test program will be undertaken by Flo-Energy to establish actual emission factors for each fuel. Based on the established emission factors, a fuel management plan will be implemented to insure the 0.0262 TPY mercury emission limit (or the applicable limit based on test data) is not exceeded. The fuel management plan will be submitted to FDER's West Palm Beach office and to the Palm Beach County Health Unit for review.

It is emphasized that the baseline mercury calculations are based on very limited data, and further testing may indicate different emission factors. Therefore, these figures are subject to change as better information becomes available. It is therefore requested, as stated previously, that only the emission limits for mercury in terms of lb/MMBtu and TPY become permit conditions.

2.4.2 FUGITIVE EMISSIONS OF PARTICULATE MATTER

Sources of fugitive particulate emissions were identified based on the descriptions of the coal and material handling and storage processes. Emissions of fugitive dust can occur from four types of coal handling operations: batch drop, coal crushing, wind erosion, and vehicular traffic. Presented in Table 2-7 is an inventory and annual average emission factors for each of the four processes. Computations are based upon EPA AP-42 (EPA, 1988a) Sections 11.2.1 and 11.2.3. The emission factors for batch drop are a function of moisture content and wind speed. Moisture content is based upon the average analysis of bituminous coal of 4.5 percent moisture (refer to Table 2-1 and AP-42). Fly ash is assumed to have a low moisture content, i.e., 2.0 percent. From published weather data, the annual average wind speed at West Palm Beach is 9.4 mph.

For railcar unloading, which will be performed in an enclosed structure, 70 percent control for enclosure is indicated, based on published literature (ERT, 1981). The reclaim hopper, being underground, will be essentially enclosed, resulting in a 90 percent control efficiency

Table 2-7. Flo-Energy Cogeneration Facility Annual Average Uncontrolled Fugitive Emission Factors

Source	Type of Operation[a]	M Moisture Content (%)	U Wind Speed (mph)	E Emission Factor (lb/ton)
Railcar Unloading	Batch Drop	4.5	9.4	0.00234
Conveyor-to-Coal Pile	Batch Drop	4.5	9.4	0.00234
Reclaim Hopper	Batch Drop	4.5	9.4	0.00234
Conveyor-to-Crusher	Batch Drop	4.5	9.4	0.00234
Coal Crusher	Coal Crushing	-	-	0.02 [b]
Crusher-to-Conveyor	Batch Drop	4.5	9.4	0.00234
Conveyor-to-Boiler Silo	Batch Drop	4.5	9.4	0.00234
Storage Pile	Wind Erosion	-	-	[c]
Coal Pile Maintenance	Vehicular Traffic	-	-	0.90328 [d]
Fly Ash Transfer	Batch Drop	2.0	9.4	0.00727

[a] Batch drop emission factors are computed from AP-42 (EPA, 1988) Section 11.2.3:
$E = 0.0032 \times (U/5)^{1.3} + (M/2)^{1.4}$ lb/ton.

[b] Emission factor for coal crusher taken from AP-42, Table 8.23-1, for high-moisture ore.

[c] Emission calculations provided in Appendix A.

[d] lb/vehicle mile traveled per day, based on AP-42 Section 11.2.1 (EPA, 1988).

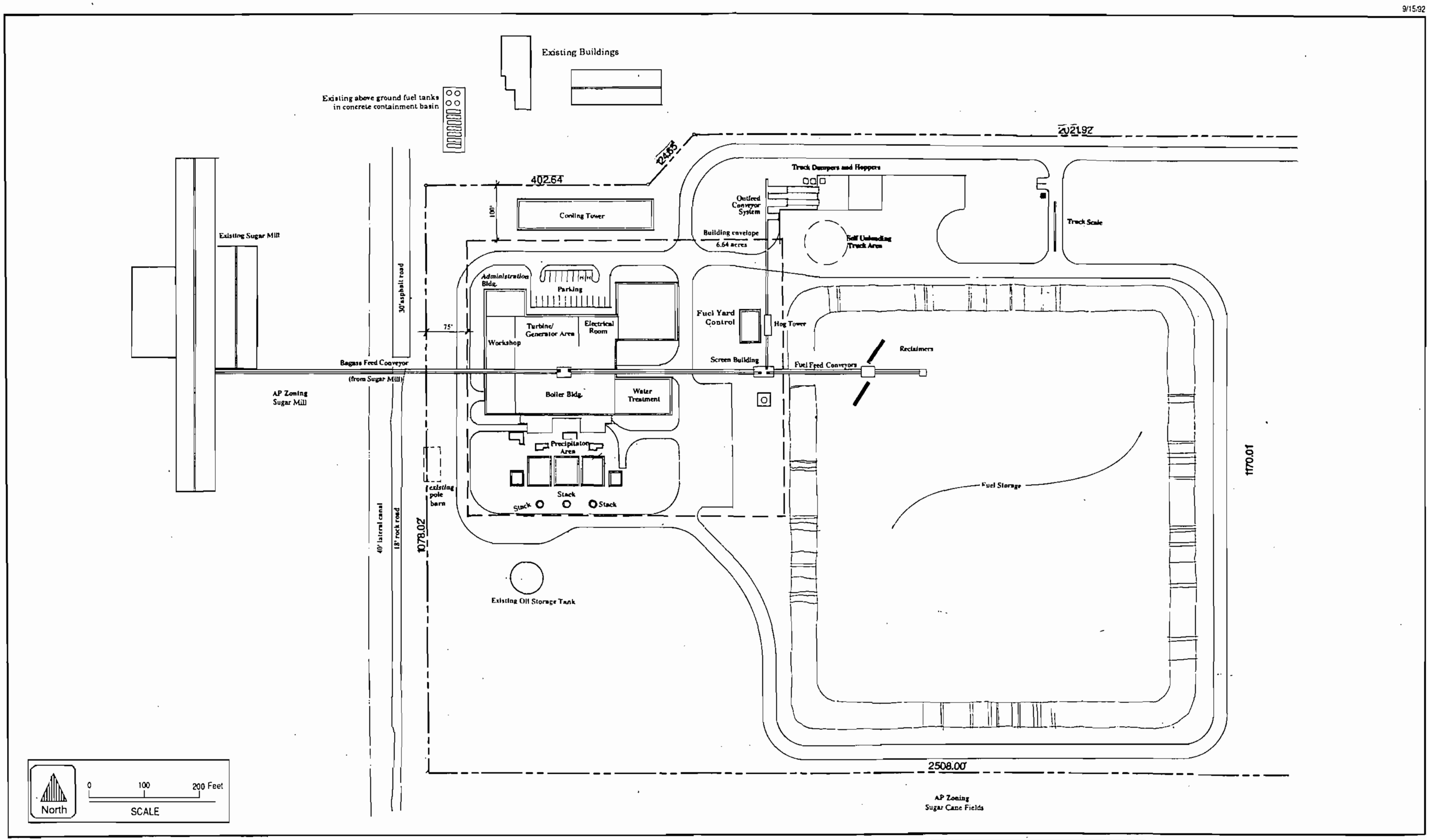

Figure 2-6 CONCEPTUAL PLOT PLAN OF PROPOSED COGENERATION FACILITY

KBN

(ERT, 1981). The uncontrolled emission factor for coal crushing was determined directly from AP-42 for high moisture ore: 0.02 lb/ton for PM(TSP) and 0.009 lb/ton for PM10. Published data indicate 70 percent control provided by enclosure of the coal crusher (ERT, 1981).

Vehicular traffic emissions were determined based on silt content of the road material, vehicle speed and weight, wheel count and wet days (i.e., precipitation more than 0.01 inch) per year. For the coal pile maintenance, one vehicle operating 8 hours a day for 365 days per year will be sufficient to maintain the pile. A control efficiency of 50 percent was applied due to watering the coal pile during dry or dusty conditions, based on published information concerning fugitive dust emission controls for coal storage piles (ERT, 1981).

A wind erosion emission factor determination is outlined in AP-42 Section 11.2.7. A computer program developed by EPA contract (Midwest Research Institute, 1990) was used to apply the AP-42 equations to the proposed coal storage pile. A summary of variables used is presented along with the wind erosion emission factors in Appendix A. A circular, conical coal pile of 500 ft diameter and 30 ft height was assumed, which is large enough to accommodate a full year's supply of coal for the facility (i.e., 112,750 TPY at 25 percent of total facility heat input). Moisture content used was 4.5 percent (as described above), and average silt content used was 2.2 percent based on publication AP-42. It was further assumed that the coal pile would be disturbed once every four days, based on using coal only 25 percent of the time during a year. In addition, it is assumed that 50 percent of the coal pile would be disturbed for each disturbance day. The resulting PM10 emissions are calculated as 95,653 g/yr, or 0.105 TPY. Corresponding PM(TSP) emissions are double this, or 0.211 TPY. Output from the computer program is provided in Appendix A.

The fly ash handling system will utilize enclosed conveyors and transfer points. However, fly ash handling will potentially generate fugitive PM emissions at the point of discharge into the dumpsters. Estimated annual emissions are based on the maximum amount of fly ash potentially generated (i.e., when 100 percent biomass is burned).

Annual average fugitive PM emissions are presented in Table 2-8. The emissions are based on the maximum annual coal throughput of 112,750 TPY. Total annual PM(TSP) fugitive emissions are 4.584 TPY, and PM10 emissions are 1.669 TPY.

The mercury control system employed on the cogeneration boilers will utilize a solid sorbent material, such as carbon. If utilized, the solid material will be delivered to the site by truck and pneumatically conveyed to a storage silo for each boiler. The silos will be controlled by use of a bin vent filter or baghouse to reduce fugitive PM emissions to 0.01 gr/dscf or less. Estimated parameters for the control devices are presented in Table 2-9.

The estimated annual PM(TSP) emissions from fugitive sources and silos total 4.839 TPY for the proposed facility. Total annual PM(10) emissions are estimated at 1.924 TPY.

2.5 EMISSIONS OF NON-REGULATED POLLUTANTS

Emission factors for non-regulated pollutants were obtained from EPA's compilation of toxic air pollutant emission factors (EPA, 1988a) and the EPA VOC and PM speciation database. Emission factors are available from these references for fuel-oil, coal, and wood combustion. Bagasse emission factors are not available. However, emissions due to bagasse firing are expected to be similar to those from wood-waste burning. Stack test results from a wood fired boiler at by Seminole Kraft Corporation in Jacksonville, Florida, conducted in 1990, provided biomass emission factors for most of the non-regulated pollutants listed. The emission factors and resulting emission rates are very low.

The estimated non-regulated pollutant emissions also account for the possibility that small amounts of treated wood may be present in the wood-waste stream. Flo-Energy will not knowingly accept treated wood. Nonetheless, the estimated emissions for arsenic, chromium, and copper are based on 3 percent treated wood in the wood-waste stream. Calculations are presented in Appendix A.

Residual ammonia emissions are associated with use of a selective non-catalytic reduction (SNCR) system for NO_x emission control. Testing at three municipal solid waste combustors located in California and equipped with SNCR systems displayed ammonia slip emissions ranging from 2 to 35 ppm, with an average of about 10 ppm. For the Flo-Energy facility, a maximum of 20 ppm

Table 2-8. Flo-Energy Cogeneration Facility Maximum Annual PM Emission Rates for Fugitive Dust Sources

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)
Railcar Unloading	0.00234	Enclosure	70	0.00070	112,750	0.040	0.35	0.014
Conveyor-to-Coal Pile	0.00234	None	0	0.00234	112,750	0.132	0.35	0.046
Reclaim Hopper	0.00234	Enclosure	90	0.00023	112,750	0.013	0.35	0.005
Conveyor-to-Crusher	0.00234	None	0	0.00234	112,750	0.132	0.35	0.046
Coal Crusher	0.02	Enclosure	70	0.006	112,750	0.338	0.45	0.152
Crusher-to-Conveyor	0.00234	None	0	0.00234	112,750	0.132	0.35	0.046
Conveyor-to-Boiler Silo	0.00234	None	0	0.00234	112,750	0.132	0.35	0.046
Storage Pile Wind Erosion	–	None	0	–	–	0.211 [a]	0.5	0.105 [a]
Coal Pile Maintenance[a]	0.90328	Watering	50	0.45164 [b]	14,600 [c]	3.297	0.35	1.154
Fly Ash Transfer	0.00727	None	0	0.00727	43,294 [d]	0.157	0.35	0.055
TOTAL						4.584		1.669

[a] Refer to Appendix A and text for derivation.

[b] lb/VMT.

[c] Vehicle miles traveled per year.

[d] 1,352,941 TPY biomass @ 3.20 percent ash; assumes all ash is fly ash.

Table 2-9. Parameters for Mercury Control System--Silo Baghouses

Emission Point	Air Flow Rate (acfm)	Particulate Emissions (gr/acf)	Particulate Emissions (lb/hr)	Operating Hours (hr/yr)	PM(TSP)/PM10 Emissions (TPY)
Mercury Removal Agent Silo 1	2,000	0.01	0.17	1,000	0.085
Mercury Removal Agent Silo 2	2,000	0.01	0.17	1,000	0.085
Mercury Removal Agent Silo 3	2,000	0.01	0.17	1,000	0.085

Note: acfm = actual cubic feet per minute.
gr/acf = grains per actual cubic foot.
hr/yr = hours per year.
lb/hr = pounds per hour.
TPY = tons per year.

NH_3 slip is considered achievable, and this results in maximum NH_3 emissions of 10.5 lb/hr per boiler when burning biomass fuels (results in highest exhaust gas flow rate and therefore highest emissions). This is equivalent to 0.0148 lb/MMBtu heat input.

Maximum hourly emissions of non-regulated pollutants are presented in Table 2-10. Estimates of maximum annual emissions of non-regulated pollutants are presented in Table 2-11. The emission factors are based upon the sources listed in Table 2-10. Each emission factor is footnoted with its specific reference. Derivations and sample calculations for these emission factors are presented in Appendix A.

2.6 STACK PARAMETERS

Stack parameters for the cogeneration facility are presented in Table 2-12. Each of the three new boilers within the proposed facility will be served by a separate stack. Each stack will be 199 feet (ft) tall and 8 ft in diameter. The locations of the three stacks are shown in Figure 2-6.

2.7 CONTROL EQUIPMENT INFORMATION

The proposed facility will utilize several emission control techniques to reduce emissions. The proposed cogeneration facility will incorporate a selective non-catalytic reduction (SNCR) system to reduce NO_x emissions. SNCR is a system which uses ammonia or urea injection into the boiler to reduce NO_x emissions. Further, the cogeneration boilers will minimize CO and VOC through proper furnace design and good combustion practices, including: control of combustion air and temperatures; distribution of fuel on the combustion surface; and better controls over the furnace loads and transient conditions. Particulate emissions will be reduced by an ESP. Mercury emissions will be controlled through a carbon injection system (or equivalent) and the ESP system.

2.8 PERMIT APPLICATION FORMS

A completed air construction permit application form for the proposed facility is contained in Appendix D.

Table 2-10. Maximum Hourly Emissions of Non-Regulated Pollutants for the Flo-Energy Cogeneration Facility (per boiler)

	Biomass				No. 2 Fuel Oil				Coal				Maximum
Non Regulated Pollutant	Emission Factor (lb/MMBtu)	Ref	Activity Factor (MMBtu/hr)	Hourly Emissions (lb/hr)	Emission Factor (lb/MMBtu)	Ref	Activity Factor (MMBtu/hr)	Hourly Emissions (lb/hr)	Emission Factor (lb/MMBtu)	Ref	Activity Factor (MMBtu/hr)	Hourly Emissions (lb/hr)	Hourly Emission[a] (lb/hr)
Ammonia	0.0148	8	715	10.6	0.0148	8	490	7.3	0.0148	8	490	7.3	10.6
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; see text.
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 2-11. Maximum Annual Emissions of Non-Regulated Pollutants for the Flo-Energy Cogeneration Facility (total all boilers) (Page 1 of 2)

	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)	Annual Emission (TPY)
Normal Operations										
Ammonia	0.0148	11.500	85.1	–	–	–	–	–	–	85.1 [a]
Antimony	UD	11.500	–	–	–	–	–	–	–	–
Arsenic	5.58E-05	11.500	0.32	–	–	–	–	–	–	0.32 [a]
Barium	1.06E-04	11.500	0.61	–	–	–	–	–	–	0.61
Bromine	1.47E-03	11.500	8.45	–	–	–	–	–	–	8.5 [a]
Cadmium	5.43E-06	11.500	0.031	–	–	–	–	–	–	0.031 [a]
Chromium	5.54E-05	11.500	0.32	–	–	–	–	–	–	0.32 [a]
Chromium^{+8}	1.35E-05	11.500	0.078	–	–	–	–	–	–	0.078 [a]
Cobalt	4.98E-04	11.500	2.86	–	–	–	–	–	–	2.86 [a]
Copper	7.23E-05	11.500	0.42	–	–	–	–	–	–	0.42
Dioxin	6.93E-12	11.500	4.0E-08	–	–	–	–	–	–	4.0E-08 [a]
Furan	3.62E-10	11.500	2.1E-06	–	–	–	–	–	–	2.1E-06 [a]
Formaldehyde	6.56E-04	11.500	3.77	–	–	–	–	–	–	3.8 [a]
Hydrogen Chloride	3.70E-02	11.500	212.75	–	–	–	–	–	–	212.8
Indium	1.27E-04	11.500	0.73	–	–	–	–	–	–	0.73 [a]
Manganese	7.98E-04	11.500	4.59	–	–	–	–	–	–	4.6 [a]
Molybdenum	2.54E-04	11.500	1.46	–	–	–	–	–	–	1.5 [a]
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 [a]
Thallium	UD	11.500	–	–	–	–	–	–	–	–
Tin	1.62E-04	11.500	0.93	–	–	–	–	–	–	0.93 [a]
Zinc	4.24E-04	11.500	2.44	–	–	–	–	–	–	2.44 [a]
Zirconium	9.29E-05	11.500	0.53	–	–	–	–	–	–	0.53 [a]
25% Oil Firing										
Ammonia	0.0148	8.118	60.1	0.0148	2.706	10.01	–	–	–	70.1
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 2-11. Maximum Annual Emissions of Non-Regulated Pollutants for the Flo-Energy Cogeneration Facility (total all boilers) (Page 2 of 2)

Non Regulated Pollutant	Biomass			No. 2 Fuel Oil			Coal			Total Annual Emission (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)	
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>25% Coal Firing</u>										
Ammonia	0.0148	8.118	60.1	–	–	–	0.0148	2.706	10.01	70.1
Antimony	UD	8.118	–	–	–	–	3.49E-05	2.706	0.047	0.047 [a]
Arsenic	5.58E-05	8.118	0.23	–	–	–	2.64E-05	2.706	0.036	0.27
Barium	1.06E-04	8.118	0.43	–	–	–	7.44E-04	2.706	1.01	1.44 [a]
Bromine	1.47E-03	8.118	5.97	–	–	–	7.90E-04	2.706	1.069	7.04
Cadmium	5.43E-06	8.118	0.022	–	–	–	1.36E-06	2.706	0.0018	0.024
Chromium	5.54E-05	8.118	0.22	–	–	–	1.66E-05	2.706	0.022	0.24
Chromium^{+6}	1.35E-05	8.118	0.055	–	–	–	3.32E-06	2.706	0.004	0.059
Cobalt	4.98E-04	8.118	2.02	–	–	–	7.20E-05	2.706	0.097	2.1
Copper	7.23E-05	8.118	0.29	–	–	–	1.71E-04	2.706	0.23	0.52 [a]
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	–	–	–	2.20E-04	2.706	0.30	2.96
Hydrogen Chloride	3.70E-02	8.118	150.183	–	–	–	7.90E-02	2.706	106.89	257.1 [a]
Indium	1.27E-04	8.118	0.52	–	–	–	–	2.706	–	0.52
Manganese	7.98E-04	8.118	3.24	–	–	–	3.10E-05	2.706	0.042	3.3
Molybdenum	2.54E-04	8.118	1.03	–	–	–	8.83E-05	2.706	0.119	1.2
Nickel	4.41E-05	8.118	0.18	–	–	–	1.02E-03	2.706	1.38	1.56 [a]
Phosphorus	3.53E-04	8.118	1.43	–	–	–	8.60E-04	2.706	1.16	2.60 [a]
Selenium	UD	8.118	–	–	–	–	5.34E-05	2.706	0.072	0.072 [a]
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	–	–	–	8.83E-05	2.706	0.119	0.78
Zinc	4.24E-04	8.118	1.72	–	–	–	3.49E-04	2.706	0.47	2.2
Zirconium	9.29E-05	8.118	0.38	–	–	–	–	2.706	–	0.38

Note: UD = undetectable levels in gas stream.

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

Table 2-12. Stack Parameters for the Flo-Energy Cogeneration Facility

Parameter[a]	Fuel Type Biomass	 No. 2 Fuel Oil	 Coal
Stack Height (ft)	199	199	199
Stack Diameter (ft)	8.0	8.0	8.0
Gas Flow Rate (acfm)	240,000-305,000	163,500	210,300
Gas Velocity (ft/s)	79.6-101.1	54.2	69.7
Gas Temperature (°F)	350	350	350

Note:
acfm = actual cubic feet per minute.
°F = degrees Fahrenheit.
ft = feet.
ft/s = feet per second.

[a] Parameters apply to each of the three proposed stacks (one stack per boiler).

2.9 COMPLIANCE DEMONSTRATION

Flo-Energy will demonstrate compliance with the maximum heat input limits for the facility by monitoring fuel input rates and fuel characteristics on a periodic basis. In addition, steam production parameters (i.e., steam amount, pressure, and temperature) and feedwater parameters will be continuously monitored to allow calculation of heat input by use of an assumed heat transfer efficiency for each fuel.

Continuous stack gas monitoring for opacity, NO_x, CO, and oxygen or CO_2 will be performed. In addition, per the zoning conditions recommended by Palm Beach County and agreed to by Flo-Energy, stack testing will be performed for PM, NO_x, CO, SO_2, lead, mercury and VOC every 6 months during the first 2 years of operation. If these tests show compliance with the permitted emission limits, the stack testing frequency will be reduced to that typically required by FDER (i.e., once every year or once every 5 years, depending upon pollutant).

Monitoring of SO_2 emissions due to oil and coal burning will be based on fuel analysis data.

3.0 AIR QUALITY REVIEW REQUIREMENTS AND APPLICABILITY

The following discussion pertains to the federal and state air regulatory requirements and their applicability to Flo-Energy's proposed cogeneration facility. These regulations must be satisfied before construction can begin on the proposed facility.

3.1 NATIONAL AND STATE AAQS

The existing national and Florida ambient air quality standards (AAQS) are presented in Table 3-1. National primary AAQS were promulgated to protect the public health, and national secondary AAQS were promulgated to protect the public welfare from any known or anticipated adverse effects associated with the presence of pollutants in the ambient air. Areas of the country in violation of AAQS are designated as nonattainment areas, and new sources to be located in or near these areas may be subject to more stringent air permitting requirements.

3.2 PSD REQUIREMENTS

3.2.1 GENERAL REQUIREMENTS

Federal PSD requirements are contained in the Code of Federal Regulations (CFR), Title 40, Part 52.21, Prevention of Significant Deterioration of air quality. The State of Florida has adopted PSD regulations [Chapter 17-2.510, Florida Administrative Code (F.A.C.)] that essentially are identical to the federal regulations. PSD regulations require that all new major stationary sources or major modifications to existing major sources of air pollutants regulated under CAA be reviewed and a construction permit issued. Florida's State Implementation Plan (SIP), which contains PSD regulations, has been approved by the U.S. Environmental Protection Agency (EPA), and, therefore, PSD approval authority in Florida has been granted to FDER.

A "major facility" is defined under PSD regulations as any one of 28 named source categories that has the potential to emit 100 tons per year (TPY) or more of any pollutant regulated under the CAA, or any other stationary facility that has the potential to emit 250 TPY or more of any pollutant regulated under CAA. A "source" is defined as an identifiable piece of process equipment or emissions unit. "Potential to emit" means the capability, at maximum design capacity, to emit a pollutant, considering the application of control equipment and any other federally enforceable limitations on the source's capacity. A "major modification" is defined under PSD regulations as a change at an existing major stationary facility that increases emissions by greater than significant amounts. PSD significant emission rates are shown in Table 3-2.

Table 3-1. National and State AAQS, Allowable PSD Increments, and Significance Levels ($\mu g/m^3$)

		AAQS					
		National		State of Florida	PSD Increments		Significant Impact Levels
Pollutant	Averaging Time	Primary Standard	Secondary Standard		Class I	Class II	
Particulate Matter (TSP)	Annual Geometric Mean	NA	NA	NA	5	19	1
	24-Hour Maximum[a]	NA	NA	NA	10	37	5
Particulate Matter (PM10)	Annual Arithmetic Mean	50	50	50	4[c]	17[c]	1
	24-Hour Maximum[b]	150	150	150	8[c]	30[c]	5
Sulfur Dioxide	Annual Arithmetic Mean	80	NA	60	2	20	1
	24-Hour Maximum[b]	365	NA	260	5	91	5
	3-Hour Maximum[b]	NA	1,300	1,300	25	512	25
Carbon Monoxide	8-Hour Maximum[b]	10,000	10,000	10,000	NA	NA	500
	1-Hour Maximum[b]	40,000	40,000	40,000	NA	NA	2,000
Nitrogen Dioxide	Annual Arithmetic Mean	100	100	100	2.5	25	1
Ozone	1-Hour Maximum[d]	235	235	235	NA	NA	NA
Lead	Calendar Quarter Arithmetic Mean	1.5	1.5	1.5	NA	NA	NA

[a] Maximum concentration not to be exceeded more than once per year.

[b] Achieved when the expected number of exceedances per year is less than 1.

[c] Proposed by EPA in the Federal Register on October 5, 1989.

[d] Achieved when the expected number of days per year with concentrations above the standard is less than 1.

Note:
Particulate matter (TSP) = total suspended particulate matter.
Particulate matter (PM10) = particulate matter with aerodynamic diameter less than or equal to 10 micrometers.
$\mu g/m^3$ = micrograms per cubic meter.
NA = Not applicable, i.e., no standard exists.

Sources: Federal Register, Vol. 43, No. 118, June 19, 1978.
40 CFR 50.
40 CFR 52.21.
Chapter 17-2.400, F.A.C.

Table 3-2. PSD Significant Emission Rates and De Minimis Monitoring Concentrations

Pollutant	Regulated Under	Significant Emission Rate (TPY)	De Minimis Monitoring Concentration ($\mu g/m^3$)
Sulfur Dioxide	NAAQS, NSPS	40	13, 24-hour
Particulate Matter (TSP)	NAAQS, NSPS	25	10, 24-hour
Particulate Matter (PM10)	NAAQS	15	10, 24-hour
Nitrogen Oxides	NAAQS, NSPS	40	14, annual
Carbon Monoxide	NAAQS, NSPS	100	575, 8-hour
Volatile Organic Compounds (Ozone)	NAAQS, NSPS	40	100 TPY[a]
Lead	NAAQS	0.6	0.1, 3-month
Sulfuric Acid Mist	NSPS	7	NM
Total Fluorides	NSPS	3	0.25, 24-hour
Total Reduced Sulfur	NSPS	10	10, 1-hour
Reduced Sulfur Compounds	NSPS	10	10, 1-hour
Hydrogen Sulfide	NSPS	10	0.2, 1-hour
Asbestos	NESHAP	0.007	NM
Beryllium	NESHAP	0.0004	0.001, 24-hour
Mercury	NESHAP	0.1	0.25, 24-hour
Vinyl Chloride	NESHAP	1	15, 24-hour

[a] No de minimis concentration; an increase in VOC emissions of 100 TPY or more will require monitoring analysis for ozone.

Note: Ambient monitoring requirements for any pollutant may be exempted if the impact of the increase in emissions is below de minimis monitoring concentrations.

NAAQS = National Ambient Air Quality Standards.
NM = No ambient measurement method.
NSPS = New Source Performance Standards.
NESHAP = National Emission Standards for Hazardous Air Pollutants.
$\mu g/m^3$ = micrograms per cubic meter.

Source: F.A.C., Rule 17-2.510, Table 500-2.

PSD review is used to determine whether significant air quality deterioration will result from the new or modified facility. Major new facilities and major modifications are required to undergo the following analyses related to PSD for each pollutant emitted in significant amounts:

1. Source information,
2. Control technology review,
3. Source impact analysis,
4. Preconstruction air quality monitoring analysis, and
5. Additional impact analyses.

In addition to these analyses, a new source also must be reviewed with respect to good engineering practices (GEP) stack height regulations. If the proposed new source or modification is located in a nonattainment area for any pollutant, the source may be subject to nonattainment new source review requirements.

Discussions concerning each of these requirements are presented in the following sections.

3.2.2 INCREMENTS/CLASSIFICATIONS

The 1977 CAA amendments address the prevention of significant deterioration of air quality. The law specifies that certain increases in air quality concentrations above the baseline concentration level of SO_2 and PM(TSP) would constitute significant deterioration. The magnitude of the allowable increment depends on the classification of the area in which a new source (or modification) will be located or will have an impact. Congress also directed EPA to evaluate PSD increments for other criteria pollutants and, if appropriate, promulgate PSD increments for such pollutants.

Three classifications were designated, based on criteria established in the CAA amendments. Certain types of areas (international parks, national wilderness areas, memorial parks larger than 5,000 acres, and national parks larger than 6,000 acres) were designated as Class I areas. All other areas of the country were designated as Class II. PSD increments for Class III areas were defined, but no areas were designated as Class III. However, Congress made provisions in the law to allow the redesignation of Class II areas to Class III areas.

In 1977, EPA promulgated PSD regulations related to the requirements for classifications, increments, and area designations as set forth by Congress. PSD increments were initially set for only SO_2 and PM(TSP). However, in 1988, EPA promulgated final PSD regulations for NO_x and established PSD increments for nitrogen dioxide (NO_2).

The current federal PSD increments are shown in Table 3-1. As shown, Class I increments are the most stringent, allowing the smallest amount of air quality deterioration, while the Class III increments allow a greater amount of deterioration. FDER has adopted the EPA class designations and allowable PSD increments for PM(TSP), SO_2, and NO_2. The Florida NO_2 increments were adopted in August 1990.

On October 5, 1989, EPA proposed PSD increments for PM10. Those proposed increments are shown in Table 3-1. The PM10 increments as proposed are somewhat lower in magnitude than the current PM(TSP) increments.

The term "baseline concentration" evolves from federal and state PSD regulations and refers to a fictitious concentration level corresponding to a specified baseline date and certain additional baseline sources. In reference to the baseline concentration, the baseline date actually includes three different dates:

1. The major source baseline date, which is January 6, 1975, in the cases of SO_2 and PM(TSP), and February 8, 1988, in the case of NO_2;
2. The minor source baseline date, which is the earliest date after the trigger date on which a major stationary source or major modification subject to PSD regulations submits a complete PSD application; and
3. The trigger date, which is August 7, 1977, for SO_2 and PM(TSP), and February 8, 1988, for NO_2.

By definition in the PSD regulations, baseline concentration means the ambient concentration level that exists in the baseline area at the time of the applicable baseline date. A baseline concentration is determined for each pollutant for which a baseline date is established and includes:

1. The actual emissions representative of sources in existence on the applicable minor source baseline date; and

2. The allowable emissions of major stationary facilities that began construction before January 6, 1975, for SO_2 and PM(TSP) sources, or February 8, 1988, for NO_x sources, but which were not in operation by the applicable baseline date.

The following emissions are not included in the baseline concentration and, therefore, affect PSD increment consumption:

1. Actual emissions representative of a major stationary source on which construction began after January 6, 1975, for SO_2 and PM(TSP) sources, and after February 8, 1988, for NO_x sources; and
2. Actual emission increases and decreases at any stationary facility occurring after the major source baseline date that result from a physical change or change in the method of operation of the facility.

The minor source baseline date for SO_2 and PM(TSP) has been set as December 27, 1977, for the entire State of Florida (Chapter 17-2.450, F.A.C.). The minor source baseline date for NO_2 has been set as March 28, 1988, for all of Florida.

3.2.3 CONTROL TECHNOLOGY REVIEW

The control technology review requirements of the federal and state PSD regulations require that all applicable federal and state emission-limiting standards be met, and that BACT be applied to control emissions from the source [Chapter 17-2.500(5)(c), F.A.C]. The BACT requirements are applicable to all regulated pollutants for which the increase in emissions from the facility or modification exceeds the significant emission rate (see Table 3-2).

BACT is defined in Chapter 17-2.100(25), F.A.C. as:

> An emissions limitation, including a visible emission standard, 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 (including fuel cleaning or treatment or innovative fuel combustion techniques) for control of such pollutant. If the Department determines that technological or economic limitations on the application of measurement methodology to a particular part of a source or facility would make the imposition of an emission standard infeasible, a design, equipment, work practice, operational standard or combination thereof, may be prescribed instead to satisfy the requirement for the application of BACT. Such standard shall, to the degree possible, set forth the emissions reductions achievable by implementation of such design, equipment, work practice, or operation.

The requirements for BACT were promulgated within the framework of PSD in the 1977 amendments of the CAA [Public Law 95-95; Part C, Section 165(a)(4)]. The primary purpose of BACT is to optimize consumption of PSD air quality increments and thereby enlarge the potential for future economic growth without significantly degrading air quality (EPA, 1978; 1980). Guidelines for the evaluation of BACT can be found in EPA's Guidelines for Determining Best Available Control Technology (BACT) (EPA, 1978) and in the PSD Workshop Manual (EPA, 1980). These guidelines were promulgated by EPA to provide a consistent approach to BACT and to ensure that the impacts of alternative emission control systems are measured by the same set of parameters. In addition, through implementation of these guidelines, BACT in one area may not be identical to BACT in another area. According to EPA (1980),

> BACT analyses for the same types of emissions unit and the same pollutants in different locations or situations may determine that different control strategies should be applied to the different sites, depending on site-specific factors. Therefore, BACT analyses must be conducted on a case-by-case basis.

The BACT requirements are intended to ensure that the control systems incorporated in the design of a proposed facility reflect the latest in control technologies used in a particular industry and take into consideration existing and future air quality in the vicinity of the proposed facility. BACT must, as a minimum, demonstrate compliance with New Source Performance Standards (NSPS) for a source (if applicable). An evaluation of the air pollution control techniques and systems, including a cost-benefit analysis of alternative control technologies capable of achieving a higher degree of emission reduction than the proposed control technology, is required. The cost-benefit analysis requires the documentation of the materials, energy, and economic penalties associated with the proposed and alternative control systems, as well as the environmental benefits derived from these systems. A decision on BACT is to be based on sound judgment, balancing environmental benefits with energy, economic, and other impacts (EPA, 1978).

Historically, a "bottom-up" approach consistent with the BACT Guidelines and PSD Workshop Manual has been used. With this approach, an initial control level, which is usually NSPS, is evaluated against successively more stringent controls until a BACT level is selected. However, EPA developed a concern that the bottom-up approach was not providing the level of BACT decisions originally intended. As a result, in December 1987, the EPA Assistant Administrator for Air and Radiation mandated changes in the implementation of the PSD program including the adoption of a new "top-down" approach to BACT decisionmaking.

The top-down BACT approach essentially starts with the most stringent (or top) technology and emissions limits that have been applied elsewhere to the same or a similar source category. The applicant must next provide a basis for rejecting this technology in favor of the next most stringent technology or propose to use it. Rejection of control alternatives may be based on technical or economic infeasibility. Such decisions are made on the basis of physical differences (e.g., fuel type), locational differences (e.g., availability of water), or significant differences that may exist in the environmental, economic, or energy impacts. The differences between the proposed facility and the facility on which the control technique was applied previously must be justified. Recently, EPA issued a draft guidance document on the top-down approach entitled Top-Down Best Available Control Technology Guidance Document (EPA, 1990a).

3.2.4 AIR QUALITY MONITORING REQUIREMENTS

In accordance with requirements of 40 CFR 52.21(m) and Chapter 17-2.500(f), F.A.C, any application for a PSD permit must contain an analysis of continuous ambient air quality data in the area affected by the proposed major stationary facility or major modification. For a new major facility, the affected pollutants are those that the facility potentially would emit in significant amounts. For a major modification, the pollutants are those for which the net emissions increase exceeds the significant emission rate (see Table 3-2).

Ambient air monitoring for a period of up to 1 year is generally appropriate to satisfy the PSD monitoring requirements. A minimum of 4 months of data is required. Existing data from the vicinity of the proposed source may be used if the data meet certain quality assurance requirements; otherwise, additional data may need to be gathered. Guidance in designing a PSD monitoring network is provided in EPA's Ambient Monitoring Guidelines for Prevention of Significant Deterioration (EPA, 1987a).

Under the exemption rule, FDER may exempt a proposed major stationary facility or major modification from the monitoring requirements with respect to a particular pollutant if the emissions increase of the pollutant from the facility or modification would cause, in any area, air quality impacts less than the de minimis levels presented in Table 3-2 [Chapter 17-2.500(3)(e), F.A.C.].

3.2.5 SOURCE IMPACT ANALYSIS

A source impact analysis must be performed for a proposed major source subject to PSD for each pollutant for which the increase in emissions exceeds the significant emission rate (Table 3-2). The PSD regulations specifically provide for the use of atmospheric dispersion models in performing impact analyses, estimating baseline and future air quality levels, and determining compliance with AAQS and allowable PSD increments. Designated EPA models normally must be used in performing the impact analysis. Specific applications for other than EPA-approved models require EPA's consultation and prior approval. Guidance for the use and application of dispersion models is presented in the EPA publication Guideline on Air Quality Models (EPA, 1987b). The source impact analysis for criteria pollutants can be limited to the new or modified source if the net increase in impacts as a result of the new or modified source is below specified significance levels, as presented in Table 3-1.

EPA and the National Park Service are currently developing significant impact levels for Class I areas. The significance levels have not yet been finalized. Proposed significance levels for the Class I areas are discussed in Section 6.0.

Various lengths of record for meteorological data can be used for impact analyses. A 5-year period can be used with corresponding evaluation of highest, second-highest short-term concentrations for comparison to AAQS or PSD increments. The term "highest, second-highest" (HSH) refers to the highest of the second-highest concentrations at all receptors (i.e., the highest concentration at each receptor is discarded). The second-highest concentration is significant because short-term AAQS specify that the standard should not be exceeded at any location more than once a year. If less than 5 years of meteorological data are used in the modeling analysis, the highest concentration at each receptor must normally be used for comparison to air quality standards.

3.2.6 ADDITIONAL IMPACT ANALYSES

In addition to air quality impact analyses, federal and State of Florida PSD regulations require analysis of the impairment to visibility and the impacts on soils and vegetation that would occur as a result of the proposed source [40 CFR 52.21; Chapter 17-2.500(5)(e), F.A.C.]. These analyses are to be conducted primarily for PSD Class I areas. Impacts from general commercial, residential, industrial, and other growth associated with the source also must be addressed. These analyses are required for each pollutant emitted in significant amounts (Table 3-2).

3.2.7 GOOD ENGINEERING PRACTICE STACK HEIGHT

The 1977 CAA amendments require that the degree of emission limitation required for control of any pollutant not be affected by a stack height that exceeds GEP or any other dispersion technique. On July 8, 1985, EPA promulgated final stack height regulations (EPA, 1985). Identical regulations have been adopted by FDER [Chapter 17-2.270, F.A.C.]. GEP stack height is defined as the highest of:

1. 65 meters (m); or
2. a height established by applying the formula:

$$Hg = H + 1.5L$$

where: Hg = GEP stack height,
H = Height of the structure or nearby structure, and
L = Lesser dimension (height or projected width) of nearby structure(s) or

3. A height demonstrated by a fluid model or field study.

"Nearby" is defined as a distance up to five times the lesser of the height or width dimensions of a structure or terrain feature but not greater than 0.8 kilometers (km). Although GEP stack height regulations require that the stack height used in modeling for determining compliance with AAQS and PSD increments not exceed the GEP stack height, the actual stack height may be greater.

3.3 NONATTAINMENT RULES

Based on the current nonattainment provisions (Chapter 17-2.510, F.A.C.), all major new facilities and modifications to existing major facilities located in a nonattainment area must undergo nonattainment review if the proposed pieces of equipment have the potential to emit 100 TPY or more of the nonattainment pollutant, or if the modification results in a significant net emission increase of the nonattainment pollutant.

For major facilities or major modifications that locate in an attainment or unclassifiable area, the nonattainment review procedures apply if the source or modification is located within the area of influence of a nonattainment area. The area of influence is defined as an area that is outside the boundary of a nonattainment area but within the locus of all points that are 50 km outside the boundary of the nonattainment area. Based on Chapter 17-2.510(2)(a)2.a, F.A.C., all VOC sources that are located within an area of influence are exempt from the provisions of new source review for nonattainment areas. Sources that emit other nonattainment pollutants and are located within the area of influence are subject to nonattainment review unless the maximum allowable emissions from the proposed source do not have a significant impact within the nonattainment area.

3.4 SOURCE APPLICABILITY

3.4.1 PSD REVIEW

3.4.1.1 Pollutant Applicability

The cogeneration facility site is located in Palm Beach County, which has been designated by EPA and FDER as an attainment area for all criteria pollutants except ozone. Accordingly, VOC emissions are regulated under the nonattainment regulations, rather than PSD rules. Palm Beach County and surrounding counties are designated as PSD Class II areas for SO_2, PM(TSP), and NO_2. The site is approximately 90 km north of the nearest PSD Class I area, which is the Everglades National Park in Dade County.

The Okeelanta sugar mill is considered to be an existing major facility because potential emissions of any regulated pollutant exceed 100 TPY. As a result, PSD review is required for the proposed modification for each pollutant for which the net increase in emissions exceeds the PSD significant emission rates presented in Table 3-2 (i.e., a major modification).

Baseline emissions for PSD source applicability are based on emission factors and the last two crop years (1990-1991 crop year and 1991-1992 crop year) of operational data from the Okeelanta sugar mill. For bagasse, the particulate matter (PM) emission factor in terms of lb PM/lb steam was determined from stack test results under measured steam production. The tests were performed on each boiler separately. The total steam produced during the year is not exclusively from bagasse; a portion is from oil firing. By determining the fuel inputs during the years, the total amount of steam due to bagasse firing was determined. The emission factors for bagasse were then applied to the steam rate produced from bagasse.

Industry test data was used for determining emission factors for SO_2, NO_x, CO, and VOC due to bagasse firing. Further, for NO_x, an average was taken between the industry average and the AP-42 value. The emission factor for mercury emissions due to bagasse burning is the same as the factor used to estimate future mercury emissions (refer to Section 2.0), except that current emissions reflect no mercury control system. Emission factors for lead were obtained from tests conducted at Seminole Kraft Corporation in 1990 on wood fired boilers. Also from these tests, there were no detectable emissions of beryllium or fluoride.

Sulfuric acid mist emissions for both bagasse and No. 6 fuel oil are based upon EPA AP-42, which indicates sulfuric acid mist is approximately 3 percent of sulfur dioxide emissions.

Emission factors for the burning of No. 6 fuel oil is provided in AP-42 (EPA, 1988a). Emission factors for PM (2.5% sulfur fuel oil), SO_2, NO_x, CO, and VOC were obtained from this source. The emission factor for mercury is based upon average content in the No. 6 fuel oil. (KBN, 1992)

Beryllium and lead emission factors for oil firing were obtained from Toxic Air Pollutant Emission Factors, Second Edition (EPA, 1990c). The fluoride emission factor was obtained from Emissions Assessment of Conventional Stationary Combustion Systems: Volume V (EPA, 1981).

The baseline emissions for Okeelanta for each regulated pollutant are presented in Table 3-3. Detailed calculations and derivations for the emission factors and source activity factors are presented in Appendix B.

Also shown in Table 3-3 are the maximum annual emissions for the cogeneration facility. The net increase in maximum annual emissions from the proposed cogeneration facility project are compared to the PSD significant emission rates in Table 3-3. As shown, potential emissions of SO_2, fluoride (Fl), beryllium (Be), and sulfuric acid mist will exceed the PSD significant emission rate. Therefore, the proposed facility is subject to PSD review for these pollutants. Annual emissions of particulate matter, NO_x, CO, VOCs, and Pb will be reduced as a result of the proposed project.

3.4.1.2 Ambient Monitoring

Based upon the increase in emissions due to the proposed project, a PSD preconstruction ambient monitoring analysis is required for SO_2, Fl, Be and sulfuric acid mist. However, if the increase in impacts of a pollutant is less than the de minimis monitoring concentration, then an exemption from the preconstruction ambient monitoring requirement may be granted for that pollutant. In addition, if an acceptable ambient monitoring method for the pollutant has not been established by EPA, monitoring is not required.

Table 3-3. PSD Source Applicability Analysis for the Flo-Energy Cogeneration Facility

Regulated Pollutant	Baseline Emissions (TPY)	Cogeneration Facility Emissions (TPY)	Net Change (TPY)	Significant Emission Rate (TPY)	PSD Applies ?
Particulate (TSP)	473.7	177.3[b]	-296.6	25	No
Particulate (PM10)	426.3	174.4[c]	-252.0	15	No
Sulfur Dioxide	748.3	1,700	951.7	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	0.19	-0.09	0.6	No
Mercury	0.0256[d]	0.0262	0.0006	0.1	No
Beryllium	0.0004	0.0080	0.0076	0.0004	Yes
Fluorides	0.04	32.5	32.5	3	Yes
Sulfuric Acid Mist	22.4	51.2	28.8	7	Yes
Total Reduced Sulfur	--	--	0	10	No
Asbestos	--	--	0	0.007	No
Vinyl Chloride	--	--	0	0	No

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

[b] Includes 172.5 TPY from boilers and 4.8 TPY from fugitive dust sources.

[c] Includes 172.5 TPY from boilers and 1.9 TPY from fugitive dust sources.

[d] The estimated average annual emission rate for the most recent 2 years is 0.0256 TPY. The highest annual emission rate for either of the last 2 years is 0.0262 TPY.

The maximum 24-hour average SO_2 concentration due to the proposed cogeneration units only is predicted to be 74 micrograms per cubic meter ($\mu g/m^3$). The methodology used to predict these impacts is presented in Section 6.0, along with the impact analysis results. The de minimis concentration level for SO_2 is 13 $\mu g/m^3$, 24-hour average (see Table 3-2). The maximum 24-hour SO_2 impacts are greater than the de minimis level, and, therefore, an ambient monitoring analysis is required for SO_2. The monitoring analysis is presented in Section 4.0. There is no acceptable monitoring method for sulfuric acid mist; therefore this pollutant is exempt from the preconstruction monitoring requirements.

For non-criteria pollutants such as Fl and Be, it is EPA's policy not to require ambient monitoring (EPA, 1987a). Modeling results will be used to determine if impacts of these pollutants are acceptable.

3.4.1.3 GEP Stack Height Analysis

The GEP stack height regulations allow any stack to be the highest of at least 65 m [213 feet (ft)] high or a height established by applying the formula:

$$Hg = H + 1.5L$$

where: Hg = GEP stack height,
H = Height of the structure or nearby structure, and
L = Lesser dimension (height or projected width) of nearby structure(s)

The boiler buildings are the significant structures associated with the proposed cogeneration facility. The building has a height of 128 feet and a total combined width of 180 ft. From the above formula, the GEP stack height is 128 + (1.5 x 128) = 320 ft. The three stacks for the proposed facility will be 199 ft high and therefore do not exceed the GEP stack height. The potential for downwash of the emissions as from the facility due to the presence of nearby structures is discussed in Section 6.0, Source Impact Analysis.

3.4.2 NONATTAINMENT REVIEW

The cogeneration facility site is located in Palm Beach County, which has been designated as a nonattainment area for ozone. As a result, nonattainment review applies if the increase of VOC emissions due to the proposed facility is greater than 40 TPY of VOC. As shown in Table 3-3, there will be a net decrease in VOC emissions. As a result, nonattainment new source review does not apply to the proposed project.

4.0 PRECONSTRUCTION AMBIENT MONITORING ANALYSIS

As discussed in Section 3.3, Source Applicability, a preconstruction ambient monitoring analysis is required for SO_2. The preconstruction monitoring analysis is presented in this section.

Guidelines concerning the requirements for PSD preconstruction monitoring are given in the document entitled "Ambient Monitoring Guidelines for Prevention of Significant Deterioration (PSD)" (EPA, 1987a). The guidelines cover the collection of new data to fulfill the requirements, as well as the use of existing representative air quality data. To determine if existing data are "representative", the major considerations are monitor location, quality of the data, and currentness of data.

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. Data collected from the station are summarized in Table 4-1 for the period January 1989 through August 1991.

The first criterion in determining if existing data are representative is monitor location. According to the PSD guidelines, a "regional" monitoring site may be used if the proposed source will be located in an area that is generally free from the impact of other points and area sources associated with human activities. The regional site must be located in an area of similar terrain and represent the air quality across a broad region. The SO_2 monitoring site in Belle Glade meets this criterion.

The second criterion relates to the quality of the monitoring data (i.e., the data must meet all PSD quality assurance requirements). The FSCL monitoring network has had full PSD approval for several years and meets the PSD requirements.

The third criterion states that the data must be current. Generally, this means the data must not be more than 3 years old. The data presented in Table 4-1 were collected within the past 3 years and therefore meet the PSD criteria.

Table 4-1. SO_2 Concentrations Measured at the Monitoring Station in Belle Glade

Site Number	Location	Period	Number of Observations	Measured Concentration (µg/m³) 3-Hour Highest	3-Hour Second Highest	24-Hour Highest	24-Hour Second-Highest	Annual
3420-017-J02	Bella Glade: Duda Rd, 1 mile south of Old SR 80	Jan - Dec 1989	5,974	50	42	19	19	8
		Jan - Sept 1990	5,611	67	53	30	21	8
		Jan - Aug 1991	4,279	34	30	16	14	4

In summary, the continuous SO_2 data collected at the monitoring site in Belle Glade fulfills the PSD preconstruction monitoring criteria. The data therefore should satisfy the preconstruction monitoring requirements for SO_2.

5.0 BEST AVAILABLE CONTROL TECHNOLOGY EVALUATION

As presented in Section 3.4, the net increase in the emissions of SO_2, Be, F, and sulfuric acid mist from the proposed Flo-Energy cogeneration project will exceed their respective PSD significant emission rates when coal is fired as an auxiliary fuel (see Table 3-3). Therefore, BACT analyses for these four pollutants is required for the proposed spreader stoker boilers firing bituminous coal. The complete "top-down" BACT evaluation for each PSD pollutant includes the identification of the respective control technologies; the environmental, energy, and economic impact evaluations of all technically feasible control methods; and the BACT analysis summary.

5.1 BACT DETERMINATION FOR SULFUR DIOXIDE (SO_2) EMISSIONS

5.1.1 IDENTIFICATION OF SO_2 EMISSION CONTROL TECHNOLOGIES FOR UTILITY BOILERS

In this Section, the available control technologies capable of reducing SO_2 emissions produced from firing eastern bituminous coal as an auxiliary fuel will be evaluated. Potential application as BACT for the three proposed spreader stoker boilers, rated on coal at 490 MMBtu/hr each, is discussed.

In boilers firing fossil fuels, sulfur compounds are produced by the combustion process in which nearly complete oxidation of the fuel-bound sulfur occurs. These sulfur compounds are primarily SO_2, with a smaller quantity of sulfur trioxide (SO_3) that eventually converts into acid mist. The amount of SO_2 emissions is directly proportional to the sulfur and sulfate content in the fuel. Reducing SO_2 emissions by boiler modification is not feasible because the firing mechanism does not affect SO_2 emissions. Generally, complete oxidation of sulfur in fuel is readily achieved before the complete combustion of the primary carbon fuel element in fossil fuel. Typically, SO_2 emission reduction is accomplished by treating the flue gas with a variety of flue gas desulfurization (FGD) processes.

Standard FGD processes for spreader stoker boilers are add-on SO_2 scrubbers of either the wet or dry type. The following discussion of each potential add-on scrubber type for SO_2 removal includes a description of the technology and, if it is concluded that the technology is technically feasible, the potential SO_2 emission reduction level.

Wet Scrubbing Systems

Wet scrubbing is a gaseous and liquid phase reaction process in which the SO_2 gas is transferred to the scrubbing liquid under saturated conditions. The wet scrubbing process creates a liquid waste stream. Therefore, a wastewater treatment and disposal system is generally required for a wet scrubbing system.

Wet scrubbing systems include three different types which are classified by the reagents used in the scrubbing process. The type of reagent influences the scrubber design, the quantity and type of wastes produced, and the type of disposal system required. Either sodium-based, calcium-based, or dual-alkali-based chemicals are used from which the scrubber systems are named, such as the sodium-based scrubber, the dual-alkali scrubber, and the wet lime/limestone scrubber. Packed towers are used for the sodium-based scrubbing system, whereas spray towers are generally used for the lime/limestone scrubbing systems. A brief description of each wet scrubbing system is described below.

The sodium scrubbing systems use either a sodium hydroxide (NaOH) or a sodium carbonate ($CaCO_3$) wet scrubbing solution to absorb SO_2 from the flue gas. Because of the high reactivity of the sodium alkali sorbent compared to the lime or limestone sorbents, these systems are characterized by a low liquid-to-gas ratio. The SO_2 gas reacts with the hydroxide or carbonate to from sulfite (e.g., $NaSO_3$) initially, then sulfate ($NaSO_4$) with further oxidation. Both sodium sulfite and sulfate are highly soluble; therefore, the final scrubber effluent is a mixture of sodium alkaline salt liquor that requires special disposal. Although these sodium-based systems are capable of achieving up to 95 percent SO_2 reduction, they have not been used commercially on large utility boilers and therefore are considered as unproven.

The dual-alkali scrubbing process uses the sodium-based liquor to scrub the SO_2 from the flue gas, then calcium-based chemicals are used to regenerate the sodium hydroxide or $NaCO_3$ solution. The sodium scrubbing and the dual-alkali scrubbing processes are not commercially available or proven for large coal-fired boilers. The primary reasons for not using the sodium-based system are the expensive cost of premium chemicals, less availability of sodium-based chemical, and the highly alkaline waste liquid produced. The dual-alkali system also presents similar undesirable effects if applied to coal-fired boilers. It will be shown later in the discussions of the BACT/LAER clearinghouse information for coal-fired boilers that neither the sodium-based systems nor the dual-alkali systems have been determined to be BACT for any coal-fired facility.

Therefore, the sodium-based and the dual-alkali scrubbing processes are considered as technically infeasible for the proposed project and both technologies are eliminated from any further consideration as BACT.

The wet scrubbing system that is most widely used for SO_2 removal in large coal-fired utility boilers is the calcium-based wet FGD system. It is estimated that approximately 82 percent of the coal-fired megawatt capacity in the United States is equipped with this FGD technology. Depending on whether lime or limestone is used, the SO_2 reacts with the hydrate or carbonate to form calcium sulfite (i.e., $CaSO_3 \bullet \frac{1}{2} H_2O$) initially, then sulfates (i.e., $CaSO_4 \bullet 2H_2O$) with further oxidation. The calcium sulfite or sulfate slurry is insoluble which requires settling ponds and separation equipment and a wastewater treatment facility in order to properly handle the solid and wastewater disposal.

The most frequently utilized wet FGD technology is the wet limestone system. The preferred version of the technology is the spray tower. In this system, a slurry of atomized limestone is sprayed into a tall vertical absorber tower through a series of nozzles. The flue gas enters usually at the bottom of the tower, passes vertically up through the spray droplets, and exits the vessel at the top.

The slurry is recirculated through the absorber system. This recirculation increases the scrubbing utilization of the carbonate reagent. A bleedstream is taken off from the recycled slurry stream to avoid build-up inside the spray tower. The scrubbing reaction produces calcium sulfite as the byproduct. Many systems further oxidize the sulfite into calcium sulfate, which is easier to dewater. Byproducts and unreacted reagent in the bleedstream is dewatered using a variety of equipment including thickeners, centrifuges, and vacuum filters. Dewatering systems reduce the water content in the filtered waste solid to between 10 to 50 percent by weight, depending on the system.

Several wet scrubber systems utilize lime rather than limestone as the alkaline reagent. Quick lime (calcium oxide) is slaked with water to form hydrated lime (calcium hydroxide). The slurry of calcium hydroxide and water is then sprayed into the spray tower. This alternative of using lime instead of limestone is less attractive economically because the cost of either quick lime or hydrated lime is much higher than limestone pebbles. While a limestone system requires more initial capital costs for auxiliary equipment (i.e., limestone pulverizer, conveyor and slaker system, etc.), the lower operating cost of the reagent provides a substantial annual savings. This is especially beneficial for a facility using medium and high sulfur coals, where considerably more reagent chemicals are needed.

Technically, wet lime/limestone scrubbing processes are capable of reducing SO_2 emissions with a removal efficiency between 70 to 93 percent. Theoretically, a higher efficiency of up to 95 percent may be achievable by adding adipic acid to the scrubbing liquid because the reactions between the lime and limestone with SO_2 are more favorable at lower pH levels. Process controls for the wet FGD technology have not advanced precisely enough to confidently state that performance at one location can be duplicated at another. Margins of allowances must be applied to the best performances achieved at other plants. Since the wet lime/limestone scrubbing processes can potentially achieve 95 percent removal efficiency, the 95 percent will be used in this analysis.

Dry Scrubbing System

In the dry scrubbing process, the flue gas entering the scrubber contacts an atomized slurry of either wet lime or wet sodium carbonate (Na_2CO_3) sorbent. The exact mechanisms for the absorption of the gaseous SO_2 and formation of alkaline salts are not clear. Overall, the SO_2 gas reacts with lime or sodium sorbent to form initially either calcium sulfite ($CaSO_3 \bullet \frac{1}{2}H_2O$) or sodium sulfite ($Na_2SO_3$). Upon further oxidation or SO_2 absorption enhanced by the drying process, the sulfite salts will transform into calcium sulfate ($CaSO_4 \bullet 2H_2O$) or sodium sulfate solids. A typical spray dryer will use lime as the reagent because it is more readily available than sodium carbonate.

Lime slurry is injected into the spray dryer chamber through either a rotary atomizer or pressurized fluid nozzles. Rotary atomizers use centrifugal energy to atomize the slurry. The slurry is fed to the center of a rapidly rotating disk or wheel where it flows outward to the edge of the disk. The slurry is atomized as it leaves the surface of the rapidly rotating disk.

Fluid nozzles use kinetic energy to atomize the slurry. High velocity air or steam is injected into the lime slurry stream, breaking the slurry into droplets, which are ejected at near sonic velocities into the spray drying chamber. Slurry droplets of comparable size can be obtained with both fluid nozzles and rotary atomizers, minimizing differences in performance due to atomizer type.

The moisture in the lime slurry evaporates and cools the flue gas, and the wet lime absorbs SO_2 in the flue gas and reacts to form pseudo liquid-solid phase salts that are then dried into insoluble crystals by the heat content of the flue gases. The spray dryer chamber is designed to provide sufficient contact and residence time to complete the above reaction process. The prolonged residence time in the chamber is typically designed for 10 to 15 seconds. Sufficient contact between the flue gas and the slurry solution is maintained in the absorber vessel allowing the absorbing reactions and the drying process to be completed.

The particulate exiting the spray dryer scrubber contains fly ash, dried calcium salts and dried unreacted lime. Moisture content of the dried calcium salt leaving the absorber is about 2 to 3 percent, eventually decreasing to about 1 percent downstream. The simultaneous evaporation and reaction in the spray drying process increases the moisture and particulate content of the flue gas and reduces the flue gas temperature.

In the spray dryer scrubber, the amount of water used is optimized to produce an exit stream with "dry" particulates and gases with no liquid discharge from the scrubber. The flue gas temperature exiting the spray dryer scrubber is typically 18 to 30°F above adiabatic saturation. The "dry" reaction products and coal fly ash are both removed from the flue gas by a particulate collection device downstream. This differs from the wet scrubber system, wherein the slurry leaving that system must be dewatered at great cost and the gas is cooled to adiabatic saturation temperature.

Key design and operating parameters that can significantly affect spray dryer scrubber performance are reagent-to-sulfur stoichiometric ratio, slurry droplet size, inlet water content, residence time, and scrubber outlet temperature. An excess amount of lime above the theoretical requirement is generally fed to the spray dryer to compensate for mass transfer limitations and incomplete mixing. Droplet size affects scrubber performance. Smaller droplet size increases the surface area for reaction between lime and acid gases and increases the rate of water evaporation. A longer residence time results in higher chemical reactivities and the reagent-SO_2 reaction occurs more readily when the lime is wet. The scrubber outlet temperature is controlled by the amount of water in the slurry. Typically, effective utilization of lime and effective sulfur dioxide removal occur at temperatures close to adiabatic saturation, but the flue gas temperature must be kept high enough to ensure the slurry and reaction products are adequately dried prior to the particulate collection process.

The dry scrubber usually is located upstream of the particulate control device, which is either an electrostatic precipitator (ESP) or a fabric filter (baghouse) system. A baghouse can provide slightly greater SO_2 removal compared to an ESP system. When a baghouse is used, a layer of porous filter cake forms on the filter bag surfaces. This filter cake contains unspent reagent which provides a site for additional SO_2 removal since the flue gases pass through the filter cake.

Based on BACT determinations previously issued, the spray dryer FGD system can achieve between 70 to 95 percent SO_2 removal for coal-fired boilers, with the majority designed for 92 percent removal (EPA, 1992a). The higher removal efficiencies of greater than 90 percent can be achieved by maintaining an optimum ratio of reagent and SO_2 gas and using a fabric filter for particulate removal. Discussions with FGD vendors indicate that a 92 percent control efficiency is a prudent guarantee based on higher efficiencies being unproven on this relatively new technology and use of an ESP as the PM control device. As a result, a 92 percent SO_2 removal was used for the BACT analysis for the spray dryer.

Low-Sulfur Coal

The sulfur content of eastern bituminous coal ranges from 0.5 to 3.0 percent by weight for eastern bituminous coal. Since the level of SO_2 emissions is directly related to the amount of sulfur in the fuel, a low-sulfur-containing fuel can be used to meet the SO_2 emission limitation specified by the NSPS regulations for electric utility steam boilers.

Under the current NSPS regulations for electric utility steam generators (40 CFR 60, Subpart Da), a heat specific SO_2 emission rate of 1.2 lb/MMBtu must be met by the proposed boilers. The boilers have been classified as resource recovery units because the proposed primary fuels are biomass that include bagasse and wood waste. The average sulfur content of eastern bituminous coal is 2 percent which is equivalent to a SO_2 emission factor of approximately 3.33 lb/MMBtu. Flo-Energy is proposing to use 0.7 percent sulfur coal to meet the NSPS limit, and will limit total annual SO_2 emissions from both Flo-Energy and Sol-Energy (Okeelanta and Osceola) cogeneration projects combined to an average of 1,000 TPY over the life of these projects.

5.1.2 EVALUATION OF TECHNICALLY FEASIBLE SO_2 CONTROL METHODS FOR COAL FIRING

This section examines the two technically feasible alternative SO_2 control methods (i.e., the wet lime scrubber and the lime spray dryer scrubber) identified in the previous discussion. Each alternative will be further examined with regard to its technical issues, environmental effects, energy requirements and impacts, and economic impacts.

Presented in Table 5-1 is a summary of all BACT determinations for SO_2 emissions from spreader stoker and pulverized-coal-fired boilers issued since 1986. This information was obtained from the BACT/LAER Informational System (BLIS) database through EPA's National Computer Center located at Research Triangle Park in North Carolina, and from regulatory agencies in various states that were contacted.

5.1.2.1 Ranking of Feasible Control Technologies

A baseline emission level must be established as the basis for top-down BACT ranking and for economic analysis purposes. The baseline is defined as the uncontrolled rate of a process being reviewed. Thus, the SO_2 emission level associated with the firing of 0.7 percent sulfur eastern bituminous coal and no add-on SO_2 controls will be used as the baseline emission level.

Presented in Table 5-2 is the BACT top-down hierarchy of both proposed SO_2 reduction methods, their general ranges of control effectiveness, and their design control efficiencies applied to the proposed boilers. As discussed previously, the wet limestone scrubber and lime spray dryer scrubber can be designed to achieve SO_2 removal efficiencies of 95 and 92 percent, respectively. Therefore, the BACT top-down hierarchy ranks the wet lime/limestone scrubber first and the lime spray dryer process second. The wet scrubber option will be first compared to the dry scrubbing option in terms of total and incremental values, and then the dry scrubbing option will be compared to the low sulfur coal option.

It is noted that, for the proposed Flo-Energy boilers, an FGD system would be operated only when burning coal, due to the very low sulfur content of biomass fuels. Thus, the baseline SO_2 emissions shown in Table 5-2 reflect the SO_2 emissions due only to coal burning.

5.1.2.2 Analysis of Add-On FGD Systems

Technical Issues--The wet limestone absorber is a "first generation" scrubber that can typically achieve SO_2 removal efficiencies in the 70 to 95 percent range. The wet scrubber design has included packed towers and medium-to-high pressure drop venturis, and many were designed for

Table 5-1. Summary of BACT Determinations for SO2 Emissions from Coal-fired External Combustion Boilers

Company Name	State	Permit Number	Permit Issued Date	Boiler Throughput (MMBtu/hr)	Boiler Type	Fuel Type	SO2 Emission Limit		Comments	Eff. (%)
							(lb/hr)	(lb/MMBtu)		
Cogentrix of Dinwiddie	VA	51021	16-Apr-92	375	SSB, 8 Ea.	--	48.8	0.13	Lime Spray Dryer/Fabric filter	90%
Hadson Power 14, Buena Vista	VA	21130	08-Apr-92	379	SSB	Coal	42.3	0.112	Lime Injection	93%
Orl. Utl. Comm., Stanton NRG Unit 2	FL	PSD-FL-084	23-Dec-91	4,286	PC	Coal	--	0.25	Wet Limestone FGD 30D Rol Avg.	92%
PG&E/Bechtel Generating Co.	FL	PSD-FL-???	06-Sep-91	3,422	PC	Coal	581.7	0.17	Lime Spray Drying	95%
Old Dominion Electric Cooperative	VA	30867	29-Apr-91	2,042.5	PC, 2 Ea.	BC, 1-1.3% S	--	0.156	Wet Limestone FGD 30D Rol Avg.	94%
Multitrade Limited Partnership*	VA	30871	08-Apr-91	356.3	SSB, 3 Ea.	Coal 0.85% S & Wood	71.3	0.2	Uncontrolled	--
Roanoke Valley Project	NC	6964	24-Jan-91	1700.0	PC	--	--	0.213	Dry Lime FGD	92%
Cogentrix of Richmond	VA	51033	02-Jan-91	375	SSB, 8 Ea.	EB Coal, 1.1%S	48.8	0.13	Dry Scrubber/Baghouse	90%
Keystone	NJ	--	1991	--	PC	--	--	--	--	--
Chambers Work Project	NJ		01-Oct-90	220MW	PC	--	--	--	--	--
Thomaston Mills, Inc.	GA	2211-145-10559	21-Sep-90	214.75	SSB	Coal, 1.5% S	--	0.23	Spray Dryer w/ Lime Inj.	90%
Wisconsin Electric Power Co.	WI	90-POY-037	05-Sep-90	--	--	--	--	--	--	--
Hadson Power 13, Hopewell	VA	51019	17-Aug-90	379	--	Coal 1.3% S Max	61.3	0.162	Lime Spray Dryer	92%
Mecklenburg Cogeneration	VA	30861	18-May-90	834.5	PC, 2 Ea.	Coal, 1% S Ann Avg.	143.5	0.172	Water-lime Spray Dryer & FF	92%
Logan Township Power Plant	NJ	--	1990	--	PC	--	--	--	Lime Spray Dryer FGD	--
Hadson Power II	VA	61093	22-Nov-89	379	--	Coal 1.3% S Max	61.3	0.162	Lime Injection	92%
Intermountain Power Project	UT	BAQE-672-89	24-Oct-89	8,352	--	--	--	0.150	430,922 TPY Coal; 1.6 MM GPY Res Oil	--
Cogentrix of Rocky Mount	NC	6563	20-Jul-89	375	SSB, 4 Ea.	Coal	--	0.31	Dry Lime FGD	--
P.H. Glatfeller Co.	PA	67-306-006	11-Feb-88	633	Boiler	BC & Wood Waste	--	1.2	Limestone Inj. 90%.	--
Holly Farms Poultry Ind.	NC	3354R7	30-Nov-87	99	--	Coal/Wood	158.4	1.6	Low Sulfur Coal, 0.94% S	--
Cogentrix Michigan Leasing Corp.	MI	48-87	31-Jul-87	214	SSB, 3 Ea.	Coal, 3%S Max.	357.4	1.67	Lime Spray Dryer, Max. 3% S	90%
Utah Power & Light Co.	UT	--	27-Jul-87	400 MW	--	Coal	--	1.20	NSPS	80%
Multitrade of Martinsville	VA	30826	24-Jul-87	120	Cogen Boiler	30% Coal & 70% Wood	155.98	1.2	Uncontrolled for NSPS, 0.8% S 30D Rol Avg.	--
Deseret Generation & Transmission	UT	BAQ-0913-1	02-Jul-87	400MW	PC	--	209.0	0.055	Limestone FGD	--
WM. H. Zimmer Generation Station	OH	14-1036	05-Feb-87	11,968	PC	Coal	6,558.5	0.548	Magnesium-Enhanced Lime FGD	91%
Archbald Power Corp.	PA	35-306-001	16-Jan-87	240	--	AC, 0.317%S	36	0.15	Limestone Injection	90%

* Permit Change to Burn only Wood

Note: SSB = Spreader Stoker Boiler; PC = Pulverized Coal; BC = Bituminous Coal; AC = Anthracite Coal.

Table 5–2. BACT "Top–down" Hierarchy of SO2 Reduction Methods for the Proposed Boilers.

Top–down Ranking	Technology	Range of Control Effectiveness (%)	Control level for BACT Analysis (%)	SO2 Emission Level (lb/MMBtu)	SO2 Annual Emissions+ (TPY)
First	Wet Lime/Limestone Scrubber	80–95	95	0.06	81.2
Second	Lime Spray Dryer Scrubber	80–92	92	0.10	129.9
Baseline	Low Sulfur Coal	––	––	1.20	1,623.6

\+ Total for all three boilers based on maximum coal firing rate.

simultaneous particulate removal in the same vessel. A number of design and operating problems have been associated with these "first generation" designs, such as:

1. Corrosion caused by high chlorides concentrations and/or improper materials selection and construction,
2. Equipment failure caused by improper equipment selection or design,
3. Scaling and plugging caused by the cementing properties of the calcium salts, improper operation and control, and improper equipment design or control system design, and
4. Solid waste disposal problems caused by the cementing properties and poor dewatering characteristics of calcium sulfite sludge.

As these "first generation" problems were identified, they were corrected by retrofit and by improved system designs. Some specific improvements made to earlier designs include:

1. Using open spray towers in place of packed bed design (e.g., turbulent contact absorbers);
2. Removing particulate separately, thus avoiding the high pressure drop of the venturi and the problems associated with scaling and mud formation, and
3. Relocating induced draft fans from downstream to upstream of the wet scrubbers, where the flue gas is not at saturation, and thus avoiding condensation and formation of acids that cause corrosion problems.

The wet limestone scrubber requires a larger auxiliary system for various processes such as raw materials and slurry preparation, solid and liquid separation, other mixing and aeration operation, and waste handing. Its applicability is generally limited by plant physical limitations because it is a nonregenerable process that generates high solid waste volumes.

The lime spray dryer process requires a particulate control system to be installed downstream and more precise control than the wet scrubber system. From an operating standpoint, a narrow operating temperature window has to be strictly adhered to in order to avoid either potential excessive heating or condensation in the particulate collection equipment downstream. Its long-term reliability is not as proven for coal-fired boilers as the wet limestone scrubber. However, its mechanical operation is less complex than the wet limestone scrubber.

For the proposed Flo-Energy project, startups and shutdowns may occur at irregular intervals because coal will only be used as an auxiliary fuel. It is likely that the scrubbers and their auxiliary equipment will not be operated for long periods of time, potentially as long as several months. For example, during and immediately after the crop season (October-March) the plant will normally operate on biomass fuels since sufficient quantities of bagasse will be available. It is unlikely that coal will be utilized at all during this 5-month period. During the off-season, the supply of biomass may not be consistently adequate to fuel the plant, and coal may need to be burned at irregular intervals. Such operations, with long periods of downtime as well as irregular periods of operation, will be detrimental to the integrity of an FGD system and consequently will likely affect the control efficiency of the system.

Environmental Effects

The primary environmental concern of using the wet limestone system is the process wastewater and the waste sludge generated. These waste streams require proper treatment and disposal. Typically, the waste sludge is landfilled on-site, potentially impacting local groundwater. The wet FGD system for Flo-Energy would generate approximately 4,350 tons of solid sludge each year, which would be landfilled off-site.

The calcium sulfate sludge could be disposed of by further processing to make gypsum that may be used by a wallboard manufacturing facility. However, this option is not viable for the proposed project since there is no known market for the gypsum in the south Florida area. In addition, manufacturers of wallboard have very rigid standards regarding acceptable levels of impurities. Some manufacturers require samples of the product prior to committing to using it since there is the possibility that its characteristics and/or impurities might render it unsuitable. They are not enthusiastic about using the material, since gypsum is a small part of the total cost of wallboard. Firing coal as an auxiliary fuel (with an FGD system) will not produce a sufficient amount of gypsum on a regular basis to render it marketable. The additional capital cost for the gypsum processing equipment would also be a concern based on the uncertainty of coal firing.

A wet limestone scrubber also has the disadvantage of high water consumption. Wet limestone scrubbers for the Flo-Energy cogeneration project will require approximately 57 million gallons of water per year. Such large water demand will have an undesirable environmental effect in south Florida, which is already experiencing declining water supply levels due to increasing demands on water consumption and lower than average rainfall.

Since the flue gas that leaves the wet limestone scrubber is saturated with moisture, there is a potential concern for condensation in the stack unless the flue gas is reheated. This condensation can be corrosive due to its acidic nature. The flue gas is typically reheated by 20 to 50°F to prevent this problem. Reheaters are subject to corrosion and in many cases scale build-up, and are very expensive to operate.

The major environmental issues concerning the use of the lime spray dryer process are solid waste disposal and water demand. Calcium salts will be generated from the dry scrubbing process that will require disposal. For every ton of SO_2 removed, there will be an additional 2.7 tons of solid waste generated. A spray dryer FGD system for Flo-Energy could therefore generate up to 4,035 tons of solid waste each year, which would be landfilled off-site. The estimated maximum water requirement for the spray dryer system at Flo-Energy is approximately 23 million gallons per year.

By using low sulfur coal to meet the NSPS, there will be no additional environmental impacts due to the control technology. SO_2 emissions from both Flo-Energy and Sol-Energy cogeneration facilities combined will be limited to an average of 1,000 TPY. This represents no increase over current SO_2 emissions from the existing Okeelanta and Osceola sugar mills.

Energy Requirements and Impacts

Both the wet limestone scrubber and lime spray dryer scrubber require electricity to drive various mechanical equipment, including fans and pumps. The estimated energy requirement is approximately 7,900 megawatt-hours per year (MW-hr/yr) for the wet limestone scrubber and approximately 3,800 MW-hr/yr for the spray dryer scrubber. These estimated energy requirements are calculated assuming the maximum allowable coal-firing for the facility. By firing compliance fuel (i.e., 0.7 percent sulfur coal) to meet NSPS, no additional energy is required, allowing more energy to be provided for public consumption.

Economic Analysis

This section presents the total capital investment (TCI) and the annualized cost (AC) of both the wet limestone scrubber and the lime spray dryer scrubber processes for the three proposed Flo-Energy cogeneration boilers. Capital costs were developed from basic equipment costs for each process and with standard cost factors for estimating the direct and indirect costs of the emission control systems (EPA, 1990b).

The basic equipment cost for the spray dryer system was based on the average budgetary quotations obtained from ABB-Flakt, Joy Environmental Systems, and United McGill. This average cost is \$3.99 million for three spray dryer scrubbers.

The basic equipment cost for the wet limestone scrubber system is approximately \$8.62 million for the three units, or about 2.16 times the cost of the spray dryer scrubbers. This factor was developed from vendor estimations and comparative costs of wet limestone and lime spray dryer scrubbers described in permit applications.

All operating costs were developed based on an equivalent 1,840 hr/yr operation on coal for each boiler (5,520 hr/yr total for the proposed project). This represents the number of hours at maximum coal-firing capacity to achieve 25 percent of the total facility annual heat input (i.e., 2.706×10^{12} Btu/yr divided by 490×10^{6} Btu/hr). Uncontrolled SO_2 emissions are based on the proposed SO_2 emissions of 1,623.6 TPY from maximum coal firing. Controlled SO_2 emissions are based on 92 percent reduction for the lime spray dryer and 95 percent reduction for the wet lime/limestone scrubber.

The cost estimates for both scrubber systems are presented in Tables 5-3 and 5-4. The total capital investment (TCI) estimated for the lime spray dryer scrubbers is \$10.35 million and for the wet limestone scrubbers is \$21.9 million. The annualized cost for the lime spray dryer scrubber is approximately \$3.81 million, and for the wet limestone scrubber is \$7.25 million.

The annualized cost figures derived above are based on the worst-case condition of firing up to 25 percent coal in a single year (i.e., 1,623.6 TPY of SO_2). However, Flo-Energy has agreed with the Palm Beach County Zoning Board to limit the total SO_2 emissions from both the Flo-Energy and Sol-Energy (Okeelanta and Osceola) cogeneration facilities combined to an average of 1,000 TPY over the life of these facilities. Consequently, it is appropriate to consider the total cost of SO_2 removal systems at both facilities in determining the true cost effectiveness of SO_2 controls. The costing of the SO_2 removal systems at the proposed Sol-Energy cogeneration facility is shown in a companion permit application. The combined annualized costs for the lime spray dryer scrubbers and the wet limestone scrubbers for Flo-Energy and Sol-Energy are approximately \$6.33 million and \$12.03 million, respectively.

Table 5–3. Capital Cost Estimates for Alternative SO2 Control Systems.

Cost Items	Cost Factors	Spray Dryer	Wet FGD
DIRECT CAPITAL COSTS (DCC):			
(1) Purchased Equipment			
(a) Basic Equipment*	Vendor Quote	$3,990,000	$8,618,400
(b) Auxiliary Equipment	included	included	included
(c) Structure Support	0.10 x (1a)	$399,000	$861,840
(d) Instrumentation & Controls	0.10 x (1a)	$399,000	$861,840
(e) Freight[1]	0.05 x (1a–1d)	$239,400	$430,920
(f) Sales Tax (Florida)	0.06 x (1a–1d)	$287,280	$517,104
(g) Subtotal	(1a–1f)	$5,314,680	$11,290,104
(2) Direct Installation[1]	0.30 x (1g)	$1,594,404	$3,387,031
Total DCC:	(1) + (2)	$6,909,084	$14,677,135
INDIRECT CAPITAL COSTS (ICC):			
(3) Indirect Installation			
(a) Engineering & Supervision[1]	0.10 x (DCC)	$690,908	$1,467,714
(b) Construction & Field Expenses[1]	0.10 x (DCC)	$690,908	$1,467,714
(c) Contruction Contractor Fee[1]	0.05 x (DCC)	$345,454	$733,857
(d) Contigencies[1]	0.20 x (DCC)	$1,381,817	$2,935,427
(4) Other Indirect Costs			
(a) Startup & Testing[1]	0.03 x (DCC)	$207,273	$440,314
(b) Working Capital	30–day DOC**	$119,776	$188,150
Total ICC:	(3) + (4)	$3,436,136	$7,233,175
TOTAL CAPITAL INVESTMENT (TCI):	DCC + ICC	$10,345,220	$21,910,311

* For the spray dryer, the basic equipment cost is the average of budgetary quotations from ABB–Flakt, Joy Environmental Systems, and United McGill. The basic equipment cost for the wet limestone scrubbers were estimated as 2.16 times the cost for the spray dryer scrubbers. The cost factor was determined from vendor estimates and comparative costs between the wet scrubber and the dry scrubber processes as as presented in similar analysis.

** 30 days of direct operating costs, calculated from the annualized cost Table 5–4 (i.e., total DOC/12 months).

[1] Based on catalytic incinerators, from OAQPS Control Cost Manual, Fourth Edition.

Table 5–4. Annualized Cost Estimates for the Alternative SO2 Control Systems.

Cost Items	Basis	Spray Dryer	Wet FGD
DIRECT OPERATING COSTS (DOC):			
(1) Labor			
Operator[2]	\$22/hr; 4,706 and 7,087 hr/yr total	\$103,540	\$155,905
Supervisor[1]	15% of operator cost	\$15,531	\$23,386
(2) Maintenance[2]	5% of direct capital cost	\$345,454	\$733,857
(3) Replacement Parts	3% of direct capital cost	\$207,273	\$440,314
(4) Utilities			
(a) Electricity	\$85 per MW–hr	\$320,901	\$670,312
(b) Water	\$0.27 / 1,000 gal	\$6,129	\$15,323
(5) Raw Chemicals			
(a) Limestone (97% purity)	\$32 / ton including freight	––	\$101,313
(b) Hydrated Lime (74% purity)	\$140 / ton including freight	\$329,591	––
(6) Solid Disposal	\$27 / ton	\$108,892	––
(7) Sludge Disposal	\$27 / ton	––	\$117,397
Total DOC		\$1,437,309	\$2,257,806
INDIRECT OPERATING COSTS (IOC):			
(7) Overhead[1]	60% of operating labor & maintenance	\$278,715	\$547,888
(8) Property Taxes[1]	1% of total capital investment	\$103,452	\$219,103
(9) Insurance[1]	1% of total capital investment	\$103,452	\$219,103
(10) Administration[1]	2% of total capital investment	\$206,904	\$438,206
Total IOC		\$692,524	\$1,424,301
CAPITAL RECOVERY COST (CRC)	CRF of 0.1627 times TCI	\$1,683,167	\$3,564,808
ANNUALIZED COST (AC):	DOC + IOC + CRC	\$3,813,001	\$7,246,914

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[1] Based on catalytic incinerators, from OAQPS Control Cost Manual, Fourth Edition.

[2] Based on maximum of 25% coal firing for the Flo–Energy cogeneration facility.

5.1.2.3 SO_2 BACT Summary

The BACT analysis for SO_2 control has evaluated the two feasible control alternatives (i.e., the limestone wet scrubber and the lime spray dryer scrubber). This section will summarize the overall technical, environmental, energy, and economic impacts of both alternatives and compare them will the alternative of firing compliance coal.

Comparison of Technical Issues

Wet limestone scrubbers and spray dryer scrubbers can reduce SO_2 emissions by 92 and 95 percent, respectively and are considered technically feasible for the Flo-Energy project. For spreader stoker and pulverized coal-fired utility boilers, both wet and dry FGD scrubber systems have been determined to be BACT (see Table 5-1). SO_2 removal efficiencies range from 90 to 95 percent with the higher range assigned to a wet scrubber system with a long averaging time period for compliance (i.e, 30-day rolling average).

However, there are also three determinations during the last five years that have specified low sulfur coal as BACT for spreader stoker boilers firing multiple fuels in which coal-firing contributes the smaller amount of the total heat input. These determinations were made for Multitrade Limited Partnership of Virginia with a 356.3 MMBtu/hr heat input, Holly Farms Poultry Industries of North Carolina with a 99.0 MMBtu/hr heat input, and Multitrade of Martinsville of Virginia with a 120 MMBtu/hr heat input. Compliance coal was specified for these facilities as 0.85 percent sulfur coal, 0.94 percent sulfur coal, and 0.8 percent sulfur coal, respectively. The Multitrade of Martinsville facility was permitted with the option of firing coal as a fuel for up to 30 percent of its total heat input.

It should be noted that all of the facilities required to use add-on FGD process are firing coal as the primary fuel. In contrast, the multifuel boilers are permitted to fire coal as an auxiliary fuel at a maximum of 30 percent of the total heat input without add-on control requirements. Therefore, the use of 0.7 percent sulfur coal at up to 25 percent of the total heat input without an FGD system is consistent with recent BACT determinations for multifuel spreader stoker boilers with a limited percentage of coal firing.

Comparison of Environmental Impacts

Both wet and dry FGD processes will produce wastewater and solid waste as byproducts. The wet scrubber produces a large volume of wastewater which must be treated before disposal;

whereas the spray dryer scrubber does not. With the wet limestone scrubber system, the solid waste is generally collected in two separate stages. Fly ash is collected in the upstream mechanical collection device. Calcium salts and unreacted reagent are removed from the scrubber slurry wastestream and dewatered separately. In some systems, the dry ash is mixed with the wet scrubber sludge before disposal. For the spray dryer, both fly ash and calcium salts are collected at the same point where the particulate removal system is installed. These solids must be disposed as a waste material.

Solid wastes generated from firing compliance fuel only will produce the smallest quantity of ash requiring disposal. Flo-Energy will recycle coal ash (i.e., for use in concrete, road bed aggregate, etc.) or dispose of the material in an off-site landfill.

In terms of water use, a wet scrubbing system at Flo-Energy would require about 57 million gallons of water per year and the dry scrubbing system about 23 million gallons. Firing compliance coal would require no additional water usage.

The wet scrubber system produces a visible moisture plume due to its being at the moisture dew point. The spray dryer system plume, being above the dew point, would tend to disperse horizontally and vertically before condensing into a visible plume. However, with cool ambient conditions a plume detached from the chimney would sometimes form. The wet scrubber system would produce a visible moisture plume more frequently than a spray dryer system.

For the case of firing compliance coal without additional controls, the plume rise of the flue gases will be higher because of the higher thermal content of the flue gas. Higher temperatures and lower moisture in the flue gas would mean enhanced plume rise and flue gas dispersion and a less visible plume.

In conclusion, the firing of compliance coal with no add-on controls will have the smallest environmental impacts because there will be less byproduct wastes, no additional water usage, and less of a visible plume.

<u>Comparison of Energy Impacts</u>--Both wet and dry scrubbers will consume additional energy for their operation. The estimated additional energy requirements are approximately 7,900 MW-hr for the wet scrubber system, and approximately 3,800 MW-hr for the spray dryer scrubber

system. No additional energy or electricity is required for firing compliance coal only. Therefore, the firing of compliance coal without add-on control devices is the preferred option in terms of energy impact.

Comparison of Economic Impacts--Based on the annualized costs presented in Table 5-4 for the lime spray dryer and the wet limestone scrubber systems, the total and incremental cost effectiveness for these add-on control devices are shown in Table 5-5. These effectiveness costs are based on maximum coal firing for the cogeneration facility and 92 percent SO_2 removal using the lime spray dryer scrubber or 95 percent SO_2 removal using the wet lime/limestone scrubbing process.

The total cost effectiveness values are $2,551 per ton of SO_2 removed for the spray dryer scrubber and $4,700 per ton of SO_2 removed for the wet limestone scrubber. The incremental cost effectiveness values are $2,551 per ton of SO_2 removed for the spray dryer scrubber and $70,625 per ton of SO_2 removed for the wet limestone scrubber. These incremental cost effectiveness values are higher than the levels that FDER and EPA have considered as reasonable for controlling SO_2 emissions (i.e., $2,000 per ton of SO_2 removed). Therefore, both the wet scrubber and the spray dryer processes are considered as economically infeasible for the project.

The cost effectiveness figures derived above are based on the worst-case condition of firing up to 25 percent coal in a single year (producing 1,623.6 TPY of SO_2). The actual average case of producing 1,000 TPY SO_2 uncontrolled at Flo-Energy and Sol-Energy is also presented in Table 5-5. Based on the combined Flo-Energy and Sol-Energy annualized costs for the wet scrubbing systems, the cost incremental effectiveness for installing add-on control devices at both facilities are estimated to be $6,880 and $190,000 per ton of SO_2 removal for using lime spray dryer scrubbers and wet limestone scrubbers, respectively (refer to Table 5-5). These cost effectiveness values are far greater that the $2,000 per ton guideline used by FDER and EPA.

Conclusion

The top-down BACT analysis for SO_2 for the proposed boilers firing coal as the auxiliary fuel is summarized in Table 5-5. As discussed above, the analysis has indicated that significant economic, environmental and energy costs are associated with the two alternative scrubber options. The estimated costs for add-on SO_2 controls are unreasonable, particularly considering that it is not intended to burn coal in the cogeneration facility, that coal may never be burned at

Table 5–5. Summary Results of the Top–Down BACT Analysis for SO2 for Flo–Energy Cogeneration Facility.

				Environmental Impacts		Energy Impacts	Economic Impacts			
Control Alternative	Total SO2 Emissions (TPY)	Total Emission Reduction (TPY)*	Incremental Emission Reduction (TPY)**	Potential toxic air impact?	Potential adverse enviromental impacts?	Additional Energy Requirements Electricity (MW–hr/yr)	Total Annualized Cost ($/yr)*	Incremental Annualized Cost ($/yr)**	Total Cost Effectiveness ($/ton)*	Incremental Cost Effectiveness ($/ton)**
Flo–Energy Facility Only– Worst Case Year										
Wet Limestone Scrubber	81.2	1,542.4	48.7	No	Yes	7,900	$7,250,000	$3,440,000	$4,700	$70,625
Spray Dry Scrubber	129.9	1,493.7	1,493.7	No	Yes	3,800	$3,810,000	$3,810,000	$2,551	$2,551
Baseline (0.7 Wt% S Coal Uncontrolled)	1,623.6	--	--	--	--	--	---	---	---	---
Flo–Energy and Sol–Energy Facilities Combined– Average SO2 Emissions										
Wet Limestone Scrubber	50	950	30	No	Yes	13,000	$12,030,000	$5,700,000	$12,663	$190,000
Spray Dry Scrubber	80	920	920	No	Yes	6,200	$6,330,000	$6,330,000	$6,880	$6,880
Baseline (0.7 Wt% S Coal Uncontrolled)	1,000	--	--	--	--	--	---	---	---	---

* Total emission reduction, total annualized cost, and total cost effectiveness are calculated based on similar baseline values (i.e., firing compliance coal only).

** Incremental values are the same as those calculated for total values because of similar reduction efficiency designed for both wet and dry scrubbing systems.

the facility, and that coal will be burned only if the supply of biomass fuels is not adequate. If add-on controls were required, a very high capital cost would be incurred for equipment that may never be used. No other facility in the United States has been identified where add-on SO_2 controls were required as BACT when the heat input due to fossil fuels was less than 30 percent. In three recent BACT determinations for multifuel stoker boilers, coal is used as supplementary fuel for up to 30 percent of heat input without the use of add-on SO_2 controls. Based on these considerations, using low-sulfur (1.2 lb/MMBtu maximum) coal as the compliance fuel, not to exceed 25 percent of the total annual heat input, represents BACT for the Flo-Energy cogeneration project.

Furthermore, the proposed cogeneration facility will have relatively minor impacts on ambient SO_2 levels. The modeling results show a low SO_2 impact of less than 6 $\mu g/m^3$, annual average, on the surrounding area. Per the Palm Beach County zoning conditions, the total combined annual SO_2 emissions from the Flo-Energy and Sol-Energy cogeneration facilities cannot exceed the current SO_2 emissions of approximately 1,000 TPY on a long-term average basis. Thus, the average SO_2 loading to the atmosphere will not increase due to the proposed project. The higher stacks associated with the new cogeneration facility, compared to the shorter stacks of the existing sugar mill facility, will result in a general air quality improvement for SO_2 and all other pollutants.

5.2 BACT DETERMINATION FOR BERYLLIUM

The presence of trace elements in bituminous coal can result in emissions of Be and other trace elements to the atmosphere. The high temperatures in the boiler furnace vaporizes some of these elements. Subsequently, as the temperature of the flue gas drops following the boiler heat recovery system, some of these elements condense onto fine particulate matter or nucleate into new particles. Most of these particulates are then collected in the particulate collection system, if present. For the proposed project, Be will exist as a solid particulate at temperatures existing in the ESP control device (i.e., approximately 350°F). Therefore, the proposed particulate control device will also control Be emissions.

There are no applicable NSPS for Be emissions from utility boilers. Technologies currently available for further reduction of Be and collection of fine particulate matter include ESPs, fabric filters, and wet scrubbers. Fabric filters and ESPs are the most effective; they reduce most heavy metal emissions, including Be emissions, by 98 percent or greater. Although similar in effectiveness, fabric filters are somewhat superior to ESPs because of their higher degree of fine particle control.

Review of the BACT Clearinghouse information revealed that four wood-fired boilers received BACT determinations for Be emissions. Of these, two were stated to use ESPs as the control device. Be emission limits were approximately 10 lb/10^{12} Btu for both.

For the proposed project, the PM control device will be designed to meet the NSPS level of 0.03 lb/MMBtu for PM emissions. Although the fabric filter would provide somewhat better control of fine particles, the total Be emission rate would be similar to that of the ESP.

Based on these considerations, an emission level for Be based on the ESP technology, which is the selected PM control device for the project, is considered as BACT for the proposed project. Be emissions from the Flo-Energy cogeneration project are estimated to be, based on ESP technology, 0.35 lb/10^{12} and 5.9 lb/10^{12} Btu for oil firing and coal firing, respectively.

5.3 BACT DETERMINATIONS FOR FLUORIDE AND SULFURIC ACID MIST

Fluoride and sulfuric acid mist are discussed together as acid gases since these compounds can be controlled by similar methods. The emissions of fluoride and sulfuric acid mists are generated from the emissions of fluorine and sulfur trioxide (SO_3) when coal is combusted. Both fluorine and sulfur trioxide can further react with water present in the flue gas to form hydrofluoric and sulfuric acid mists.

The control of acid gas emissions is primarily controlled by removing the precursor pollutants from the flue gas with either wet or dry scrubbing processes. Based on the high cost effectiveness presented for controlling SO_2 emissions from coal-firing, installing a similar system for acid gas removal only would also be economically infeasible. The firing of low sulfur coal acts to control sulfuric acid mist emissions by reducing the amount of sulfur in the stack gases. Therefore, the use of low sulfur coal is considered as BACT for fluorides and sulfuric acid emissions.

6.0 AIR QUALITY IMPACT ANALYSIS

6.1 GENERAL MODELING APPROACH

An air quality analysis for the proposed cogeneration facility was conducted for SO_2, which is the only regulated pollutant subject to PSD review. The purpose of the analysis is to demonstrate compliance with Florida AAQS and, since the Flo-Energy cogeneration facility is an increment consuming facility, demonstrate compliance with the allowable EPA/FDER PSD Class I and Class II increments for SO_2. In addition, an impact analysis for all emitted toxic air pollutants was performed for comparison to FDER's no-threat levels (NTLs).

The general modeling approach followed EPA and FDER modeling guidelines for determining compliance with AAQS and PSD increments. For each criteria pollutant that is emitted in excess of the PSD significant emission rate due to a proposed project, a significant impact analysis is performed to determine whether the emission increase(s) alone will result in predicted impacts in excess of the EPA/FDER significant impact levels. If the project's impacts are above the significant impact levels, a more detailed modeling analysis is performed. Current FDER policies stipulate that the highest annual average and highest short-term (i.e., 24 hours or less) concentrations are to be compared to the applicable significant impact levels. If the screening analysis indicates that maximum predicted concentrations are within 75 percent of the significant impact levels, modeling refinements are performed.

The proposed facility is located in the area of numerous sugar mills, which operate their boilers only part of the year. For modeling purposes, it was necessary to account for the partial year operation of the sugar mill boilers by utilizing two emission inventories, a crop-season inventory and an off-season inventory. The maximum crop season period was assumed to extend from October 1 through April 30. The maximum off-season period was assumed to extend from March 1 through October 31. Since the beginning and ending dates of the crop season vary from year to year, the two seasons were defined such that they overlap several months of the year.

The crop-season inventory included the sugar mill boiler emissions (and/or offsets for PSD purposes, if the boilers were to be shut down). The off-season inventory excluded the emissions and offsets from the sugar mill sources. The two emission inventories are identical in regards to all non-sugar-mill sources. For cases where the maximum impacts were well below the applicable standards, the analysis was simplified by conservatively assuming that the sugar mill sources operate year round.

6.2 MODEL SELECTION

The selection of an appropriate air dispersion model was based on the model's ability to simulate impacts in areas surrounding the Flo-Energy site. Within 50 km of the site, the terrain can be described as simple, i.e., flat to gently rolling. As defined in EPA modeling guidelines, simple terrain is considered to be an area where the terrain features are all lower in elevation than the top of the stack(s) under evaluation. Therefore, a simple terrain model was selected to predict maximum ground-level concentrations.

The Industrial Source Complex Short-term (ISCST2, Version 92062) dispersion model (EPA, 1992b) was used to evaluate the pollutant emissions from the proposed facility and other existing major facilities. This model is contained in EPA's User's Network for Applied Modeling of Air Pollution (UNAMAP), Version 6 (EPA, 1988b). The ISCST2 model is applicable to sources located in either flat or rolling terrain where terrain heights do not exceed stack heights. The ISCST2 model is designed to calculate hourly concentrations based on hourly meteorological parameters (i.e., wind direction, wind speed, atmospheric stability, ambient temperature, and mixing heights). The hourly concentrations are processed into non-overlapping, short-term and annual averaging periods. For example, a 24-hour average concentration is based on 24 1-hour averages calculated from midnight to midnight of each day. For each short-term averaging period selected, the highest and second-highest average concentrations are calculated for each receptor. As an option, a table of the 50 highest concentrations over the entire field of receptors can be produced.

Major features of the ISCST2 model are presented in Table 6-1. The ISCST2 model has both rural and urban mode options which affect the wind speed profile exponent law, dispersion rates, and mixing-height formulations used in calculating ground level concentrations. The criteria used to determine when the rural or urban mode is appropriate are based on land use near the source's surroundings (Auer, 1978). If the land use is classified as heavy industrial, light-moderate industrial, commercial, or compact residential for more than 50 percent of the area within a 3-km radius circle centered on the proposed source, the urban option should be selected. Otherwise, the rural option is more appropriate.

Table 6-1. Major Features of the ISCST2 Model

- Polar or Cartesian coordinate systems for receptor locations
- Rural or one of three urban options that affect wind speed profile exponent, dispersion rates, and mixing height calculations
- Plume rise as a result of momentum and buoyancy as a function of downwind distance for stack emissions (Briggs, 1969, 1971, 1972, and 1975)
- Procedures suggested by Huber and Snyder (1976); Huber (1977); Schulmann and Hanna (1986); and Schulmann and Scire (1980) for evaluating building wake effects
- Direction-specific building heights and projected widths for all sources for which downwash is considered.
- Procedures suggested by Briggs (1974) for evaluating stack-tip downwash
- Separation of multiple-point sources
- Consideration of the effects of gravitational settling and dry deposition on ambient particulate concentrations
- Capability of simulating point, line, volume, and area sources
- Capability to calculate dry deposition
- Variation of wind speed with height (wind speed-profile exponent law)
- Concentration estimates for 1-hour to annual average
- Terrain-adjustment procedures for elevated terrain, including a terrain truncation algorithm
- Receptors located above local terrain (i.e., "flagpole" receptors)
- Consideration of time-dependent exponential decay of pollutants
- The method of Pasquill (1976) to account for buoyancy-induced dispersion
- A regulatory default option to set various model options and parameters to EPA recommended values (see text for regulatory options used)
- Procedure for calm-wind processing
- Wind speeds less than 1 m/s are set to 1 m/s.

Source: EPA, 1992b.

In this analysis, the EPA regulatory default options were used to predict all maximum impacts. The regulatory default options include:

1. Final plume rise at all receptor locations,
2. Stack-tip downwash,
3. Buoyancy-induced dispersion,
4. Default wind speed profile coefficients for rural or urban option,
5. Default vertical potential temperature gradients,
6. Calm wind processing, and
7. Reducing calculated SO_2 concentrations in urban areas by using a decay half-life of 4 hours.

6.3 MODELING ANALYSIS

6.3.1 SIGNIFICANT IMPACT ANALYSIS

For the proposed cogeneration project, the significant impact area for SO_2 was based on the net emission changes due to the proposed project. Offsets for the existing Okeelanta boilers which will be shut down were accounted for in the modeling analysis for the crop season months. A description of the shutdown of the existing boilers is presented in Section 2.0. Emission and stack parameters reflective of current operation are presented in Table 6-2.

For determining maximum impacts due to the proposed cogeneration facility only, offsets from the existing Okeelanta boilers to be shut down were not accounted for in the modeling.

6.3.2 AAQS/PSD MODELING ANALYSIS

A full impact analysis is required for all pollutants subject to PSD that have a significant impact. In general, when 5 years of meteorological data are used, the highest annual and the highest, second-highest (HSH) short-term concentrations are to be compared to the applicable AAQS and allowable PSD increments. The HSH concentration is calculated for a receptor field by:

1. Eliminating the highest concentration predicted at each receptor,
2. Identifying the second-highest concentration at each receptor, and
3. Selecting the highest concentration among these second-highest concentrations.

This approach is consistent with air quality standards and allowable PSD increments, which permit a short-term average concentration to be exceeded once per year at each receptor.

Table 6-2. Summary of Okeelanta Emission, Stack, and Operating Data Used in the Modeling Analysis

ISCST2 Source Identification	Source Description	Coordinates Relative to Okeelanta Boiler No. 16 (m) X	Y	Stack Data (m) Height	Diameter	Operating Data Temperature (K)	Velocity (m/sec)	Modeled SO_2 Emissions (g/sec)
PSD Baseline[a]								
BLR4B	Boiler 4	52	34	22.9	2.29	333	7.36	10.95
BLR5B	Boiler 5	52	21	22.9	2.29	333	12.07	15.64
BLR6B	Boiler 6	52	6	22.9	2.29	334	8.74	15.64
BLR10B	Boiler 10	52	-8	22.9	2.29	334	10.35	17.15
BLR11B	Boiler 11	52	44	22.9	2.29	342	9.89	16.79
BLR12B	Boiler 12	52	-24	22.9	2.29	330	8.16	20.58
BLR14B	Boiler 14	52	-37	22.9	2.29	333	8.28	20.03
BLR15B	Boiler 15	52	-47	22.9	2.29	332	10.23	16.79
Current[a]								
BLR4	Boiler 4	52	34	22.9	2.29	333	7.36	10.95
BLR5	Boiler 5	52	21	22.9	2.29	333	12.07	15.64
BLR6	Boiler 6	52	6	22.9	2.29	334	8.74	15.64
BLR10	Boiler 10	52	-8	22.9	2.29	334	10.35	17.15
BLR11	Boiler 11	52	44	22.9	2.29	342	9.89	16.79
BLR12	Boiler 12	52	-24	22.9	2.29	330	8.16	20.58
BLR14	Boiler 14	52	-37	22.9	2.29	333	8.28	20.03
BLR15	Boiler 15	52	-47	22.9	2.29	332	10.23	16.79
BLR16	Boiler 16	0	0	22.9	1.52	497	18.38	13.29
Proposed								
OKCOGEN	Flo-Energy Boilers 1,2,& 3	219	-21	60.7	2.44	450	21.25	222.26

Note:
g/sec = grams per second.
K = Kelvin.
lb/MMBtu = pounds per million British thermal units.
m = meters.
m/sec = meters per second.
SO_2 = sulfur dioxide.

[a] Reflects worst-case 24-hour SO_2 emissions based on 48,000 gallons of 2.5% Sulfur No. 6 fuel oil during a 24-hour period.

To develop the maximum short-term concentrations for the proposed project, the modeling approach was divided into screening and refined phases to reduce the computation time required to perform the modeling analysis. For this study, the only difference between the two phases is the density of the receptor grid spacing employed when predicting concentrations. Concentrations are predicted for the screening phase using a coarse receptor grid and a 5-year meteorological data record.

Refinements of the maximum predicted concentrations are typically performed for the receptors of the screening receptor grid at which the highest and/or HSH concentrations occurred over the 5-year period. Generally, if the maximum concentration from other years in the screening analysis are within 10 percent of the overall maximum concentration, those other concentrations are refined as well. Typically, if the highest and HSH concentrations are in different locations, concentrations in both areas are refined.

Modeling refinements are performed for short-term averaging times by using a denser receptor grid, centered on the screening receptor to be refined. The angular spacing between radials is 2 degrees and the radial distance interval between receptors is 100 m. Annual modeling refinements are developed similarly. If the maximum screening concentration is located on the plant property boundary, additional plant boundary receptors are input, spaced at a 2-degree angular interval and centered on the screening receptor. The domain of the refinement grid extends to all adjacent screening receptors.

The air dispersion model is executed with the refined grid for the entire year of meteorology during which the screening concentration occurred. This approach is used to ensure that a valid HSH concentration is obtained. A more detailed description of the emission inventory, meteorological data, and screening receptor grids used in the analysis, is presented in the following sections.

6.4 METEOROLOGICAL DATA

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) stations 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 Flo-Energy 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.

The wind speed, cloud cover, and cloud ceiling values were used in the ISCST meteorological preprocessor program to determine atmospheric stability using the Turner stability scheme. Based on the temperature measurements at morning and afternoon, mixing heights were calculated with the radiosonde data using the Holzworth approach (1972). Hourly mixing heights were derived from the morning and afternoon mixing heights using the interpolation method developed by EPA (Holzworth, 1972). The hourly surface data and mixing heights were used to develop a sequential series of hourly meteorological data (i.e., wind direction, wind speed, temperature, stability, and mixing heights). Because the observed hourly wind directions were classified into one of thirty-six 10-degree sectors, the wind directions were randomized within each sector to account for the expected variability in air flow. These calculations were performed by using the EPA RAMMET meteorological preprocessor program.

6.5 EMISSION INVENTORY

6.5.1 OKEELANTA AND FLO-ENERGY

Stack and operating parameters and emission rates for the PSD baseline and current Okeelanta sources are presented in Table 6-2. Parameters for the proposed cogeneration facility are also shown. The current mill configuration is the same as in the PSD baseline period (i.e., 1975), except that Boiler No. 16 has been constructed recently. This boiler is, therefore, not in the PSD baseline.

6.5.2 OTHER AIR EMISSION SOURCES

The proposed cogeneration facility produces a significant impact for SO_2. Therefore, a detailed impact analysis has been performed for this pollutant. Flo-Energy's SIA was determined to be 80 km. An inventory of all facilities used in the modeling analyses is presented in Table 6-3. This list was developed from the 1991 Air Pollutant Information System (APIS) reports provided to KBN by FDER, supplemented by existing source permits and other recent modeling analyses performed in this area. This list includes all SO_2 sources located within 80 km of the Flo-Energy site and emitting greater than 25 TPY. Also included are four sources located outside the SIA, but which may have a significant impact on the SIA or are PSD increment consuming sources. Beyond the SIA, sources emitting less than 100 TPY were not included in the analysis.

Table 6-3. Non-Okeelanta Sources (>25 TPY) Used in the Modeling Inventories

APIS Number	Facility	County	UTM Coordinates (km) East	UTM Coordinates (km) North	Location Relative To Proposed Site (km) X	Location Relative To Proposed Site (km) Y	Distance From Proposed Site (km)	Direction From Proposed Site (degrees)	Maximum SO_2 Emissions (TPY)
52FTM500026	Sugar Cane Growers	Palm Beach	534.9	2953.3	9.9	13.9	17.1	35	4,269
52FTM260001	Everglades Sugar	Hendry	509.6	2954.2	-15.4	14.8	21.4	314	1,408
50PMB500086	Glades Correctional Institute	Palm Beach	533.4	2955.2	8.4	15.8	24.3	28	98
52FTM260003	U.S. Sugar Corp.	Hendry	506.1	2956.9	-18.9	17.5	25.8	313	5,353
52FTM500016	Atlantic Sugar Association	Palm Beach	552.9	2945.2	27.9	5.8	28.5	78	1,484
52FTM500061	U.S. Sugar -Bryant	Palm Beach	538.8	2968.1	13.8	28.7	31.8	26	2,364
52FTM500019	Osceola Farms	Palm Beach	544.2	2968.0	19.2	28.6	34.4	34	3,122
52FTM260015	Southern Gardens Citrus Processing	Hendry	487.6	2957.6	-37.4	18.2	41.6	296	173
50PMB500021	Pratt & Whitney	Palm Beach	559.2	2978.3	34.2	38.9	51.8	41	3,386
50WPB43????	Bechtel Indiantown Cogen-Proposed	Martin	545.6	2991.5	20.6	52.1	56.0	22	3,378
50WPB430001	FPL -Martin	Martin	543.1	2992.9	18.1	53.5	56.5	19	93,788
50WPB500234	Palm Beach Resource Recovery	Palm Beach	585.8	2960.2	60.8	20.8	64.3	71	1,533
50BRO062094	Waste Management	Broward	583.2	2908.0	58.2	-31.4	66.1	118	187
NA	North Broward Res. Rec.	Broward	583.6	2907.6	58.6	-31.8	66.7	118	896
50PMB500045	Lake Worth Utilities	Palm Beach	592.8	2943.7	67.8	4.3	67.9	86	2,302
50PMB500042	FPL -Riviera Beach	Palm Beach	594.2	2960.6	69.2	21.2	72.4	73	77,815
NA	South Broward Res. Rec.	Broward	579.6	2883.3	54.6	-56.1	78.3	136	1,318
50BRO060037	FPL -Fort Lauderdale	Broward	580.1	2883.3	55.1	-56.1	78.6	136	65,964
50BRO060036	FPL -Port Everglades	Broward	587.4	2885.3	62.4	-54.1	82.6	131	76,239
50DAD130020	Tarmac Florida	Dade	562.9	2861.7	37.9	-77.7	86.5	154	2,792
50DAD130348	Metro Dade Resource Recovery	Dade	564.3	2857.4	39.3	-82.0	90.9	154	2,996
NA	Lee County RRF	Lee	424.0	2946.0	-101.0	6.6	101.2	274	490

A summary of all source data used in the modeling analysis, including which sources are designated as PSD (increment consuming or expanding) sources, is presented in Table 6-4. Table 6-4 details which sources were used in the AAQS, PSD Class II, and PSD Class I modeling analyses. Included in this list is the proposed Sol-Energy (Osceola) cogeneration facility, which will replace the existing Osceola Farms sugar mill. Therefore, the existing Osceola sources are not included in the table. In general, stack, SO_2 emissions, and operating information were obtained from APIS for the year 1991. The emission data for Tarmac, Florida Power & Light Company (FPL) plants, and sugar mill sources within the SIA were available from current air operating or construction permits. The stack and operating parameters for these sources were obtained from prior PSD applications (KBN, 1990a and b).

Sources within one facility were sometimes combined if their stack heights were the same and the sources had similar operating parameters. Some small sources were sometimes combined with larger sources within the same facility (emissions were added to the larger source).

For most facilities, 3-hour worst-case emission rates were used for all averaging time analyses. For 24-hour and annual averaging times, 24-hour emission rates were used in place of 3-hour emission rates for a few sources, where available. These are noted in the footnote at the bottom of Table 6-4.

Three separate modeling emission inventories were prepared for the modeling effort.

1. For the AAQS analysis, all sources listed in Table 6-4 and located within 80 km of the proposed site, and major utilities located within 100 km of the proposed site were used.
2. The Class II inventory included PSD increment consuming and/or expanding sources within 80 km and major utility PSD increment consuming and/or expanding sources within 100 km. To be conservative and to simplify the modeling analysis, increment expanding shutdowns of sugar mill boilers (i.e., at Okeelanta and Osceola Farms) were not modeled. In addition, increment consuming sugar mill boilers (i.e., at Atlantic Sugar, Sugar Cane Growers, and U.S. Sugar Clewiston and Bryant) were assumed to operate year around.

Table 6-4. Summary of Non-Okeelanta Source Data Used in Modeling Analysis (Page 1 of 2)

		Stack						Modeled in		
APIS Number	Facility	Height (m)	Diameter (m)	Temp (K)	Velocity (m/s)	SO_2 3-Hour Emission Rate (g/s)	PSD Source? (EXP/CON)	AAQS	Class II	Class I
52FTM500016	Atlantic Sugar									
	Unit 1[a]	18.9	1.92	346	12.7	17.24		Yes	No	No
	Unit 2[a]	18.9	1.92	342	10.9	22.50		Yes	No	No
	Unit 3[a]	21.9	1.83	341	17.5	16.88		Yes	No	No
	Unit 4[a]	18.3	1.83	344	15	16.88		Yes	No	No
	Unit 5[a] PSD	27.4	1.68	339	15.7	11.80	CON	Yes	Yes	Yes
50WPB43????	Bechtel Indiantown PSD	150.9	4.88	333.2	30.5	75.64	CON	Yes	Yes	Yes
50DAD130348	Dade County RRF PSD									
	Units 1&2 proposed mod.	64.9	3.66	405.4	15.86	12.30	CON	No	No	Yes
	Units 3&4 proposed mod.	64.9	3.66	405.4	15.86	12.30	CON	No	No	Yes
	Units 5&6 proposed	76.2	4.2	399.8	15.74	17.20	CON	No	No	Yes
52FTM260001	Everglades Sugar[a]	21.9	1.1	477	10.1	11.80		Yes	No	No
50BRO060037	FPL - Lauderdale									
	CTs 1-4 PSD	45.7	4.88	411	10.97	271.10	CON	Yes	Yes	Yes
	4&5 PSD Baseline	46	4.27	422	14.63	-457.00	EXP	No	Yes	Yes
50WPB430001	FPL Martin									
	Units 1&2	152.1	7.99	420.9	21.03	1743.79		Yes	No	No
	Aux Blr PSD	18.3	1.1	535.4	15.24	12.90	CON	Yes	Yes	Yes
	Diesl Gens PSD	7.6	0.3	785.9	39.62	0.51	CON	Yes	Yes	Yes
	Units 3&4 PSD	64.9	6.1	410.9	18.9	470.40	CON	Yes	Yes	Yes
50BRO060036	FPL - Port Everglades									
	GT 1-2	15.5	5.49	733	21.34	488.39		Yes	No	No
	Units 1&2	104.9	4.27	416	18.59	637.54		Yes	No	No
	Units 3&4	104.5	5.52	108	19.2	1067.16		Yes	No	No
50PMB500042	FPL - Riviera Beach									
	Unit 2	45.7	4.57	430.2	7.62	124.86		Yes	No	No
	3&4	90.8	4.88	408	18.9	846.33		Yes	No	No
50PMB500086	Glades Corr Institute	9.8	0.4	389	11.28	2.82		Yes	No	No
50PMB500045	Lake Worth									
	Units 1&2	18.23	1.52	434.1	6.19	72.58		Yes	No	No
	Units 3&4	38.1	2.29	408	9.69	237.90		Yes	No	No
	Unit 5	22.9	0.95	450.2	18.29	11.59		Yes	No	No
NA	Lee County RRF PSD	83.8	1.88	388.5	19.81	14.00	CON	No	No	Yes
NA	North Broward RRF PSD	58.5	3.96	381	18.01	35.40	CON	Yes	Yes	Yes
52FTM500019	Osceola Farms									
	Unit 1 PSD Baseline[a]	22	1.52	342	8.18	-5.07	EXP	No	No	Yes
	Unit 2 PSD Baseline[a]	22	1.52	341	18.1	-16.32	EXP	No	No	Yes
	Unit 3 PSD Baseline[a]	22	1.93	341	14.5	-7.26	EXP	No	No	Yes

Table 6-4. Summary of Non-Okeelanta Source Data Used in Modeling Analysis (Page 2 of 2)

APIS Number	Facility	Stack Height (m)	Stack Diameter (m)	Temp (K)	Velocity (m/s)	SO_2 3-Hour Emission Rate (g/s)	PSD Source? (EXP/CON)	Modeled in AAQS	Modeled in Class II	Modeled in Class I
	Unit 4 PSD Baseline[a]	22	1.83	341	18.8	-13.61	EXP	No	No	Yes
	Cogenerator Units 1&2	54.9	2.13	449	26.05	139.20	CON	Yes	Yes	Yes
50WPB500234	Palm Beach RRF 1&2 PSD	76.2	2.04	505.2	24.9	85.05	CON	Yes	Yes	No
50PMB500021	Pratt & Whitney									
	ACHR-1	1.8	0.91	500	40.23	16.02		Yes	No	No
	ACHR-2	15.2	0.91	500	40.23	47.92		Yes	No	No
	ACHR-3	4.6	3.38	700	13.44	23.46		Yes	No	No
	BO-12	4.6	0.76	500	6.92	9.08		Yes	No	No
	LI-1 MW	8.2	0.67	2000	8.35	6.18		Yes	No	No
NA	South Broward RRF PSD	59.4	3.96	381	18.01	37.91	CON	Yes	Yes	Yes
52FTM260015	Southern Gardens PSD	22	0.64	479.8	17.48	4.99	CON	Yes	Yes	Yes
52FTM500026	Sugar Cane Growers									
	Unit 3[a]	24.4	1.6	344	15.6	4.40		Yes	No	No
	Unit 4 PSD[a]	33.5	1.63	344	10.6	24.20	CON	Yes	Yes	Yes
	Unit 4 PSD Baseline[a]	25.9	2.82	344	10.6	-24.20	EXP	No	Yes	Yes
	Unit 5[a]	24.4	1.4	344	15.2	16.20		Yes	No	No
	Unit 8 PSD[a]	47.2	3.05	344	10.6	26.70	CON	Yes	Yes	Yes
	Unit 1&2[a]	24.4	1.4	344	11.4	24.20		Yes	No	No
	Unit 6&7[a]	12.2	2.13	606	11.2	51.00		Yes	No	No
50DAD130020	Tarmac									
	Kiln 2 PSD Baseline	61	2.44	465	12.84	-5.71	EXP	No	No	Yes
	Kiln 3 PSD Baseline	61	4.57	472	10.78	-2.76	EXP	No	No	Yes
	Kiln 2 PSD	61	2.44	422	9.1	24.50	CON	No	No	Yes
	Kiln 3 PSD	61	4.57	450	11.04	51.40	CON	No	No	Yes
52FTM260003	US Sugar Clewiston									
	Unit 3[a]	27.4	2.29	340	14.54	28.16[b]		Yes	No	No
	Unit 4 PSD[a]	45.7	2.51	334	19.66	16.26[b]	CON	Yes	Yes	Yes
	Units 1&2[a]	22.9	1.86	339	35.54	95.22[b]		Yes	No	No
	Units 5&6[a]	19.8	1.83	340	9.78	4.48		Yes	No	No
52FTM500061	US Sugar-Bryant									
	Unit 5 PSD[a]	42.7	2.9	345	11.49	81.36[b]	CON	Yes	Yes	Yes
	Unit 1,2&3[a]	19.8	1.64	342	36.4	204.54[b]		Yes	No	No
50BRO062094	Waste Management PSD	11.3	1.22	721.9	36.82	5.39	CON	Yes	Yes	No

[a] These sources operate only during the crop season, October 1 through April 30.

[b] The following sources were modeled under 24 hour and annual averaging times with the following emission rates (g/s):

US Sugar Clewiston Unit 3: 22.99
US Sugar Clewiston Unit 4: 14.78
US Sugar Clewiston Unit 1&2: 80.68
US Sugar Bryant Unit 5 PSD: 79.97
US Sugar Bryant Unit 1,2&3: 79.69

3. An emission inventory for modeling SO_2 at the Everglades National Park, a PSD Class I area, was developed to include all PSD sources within 100 km from the Everglades National Park. The inventory included regional resource recovery facilities (e.g, Lee, Dade, and Broward counties), future expansion at FPL Martin power facility in Martin County, the proposed Sol-Energy (Osceola) cogeneration facility, and all increment-consuming sugar mill sources. Offsets from Okeelanta and Osceola were applied only during the crop season time period. The PSD Class I inventory was therefore subdivided into two inventories, crop-season and off-season. As discussed previously, two seasons were modeled with overlapping periods. No offsets were applied for the non-crop season. The two separate analyses were compared after screening results were complete. Highest impacts occurred during the non-crop season. Refinements and reported maximums are from this inventory.

6.6 RECEPTOR LOCATIONS

6.6.1 SIGNIFICANT IMPACT ANALYSIS

For short and long term averaging periods, 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.

6.6.2 AAQS IMPACT ASSESSMENTS

For the AAQS analysis, both near- and far-field receptor grids were used. Okeelanta's and Flo-Energy's nearest property boundary is located approximately 3.2 km from the stack locations. 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 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 property boundary receptors used for the modeling are presented in Table 6-5. All receptor locations are relative to the stack location for the recently permitted Boiler No. 16.

Table 6-5. Property Boundary Receptors Used in the Modeling Analysis

Direction (degrees)	Distance (m)	Direction (degrees)	Distance (m)
10	3674	190	2764
20	3850	200	2897
30	4178	210	3143
40	3642	220	3553
50	3163	230	4234
60	4066	240	5444
70	3849	250	7958
80	3669	260	9485
90	3609	270	9675
100	3661	280	9585
110	3832	290	9602
120	4153	300	7236
130	4234	310	5629
140	3553	320	4723
150	3143	330	4178
160	2897	340	3850
170	2764	350	3674
180	2722	360	3618

Note: Distances are relative to Okeelanta Boiler No. 16.

6.6.3 PSD CLASS II IMPACT ASSESSMENTS

To cover the spatial extent of Flo-Energy's significant impact area for SO_2 (80 km), near-field and far-field receptor grids were used for the PSD Class II screening analyses. The Class II screening grids were the same as the AAQS screening grids.

6.6.4 CLASS I IMPACT ASSESSMENT

The Everglades National Park is a PSD Class I area that is located within 100 km of the Flo-Energy plant site. Through passage of the Clean Air Act of 1990, the park's eastern edge has been expanded farther to the east. The northeastern corner of the expanded Class I area is approximately 94 km south of the Flo-Energy site (see Figure 6-1). 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 Everglades National Park. The Universal Transverse Mercator (UTM) coordinates of these Class I receptors are listed in Table 6-6. Refined modeling was performed for the Class I area by using a receptor spacing of 1.0 km centered on the receptor of interest extending to the adjacent receptors.

6.7 BUILDING DOWNWASH CONSIDERATIONS

The procedures used for addressing the effects of building downwash are those recommended in the ISC2 Dispersion Model User's Guide. The building height, length, and width are input to the model, which uses these parameters to modify the dispersion parameters. For short stacks (i.e., physical stack height is less than H_b + 0.5 L_b, where H_b is the building height and L_b is the lesser of the building height or projected width), the Schulman and Scire (1980) method is used. The features of the Schulman and Scire method are as follows:

1. Reduced plume rise as a result of initial plume dilution,
2. Enhanced plume spread as a linear function of the effective plume height, and
3. Specification of building dimensions as a function of wind direction.

For cases where the physical stack is greater than H_b + 0.5 L_b but less than GEP, the Huber and Snyder (1976) method is used. For this method, the ISCST model calculates the area of the building using the length and width, assumes the area is representative of a circle, and then calculates a building width by determining the diameter of the circle. For both methods the direction-specific building dimensions are input for H_b and L_b for 36 radial directions, with each direction representing a 10-degree sector.

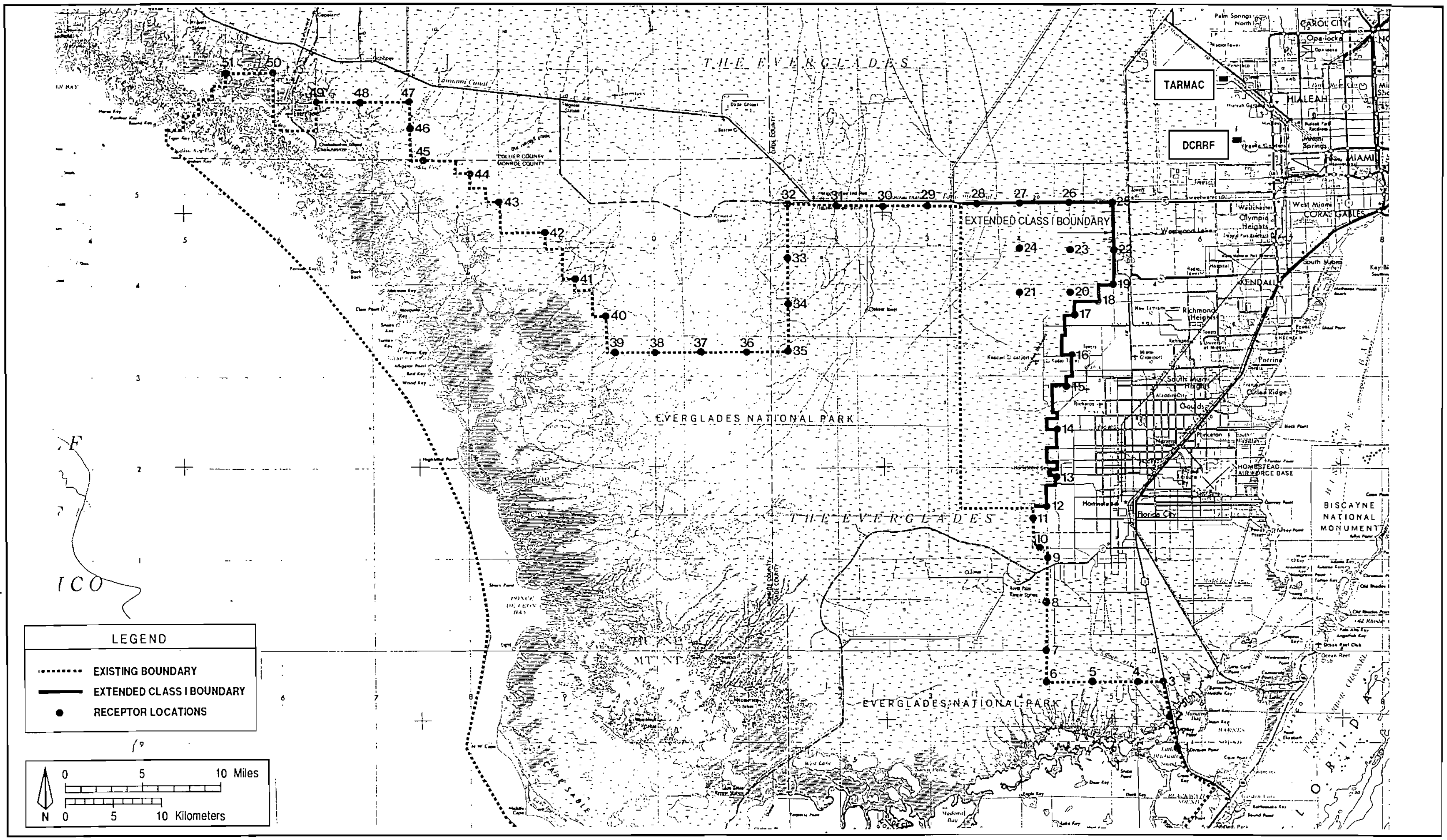

Figure 6-1 RECEPTOR LOCATIONS USED FOR THE EVERGLADES NATIONAL PARK PSD CLASS I SCREENING ANALYSES

Table 6-6. Everglades National Park Receptors Used for the Class I Screening Analyses

Receptor	UTM Coordinates (km)		Receptor	UTM Coordinates (km)	
	East	North		East	North
1	557.0	2789.0	27	540.0	2848.6
2	556.6	2792.0	28	535.0	2848.6
3	556.0	2796.0	29	530.0	2848.6
4	553.0	2796.5	30	525.0	2848.6
5	548.0	2796.5	31	520.0	2848.6
6	542.7	2796.5	32	515.0	2848.6
7	542.7	2800.0	33	515.0	2843.0
8	542.7	2805.0	34	515.0	2838.0
9	542.7	2810.0	35	515.0	2833.0
10	542.0	2811.0	36	510.0	2833.0
11	541.3	2814.0	37	505.0	2833.0
12	542.7	2816.0	38	500.0	2833.0
13	544.1	2820.0	39	495.0	2833.0
14	543.5	2824.6	40	494.5	2837.0
15	545.0	2829.0	41	491.5	2841.0
16	545.7	2832.2	42	488.5	2845.5
17	546.2	2835.7	43	483.0	2848.5
18	548.6	2837.5	44	480.0	2852.5
19	550.3	2839.0	45	475.0	2854.0
20	445.0	2839.0	46	473.5	2857.0
21	440.0	2839.0	47	473.5	2860.0
22	550.5	2844.0	48	469.0	2860.0
23	545.0	2844.0	49	464.0	2860.0
24	540.0	2844.0	50	459.5	2864.0
25	550.3	2848.6	51	454.0	2864.0
26	545.0	2848.6			

Note: km = kilometers.
UTM = Universal Transverse Mercator.

The existing Okeelanta and proposed Flo-Energy stacks have heights that are below that required to completely avoid building downwash effects. Therefore, the modeling analysis addresses the effects of aerodynamic downwash for these stacks. To determine the potential for downwash to occur, the following buildings were analyzed from a layout plan of the site.

Building	Height (m)	Length (m)	Width (m)
Proposed Boilers 1,2,3	39.01	54.9	22.9
Mill Tandems A & B	16.85	135.0	42.6
South Evaporators	22.86	22.9	12.2
North Evaporators	19.81	22.9	38.4
Power Plant	14.02	21.3	21.9
Tank	24.38	—	71.8[a]
Refinery	27.43	91.5	36.5

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[a] Tank diameter.

The potential for downwash was determined for each 1 degree within each 10-degree direction sector. For each direction, a building structure was determined to be within the zone of influence of a stack if the stack is within $5L_b$ downwind off the building, $2L_b$ upwind of the building, or $0.5L_b$ crosswind of the building. Based on this analysis, direction-specific building heights and widths were developed for each 10-degree direction sector and included for both existing and proposed stacks on the site.

6.8 BACKGROUND CONCENTRATIONS

To estimate total air quality concentrations, a background concentration must be added to the modeling results. The background concentration is considered to be the air quality concentration contributed by sources not included in the modeling evaluation.

In order to develop a conservative estimate of the SO_2 background with the existing Okeelanta boilers shut down, the second highest 3-hour and 24-hour and highest annual average SO_2 concentrations measured at the Belle Glade monitor during the period 1989-1991 were used. Based on this analysis, the background SO_2 concentrations were determined to be 53 and 21 $\mu g/m^3$ for the 3- and 24-hour averaging periods, respectively, and 8 $\mu g/m^3$ for the annual averaging period. These background levels were added to model-predicted concentrations to estimate total air quality levels for comparison to AAQS.

6.9 AIR QUALITY MODELING RESULTS

6.9.1 SIGNIFICANT IMPACT ANALYSIS

The maximum air quality impacts from the proposed Flo-Energy facility only are presented in Table 6-7. As shown, the facility's maximum annual, 24-hour, and 3-hour predicted SO_2 concentrations are 5.5, 74, 164 $\mu g/m^3$, respectively. These all occur at the plant property boundary. These maximum impacts are above the respective SO_2 significant impact levels of 1, 5, and 25 $\mu g/m^3$. Therefore, a full impact assessment was performed for this pollutant to demonstrate compliance with allowable PSD increments and AAQS. It was determined that the distance of the total facility's significant impact for SO_2 is 80 km, based on the maximum 3-hour worst-case coal-burning emissions.

6.9.2 AAQS ANALYSIS

The results of the SO_2 screening modeling analyses for the near- and far-field receptor grid are presented in Tables 6-8 and 6-9 respectively. Results from a more detailed screening grid, centered about receptor location 30°, 17000 m, are presented in Table 6-10. This grid was analyzed because the screening analysis indicated maximum annual and 24-hour impacts may be located in this area. The maximum annual, 24-hour, and 3-hour impacts from the screening analysis are 36, 213, and 835 $\mu g/m^3$, respectively. For the 24-hour and 3-hour averaging times, maximum concentrations were predicted at the edge of the screening grid, located 80 km from the Flo-Energy site. The maximum concentrations were caused primarily by other modeled sources. The results indicate that the maximum SO_2 concentrations will not exceed SO_2 AAQS at any location in the vicinity of the Flo-Energy plant.

Based on the screening analysis, refinements were performed for the annual and 24-hour averaging periods. The refined concentrations, including background SO_2 levels, are presented in Table 6-11. The predicted maximum annual, 24-hour, and 3-hour concentrations are 52, 236, and 888 $\mu g/m^3$, respectively. These annual and 24-hour maximum predicted impacts are due primarily to sources other than Flo-Energy, and are located approximately 16 km from the Flo-Energy site. The predicted 3-hour maximum is also due primarily to other sources and occurs about 80 km from the proposed site. This analysis indicates that AAQS will be met at locations within the SIA. Source contributions for refined maximums are detailed in Appendix E.

Table 6-7. Maximum Predicted SO_2 Concentrations for the Proposed Facility Only

Averaging Time	Concentration[a] ($\mu g/m^3$)	Receptor Location[b] Direction (degrees)	Distance (m)	Period Ending (YYMMDDHH)
Annual	5.5	320.	4723.	82------
	4.0	320.	4723.	83------
	4.0	320.	4723.	84------
	3.8	320.	4723.	85------
	3.0	270.	9675.	86------
24-Hour Highest	62	220.	3553.	82110924
	53	320.	4723.	83040724
	74	180.	2722.	84053124
	62	140.	3553.	85012124
	43	240.	5444.	86121424
24-Hour HSH[c]	59	220.	3553.	82110724
	46	320.	4723.	83020124
	45	340.	3850.	84050224
	41	230.	4234.	85100824
	36	220.	3553.	86060524
3-Hour Highest	149	360.	3618.	82062009
	143	180.	2722.	83050609
	146	180.	2722.	84053118
	164	170.	2764.	85123012
	129	200.	2897.	86101806
3-Hour HSH[c]	120	360.	3618.	82061912
	131	180.	2722.	83011415
	136	180.	2722.	84041109
	123	170.	2764.	85122712
	112	160.	2897.	86122703

Note: YY=Year, MM=Month, DD=Day, HH=Hour

[a] Maximum concentrations indicated are for the proposed facility with no offsets.

[b] All receptor coordinates are reported with respect to the Boiler No. 16 Stack Location.

[c] Highest, second-highest (HSH) concentrations shown.

Table 6-8. Maximum Predicted SO_2 Concentrations for the AAQS Screening Analysis, Near-Field Receptors

Averaging Time	Concentration ($\mu g/m^3$)	Receptor Location[a] Direction (degrees)	Receptor Location[a] Distance (m)	Period Ending (YYMMDDHH)
Annual	36	30.	17000.	82------
	30	30.	17000.	83------
	31	30.	17000.	84------
	28	30.	17000.	85------
	29	30.	17000.	86------
24-Hour[b]	162	30.	17000.	82070824
	183	30.	17000.	83040624
	176	30.	17000.	84041224
	182	30.	17000.	85010124
	173	30.	17000.	86081224
3-Hour[b]	446	30.	17000.	82070909
	381	30.	17000.	83040609
	424	30.	17000.	84072015
	442	30.	17000.	85060318
	360	30.	17000.	86080909

Note: YY=Year, MM=Month, DD=Day, HH=Hour

[a] All receptor coordinates are reported with respect to the Boiler No. 16 stack location.

[b] All short-term concentrations indicate highest, second-highest concentrations.

Table 6-9. Maximum Predicted SO_2 Concentrations for the AAQS Screening Analysis, Far-Field Receptors

Averaging Time	Concentration ($\mu g/m^3$)	Receptor Location[a] Direction (degrees)	Receptor Location[a] Distance (m)	Period Ending (YYMMDDHH)
Annual	22	20.	30000.	82------
	18	130.	80000.	83------
	23	20.	30000.	84------
	21	20.	30000.	85------
	21	20.	30000.	86------
24-Hour[b]	146	130.	80000.	82011824
	154	130.	80000.	83081024
	213	130.	80000.	84050224
	188	130.	80000.	85052124
	123	90.	70000.	86032124
3-Hour[b]	631	130.	80000.	82011815
	613	130.	80000.	83081018
	634	130.	80000.	84063015
	835	130.	80000.	85101112
	622	130.	80000.	86010212

Note: YY=Year, MM=Month, DD=Day, HH=Hour

[a] All receptor coordinates are reported with respect to the Boiler No. 16 stack location.

[b] All short-term concentrations indicate highest, second-highest concentrations.

Table 6-10. Maximum Predicted SO_2 Concentrations for the AAQS Detailed Screening Analysis Grid[a], Annual and 24-Hour Averaging Time Only

Averaging Time	Concentration ($\mu g/m^3$)	Receptor Location[b] Direction (degrees)	Distance (m)	Period Ending (YYMMDDHH)
Annual	36	30.	17000.	82------
	30	30.	17000.	83------
	33	30.	16000.	84------
	31	30.	16000.	85------
	33	30.	16000.	86------
24-Hour[c]	168	30.	16000.	82112624
	183	30.	17000.	83040624
	199	35.	16000.	84092624
	182	30.	17000.	85010124
	205	30.	16000.	86110724

Note: YY=Year, MM=Month, DD=Day, HH=Hour

[a] Centered on screening grid receptor location (17,000 m, 30°).

[b] All receptor coordinates are reported with respect to the Boiler No. 16 stack location.

[c] All short-term concentrations indicate highest, second-highest concentrations.

Table 6-11. Maximum Predicted SO_2 Concentrations as Compared With AAQS - Refined Analysis

Averaging Time	Concentration ($\mu g/m^3$)			Receptor Locations[a]		Period Ending	Florida AAQS
	Total	Modeled	Background	Direction (degrees)	Distance (m)	(YYMMDDHH)	($\mu g/m^3$)
Annual	52	44	8	32	17100	82---------	60
24-Hour[b]	236	215	21	32	16000	84122624	260
	226	205	21	30	16000	86110724	
	234	213	21	130	80000	84050224	
3-Hour[b]	888	835	53	130	80000	85101112	1,300

Note: YY=Year, MM=Month, DD=Day, HH=Hour

[a] Receptors Locations are Relative to the Boiler No. 16 stack location.

[b] All short-term concentrations are highest, second-highest concentrations.

6.9.3 PSD CLASS II ANALYSIS

The results of the PSD Class II screening analysis for the near-field and far-field receptor grids are presented in Tables 6-12 and 6-13, respectively. Based on the screening results, refined modeling analyses were performed for each averaging time. Source contributions for refined maximums are detailed in Appendix E. The refined results, summarized in Table 6-14, indicate that the maximum SO_2 PSD Class II increment consumption will not exceed the allowable PSD increments. The maximum annual, 24-hour, and 3-hour predicted increment consumption of 8.7, 68, and 156 $\mu g/m^3$, respectively, are below the allowable PSD Class II increments of 20, 91, and 512 $\mu g/m^3$. The maximum annual and 24-hour increment consumption values are due primarily to sources other than Flo-Energy, and occur about 30 km from the Flo-Energy site. The maximum 3-hour increment consumption value is due primarily to the proposed cogeneration facility and occurs at the property boundary.

6.9.4 PSD CLASS I ANALYSIS

The SO_2 PSD Class I screening grid modeling results are presented in Tables 6-15 and 6-16. The refined modeling results are presented in Table 6-17. The refined results indicate that the maximum annual, 24-hour, and 3-hour PSD increment consumed at the expanded Everglades National Park are 0.6, 5.42, and 19 $\mu g/m^3$, respectively. Source contributions for refined maximums are detailed in Appendix E. These impacts are below the allowable PSD Class I increments of 2 and 25 $\mu g/m^3$ for the annual and 3-hour averaging times, respectively. The proposed facility with other increment consuming sources will therefore meet the allowable annual and 24-hour PSD increments in the Class I area.

However, the modeling indicates that the 24-hour Class I increment of 5 $\mu g/m^3$ will be slightly exceeded in the Class I area. The analysis shows that only two 24-hour periods in the 5-year meteorological database exceed the Class I increment. Source contributions to these maximums show that the proposed Flo-Energy cogeneration project will contribute only ~~0.03~~ 0,04 $\mu g/m^3$ to the HSH concentration of 5.42 $\mu g/m^3$. This contribution is less than the National Park Service's recommended 24-hour SO_2 Class I significance level of 0.07 $\mu g/m^3$. Therefore, the Flo-Energy project does not significantly contribute to the predicted 24-hour exceedance in the Class I area. DaB

6.9.5 TOXIC IMPACT ANALYSIS

The maximum impacts of regulated and nonregulated toxic air pollutants that will be emitted by the Flo-Energy facility are presented in Table 6-18. Each pollutant's maximum 8-hour, 24-hour, and annual impact is compared to the respective FDER no-threat level (NTL). The table shows that all toxic pollutant impacts will be below respective NTLs.

Table 6-12. Maximum Predicted SO_2 Concentrations for the PSD Class II Screening Analysis, Near-Field Receptors

Averaging Time	Concentration ($\mu g/m^3$)	Receptor Location[a] Direction (degrees)	Receptor Location[a] Distance (m)	Period Ending (YYMMDDHH)
Annual	6.1	320.	4723.	82------
	4.7	320.	4723.	83------
	4.7	320.	4723.	84------
	4.4	320.	4723.	85------
	3.8	310.	5629.	86------
24-Hour[b]	62	220.	3553.	82110724
	44	320.	4723.	83020124
	45	340.	3850.	84050224
	42	230.	4234.	85100824
	41	220.	3553.	86060524
3-Hour[b]	120	360.	3618.	82061912
	131	180.	2722.	83011415
	136	180.	2722.	84041109
	123	170.	2764.	85122712
	112	160.	2897.	86122703

Note: YY=Year, MM=Month, DD=Day, HH=Hour

[a] All receptor coordinates are reported with respect to the Boiler No. 16 stack location.

[b] All short-term concentrations indicate highest, second-highest concentrations.

Table 6-13. Maximum Predicted SO_2 Concentrations for the PSD Class II Screening Analysis, Far-Field Receptors

Averaging Time	Concentration ($\mu g/m^3$)	Receptor Location[a] Direction (degrees)	Receptor Location[a] Distance (m)	Period Ending (YYMMDDHH)
Annual	7.7	20.	30000.	82------
	5.7	20.	30000.	83------
	8.7	20.	30000.	84------
	7.6	20.	30000.	85------
	7.6	20.	30000.	86------
24-Hour[b]	61	20.	30000.	82100324
	44	20.	30000.	83012024
	68	20.	30000.	84121524
	45	20.	30000.	85111424
	55	20.	30000.	86032624
3-Hour[b]	117	20.	30000.	82020803
	114	40.	30000.	83120712
	114	40.	30000.	84053121
	124	20.	30000.	85082803
	117	20.	30000.	86032618

Note: YY=Year, MM=Month, DD=Day, HH=Hour

[a] All receptor coordinates are reported with respect to the Boiler No. 16 stack location.

[b] All short-term concentrations indicate highest, second-highest concentrations.

Table 6-14. Maximum Predicted SO_2 Concentrations as Compared with PSD Class II Increments - Refined Analysis

Averaging Time	Concentration ($\mu g/m^3$)	Receptor Location[a] Direction (degrees)	Receptor Location[a] Distance (m)	Period Ending (YYMMDDHH)	Allowable Increment ($\mu g/m^3$)
Annual	8.7	20.	30000.	84-----	20
24-Hour[b]	62	220.	3553.	82110724	91
	61	20.	30000.	82100324	
	68	20.	30000.	84121524	
3-Hour[b]	156	184.	2729.	83011415	512
	136	180.	2722.	84041109	
	131	168.	2783.	85122712	

Note: YY=Year, MM=Month, DD=Day, HH=Hour

[a] All receptor coordinates are with respect to Boiler No. 16 stack location.

[b] All short-term concentrations are highest, second-highest concentrations.

Table 6-15. Maximum Predicted SO_2 Concentrations for the PSD Class I Screening Analysis, Summer Season[a]

Averaging Time	Concentration ($\mu g/m^3$)	Receptor Location[b] UTM-E (m)	Receptor Location[b] UTM-N (m)	Period Ending (YYMMDDHH)
Annual	0.54	550300.	2848600.	82-----
	0.64	550300.	2848600.	83-----
	0.52	550300.	2848600.	84-----
	0.47	545000.	2848600.	85-----
	0.48	550300.	2848600.	86-----
24-Hour[c]	4.01	500300.	2848600.	82083024
	5.42	550300.	2839000.	83081724
	3.79	530000.	2848600.	84053124
	3.75	545000.	2848600.	85102524
	3.20	550300.	2848600.	86033024
3-Hour[c]	18.4	550000.	2832500.	82071621
	19.0	545000.	2844000.	83061706
	17.4	540000.	2839000.	84041121
	18.4	545000.	2844000.	85032521
	16.8	464000.	2860000.	86103106

Note: YY=Year, MM=Month, DD=Day, HH=Hour

[a] Maximum period during which sugar mills are not operating, which extends from 3/1 through 10/31.

[b] All receptor coordinates are reported in Universal Transverse Mercator (UTM) coordinates.

[c] All short-term concentrations indicate highest, second-highest concentrations.

Table 6-16. Maximum Predicted SO_2 Concentrations for the PSD Class I Screening Analysis, Winter Season[a]

Averaging Time	Concentration ($\mu g/m^3$)	Receptor Location[b] UTM-E (m)	Receptor Location[b] UTM-N (m)	Period Ending (YYMMDDHH)
Annual	0.52	550300.	2848600.	82-----
	0.44	540000.	2848600.	83-----
	0.49	545000.	2848600.	84-----
	0.42	545000.	2848600.	85-----
	0.38	545000.	2848600.	86-----
24-Hour[c]	3.54	550300.	2848600.	82100224
	4.08	540000.	2848600.	83101624
	3.31	540000.	2848600.	84011624
	3.44	535000.	2848600.	85123124
	3.05	530000.	2848600.	86102824
3-Hour[c]	16.0	545000.	2848600.	82112318
	17.3	542700.	2810000.	83040406
	16.2	540000.	2848600.	84030409
	18.2	535000.	2848600.	85120224
	16.2	530000.	2848600.	86102806

Note: YY=Year, MM=Month, DD=Day, HH=Hour

[a] Maximum period during which sugar mills are operating, which extends from 10/1 through 4/30.

[b] All receptor coordinates are reported in Universal Transverse Mercator (UTM) coordinates.

[c] All short-term concentrations indicate highest, second-highest concentrations.

Table 6-17. Maximum Predicted SO_2 Concentrations as Compared with PSD Class I Increments - Refined Analysis

Averaging Time	Concentration ($\mu g/m^3$)	Receptor Location[a] UTM-E (m)	Receptor Location[a] UTM-N (m)	Period Ending (YYMMDDHH)	Allowable Increment ($\mu g/m^3$)
Annual	0.6	550300.	2848600.	82-----	2
24-Hour[b]	5.42[c]	550300.	2839000.	83081724	5
3-Hour[b]	19.0	549327.	2848000.	82083006	25
	18.5	547000.	2848600.	83061609	
	19.0	545000.	2844000.	83061706	

Note: YY=Year, MM=Month, DD=Day, HH=Hour

[a] All receptor coordinates are reported in Universal Transverse Mercator (UTM) coordinates.

[b] All short-term concentrations are highest, second-highest concentrations.

[c] The proposed Flo-Energy cogeneration facility contributes only ~~0.05~~4 $\mu g/m^3$ to this concentration. The facility's contribution is less than the National Park Service's recommended 24-hour SO_2 Class I significance level of 0.07 $\mu g/m^3$.

0.04

DaB

Table 6-18. Maximum Impacts of Toxic Pollutants for Flo-Energy Cogeneration Facility (total all boilers)

Pollutant	Maximum Hourly Emissions[a] (lb/hr)	Concentrations ($\mu g/m^3$)					
		8-Hour		24-Hour		Annual	
		Impact	NTL	Impact	NTL	Impact	NTL
Ammonia	31.8	0.7431	180	0.56	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	0.0123	0.0007	0.5	0.0005	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
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).

7.0 ADDITIONAL IMPACT ANALYSIS

7.1 IMPACTS ON SOILS AND VEGETATION

7.1.1 VICINITY OF OKEELANTA

The primary crop in the area of the Flo-Energy site is sugar cane. Soils are primarily organic peat-type soils. As described in the air quality impact analysis (Section 6.0), the maximum predicted SO_2 concentrations in the vicinity of the site as a result of the proposed cogeneration facility are predicted to be well below the AAQS for SO_2. Since the AAQS are designed to protect the public welfare, including effects upon soils and vegetation, no detrimental effects on soils or vegetation should occur in this area. It is also reiterated that the long-term average SO_2 emission rate of 1,000 TPY from both the Flo-Energy and Sol-Energy cogeneration facilities represents no increase over the current annual SO_2 emission rate from the existing Okeelanta and Osceola Farms sugar mills.

7.1.2 PSD CLASS I AREA

This section focuses on the ecological effects of the proposed facility's impacts on Air Quality Related Values (AQRV), as defined under PSD regulations, in the Everglades National Park (ENP). The ENP is located approximately 90 km south of the Flo-Energy site. The AQRVs are defined as being:

> "All those values possessed by an area except those that are not affected by changes in air quality and include all those assets of an area whose vitality, significance, or integrity is dependent in some way upon the air environment. These values include visibility and those scenic, cultural, biological, and recreational resources of an area that are affected by air quality. Important attributes of an area are those values or assets that make an area significant as a monument, preserve, or primitive area. They are the assets that are to be preserved if the area is to achieve the purposes for which it was set aside" (Federal Register, 1978).

The AQRVs include freshwater and coastal wetlands, dominant plant communities, unique and rare plant communities, soils and associated periphyton, and the wildlife dependent upon these communities for habitat. Rare, endemic, threatened, and endangered species of the national park and bioindicators of air pollution (e.g., lichens) are also evaluated.

Only the pollutant SO_2 is considered in this analysis, since the proposed project will result in a net decrease in emissions of all criteria pollutants except SO_2.

7.1.2.1 Impacts to Vegetation

Sulfur is an essential plant nutrient which is normally taken up as sulfate ions by the roots. When sulfur dioxide in the atmosphere enters the foliage through pores in the leaves, it reacts with water in the leaf interior to form sulfite ions. Sulfite ions are highly toxic, and they interact with enzymes, compete with normal metabolites, and interfere with a variety of cellular functions (Horsman and Wellburn, 1976). However, sulfite is oxidized to sulfate ions within the leaf. These sulfate ions can then be used by the plant as a nutrient. Small amounts of sulfite can be oxidized in the plant before they induce harmful effects.

SO_2 at elevated levels in the ambient air has long been known to cause injury to plants. Acute SO_2 injury usually develops within a few hours or days of exposure. Symptoms include marginal, flecked, and/or intercostal necrotic areas that initially appear water-soaked and dullish green. This type injury generally occurs to younger leaves. Chronic injury usually is evident by signs of chlorosis, bronzing, premature senescence, reduced growth, and possible tissue necrosis (EPA, 1982).

Many studies have been conducted to determine the effects of high-concentration, short-term SO_2 exposure on natural community vegetation. Sensitive plants include ragweed, legumes, blackberry, southern pine, and red and black oak. These species are potentially injured by 3-hour exposure to SO_2 concentrations ranging from 790 to 1,570 $\mu g/m^3$. Intermediate plants include locust and sweetgum. These species can be injured by 3-hour exposure to SO_2 concentrations ranging from 1,570 to 2,100 $\mu g/m^3$. Resistant species, which are not injured at concentrations below 2,100 $\mu g/m^3$ for 3 hours, include white oak and dogwood (EPA, 1982).

A study of native Floridian vegetation species (Woltz and Howe, 1981) demonstrated that cypress, slash pine, live oak, and mangrove exposed to 1,300 $\mu g/m^3$ SO_2 for 8 hours were not visibly damaged. This finding supports the levels cited by other researchers on the effects of SO_2 on vegetation. A corroborative study (McLaughlin and Lee, 1974) demonstrated that approximately 20 percent of a cross-section of plants ranging from sensitive to tolerant were visibly injured when exposed to an SO_2 concentration of 920 $\mu g/m^3$ for 3 hours.

Jack pine seedlings exposed to SO_2 concentrations of 470 to 520 $\mu g/m^3$ for 24 hours demonstrated inhibition of foliar lipid synthesis; however, this inhibition was reversible (Malhotra and Kahn, 1978). Black oak exposed to 1,310 $\mu g/m^3$ SO_2 for 24 hours a day for 1 week demonstrated a 48 percent reduction in photosynthesis (Carlson, 1979).

In a recent study, two lichen species indigenous to the ENP area exhibited signs of SO_2 damage in the form of decreased biomass gain and photosynthetic rate as well as membrane leakage when exposed to concentrations of 200 to 400 $\mu g/m^3$ for 6 hours/week for 10 weeks (Hart et al., 1988).

As described in Section 6.0, the maximum 3-hour and 24-hour predicted increment consumption SO_2 concentrations expected at the point of maximum impact in the ENP are 19 $\mu g/m^3$ and 5 $\mu g/m^3$, respectively. Upon comparison of these concentrations to those causing injury to native species, it is evident that SO_2-sensitive species (or more tolerant species) would not be damaged by the predicted concentrations. These levels are less than 10 percent of the most conservative concentration (200 $\mu g/m^3$) that has been shown to cause injury to SO_2-sensitive species.

The 24-hour and annual SO_2 concentrations predicted within the ENP due to all increment-consuming sources (5 and 0.6 $\mu g/m^3$, respectively), when added to background concentrations of 21 and 8 $\mu g/m^3$, respectively, result in total SO_2 impacts of 26 and 9 $\mu g/m^3$, respectively. These levels are much lower than those known to cause damage to test species. By comparison of these levels, it is apparent that the modeled 24-hour incremental increase of SO_2 is well below the concentrations that caused damage in SO_2-sensitive plants. The predicted annual increment increase in SO_2 (0.6 $\mu g/m^3$) adds slightly to background levels of this gas and poses only a minimal threat to area vegetation.

On a long-term basis, SO_2 levels in the ENP will not increase as a result of the Flo-Energy and Sol-Energy cogeneration projects. As described previously, annual average SO_2 emissions from the projects will not increase above current levels on a long-term basis.

7.1.2.2 <u>Impacts to Soils</u>

For soils, potential and hypothesized effects of atmospheric deposition include:

1. Increased soil acidification;
2. Alteration in cation exchange;
3. Loss of base cations; and
4. Mobilization of trace metals.

The potential sensitivity of specific soils to atmospheric inputs is related to two factors. First, the physical ability of a soil to conduct water vertically through the soil profile is important in influencing the interaction with deposition. Second, the ability of the soil to resist chemical changes, as measured in terms of pH and soil cation exchange capacity (CEC), is important in determining how a soil responds to atmospheric inputs.

The soils of the Everglades National Park are generally classified as histosols or entisols. Histosols (peat soils) are organic and have extremely high buffering capacities based on their CEC, base saturation, and bulk density. Therefore, they would be relatively insensitive to atmospheric inputs. The entisols are shallow sandy soils overlying limestone, such as the soils found in the pinelands. The direct connection of these soils with subsurface limestone tends to neutralize any acidic inputs. Moreover, the groundwater table is highly buffered due to the interaction with subsurface limestone formations which results in high alkalinity [as calcium carbonate ($CaCO_3$)].

The relatively low sensitivity of the soils to acid inputs coupled with the extremely low ground-level concentrations of contaminants projected for the ENP from facility emissions precludes any significant impact on soils.

7.1.2.3 Impacts to Wildlife

A wide range of physiological and ecological effects to fauna has been reported for gaseous and particulate pollutants (Newman, 1980; Newman and Schreiber, 1988). The most severe of these effects have been observed at concentrations above the secondary ambient air quality standards. Physiological and behavioral effects have been observed in experimental animals at or below these standards. No observable effects to fauna are expected at concentrations below the values reported in Table 7-1.

The major air quality risk to wildlife in the United States is from continuous exposure to pollutants above the national ambient air quality standards. This occurs in non-attainment areas, e.g., Los Angeles Basin. Risks to wildlife also may occur for wildlife living in the vicinity of an emission source that experiences frequent upsets or episodic conditions resulting from malfunctioning equipment, unique meteorological conditions, or startup operations (Newman and Schreiber, 1988). Under these conditions, chronic effects (e.g., particulate contamination) and acute effects (e.g., injury to health) have been observed (Newman, 1980).

Table 7-1. Examples of Reported Effects of Sulfur Dioxide on Wildlife at Concentrations Below National Secondary Ambient Air Quality Standards

Reported Effect	Concentration ($\mu g/m^3$)	Exposure
Respiratory stress in guinea pigs	427 to 854	1 hour
Respiratory stress in rats	267	7 hours/day; 5 day/week for 10 weeks
Decreased abundance in deer mice	13 to 157	continually for 5 months

Source: Newman and Schreiber, 1988.

For impacts on wildlife, the lowest threshold values of SO_2 reported to cause physiological changes are shown in Table 7-1. These values are up to orders of magnitude larger than maximum predicted concentrations for the Class I area. No effects on wildlife AQRVs from SO_2 are therefore expected. These results are considered indications of the risk of other air pollutants predicted to be emitted from the facility.

7.2 IMPACTS ON VISIBILITY

The visibility analysis required by PSD regulations is directed primarily toward Class I areas. The CAA amendments of 1977 provide for implementation of guidelines to prevent visibility impairment in mandatory PSD Class I areas. The guidelines are intended to protect the aesthetic quality of these pristine areas from reduction in visual range and atmospheric discoloration caused by various pollutants. The only Class I area within 100 km of the proposed facility is the Everglades National Park, located about 90 km south of the proposed site.

A Level-1 visibility screening analysis was performed to determine the potential adverse visibility effects using the approach suggested in the Workbook for Plume Visual Impact Screening and Analysis (EPA, 1988c). The level-1 screening analysis is designed to provide a conservative estimate of plume visual impacts (i.e., impacts higher than expected). The EPA model, VISCREEN, was used for this analysis. Model input and output results are presented in Table 7-2. The total PM, NO_x, and sulfuric acid mist emissions from the proposed facility, as presented in Section 3.4, were used as input to the model. As indicated, the maximum visibility impacts caused by the facility do not exceed the screening criteria inside or outside the ENP Class I area. As a result, there is no significant impact upon visibility predicted for the Class I areas.

7.3 IMPACTS DUE TO ASSOCIATED POPULATION GROWTH

There will be a small number of temporary construction workers during construction. There will be about 20 permanent employees at Flo-Energy 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.

Table 7-2. Results of Visibility Screening Analysis

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               Visual Effects Screening Analysis for
                 Source: OKEELANTA COGENERATION FACILITY
                 Class I Area: EVERGLADES NATIONAL PARK

                 ***   Level-1 Screening   ***
 Input Emissions for

    Particulates   172.50  TON/YR
    NOx (as NO2)   862.50  TON/YR
    Primary NO2       .00  TON/YR
    Soot              .00  TON/YR
    Primary SO4     50.40  TON/YR

     **** Default Particle Characteristics Assumed

               Transport Scenario Specifications:

     Background Ozone:                  .04 ppm
     Background Visual Range:         40.00 km
     Source-Observer Distance:        91.40 km
     Min. Source-Class I Distance:    91.40 km
     Max. Source-Class I Distance:   140.00 km
     Plume-Source-Observer Angle:     11.25 degrees
     Stability:  6
     Wind Speed:   1.00 m/s

                           R E S U L T S

 Asterisks (*) indicate plume impacts that exceed screening criteria

          Maximum Visual Impacts INSIDE  Class I Area
           Screening Criteria ARE NOT Exceeded
                                            Delta E       Contrast
                                          ==========    ===========
 Backgrnd Theta Azi Distance Alpha  Crit   Plume     Crit  Plume
 ======== ===== === ======== =====  ====   =====     ====  =====
  SKY       10.  84.   91.4    84.  2.00    .231      .05   .001
  SKY      140.  84.   91.4    84.  2.00    .083      .05  -.003
  TERRAIN   10.  84.   91.4    84.  2.00    .076      .05   .001
  TERRAIN  140.  84.   91.4    84.  2.00    .020      .05   .001

          Maximum Visual Impacts OUTSIDE Class I Area
           Screening Criteria ARE NOT Exceeded
                                            Delta E       Contrast
                                          ==========    ===========
 Backgrnd Theta Azi Distance Alpha  Crit   Plume     Crit  Plume
 ======== ===== === ======== =====  ====   =====     ====  =====
  SKY       10.  65.   85.3   104.  2.00    .244      .05   .001
  SKY      140.  65.   85.3   104.  2.00    .087      .05  -.003
  TERRAIN   10.  55.   81.8   114.  2.00    .100      .05   .001
  TERRAIN  140.  55.   81.8   114.  2.00    .026      .05   .001
```

8.0 PROPOSED PERMIT CONDITIONS

Presented in this section are proposed permit conditions for the Flo-Energy cogeneration facility. These proposed conditions reflect typical conditions issued in FDER construction permits for electric utility power plants. In addition, Palm Beach County's zoning approval for Flo-Energy requires that Flo-Energy request of FDER that certain conditions be incorporated into FDER's construction permit for the facility (the zoning conditions are contained in Appendix C). Accordingly, proposed permit conditions have been developed for the Flo-Energy cogeneration facility, which includes the conditions recommended by Palm Beach County. It is requested that FDER consider these proposed conditions in issuing the air construction and operating permits for the facility.

Construction Details

1. Construction of the proposed cogeneration facility shall reasonably conform to the plans described in the application.

2. Boilers No. 1, 2 and 3 shall be of the spreader stoker type.

3. Each boiler may 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 17-2.700(4).

4. Each boiler shall be equipped with instruments to measure 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.

6. The permittee shall install and operate continuous monitoring devices for each main boiler exhaust for opacity, nitrogen oxides (NO_x), and carbon monoxide (CO). The monitoring devices shall meet the applicable requirements of Section 17-2.710, 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 flue gas 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 Condition 22 below. The document "Use of Flue Gas Oxygen Meter as BACT for Combustion Controls" may 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 ESP, SNCR and mercury control systems:
a. The permittee shall submit to the Department copies of technical data pertaining to the selected PM, NO_x, and mercury emissions control 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 such as specific collection area, air/cloth ratio, and air flow rate. The Department may review these data to determine whether the selected control equipment is adequate to meet the emission limits specified in Condition 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 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 such as air/cloth ratio and air flow rate. The Department may review these data to determine whether the selected control device is adequate to meet the emission limits specified in Condition 19 below. Such 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.

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

10. 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.

Operational and Emission Restrictions

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 74.9 (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 11.5×10^{12} Btu per year.

12. Any wood waste materials burned as fuel shall be substantially free from painted and chemically treated wood, household garbage, toxic or hazardous materials or waste, and special waste.

13. Any fuel oil burned in the facility shall be "new" No. 2 fuel oil with a maximum sulfur content equivalent to 0.5 lb SO_2/MMBtu. "New" oil means an oil which has been refined from crude oil and has not been used.

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

15. The consumption of coal shall not exceed 25 percent of the total heat input to each boiler unit in any calendar quarter.

16. The permittee shall maintain a daily log of the amounts and types of fuel used. The amount, heating value, sulfur content, and equivalent SO_2 emission rate (in lb/MMBtu) of each fuel oil and coal delivery shall be kept in a log. These logs shall be kept for at least two years.

17. During the first three years of cogeneration facility operation, the existing Boilers No. 4, 5, 6, 10, 11, 12, 14, and 15 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 current operating 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 may be retained as a standby boiler for the cogeneration facility. 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 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 coal stacker/reclaimer, for which enclosure is operationally infeasible).

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

c. Water sprays or chemical wetting agents and stabilizers shall be applied to storage piles, handling equipment, 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 control system. Particulate matter emissions from each of the three silos shall not exceed 0.01 gr/acf. A visible emission reading of 5 percent or less may be used to establish compliance with this emission limit. A visible emission reading of 5 percent opacity or greater will not create a presumption that the 0.01 gr/acf emission limit is being violated; however, such a reading may require the permittee to perform a stack test on the storage silo exhaust vent, as set forth in Condition 22 below. 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 those shown in the following table:

Pollutant	Emission Limit (per boiler)						Total All Three Boilers
	Biomass		No.2 Oil		Bit. Coal		
	(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 (PM10)	0.03	21.5	0.03	14.7	0.03	14.7	172.5
Sulfur Dioxide							
24-hour average	0.10	71.5	0.5	245.0	1.2	588.0	–
Annual average[a]	0.02	–	0.5	–	1.2	–	1,700
Nitrogen Oxides							
Annual average[a]	0.15	–	0.15	–	0.17	–	862.5
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	0.19
Mercury	5.5×10^{-6} [b] 0.29×10^{-6} [c]	0.0039 [b] 0.00021 [c]	2.4×10^{-6}	0.00118	8.4×10^{-6}	0.0041	0.0262
Beryllium	–	–	3.5×10^{-7}	0.00017	5.9×10^{-6}	0.0029	0.0080
Fluorides	–	–	6.3×10^{-6}	0.003	0.024	11.8	32.47
Sulfuric Acid Mist	0.003	2.15	0.015	7.4	0.036	17.6	51.5

[a] Compliance based on 30-day rolling average, per 40 CFR 60, Subpart Da.
[b] Emission limit for bagasse.
[c] Emission limit for wood waste.

21. The following conditions apply to the total combined SO_2 emissions from the Flo-Energy and Sol-Energy cogeneration projects:

a. SO_2 emissions shall not exceed an average of 1,000 tons per year over the life of the projects.

b. If the Palm Beach County government makes available 200,000 tons or more of biomass fuel each year to Flo-Energy, under the same terms and conditions as those in the existing Okeelanta/Palm Beach Solid Waste Authority Wood-waste Agreement, the SO_2 emissions shall not exceed 1,500 tons per year for that year, and shall not exceed an average of 1,300 tons per year for each five year incremental period.

c. If the Palm Beach County government cannot make available 200,000 tons or more of biomass fuel each year to Flo-Energy, under the same terms and conditions as those in the existing Okeelanta/Palm Beach Solid Waste Authority Wood-waste Agreement, the SO_2 emissions shall not exceed 1,700 tons per year for that year, and shall not exceed an average of 1,500 tons per year for each ten year incremental period.

d. The allowable average SO_2 emissions for the five and ten year incremental periods described above shall be calculated on a weighted average for any period in which both cases occur (years in which biomass is made available and years in which biomass is not made available).

e. SO_2 emissions shall include all emissions for the Flo-Energy and Sol-Energy projects, including the existing boilers at the Okeelanta and Osceola facilities, if they are in operation during initial project operation.

Compliance Requirements
22. 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 particulates, NO_x, 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 stated in 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 17-2.700. 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
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	PM10 emissions.
6, 6C, or 19	Sulfur dioxide emissions from stationary sources.
7, 7C, or 19	Nitrogen oxide emissions from stationary sources.
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, 25, or 25A	Volatile organic compounds concentration.
101A or 108	Mercury emissions.
104	Beryllium emission rate and associated moisture content.

23. 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.

24. 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.

25. Stack tests for particulates, NO_x, SO_2, 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 Conditions 22, 23, and 24 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, the tests will thereafter occur according to the following schedule:

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

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.

26. After conducting the initial stack tests required under Condition 25 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 emission limit 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.

Reporting Requirements

27. Stack monitoring, fuel usage and fuel analysis data shall be reported to the Department's Southeast District Office 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 17-2.08, F.A.C.

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APPENDIX A

DERIVATIONS OF POLLUTANT EMISSION FACTORS FOR PROPOSED FACILITY

All pollutant emissions factors used in emission calculations are expressed in terms of lb/MMBtu for biomass, fuel oil, and coal. The basis for the emission factors is presented below.

A. Biomass

Heating value of bagasse: 4,250 Btu/lb (wood waste has higher heating value).

1. PM: The emission factor is based on the NSPS = 0.03 lb/MMBtu
    Sample calculation: Activity Factor = 11.50x10^{12} Btu/yr; 715 MMBtu/hr
    PM (lb/hr) = 715 MMBtu/hr x 0.03 lb/MMBtu = 21.5 lb/hr
    PM (TPY) = 11.50x10^{12} Btu x 0.03 lb/MMBtu x ton/2,000 lb
    = 172.5 TPY

2. SO$_2$:
    a. Average

Industry data indicate an average of 0.009% sulfur (dry basis) in bagasse, or 0.0043% (wet basis), @ 4,250 Btu/lb wet bagasse. Sulfur in wood waste is similar (reference AP-42).

0.000043 lb S/lb x 2 lb SO$_2$/lb S ÷ 4,250 Btu/lb x 10^{6}
= 0.020 lb/MMBtu
SO$_2$ (TPY) = 11.50x10^{12} x 0.020/10^{6} ÷ 2,000 = 115.0 TPY

    b. Maximum
    Based on maximum sulfur content of bagasse of approximately 0.045%, dry basis, or 0.022%, wet basis
    0.00022 x 2 ÷ 4,250 x 10^{6} = 0.10 lb/MMBtu

    SO$_2$ (lb/hr) = 715 MMBtu/hr x 0.10 lb/MMBtu = 71.5 lb/hr

3. NO$_x$: The emission factor used is based upon the boiler design and SNCR control system. The emission factor is 0.15 lb/MMBtu, 30-day rolling average.
    NO$_x$ (avg. lb/hr) = 715x10^{6} x 0.15/10^{6} = 107.3 lb/hr
    NO$_x$ (TPY) = 11.50x10^{12} x .15/10^{6} = 862.5 TPY

4. CO, VOC: The emission factors used are based upon boiler design.
    CO = 0.35 lb/MMBtu (8-hour average).
    VOC = 0.06 lb/MMBtu for biomass.
    = 0.03 lb/MMBtu for oil and coal.

5. Hg:
    a. Bagasse
    The emission factor is based upon the mercury content in the sugar cane leaves of 0.068 ppm (dry) and 0.033 ppm (wet) (Patrick, 1991) and the mercury control system. The emission factor is:

    1 lb x 0.033/10^{6} ÷ 4,250 Btu/lb = 7.8x10^{-6} lb/MMBtu.

    Mercury control system estimated 30% removal:
    7.8x10^{-6} x (1 - 0.30) = 5.5x10^{-6} lb/MMBtu

b. Wood Waste
The article entitled "Air Toxics Emissions from Wood-Fired Boilers" (Sassenrath, 1991) presents mercury emission data from three wood/bark-fired stoker spreader boilers equipped with ESP controls. The three boilers averaged 0.23 µg/dscm in the exhaust gases, which is approximately equivalent to 0.41×10^{-6} lb/MMBtu for the Okeelanta cogeneration boilers.

6. **Sulfuric Acid Mist:** From the EPA Publication AP-42, sulfuric acid mist emissions are estimated to be 3 percent of the sulfur dioxide emissions. The average emission factor is 0.03 x 0.02 lb/MMBtu = 6.0×10^{-4} lb/MMBtu.

7. **Beryllium, Fluorides:** Seminole Kraft Corporation emission tests concluded that there were no detectable emissions of beryllium while burning wood. It is assumed that bagasse is similar in nature. There is no available data on fluorides emissions from biomass combustion.

8. **Arsenic, Cadmium, Chromium, Copper, Lead, Manganese, Nickel, Zinc, Formaldehyde, Dioxins and Furans:** The emission factors were based on "Air Toxic Emissions from Wood Fired Boilers", C. Sassenrath as published in 1991 Technical Association of Pulp and Paper Industry (TAPPI) Proceedings. Except for formaldehyde, dioxins, and furans, the emission factors are reported as parts per million by weight in the particulate emissions. Three stoker boilers equipped with ESPs were tested. The average of the three was used and then converted to lb/MMBtu:

Air Toxic (µg/g PM) = lb Air Tox/10^6 lb PM = ppm PM

Emission limit for PM = 0.03 lb PM/MMBtu

Air Tox(lb/MMBtu) = 0.03 lb/MMBtu x Air Tox ppm/10^6

In addition, emissions of arsenic, chromium, and copper are estimated for the case of 5% treated wood burning (see below).

Sample calculation:

Arsenic: 92 µg/g PM x 0.03 (lb/MMBtu) = 2.8×10^{-6} lb/MMBtu

Arsenic 92 µg/g PM = 2.76×10^{-6} lb/MMBtu
Cadmium 181 µg/g PM = 5.43×10^{-6} lb/MMBtu
Chromium 206 µg/g PM = 6.18×10^{-6} lb/MMBtu
Chromium^{+6}: assume as 20% of total chromium = 1.24×10^{-6} lb/MMBtu
Copper 1,196 µg/g PM = 3.59×10^{-5} lb/MMBtu
Lead 822 µg/g PM = 2.5×10^{-5} lb/MMBtu
Manganese 26,615 µg/g PM = 7.98×10^{-4} lb/MMBtu
Nickel 1,472 µg/g PM = 4.41×10^{-5} lb/MMBtu
Zinc 14,130 µg/g PM = 4.24×10^{-4} lb/MMBtu

Sample calculation for cadmium: Activity Factor = 11.50x10^{12} Btu/yr

Cd = 5.43x10^{-6}lb/MMBtu x 11.50x10^{12} Btu/yr + 2,000
= 0.031 TPY.

Formaldehyde is presented in parts per billion (ppb). By way of the ideal gas law and known test conditions, the emission factor is converted to lb/MMBtu. The formaldehyde levels were taken from three spreader stokers equipped with ESPs. The average emission was 0.530 ppm in the exhaust gases. For the proposed cogeneration boilers, the maximum gas flow rate is 188,900 dscfm.

0.530/10^{6} x 188,900 dscfm x 60 min/hr = 6.01 ft^{3}/hr formaldehyde

From the ideal gas law: PV=mRT, solving for m (mass)

m = P x V + (R x T)

m(lb) = 2116.8 lb$_{f}$/ft^{2} x 6.01 ft^{3}/hr + (1545 ft-lb$_{f}$/30 lb$_{m}$-°R x 528 °R)
= 0.47 lb/hr

The maximum firing rate of biomass is 715 MMBtu/hr.

Form = 0.47 lb/hr x hr/715 MMBtu = 6.56x10^{-4} x lb/MMBtu

Sample calculation: Activity Factor = 11.50x10^{12} Btu/yr

Form(TPY) = 0.000656 lb/MMBtu x 11.50x10^{12} Btu/yr + 2,000
= 3.77 TPY

9. **Antimony, Barium, Phosphorus, Selenium, Silver, Thallium, Tin, and Zirconium:** Emission factors were determined from the results of emission tests conducted on wood fired boilers at Seminole Kraft Corporation in 1990. These boilers were equipped with wet scrubbers which have a lower removal efficiency than ESPs. Therefore, these calculated emissions on an ESP system are conservative. The emission factors were reported as lb Air Toxic/ton wood fuel burned. A further assumption was that wood and bagasse have the same emission factor. The emission factors were converted to lb/MMBtu.

lb Air Tox/ton fuel x ton fuel/2,000 lb fuel x lb fuel/4,250 Btu x 10^{6} = lb Air tox/MMBtu

Antimony: undetectable levels in gas stream
Barium: 0.0009 lb/ton = 1.06x10^{-4} lb/MMBtu
Phosphorus: 0.003 lb/ton = 3.53x10^{-4} lb/MMBtu
Selenium: undetectable levels in gas stream
Silver: 0.00025 lb/ton = 2.94x10^{-5} lb/MMBtu
Thallium: undetectable levels in gas stream

Sample calculation: Activity Factor = $11.50\text{x}10^{12}$ Btu/yr

Barium: $1.06\text{x}10^{-4}$ x $11.50\text{x}10^{12}$ + 2,000 + 10^{6} = 0.61 TPY

10. **Bromine, Cobalt, Indium, Molybdenum, Tin, and Zirconium:** Emission factors are available from the VOC and PM Speciation Data Base, Updated in October 1989. The factors are for a wood-fired boiler controlled by a wet scrubber.

Bromine: 0.01260 lb/ton = $1.47\text{x}10^{-3}$ lb/MMBtu
Cobalt: 0.00423 lb/ton = $4.98\text{x}10^{-4}$ lb/MMBtu
Indium: 0.00108 lb/ton = $1.27\text{x}10^{-4}$ lb/MMBtu
Molybdenum: 0.00216 lb/ton = $2.54\text{x}10^{-4}$ lb/MMBtu
Tin: 0.00137 lb/ton = $1.62\text{x}10^{-4}$ lb/MMBtu
Zirconium: 0.00079 lb/ton = $9.29\text{x}10^{-5}$ lb/MMBtu

Example Calculation:

Bromine (TPY) = $0.00147/10^{6}$ x $11.50\text{x}10^{12}$ + 2,000 = 8.45 TPY

11. **Hydrogen Chloride:** Emission factor is based fuel analysis information from Seminole Kraft Corporation. The concentration of chlorine in wood waste was found to average 153 ppm. In converting to lb/MMBtu, the emission factor of chlorine must also be converted to account for the change of form in the emission to HCl.

153 lb Cl + 10^{6} lb fuel x lb fuel/4,250 Btu x 36 lb
HCl/35 lb Cl x 10^{6} = 0.037 lb/MMBtu.

Sample calculation: Activity Factor = $11.50\text{x}10^{12}$ Btu/yr

Cl (TPY) = $0.037/10^{6}$ x $11.50\text{x}10^{12}$ + 2,000 = 212.75 TPY

12. **Dioxins and Furans:** The emission factor for dioxins and furans from wood burning was obtained from "Air Toxic Emissions from Wood Fired Boilers", C. Sassenrath as published in 1991 TAPPI Proceedings. The average of two spreader stoker boilers equipped with a multiclone and ESP was 0.007 ng/dscm (expressed as 2,3,7,8 - TCDD equivalents). With a flowrate of 320,940 dscm/hr and firing at 715 MMBtu/hr, the emission factor for dioxin is:

$0.007\text{x}10^{-9}$ g/dscm x 320,940 dscm/hr + 715 MMBtu/hr x lb/453.6 g
= $6.93\text{x}10^{-12}$ lb/MMBtu

The emission factor for furans is calculated in the same way. The average of two spreader stokers equipped with a multiclone and ESP was 0.366 ng/dscm (as toxic equivalents). The emission factor for furans is:

$0.366\text{x}10^{-9}$ x 320,940 + 715 + 453.6 = $3.62\text{x}10^{-10}$ lb/MMBtu.

Sample calculation: Activity Factor = $11.50\text{x}10^{12}$ Btu/yr

Dioxin (TPY) = $6.93\text{x}10^{-12}$ lb/MMBtu x $11.50\text{x}10^{12}$ Btu/yr + 2,000
= $4.0\text{x}10^{-8}$ TPY

Furan (TPY) = $3.62\text{x}10^{-10}$ lb/MMBtu x $11.50\text{x}10^{12}$ + 2,000
= $2.1\text{x}10^{-6}$ TPY

13. **Ammonia**

Maximum NH_3 slip will be 20 ppm based on vendor information.

Maximum flow rate per boiler = 305,000 acfm

MW NH_3 = 17

PV = mRT   M = PV/RT

M = 2,116.8 lb_f/ft^2 x 305,000 ft^3/min x 60 min/hr x 17 lb_m-^{0}R/1,545 ft-lb_f + (460 + 350)^{0}R x $20/10^6$ = 10.5 lb/hr each boiler

10.5 lb/hr + $715\text{x}10^6$ = 0.0148 lb/MMBtu

14. **Treated Wood Burning**

Although Flo-Energy will not accept treated wood at the facility, a small amount of treated wood may be present in the wood waste stream. Emissions of several toxic air pollutants have been estimated to account for this possibility, assuming 3 percent of the wood waste is wood that has been treated with chromium copper arsenate (CCA).

Assume 4,250 Btu/lb of lumber (same as biomass)

Density of white pine = 27 lb/ft^3

A. Maximum emissions

Maximum biomass burning rate = $715\text{x}10^6$ Btu/hr + 4,250 Btu/lb

= 168,235 lb/hr each boiler

Treated lumber feed = 3% of biomass feed rate = 5,047 lb/hr

= $21.5\text{x}10^6$ Btu/hr

5,047 lb/hr + 27 lb/ft^3 = 187 ft^3/hr treated wood

Wood Treated with CCA:

Avg. mix of treated wood = 0.47 lb of CCA/ft^3

187 ft^3/hr x 0.47 lb CCA/ft^3 = 87.9 lb/hr of CCA
CCA = 20% As_2O_5; MW = 230
As_2; MW = 150

20% x 150/230 = 13% As by weight

29% CrO_3; MW = 100
Cr; MW = 52

29% x 52/100 = 15% Cr by weight

11% CuO; MW = 80
Cu; MW = 64

11% x 64/80 = 9% Cu by weight

Electrostatic precipitator for particulate control--99% efficiency based on "Impact of Particulate Emissions Control on the Control of Other MWC Air Emissions" (EPA, 1990).

As = 87.9 x 0.13 x (1-0.99) = 0.114 lb/hr

0.114 lb/hr ÷ 21.5x10^6 Btu/hr = 5.31x10^{-3} lb/MMBtu

Cr = 87.9 x 0.15 x (1-0.99) = 0.132 lb/hr

Cr^{+6}: 20% of Cr is Cr^{+6}, remainder is metal

0.132 lb/hr x 0.20 = 0.0264 lb/hr

0.0264 ÷ 21.5x10^6 = 1.23x10^{-3} lb/MMBtu

Cr metal = 0.132 lb/hr x 0.80 = 0.106 lb/hr

0.106 ÷ 21.5x10^6 = 4.93x10^{-3} lb/MMBtu

Cu = 87.9 x 0.09 x (1-0.99) = 0.079 lb/hr

0.079 ÷ 21.5x10^6 = 3.68x10^{-3} lb/MMBtu

<u>Arsenic</u>
Biomass--97% @ 2.76x10^{-6} lb/MMBtu
Treated Wood--3% @ 5.31x10^{-3} lb/MMBtu
Weighted Average = 1.62x10^{-4} lb/MMBtu

<u>Chromium</u>
Biomass--97% @ 6.18x10^{-6} lb/MMBtu
Treated Wood--3% @ 4.93x10^{-3} lb/MMBtu
Weighted Average = 1.54x10^{-4} lb/MMBtu

Chromium^{+6}
Biomass--97% @ 1.24×10^{-6} lb/MMBtu
Treated Wood--3% @ 1.23×10^{-3} lb/MMBtu
Weighted average = 3.81×10^{-5} lb/MMBtu

Copper
Biomass--97% @ 3.59×10^{-5} lb/MMBtu
Treated Wood--3% @ 3.68×10^{-3} lb/MMBtu
Weighted Average = 1.45×10^{-4} lb/MMBtu

B. Annual Emissions

On an annual basis, 3 percent of the wood waste amount equates to 13,000 TPY of treated wood (0.11×10^{12} Btu/yr). Remainder of total heat input (11.39×10^{12} Btu/yr) would be from clean biomass. Thus, treated wood would represent 1 percent of total biomass on an annual basis. Calculations are similar to maximum hourly calculations.

Arsenic
Biomass--99% @ 2.76×10^{-6} lb/MMBtu
Treated wood--1% @ 5.31×10^{-3} lb/MMBtu
Weighted average--5.58×10^{-5} lb/MMBtu

Chromium
Biomass--99% @ 6.18×10^{-6} lb/MMBtu
Treated wood--1% @ 4.93×10^{-3} lb/MMBtu
Weighted average--5.54×10^{-5} lb/MMBtu

Chromium^{+6}
Biomass--99% @ 1.24×10^{-6} lb/MMBtu
Treated wood--1% @ 1.23×10^{-3} lb/MMBtu
Weighted average--1.35×10^{-5} lb/MMBtu

Copper
Biomass--99% @ 3.59×10^{-5} lb/MMBtu
Treated wood--1% @ 3.68×10^{-3} lb/MMBtu
Weighted average--7.23×10^{-5} lb/MMBtu

B. No. 2 Fuel Oil

Heating value of No. 2 Fuel Oil: 138,000 Btu/gal

1. PM: The emission factor is based on the NSPS = 0.03 lb/MMBtu

Sample calculation: Activity Factor = 2.706×10^{12} Btu/yr

$$\begin{aligned}\text{PM (TPY)} &= 2.706\times10^{12}\ \text{Btu/yr} \times 0.03\ \text{lb/MMBtu} \div 2{,}000 \\ &= 40.59\ \text{TPY}\end{aligned}$$

2. **SO_2**: The emission factor is based upon the maximum sulfur content of No. 2 distillate fuel oil. The emission factor is 0.5 lb/MMBtu.

Sample calculation: Activity Factor= $2.706\text{x}10^{12}$ Btu/yr

$$\begin{aligned} SO_2\ (TPY) &= 2.706\text{x}10^{12}\ \text{Btu/yr x } 0.5\ \text{lb/MMBtu} + 2{,}000 \\ &= 676.50\ \text{TPY} \end{aligned}$$

3. **NO_x, CO, VOC**: The emission factors are based on emissions achievable with low-NO_x burners, SNCR (or equivalent), and good combustion.

NO_x: 0.15 lb/MMBtu (30-day rolling average)
CO: 0.2 lb/MMBtu (8-hour average)
VOC: 0.03 lb/MMBtu

Sample calculation: Activity Factor= $2.706\text{x}10^{12}$ Btu/yr

$$\begin{aligned} NO_x\ (TPY) &= 0.15\ \text{lb/MMBtu x } 2.706\text{x}10^{12}\ \text{Btu/yr} + 2{,}000 \\ &= 202.95\ \text{TPY} \end{aligned}$$

4. **Hg**: The emission factor is obtained from <u>Toxic Air Pollutant Emission Factors - A Compilation for Selected Air Toxic Compounds and sources, Second Edition</u> EPA publication 450/2-90-011 (1990). From this value a 30 percent reduction is taken to account for the mercury control system. The final emission factor is $2.4\text{x}10^{-6}$ lb/MMBtu.

5. **Lead**: The emission factor for lead was obtained from <u>Toxic Air Pollutant Emission Factors - A Compilation for Selected Air Toxic Compounds and Sources, Second Edition</u> EPA publication 450/2-90-011 (1990). The uncontrolled emission factor is $8.90\text{x}10^{-6}$ lb/MMBtu. A removal efficiency of 90% is achievable with an ESP: $0.89\text{x}10^{-6}$ lb/MMBtu.

Sample calculation: Activity Factor = $2.706\text{x}10^{12}$ Btu/yr

$$\text{Lead (TPY)} = 0.89\text{x}10^{-6}/10^{6} \text{ x } 2.706\text{x}10^{12} + 2{,}000 = 0.0012\ \text{TPY}$$

6. **Beryllium**: The emission factor was obtained from <u>Estimating Air Toxics Emissions from Oil and Coal Combustion Sources</u> EPA publication EPA-450/2-89-001 (1989). The emission factor is $0.35\text{x}10^{-6}$ lb/MMBtu.

7. **Sulfuric Acid Mist**: From the EPA Publication AP-42, sulfuric acid mist emissions for boiler's similar to that of the proposed facility, the emissions are estimated to be 3 percent of the sulfur dioxide emissions. The emission factor = 0.03 x 0.5 lb/MMBtu = 0.015 lb/MMBtu.

8. **Antimony, Barium, Bromine, Cobalt, Fluoride, Hydrogen Chloride, Molybdenum, Phosphorus, Silver, Thallium, Tin, Zinc, and Zirconium:** There are no available emission factors for distillate No. 2 fuel oil in the literature. However, emission factors for these pollutants for firing residual No. 6 fuel oil are available from Emission Assessment of Conventional Stationary Combustion Systems: Volume V, EPA publication EPA-600/7-81-0300c (1981). Use of these factors will provide a conservative set of emission factors for distillate oil. These emission factors are presented as pg/J. The emission factors are converted to lb/MMBtu.

pg/J x 10^{-12} g/pg x 1,055 J/Btu x 10^{6} Btu/MMBtu = 2.324x10^{-6} lb/MMBtu.

The converted emission factor is then reduced by 90 percent to account for ESP system removal, except for bromine, fluoride, and hydrogen chloride which are emitted as gases.

Example: Zinc - 28.8 pg/J x 2.324x10^{-6} x (1-.90) = 6.69x10^{-6} lb/MMBtu

Antimony: 10 pg/J = 2.32x10^{-6} lb/MMBtu
Barium: 28.8 pg/J = 6.69x10^{-6} lb/MMBtu
Bromine: 3.0 pg/J = 6.97x10^{-6} lb/MMBtu
Cobalt: 50.5 pg/J = 1.17x10^{-5} lb/MMBtu
Fluoride: 2.7 pg/J = 6.27x10^{-6} lb/MMBtu
Hydrogen Chloride: 274 pg/J = 6.37x10^{-4} lb/MMBtu
Molybdenum: 21 pg/J = 4.88x10^{-6} lb/MMBtu
Phosphorus: 25 pg/J = 5.81x10^{-6} lb/MMBtu
Tin: 142 pg/J = 3.30x10^{-5} lb/MMBtu
Zinc: 28.8 pg/J = 6.69x10^{-6} lb/MMBtu

Sample calculation: Activity Factor = 2.706x10^{12} Btu/yr

Zinc (TPY) = 2.706x10^{12} x 6.69x10^{-6} ÷ 2,000 ÷ 10^{6} = 0.0091 TPY

9. **Arsenic, Cadmium, Chromium, Copper, Formaldehyde, Manganese, Nickel, and Selenium:** Emission factors were obtained from Toxic Air Pollutant Emission Factors - A Compilation for Selected Air Toxic Compounds and sources, Second Edition EPA publication 450/2-90-011 (1990). These emission factors reflect ESP control and are reported as lb/10^{12} Btu.

Arsenic: 5.0 x10^{-7} lb/MMBtu
Cadmium : 1.58x10^{-6} lb/MMBtu
Chromium: 1.39x10^{-5} lb/MMBtu
Chromium^{+6}: 20% of Chromium - 2.78x10^{-6} lb/MMBtu
Copper: 4.2 x10^{-5} lb/MMBtu
Formaldehyde: 4.05x10^{-4} lb/MMBtu
Manganese: 3.08x10^{-6} lb/MMBtu
Nickel: 4.76x10^{-5} lb/MMBtu
Selenium: 4.60x10^{-6} lb/MMBtu

Sample calculation: Activity Factor = 2.706x10^{12} Btu/yr

Arsenic: 5.0x10^{-7} lb/MMBtu x 2.706x10^{12} Btu/yr ÷ 2,000 = 0.00068 TPY

10. **Dioxins and Furans:** No emission factors were available in the literature for dioxins and furans for oil combustion.

11. **Ammonia**
See calculations for biomass--0.0148 lb/MMBtu.

C. Bituminous Coal

1. **PM, SO_2:** The emission factors for PM and SO_2 are based on the NSPS. For PM, the emission factor is 0.03 lb/MMBtu. For SO_2, the emission factor is 1.2 lb/MMBtu.

Sample calculation: Activity Factor = $2.706\text{x}10^{12}$ Btu/yr

PM (TPY) = $2.706\text{x}10^{12}$ Btu x 0.03 lb/MMBtu + 2,000 + 10^6 = 40.59 TPY
SO_2 (TPY)= $2.706\text{x}10^{12}$ Btu x 1.2 lb/MMBtu + 2,000 + 10^6 = 1,620 TPY

2. **NO_x:** The emission factor used is based upon the boiler design and SNCR control system. The emission factor is 0.17 lb/MMBtu, 30-day rolling average.

NO_x (TPY): 0.17 lb/MMBtu = 230.01 TPY

3. **CO, VOC:** The emission factors used are based upon boiler design.

CO (TPY): 0.2 lb/MMBtu (8-hour average)
VOC (TPY): 0.03 lb/MMBtu

4. **Hg:** The emission factor is obtained from "Mercury Emissions to the Atmosphere in Florida" (KBN,1992) for a coal fired boiler with an ESP. The average emission factor is $8.4\text{x}10^{-6}$ lb/MMBtu.

5. **Sulfuric Acid Mist:** From the EPA Publication AP-42, sulfuric acid mist emissions for boiler's similar to that of the proposed facility, the emissions are estimated to be 3 percent of the concurrent sulfur dioxide emissions. The emission factor = 0.03 x 1.2 lb/MMBtu = 0.036 lb/MMBtu.

6. **Antimony, Barium, Bromine, Cobalt, Hydrogen Chloride, Fluorides, Molybdenum, Phosphorus, Selenium, Tin, and Zinc:** Emission factors were obtained from Emission Assessment of Conventional Stationary Combustion Systems: Volume V EPA publication EPA-600/7-81-0300c (1981). These emission factors were reported as ng/J. The factors were converted to lb/MMBtu. The proposed facility's boilers are similar to the spreader stoker design. From Table 31, uncontrolled emission factors were taken and then a 90% reduction was applied to account for removal by the ESP system for each pollutant except hydrogen chloride, fluorides, and bromine.

ng/J x 1055 J/Btu x 1,000,000 Btu/MMBtu x 10^{-9} g/ng x lb/454 g
= $2.324\text{x}10^{-3}$ (lb/MMBtu)/(ng/J)

Sample calculation:

Antimony = 0.15 ng/J x 2.324x10^{-3} (lb/MMBtu)/(ng/J) x (1-.9)
= 3.49x10^{-5} lb/MMBtu

Antimony: 0.15 ng/J = 3.49x10^{-5} lb/MMBtu
Barium: 3.2 ng/J = 7.44x10^{-4} lb/MMBtu
Bromine: 0.34 ng/J = 7.90x10^{-4} lb/MMBtu (no control)
Cobalt: 0.31 ng/J = 7.20x10^{-5} lb/MMBtu
Hydrogen Chloride: 33.9 ng/J = 7.90x10^{-2} lb/MMBtu (no control)
Fluoride: 10.3 ng/J = 2.39x10^{-2} lb/MMBtu (no control)
Molybdenum: 0.38 ng/J = 8.83x10^{-5} lb/MMBtu
Phosphorus: 3.7 ng/J = 8.60x10^{-4} lb/MMBtu
Selenium: 0.23 ng/J = 5.34x10^{-5} lb/MMBtu
Tin: 0.38 ng/J = 8.83x10^{-5} lb/MMBtu
Zinc: 1.5 ng/J = 3.49x10^{-4} lb/MMBtu

Sample calculation: Activity Factor = 2.706x10^{12} Btu/yr

Antimony: 3.49x10^{-5} x 2.706x10^{12} + 2,000 = 0.047 TPY

7. **Arsenic, Beryllium, Cadmium, Chromium, Copper, Formaldehyde, Lead, Manganese, and Nickel:** Emission factors were obtained from Estimating Air Toxics Emissions from Oil and Coal Combustion Sources EPA publication EPA-450/2-89-001 (1989). The emission factors are presented by boiler type/control status and presented in units of lb/10^{12} Btu. When listed, the boiler type/control status of choice is spreader stoker with ESP. Otherwise, a 90% reduction was made to the uncontrolled value.

Arsenic: 264 lb/10^{12} Btu (uncontrolled) x (1-.9)
= 2.64x10^{-5} lb/MMBtu
Beryllium: 5.9 lb/10^{12} Btu (ESP) = 5.90x10^{-6} lb/MMBtu
Cadmium: 1.36 lb/10^{12} Btu (ESP) = 1.36x10^{-6} lb/MMBtu
Chromium: 16.6 lb/10^{12} Btu (ESP) = 1.66x10^{-5} lb/MMBtu
Chromium^{+6}: 20% of chromium = 3.32x10^{-6} lb/MMBtu
Copper: 171 lb/10^{12} Btu (ESP) = 1.71x10^{-4} lb/MMBtu
Formaldehyde: 220 lb/10^{12} Btu (no control with ESP)
= 2.20 x 10^{-4} lb/MMBtu
Manganese: 31 lb/10^{12} Btu (ESP) = 3.10x10^{-6} lb/MMBtu
Nickel: 1,020 lb/10^{12} Btu (ESP) = 1.02x10^{-3} lb/MMBtu

Sample calculation: Activity Factor = 2.706x10^{12} Btu/yr

Beryllium: 5.90x10^{-6} x 2.706x10^{12} + 2,000 = 0.0080 TPY

8. **Ammonia**
See calculations for biomass--0.0148 lb/MMBtu

REFERENCES FOR APPENDIX A

TABLE 8.23-1. UNCONTROLLED PARTICULATE EMISSION FACTORS FOR METALLIC MINERAL PROCESSES[a]

Process	Low moisture ore[b]		High moisture ore[b]		Emission Factor Rating
	Emissions kg/Mg (lb/ton)	Particulate emissions < 10 μm kg/Mg (lb/ton)	Emissions kg/Mg (lb/ton)	Particulate emissions < 10 μm kg/Mg (lb/ton)	
Crushing[c]					
Primary	0.2 (0.5)	0.02 (0.05)	0.01 (0.02)	0.004 (0.009)	C
Secondary	0.6 (1.2)	NA	0.03 (0.05)	0.012 (0.02)	D
Tertiary	1.4 (2.7)	0.08 (0.16)	0.03 (0.06)	0.001 (0.02)	E
Wet grinding	Negligible	-	Negligible	-	
Dry grinding[d]					
With air conveying and/or air classification	14.4 (28.8)	13.0 (26.0)	d	d	C
Without air conveying or air classification	1.2 (2.4)	0.16 (0.31)	d	d	D
Drying[e]					
All minerals but titanium/zirconium sands	9.8 (19.7)	5.9 (12.0)	e	e	C
Titanium/zirconium with cyclones	0.3 (0.5)	NA	e	e	C
Material handling and transfer[f]					
All minerals but bauxite	0.06 (0.12)	0.03 (0.06)	0.005 (0.01)	0.002 (0.006)	C
Bauxite/alumina	0.6 (1.1)	NA	NA	NA	C

[a] References 9-12. Controlled particulate emission factors are discussed in Section 8.23.3. NA = not available.

[b] Defined in Section 8.23.2.

[c] Based on weight of material entering primary crusher.

[d] Based on weight of material entering grinder. Factors are the same for both high moisture and low moisture ores, because material is usually dried before entering grinder.

[e] Based on weight of material exiting dryer. Factors are the same for both high moisture and low moisture ores. SO_x emissions are fuel dependent (see Chapter 1). NO_x emissions depend on burner design, combustion temperature, etc. (see Chapter 1).

[f] Based on weight of material transferred. Applies to each loading or unloading operation and to each conveyor belt transfer point.

[g] Bauxite with moisture content as high as 15 - 18% can exhibit the emission characteristics of low moisture ore. Use low moisture factor for bauxite unless material exhibits obvious sticky, nondusting characteristics.

WORKBOOK ON ESTIMATION OF EMISSIONS AND DISPERSION MODELING FOR FUGITIVE PARTICULATE SOURCES

Document P-A857

September 1981

Prepared for

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TABLE 3.2.3-2

RAIL CAR UNLOADING: EFFICIENCIES OF CONTROL TECHNIQUES AND METHODS

Technique	Control Efficiency	Comments	Reference
Enclosure with fabric filter	99% (+) 70% without bag filter	CERs are best calculated from the method outlined in Appendix A.	EPA 1976a
Hood with fabric filter	99%(+)	Same as above.	EPA 1978a
Sprays	80%		EPA 1978a
(Rainfall)	(See text)	For operations in the open, sufficient rain should reduce emissions.	

TABLE 3.2.17-2

TRANSFER POINTS:

EFFICIENCIES OF CONTROL TECHNIQUES AND METHODS

Technique	Control Efficiency	Comments	Reference
Enclosure	90%		Szabo 1978
	70-99%*		EPA 1978a
Enclosure with control device	99(+)%	See Appendix A for calculating controlled emissions.	EPA 1978a
Spraying	70-95%		EPA 1978a
Telescopic chutes	75%		EPA 1978a

---

*Lower value uses "weathertight" system; higher value utilizes dust collection system.

TABLE 3.2.20-2

PRIMARY COAL CRUSHING:
EFFICIENCIES OF CONTROL TECHNIQUES AND METHODS

Technique	Control Efficiency	Comments	Reference
Wet suppression	83%	For particles <50μ	Wachter 1980
	92%	For particles <10μ	Wachter 1980
	90%		EPA 1976a
Enclosure	60-80%		EPA 1976a
Oiling	80%	Based on EE	Colorado 1981
Water spray	50%		EPA 1976a
	95%		PEDCo 1976a
Enclosure with control device	99(+)%	See Appendix A for alternative method of calculating controlled emissions.	PEDCo 1976a

TABLE 3.2.14-2

VEHICULAR TRAFFIC AROUND STORAGE PILES: EFFICIENCIES OF CONTROL TECHNIQUES AND METHODS

Technique	Control Efficiency	Comments	Reference
Watering	50%	Should be applied frequently in active areas.	EPA 1978a
Oiling	75%	Should be applied frequently in active areas; may not be viable if environmental agencies are concerned about runoff and VOC evaporation.	EPA 1978a
Surfactant	90-95%		EPA 1978a
Reducing traffic on piles	Up to 100% if no traffic.	No objective factors have been developed for estimating effectiveness.	

```
                    Spreadsheet as of 09:54:01 on 08-17-1992

Input Filename: coalpil.epc
Inventory area: Okeelanta Cogenerati
Source ID: Coal Pile  Filename: A:\CoalPil.EPC

Emissions estimate year:     91
Based on wind data year:     91
Fastest mile filename:     westp91.met
System of units:     English
Source life (inclusive days of year)
     Start day: 1
       End day: 365
F=flat area, PC=conical pile, PO=oval pile:     PC
 Pile height ( ft) : 30
 Pile diameter ( ft) : 500
 Area (sq ft):      197658
Material description:     Coal
Percent moisture content:     4.5
Percent  silt content:     2.2
Threshold friction velocity, U*t, (cm/sec):      112
Roughness height (cm):     0.3
Mode (mm) of size distribution       3.533677#      (# denotes calculated value)
Lc value (cf. Fig. 6-3 of reference manual):


Frequency of disturbance information :
 Us/Ur =  .9 -- subarea #  1      --  50 % of regime disturbed every  4 day(s)
 Us/Ur =  .6 -- subarea #  1      --  50 % of regime disturbed every  4 day(s)
 Us/Ur =  .2 -- subarea #  1      --  50 % of regime disturbed every  4 day(s)
```

```
Total emissions emitted over the period:  95652.99 g


Threshold velocity =  112  cm/s
Control:  Effective windspeed ratio =  1

-----------------------------------------------
Us/Ur =  .9    Disturbance interval = 4  days
                                   u*
Period  9 - 13  high on  10  1.2069  m/s  1438.047  g emitted
Period  13 - 17  high on  16   1.12644  m/s  90.01624  g emitted
Period  33 - 37  high on  34   1.16667  m/s  712.3215  g emitted
Period  41 - 45  high on  45   1.32759  m/s  4235.759  g emitted
Period  45 - 49  high on  46   1.40805  m/s  6618.004  g emitted
Period  61 - 65  high on  62   1.85058  m/s  27114.97  g emitted
Period  65 - 69  high on  68   1.24713  m/s  2267.197  g emitted
Period  73 - 77  high on  77   1.16667  m/s  712.3215  g emitted
Period  77 - 81  high on  77   1.16667  m/s  712.3215  g emitted
Period  85 - 89  high on  88   1.12644  m/s  90.01624  g emitted
Period  89 - 93  high on  93   1.24713  m/s  2267.197  g emitted
Period  93 - 97  high on  93   1.24713  m/s  2267.197  g emitted
Period  137 - 141  high on  141   1.24713  m/s  2267.197  g emitted
Period  141 - 145  high on  141   1.24713  m/s  2267.197  g emitted
Period  165 - 169  high on  168   1.16667  m/s  712.3215  g emitted
Period  189 - 193  high on  193   1.56897  m/s  12623.55  g emitted
Period  193 - 197  high on  193   1.56897  m/s  12623.55  g emitted
Period  205 - 209  high on  207   1.2069  m/s  1438.047  g emitted
Period  209 - 213  high on  212   1.32759  m/s  4235.759  g emitted
Period  321 - 325  high on  323   1.2069  m/s  1438.047  g emitted
Period  329 - 333  high on  333   1.12644  m/s  90.01624  g emitted
Period  333 - 337  high on  333   1.12644  m/s  90.01624  g emitted
Period  349 - 353  high on  353   1.16667  m/s  712.3215  g emitted
Period  353 - 357  high on  353   1.16667  m/s  712.3215  g emitted

Summary for Us/Ur =  .9     Disturbance Interval =  4
 87735.69  Total g emitted over  1  -  365
---------------------------------------------------------------
Us/Ur =  .6    Disturbance interval = 4  days

Period  61 - 65  high on  62   1.23372  m/s  7917.303  g emitted

Summary for Us/Ur =  .6     Disturbance Interval =  4
 7917.303  Total g emitted over  1  -  365
---------------------------------------------------------------
Us/Ur =  .2    Disturbance interval = 4  days


Summary for Us/Ur =  .2     Disturbance Interval =  4
 0  Total g emitted over  1  -  365
---------------------------------------------------------------
Summary for entire source:  95652.99   g emitted over period  1  -  365
NOTE: For a variety of reasons given in the user manual, the erosion estimates
      presented above may be considered as CONSERVATIVELY HIGH.  See the
      user manual for more information.
```

PM10 - 0.1054 TPY

Table ____. Fastest 1-Mile Wind Speeds[a] Used for the Wind Erosion Analysis

Week Number	Wind Speeds (mph) by Day of Week						
	SU	M	T	W	TH	F	SA
1	0	0	22	17	17	12	18
2	18	17	10	16	30	23	23
3	17	15	18	28	21	13	22
4	23	20	15	9	23	18	16
5	21	24	20	17	16	21	17
6	29	21	20	16	12	18	24
7	14	20	18	22	33	35	25
8	20	22	23	20	16	21	18
9	13	17	16	18	12	17	25
10	46	25	16	17	18	21	31
11	24	20	17	22	18	17	26
12	23	29	18	16	18	23	20
13	14	17	22	21	22	28	26
14	23	21	23	31	29	25	23
15	20	21	21	15	16	21	23
16	23	23	20	20	17	15	22
17	23	15	21	16	22	22	17
18	18	21	21	16	12	16	16
19	20	21	21	22	22	18	17
20	15	21	22	18	17	21	18
21	23	30	31	30	17	21	20
22	21	23	20	14	14	15	14
23	20	16	17	23	20	16	18
24	20	20	17	14	15	14	16
25	15	29	20	13	15	17	15
26	21	17	14	12	12	15	12
27	15	20	25	18	18	18	15
28	14	12	18	14	30	39	24
29	23	26	17	16	14	23	18
30	17	13	13	17	15	30	9
31	14	17	25	33	20	16	13
32	15	20	17	15	13	17	14
33	13	15	18	16	13	15	20
34	16	18	13	23	14	18	16
35	23	15	17	17	14	14	12
36	16	14	23	14	17	14	14
37	17	14	13	12	14	16	15
38	15	23	13	18	13	10	12
39	17	13	15	20	20	12	14
40	21	23	23	21	15	13	16
41	17	22	23	21	15	10	12
42	10	14	13	20	14	20	16
43	14	14	18	23	25	22	21
44	22	20	24	24	13	15	13
45	15	21	21	14	18	17	23
46	18	14	13	17	17	18	16
47	17	21	30	26	21	17	16

48	17	23	20	23	23	28	23
49	18	24	23	23	17	16	17
50	17	15	12	13	22	17	14
51	18	24	17	13	29	28	23
52	9	13	15	9	16	15	13
53	14	15	10	0	0	0	0

[a]. Palm Beach International Airport, West Palm Beach, 1991

Note: Anemometer Height is 10.0 m

PM Speciated Emission Factor Profile

Profile Name : Wood-Fired Boiler
Profile Number : 12704
Data Quality : B/D

Control Device : Wet Scrubber
Reference(s) : 149
Data Source : Average of 3 replicates. Dilution sampler with 2-stage virtual impactor.

SCC Code : 10200902
SCC Name : EXTCOMB BOILER
SCC Name : INDUSTRIAL
SCC Name : WOOD/BARK WASTE
SCC Name : WOOD/BARK>50K STM

Emission Factor Units: LBS PER TONS BURNED

Mass Fraction Data -		(0-2.5)	(0-6)	(0-10)
	Size Interval (um) :	(0-2.5)	(0-6)	(0-10)
	Mass Fraction :	0.980	0.980	0.980

Total Particulate Matter -

CAS Number	Species No	Species Sym	Emission Factors 0-2.5 um	2.5-10 um	0-10 um	Total Particulate
7440-48-4	27	Co	0.00423	0.00000	0.00423	NA
7726-95-6	35	Br	0.01277	0.00000	0.01277	0.01260
7440-67-7	40	Zr	0.00056	0.00000	0.00056	0.00079
7439-98-7	42	Mo	0.00176	0.00000	0.00176	0.00216
7440-74-6	49	In	0.00071	0.00000	0.00071	0.00108
7440-31-5	50	Sn	0.00092	0.00000	0.00092	0.00137

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149 Cooper, J. A., C. A. Frazier, and J. E. Houck. Seattle-Tacoma Aerosol Characterization Study (STACS). Draft Final Report to the Puget Sound Air Pollution Control Agency by NEA, Inc. 1983.

PB89-194229

United States
Environmental Protection
Agency

Office of Air Quality
Planning And Standards
Research Triangle Park, NC 27711

EPA-450/2-89-001
April 1989

AIR

EPA

ESTIMATING AIR TOXICS EMISSIONS FROM COAL AND OIL COMBUSTION SOURCES

TABLE 4-8. CALCULATED UNCONTROLLED BERYLLIUM EMISSION FACTORS FOR DISTILLATE OIL-FIRED BOILERS[a]

	Summary Emission Factor[b,c]	Previous Studies	
		Suprenant et al., 1980b	Suprenant et al., 1980a
Emission Factor ($lb/10^{12}$ Btu)	2.5	0.09[d]	0.05
Concentration in Fuel (ppm)	0.05	0.0076[d]	---

---

[a] Calculated assuming all beryllium present in oil feed is emitted through the stack.

[b] Calculated from typical level of beryllium in distillate oil derived in Section 3. Emission factor assumes all beryllium present in oil feed is emitted through the stack. A density of 7.05 lb/gal and heating value of 141,000 Btu/gal are assumed.

[c] Calculated beryllium emission factors ($lb/10^{12}$ Btu) for distillate oil-fired boilers are: multiclone, 1.58; ESP, 0.35; scrubber, 0.15. See text for discussion.

[d] There is a discrepancy between the calculated emission factor and the values measured for beryllium in the fuel as reported in this reference. The reference states the assumption that all beryllium measured in the oil feed is emitted through the stack, but the numbers presented do not agree with this statement. This discrepancy could not be resolved from the information given in the reference.

TABLE 4-42. SUMMARY OF MEASURED ARSENIC EMISSION FACTORS FOR BITUMINOUS COAL-FIRED INDUSTRIAL BOILERS

Boiler Type/ Control Status	Emission Factor ($lb/10^{12}$ Btu) Average[a]	Emission Factor ($lb/10^{12}$ Btu) Range	Number of Boilers	Number of Data Points
Pulverized Dry Bottom:				
Uncontrolled	690	---	1	2
Multiclone	7900	---	1	1
Multiclone/Scrubber	214	---	1	1
ESP	44.6	15.8-120	5	6
Pulverized Wet Bottom:				
Multiclone	32.5	---	1	1
Spreader Stoker:				
Uncontrolled	264	0.27-835	7	14
Multiclone	478	102-853	2	2
Multiclone/ESP	43.4	31-53.7	2	3
Overfeed Stoker:				
Uncontrolled	1030	60-2600	4	5
Economizer/Dust Collector	395	370-420	1	2

[a] Each boiler tested was weighted equally in determining this average. An arithmetic mean value was calculated for each boiler, and then a mean of these means was calculated.

TABLE 4-47. SUMMARIZED BERYLLIUM EMISSION FACTORS FOR COAL-FIRED BOILERS

Boiler Type/Control Status	Emission Factor (lb/10^{12} Btu) by Coal Type Bituminous	 Lignite	 Anthracite
<u>Pulverized (Dry or Wet Bottom)</u>:			
Uncontrolled	81	131	50
Multiclone	52	84	32
ESP	3.0	4.9	1.8
Scrubber	0.11	0.18	0.07
<u>Cyclone Boilers</u>:			
Uncontrolled	<81	<130	<50
Multiclone	<52	<84	<32
ESP	0.52	0.84	0.32
<u>Stoker Boilers</u>:			
Uncontrolled	73	118	45
Multiclone	9.8-46	16-74	6-28
ESP	5.9	9.5	3.6

TABLE 4-60. SUMMARY OF MEASURED CADMIUM EMISSION FACTORS FOR BITUMINOUS COAL-FIRED INDUSTRIAL BOILERS

Boiler Type/ Control Status	Emission Factor ($lb/10^{12}$ Btu)		Number of Boilers	Number of Data Points
	Average[a]	Range		
Pulverized Dry Bottom:				
Uncontrolled	290	---	1	1
Multiclone	465	---	1	1
ESP	20	0.49-39	5	5
Multiclone/Scrubber	0.98	---	1	1
Pulverized Wet Bottom:				
Multiclone	1.5	---	1	1
Spreader Stoker:				
Uncontrolled	21	4.1-65	7	14
Multiclone	0.56	0.19-0.93	2	2
ESP	1.36	0.009-4.2	2	3
Overfeed Stoker:				
Uncontrolled	82	12-300	4	5
Economizer/Dust Collector	56.	44-67	1	2

[a] Each boiler was weighted equally in determining this average. An arithmetic mean value was calculated for each boiler, and then a mean of these means was calculated.

TABLE 4-72. SUMMARY OF MEASURED CHROMIUM EMISSION FACTORS FOR BITUMINOUS COAL-FIRED INDUSTRIAL BOILERS

Boiler Type/ Control Status	Emission Factor (lb/10^{12} Btu)		Number of Boilers	Number of Data Points
	Average[a]	Range		
Pulverized Dry Bottom:				
Multiclone	2,560	---	1	1
ESP	1,130	5.8-1,500	4	4
Multiclone/Scrubber	126	---	1	1
Pulverized Wet Bottom:				
Multiclone	12.3	---	1	1
Spreader Stoker:				
Uncontrolled	3,880	30-8,400	7	13
Multiclone	194	62-325	2	2
Multiclone/ESP	16.6	16-17.2	2	2
2 Mechanical Collectors in series	1.5[b]	—	1	3
Overfeed Stoker:				
Uncontrolled	9,380	1,400-49,000	4	5
Economizer/Dust Collector	15,400	8,800-22,000	1	2

---

[a] Each boiler was weighted equally in determining the average. An arithmetic mean value was calculated for each boiler, and then a mean of these means was calculated.

[b] This factor is for hexavalent chromium (Cr^{+6}). The average emission factor was given in the reference, but the range of values was not.

TABLE 4-80. SUMMARY OF MEASURED COPPER EMISSION FACTORS FOR BITUMINOUS COAL-FIRED INDUSTRIAL BOILERS

Boiler Type/ Control Status	Emission Factor ($lb/10^{12}$ Btu)		Number of Boilers	Number of Data Points
	Average[a]	Range		
Pulverized Dry Bottom:				
Uncontrolled	3150	---	1	1
Multiclone	9530	---	1	1
ESP	155	80.6-230	2	2
Multiclone/Scrubber	19.5	---	1	1
Pulverized Wet Bottom:				
Multiclone	45.1	---	1	1
Spreader Stoker:				
Uncontrolled	448	5.2-1100	7	14
Multiclone	790	411-1170	2	2
ESP	171	0.04-309	2	3
Overfeed Stoker:				
Uncontrolled	1930	200-3500	4	5
Economizer/Dust Collector	4550	4200-4900	1	2

[a] Each boiler was weighted equally in determining this average. An arithmetic mean value was calculated for each boiler, and then a mean of these means was calculated.

TABLE 4-97. SUMMARY OF MEASURED MANGANESE EMISSION FACTORS FOR BITUMINOUS COAL-FIRED INDUSTRIAL BOILERS

Boiler Type/ Control Status	Emission Factor ($lb/10^{12}$ Btu) Average[a]	Range	Number of Boilers	Number of Data Points
Pulverized Dry Bottom:				
Multiclone	790	---	1	1
ESP	661	274-790	4	4
Multiclone/Scrubber	15	---	1	1
Pulverized Wet Bottom:				
Multiclone	15	---	1	1
Spreader Stoker:				
Uncontrolled	2310	16-14,000	7	14
Multiclone	103	23.9-183	2	2
✓ ESP	31	10.6-51.4	2	3
Overfeed Stoker:				
Uncontrolled	1930	230-6700	4	5
Economizer/Dust Collector	2050	1100-3000	1	2

[a] Each boiler weighted equally in determining this average. An arithmetic mean value was calculated for each boiler, and then a mean of these means was calculated.

TABLE 4-108. SUMMARY OF MEASURED NICKEL EMISSION FACTORS FOR BITUMINOUS COAL-FIRED INDUSTRIAL BOILERS

Boiler Type/ Control Status	Emission Factor (lb/10^{12} Btu)		Number of Boilers	Number of Data Points
	Average[a]	Range		
Pulverized Dry Bottom:				
Multiclone	1,390	---	1	1
ESP	470	10-930	2	2
Multiclone/Scrubber	60	---	1	1
Pulverized Wet Bottom:				
Multiclone	1.5	---	1	1
Spreader Stoker:				
Uncontrolled	5,770	32-20,600	6	12
Multiclone	130	31-230	2	2
ESP	1,020	---	1	1
Overfeed Stoker:				
Uncontrolled	4,610	840-23,000	4	5
Economizer/Dust Collector	22,200	16,500-28,000	1	2

[a] Each boiler was weighted equally in determining this average. An arithmetic mean value was calculated for each boiler, and then a mean of these means was calculated.

TABLE 4-116. SUMMARY OF MEASURED LEAD EMISSION FACTORS FOR BITUMINOUS COAL-FIRED UTILITY BOILERS

Boiler Type/ Control Status	Emission Factor ($lb/10^{12}$ Btu) Average[a]	Emission Factor ($lb/10^{12}$ Btu) Range	Number of Boilers Tested	Number of Data Points
Pulverized Dry Bottom:	2000 lb/10^{12}			
Uncontrolled	316	2.8 - 1249	4	5
ESP or Mechanical Ppt./ESP	⑲ 49	7.0 - 90.9	2	26
Scrubber	16.8	2.8 - 24.2	3	2
Tangential Cyclone + 2 ESP	163	95 - 282	1	4
Wall Fired Cyclone + 2 ESP	98	76 - 107	1	4
Pulverized Wet Bottom:				
ESP	63.8	1.1 - 183.8	7	7
Mechanical Ppt./ESP	646	---	1	1
Scrubber	22.3	22.3	1	1
Cyclone:				
ESP	15.3	4.0 - 19.2	6	6
Mechanical Ppt.	213	---	1	1
Wet Scrubber	4	---	1	1
Stoker:				
Mechanical Ppt. or Multiclone	1408	1154 - 1663	3	3
Fabric Filter	2.6	---	1	1
Cyclone · ESP + Scrubber	50	0.2 - 149	2	4

---

[a] Each boiler tested was weighted equally in determining this average. An arithmetic mean value was calculated for each boiler, and then a mean of these means was calculated.

TABLE 4-123. MEASURED FORMALDEHYDE EMISSION FACTORS FOR COAL-FIRED BOILERS AND FURNACES

Emission Factor ($lb/10^{12}$ Btu)	Boiler Type	Sectors[a]	Control Status	Reference
130	Pulverized Dry Bottom	U	Uncontrolled	Hangebrauck _et al._, 1964
90	Pulverized Dry Bottom	I	Uncontrolled	Hangebrauck _et al._, 1964
140	Chaingrate Stoker	U	Uncontrolled	Hangebrauck _et al._, 1964
220	Spreader Stoker	I	Uncontrolled	Hangebrauck _et al._, 1964
2100	Underfeed Stoker	I	Uncontrolled	Hangebrauck _et al._, 1964
380	Underfeed Stoker	C	Uncontrolled	Hangebrauck _et al._, 1964
63	Hand Stoked	R	Uncontrolled	Hangebrauck _et al._, 1964

[a] U = Utility, I = Industrial, C = Commercial/Institutional, R = Residential.

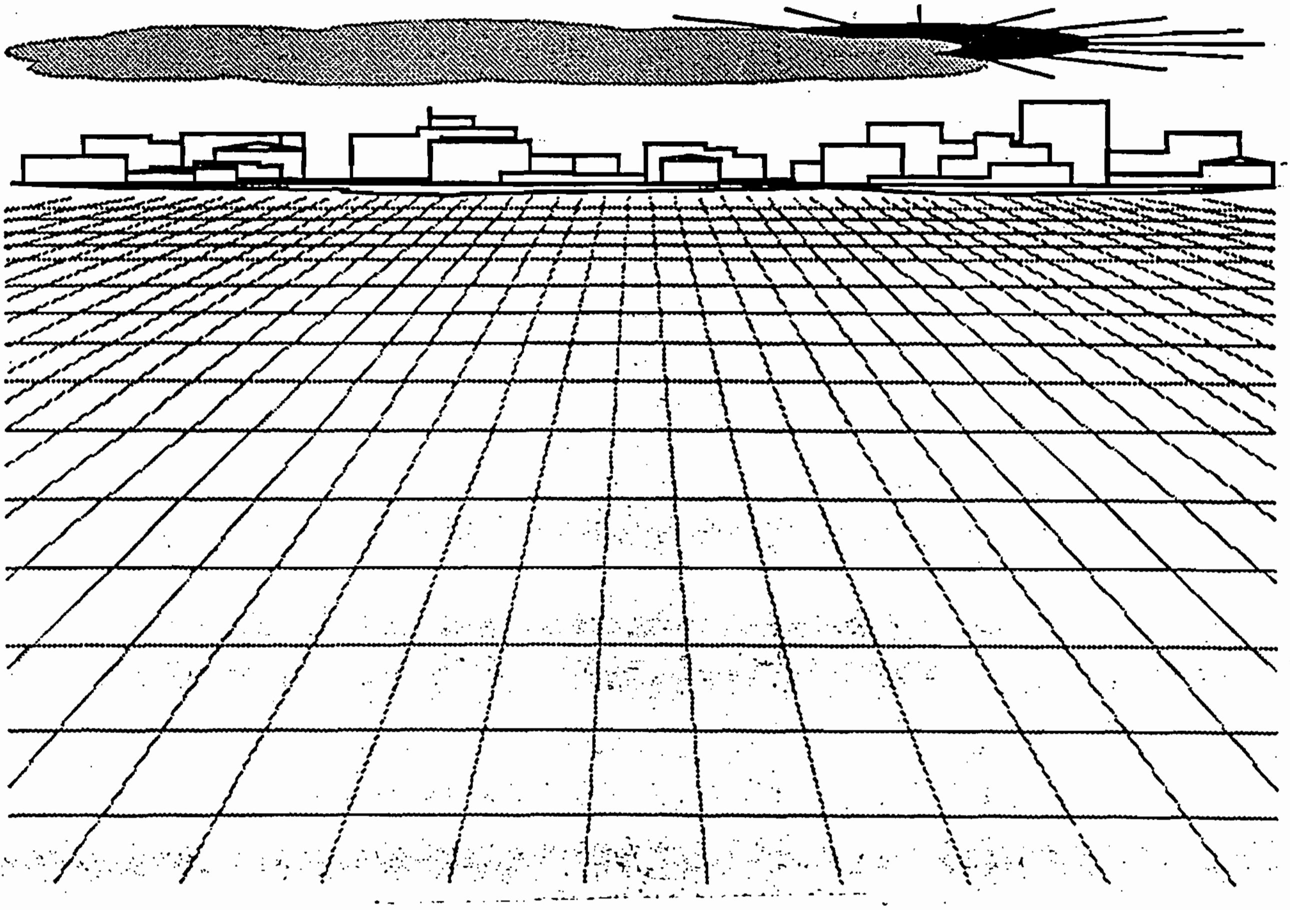
United States
Environmental Protection
Agency

Office of Air Quality
Planning And Standards
Research Triangle Park, NC 27711

EPA-450/2-90-011
October 1990

AIR

TOXIC AIR POLLUTANT EMISSION FACTORS - A COMPILATION FOR SELECTED AIR TOXIC COMPOUNDS AND SOURCES, SECOND EDITION



$7,500 pd.
9-18-92
Recpt.#180796

STATE OF FLORIDA

DEPARTMENT OF ENVIRONMENTAL REGULATION

AC50-219413
PSD-FL-196

APPLICATION TO OPERATE/CONSTRUCT AIR POLLUTION SOURCES

SOURCE TYPE: *Steam Generating Units* [*X*] New[1] [ ] Existing[1]

APPLICATION TYPE: [*X*] Construction [ ] Operation [ ] Modification

COMPANY NAME: *Flo-Energy, Inc.* COUNTY: *Palm Beach*

Identify the specific emission point source(s) addressed in this application (i.e., Lime Kiln No. 4 with Venturi Scrubber; Peaking Unit No. 2, Gas Fired) *Boilers No. 1, No. 2, No. 3*

SOURCE LOCATION: Street *6 mi. south of South Bay off U.S. 27* City *South Bay*

UTM: East *17-524.9* North *2940.1*

Latitude *26* ° *35* ' *00* "N Longitude *80* ° *45* ' *00* "W

APPLICANT NAME AND TITLE: *Gus Cepero, Vice-President*

APPLICANT ADDRESS: *P.O. Box 86, South Bay, FL 33493*

SECTION I: STATEMENTS BY APPLICANT AND ENGINEER

A. APPLICANT

I am the undersigned owner or authorized representative* of *Flo-Energy, Inc.*

I certify that the statements made in this application for a *construction* permit are true, correct and complete to the best of my knowledge and belief. Further, I agree to maintain and operate the pollution control source and pollution control facilities in such a manner as to comply with the provision of Chapter 403, Florida Statutes, and all the rules and regulations of the department and revisions thereof. I also understand that a permit, if granted by the department, will be non-transferable and I will promptly notify the department upon sale or legal transfer of the permitted establishment.

*Attach letter of authorization

Signed: Cepero

Gus Cepero, Vice-President
Name and Title (Please Type)

Date: 9/17/92 Telephone No. *(407) 996-9072*

B. PROFESSIONAL ENGINEER REGISTERED IN FLORIDA (where required by Chapter 471, F.S.) This is to certify that the engineering features of this pollution control project have been designed/examined by me and found to be in conformity with modern engineering principles applicable to the treatment and disposal of pollutants characterized in the permit application. There is reasonable assurance, in my professional judgement, that

---

[1] See Florida Administration Code Rule 17-2.100(57) and (104)

the pollution control facilities, when properly maintained and operated, will discharge an effluent that complies with all applicable statutes of the State of Florida and the rules and regulations of the department. It is also agreed that the undersigned will furnish, if authorized by the owner, the applicant a set of instructions for the proper maintenance and operation of the pollution control facilities and, if applicable, pollution sources.

Signed David A. Buff

David A. Buff
Name (Please Type)

KBN Engineering and Applied Sciences, Inc.
Company Name (Please Type)

1034 NW 57th Street, Gainesville, FL 32605
Mailing Address (Please Type)

DAVID A. BUFF
NO. 19011

Florida Registration No. *19011* Date: 9/16/92 Telephone No. *(904) 331-9000*

SECTION II: GENERAL PROJECT INFORMATION

A. Describe the nature and extent of the project. Refer to pollution control equipment, and expected improvements in source performance as a result of installation. State whether the project will result in full compliance. Attach additional sheet if necessary.

Refer to PSD report

B. Schedule of project covered in this application (Construction Permit Application Only)

Start of Construction *May 1993* Completion of Construction *December 1995*

C. Costs of pollution control system(s): (Note: Show breakdown of estimated costs only for individual components/units of the project serving pollution control purposes. Information on actual costs shall be furnished with the application for operation permit.)

Selective non-catalytic reduction systems: $4.5 million

Electrostatic precipitators: $5.0 million

Mercury control systems: $0.5 million

D. Indicate any previous DER permits, orders and notices associated with the emission point, including permit issuance and expiration dates.

Not applicable

E. Requested permitted equipment operating time: hrs/day *24*; days/wk *7*; wks/yr *52*;
If power plant, hrs/yr *8,760*; if seasonal, describe: ______

F. If this is a new source or major modification, answer the following questions. (Yes or No)

1. Is this source in a non-attainment area for a particular pollutant? *Yes*
   a. If yes, has "offset" been applied? *No*
   b. If yes, has "Lowest Achievable Emission Rate" been applied? *No*
   c. If yes, list non-attainment pollutants. *Ozone*
2. Does best available control technology (BACT) apply to this source? If yes, see Section VI. *Yes*
3. Does the State "Prevention of Significant Deterioration" (PSD) requirement apply to this source? If yes, see Sections VI and VII. *Yes*
4. Do "Standards of Performance for New Stationary Sources" (NSPS) apply to this source? *Yes*
5. Do "National Emission Standards for Hazardous Air Pollutants" (NESHAP) apply to this source? *No*

H. Do "Reasonably Available Control Technology" (RACT) requirements apply to this source? *No*
   a. If yes, for what pollutants? ______
   b. If yes, in addition to the information required in this form, any information requested in Rule 17-2.650 must be submitted.

Attach all supportive information related to any answer of "Yes". Attach any justification for any answer of "No" that might be considered questionable.

SECTION III: AIR POLLUTION SOURCES & CONTROL DEVICES (Other than Incinerators)

A. Raw Materials and Chemicals Used in your Process, if applicable:

Description	Contaminants		Utilization Rate - lbs/hr	Relate to Flow Diagram
	Type	% Wt		
	Not applicable			

B. Process Rate, if applicable: (See Section V, Item 1)

1. Total Process Input Rate (lbs/hr): *Not applicable*

2. Product Weight (lbs/hr): *Not applicable*

C. Airborne Contaminants Emitted: (Information in this table must be submitted for each emission point, use additional sheets as necessary)

Name of Contaminant	Emission[1]		Allowed[2] Emission Rate per Rule 17-2	Allowable[3] Emission lbs/hr	Potential[4] Emission		Relate to Flow Diagram
	Maximum lbs/hr	Actual T/yr			lbs/hr	T/yr	
	See Section 2.0 of						
	PSD report						

[1] See Section V, Item 2.

[2] Reference applicable emission standards and units (e.g. Rule 17-2.600(5)(b)2. Table II, E. (1) - 0.1 pounds per million BTU heat input)

[3] Calculated from operating rate and applicable standard.

[4] Emission, if source operated with~~out~~ control (See Section V, Item 3).

D. Control Devices: (See Section V, Item 4)

Name and Type (Model & Serial No.)	Contaminant	Efficiency	Range of Particles Size Collected (in microns) (If applicable)	Basis for Efficiency (Section V Item 5)
Electrostatic Precip.	*PM*	*>98%*	*Submicron*	*manufacturer*
Mercury Control System	*Hg*	*0-30%*	*N/A*	*manufacturer*
NO_x Control System	*NO_x*	*approx 40%*	*N/A*	*manufacturer*

E. Fuels

Type (Be Specific)	Consumption*		Maximum Heat Input (MMBTU/hr)
	avg/hr	max./hr	
Biomass		*168,236 lb/hr*	*715*
No. 2 Oil		*3,551 gal/hr*	*490*
Coal		*40,833 lb/hr*	*490*

*Units: Natural Gas--MMCF/hr; Fuel Oils--gallons/hr; Coal, wood, refuse, others--lbs/hr.

Fuel Analysis:

Percent Sulfur: *Refer to Section 2.0 of PSD report* Percent Ash: ________

Density: ________ lbs/gal Typical Percent Nitrogen: ________

Heat Capacity: ________ BTU/lb ________ BTU/gal

Other Fuel Contaminants (which may cause air pollution): ________

F. If applicable, indicate the percent of fuel used for space heating.

Annual Average *N/A* Maximum ________

G. Indicate liquid or solid wastes generated and method of disposal.

Wastewater, which is primarily cooling water, will either be sent to a percolation pond, reused, or sent to wastewater treatment plant and then to percolation pond. Ash will be disposed by landspreading or disposed offsite in an approved landfill.

H. Emission Stack Geometry and Flow Characteristics (Provide data for each stack):

Stack Height: *199* ft. Stack Diameter: *8.0* ft.

Gas Flow Rate: ______ ACFM *see PSD report* DSCFM Gas Exit Temperature: *see PSD report* °F.

Water Vapor Content: ______ % Velocity: ______ FPS

SECTION IV: INCINERATOR INFORMATION

Not applicable

Type of Waste	Type O (Plastics)	Type II (Rubbish)	Type III (Refuse)	Type IV (Garbage)	Type IV (Pathological)	Type V (Liq. & Gas By-prod.)	Type VI (Solid By-prod.)
Actual lb/hr Incinerated							
Uncontrolled (lbs/hr)							

Description of Waste ______

Total Weight Incinerated (lbs/hr) ______ Design Capacity (lbs/hr) ______

Approximate Number of Hours of Operation per day ______ day/wk ______ wks/yr. ______

Manufacturer ______

Date Constructed ______ Model No. ______

	Volume $(ft)^3$	Heat Release (BTU/hr)	Fuel		Temperature (°F)
			Type	BTU/hr	
Primary Chamber					
Secondary Chamber					

Stack Height: ______ ft. Stack Diameter: ______ Stack Temp. ______

Gas Flow Rate: ______ ACFM ______ DSCFM* Velocity: ______ FPS

*If 50 or more tons per day design capacity, submit the emissions rate in grains per standard cubic foot dry gas corrected to 50% excess air.

Type of pollution control devices: [ ] Cyclone [ ] Wet Scrubber [ ] Afterburner

[ ] Other (specify) ______

Brief description of operating characteristics of control devices: ______

______

______

______

______

Ultimate disposal of any effluent other than that emitted from the stack (scrubber water, ash, etc.):

______

______

______

______

NOTE: Items 2, 3, 4, 6, 7, 8, and 10 in Section V must be included where applicable.

SECTION V: SUPPLEMENTAL REQUIREMENTS

Please provide the following supplements where required for this application.

1. Total process input rate and product weight -- show derivation [Rule 17-2.100(127)]
   Not applicable.
2. To a construction application, attach basis of emission estimate (e.g., design calculations, design drawings, pertinent manufacturer's test data, etc.) and attach proposed methods (e.g., FR Part 60 Methods, 1, 2, 3, 4, 5) to show proof of compliance with applicable standards. To an operation application, attach test results or methods used to show proof of compliance. Information provided when applying for an operation permit from a construction permit shall be indicative of the time at which the test was made.
   See Section 2.0 of PSD report.
3. Attach basis of potential discharge (e.g., emission factor, that is, AP42 test).
   See Section 2.0 of PSD report.
4. With construction permit application, include design details for all air pollution control systems (e.g., for baghouse include cloth to air ratio; for scrubber include cross-section sketch, design pressure drop, etc.)
   See Section 2.0 of PSD report.
5. With construction permit application, attach derivation of control device(s) efficiency. Include test or design data. Items 2, 3 and 5 should be consistent: actual emissions = potential (1-efficiency).
   See Section 2.0 of PSD report.
6. An 8 ½" x 11" flow diagram which will, without revealing trade secrets, identify the individual operations and/or processes. Indicate where raw materials enter, where solid and liquid waste exit, where gaseous emissions and/or airborne particles are evolved and where finished products are obtained.
   See Section 2.0 of PSD report.
7. An 8 ½" x 11" plot plan showing the location of the establishment, and points of airborne emissions, in relation to the surrounding area, residences and other permanent structures and roadways (Examples: Copy of relevant portion of USGS topographic map).
   See Section 2.0 of PSD report.
8. An 8 ½" x 11" plot plan of facility showing the location of manufacturing processes and outlets for airborne emissions. Relate all flows to the flow diagram.
   See Section 2.0 of PSD report.

9. The appropriate application fee in accordance with Rule 17-4.05. The check should be made payable to the Department of Environmental Regulation.

10. With an application for operation permit, attach a Certificate of Completion of Construction indicating that the source was constructed as shown in the construction permit.

SECTION VI: BEST AVAILABLE CONTROL TECHNOLOGY

See PSD report

A. Are standards of performance for new stationary sources pursuant to 40 C.F.R. Part 60 applicable to the source?

[ ] Yes [ ] No

Contaminant	Rate or Concentration

B. Has EPA declared the best available control technology for this class of sources (If yes, attach copy)

[ ] Yes [ ] No

Contaminant	Rate or Concentration

C. What emission levels do you propose as best available control technology?

Contaminant	Rate or Concentration

D. Describe the existing control and treatment technology (if any).

1. Control Device/System:
2. Operating Principles:
3. Efficiency:*
4. Capital Costs:

*Explain method of determining

5. Useful Life:

6. Operating Costs:

7. Energy:

8. Maintenance Cost:

9. Emissions:

Contaminant	Rate or Concentration

10. Stack Parameters

a. Height: ft.

b. Diameter ft.

c. Flow Rate: ACFM

d. Temperature: °F.

e. Velocity: FPS

E. Describe the control and treatment technology available (As many types as applicable, use additional pages if necessary).

1.

a. Control Devices:

b. Operating Principles:

c. Efficiency:[1]

d. Capital Cost:

e. Useful Life:

f. Operating Cost:

g. Energy:[2]

h. Maintenance Cost:

i. Availability of construction materials and process chemicals:

j. Applicability to manufacturing processes:

k. Ability to construct with control device, install in available space, and operate within proposed levels:

2.

a. Control Device:

b. Operating Principles:

c. Efficiency:[1]

d. Capital Cost:

e. Useful Life:

f. Operating Cost:

g. Energy:[2]

h. Maintenance Cost:

i. Availability of construction materials and process chemicals:

---

[1] Explain method of determining efficiency.

[2] Energy to be reported in units of electrical power - KWH design rate.

j. Applicability to manufacturing processes:

k. Ability to construct with control device, install in available space, and operate within proposed levels:

3.

a. Control Device:
b. Operating Principles:
c. Efficiency:[1]
d. Capital Cost:
e. Useful Life:
f. Operating Cost:
g. Energy:[2]
h. Maintenance Cost:
i. Availability of construction materials and process chemicals:
j. Applicability to manufacturing processes:
k. Ability to construct with control device, install in available space, and operate within proposed levels:

4.

a. Control Device:
b. Operating Principles:
c. Efficiency:[1]
d. Capital Cost:
e. Useful Life:
f. Operating Cost:
g. Energy:[2]
h. Maintenance Cost:
i. Availability of construction materials and process chemicals:
j. Applicability to manufacturing processes:
k. Ability to construct with control device, install in available space, and operate within proposed levels:

F. Describe the control technology selected:

1. Control Device:
2. Efficiency:[1]
3. Capital Cost:
4. Useful Life:
5. Operating Cost:
6. Energy:[2]
7. Maintenance Cost:
8. Manufacturer:
9. Other locations where employed on similar processes:

a. (1) Company:
(2) Mailing Address:
(3) City:
(4) State:

---

[1] Explain method of determining efficiency.
[2] Energy to be reported in units of electrical power - KWH design rate.

(5) Environmental Manager:

(6) Telephone No.:

(7) Emissions:[1]

Contaminant	Rate or Concentration

(8) Process Rate:[1]

b. (1) Company:

(2) Mailing Address:

(3) City: (4) State:

(5) Environmental Manager:

(6) Telephone No.:

(7) Emissions:[1]

Contaminant	Rate or Concentration

(8) Process Rate:[1]

10. Reason for selection and description of systems:

[1] Applicant must provide this information when available. Should this information not be available, applicant must state the reason(s) why.

SECTION VII - PREVENTION OF SIGNIFICANT DETERIORATION

See PSD report

A. Company Monitored Data

1. ____________ no. sites ____________ TSP ____________( ) SO^{2*} ____________ Wind spd/dir

Period of Monitoring ______/____/______ to ______/____/______
month day year month day year

Other data recorded ____

Attach all data or statistical summaries to this application.

*Specify bubbler (B) or continuous (C).

2. Instrumentation, Field and Laboratory

a. Was instrumentation EPA referenced or its equivalent? ☐ Yes ☐ No

b. Was instrumentation calibrated in accordance with Department procedures?

☐ Yes ☐ No ☐ Unknown

B. Meteorological Data Used for Air Quality Modeling

1. ______ Year(s) of data from ________/____/________ to ________/____/________
month day year month day year

2. Surface data obtained from (location)______________________________

3. Upper air (mixing height) data obtained from (location) ____________________

4. Stability wind rose (STAR) data obtained from (location) ____________________

C. Computer Models Used

1. ______________________________ Modified? If yes, attach description.

2. ______________________________ Modified? If yes, attach description.

3. ______________________________ Modified? If yes, attach description.

4. ______________________________ Modified? If yes, attach description.

Attach copies of all final model runs showing input data, receptor locations, and principle output tables.

D. Applicants Maximum Allowable Emission Data

Pollutant	Emission Rate	
TSP	______________________	grams/sec
SO^2	______________________	grams/sec

E. Emission Data Used in Modeling

Attach list of emission sources. Emission data required is source name, description of point source (on NEDS point number), UTM coordinates, stack data, allowable emissions, and normal operating time.

F. Attach all other information supportive to the PSD review.

G. Discuss the social and economic impact of the selected technology versus other applicable technologies (i.e, jobs, payroll, production, taxes, energy, etc.). Include assessment of the environmental impact of the sources.

H. Attach scientific, engineering, and technical material, reports, publications, journals, and other competent relevant information describing the theory and application of the requested best available control technology.

APPENDIX E

SOURCE CONTRIBUTION TO MAXIMUM 24-HOUR AND 3-HOUR AAQS AND PSD IMPACTS

Table E-1. Source Contributions to Key Short-term AAQS and PSD Maximum Impacts

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AAQS; 24-Hour

Total Modeled Concentration: 214.9 $\mu g/m^3$, at (32°, 16000m), End Date 84122624.

Sugar Cane Growers - 208.2 $\mu g/m^3$
Atlantic Sugar - 0.9
FPL Riviera - 4.7
West Palm Bch. RRF - 0.2
Lake Worth Util. 0.9

AAQS; 3-Hour

Total Modeled Concentration: 835.3 $\mu g/m^3$, at (130°, 80000m), End Date 85101112.

FPL Port Everglades - 835.3 $\mu g/m^3$

PSD Class II; 3-Hour

Total Modeled Concentration: 155.5 $\mu g/m^3$, at (184°, 2729m), End Date 83011415.

Proposed Flo-Energy -155.5 $\mu g/m^3$

PSD Class II: 24-Hour

Total Modeled Concentration: 67.9 $\mu g/m^3$, at (20°, 30000m), End Date 84121524.

Sol-Energy Cogeneration - 19.5 $\mu g/m^3$
U.S Sugar Corp - Bryant - 48.3
Palm Beach County RRF - 0.1

PSD Class I: 24-Hour

Total Concentration: 5.42 $\mu g/m^3$, at (550300,2839000), End Date 83081724.

Proposed Flo-Energy Cogen - 0.04
Proposed Sol-Energy Cogen - 1.33
Dade Co. RRF - 0.53
Tarmac - 1.95
FPL Lauderdale - -0.75
S. Broward Co. RRF - 0.22
N. Broward Co. RRF - 0.45
Bechtel Indiantown - 0.10
FPL Martin - 1.54

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POLLUTANT	CAS NUMBER	SIC CODE	INDUSTRIAL PROCESS	EMISSION SOURCE	SCC CODE	EMISSION FACTOR	NOTES	REFERENCE
Indene	95136		Scrap tire, open burning	Tires in experimental burn hut		0.577 lb/ton tire	XAD-2 extracts w/MS analysis, Chunk condition = 1/4-1/6 of tire, burn rate = 2.3 kg/hr, uncontrolled	212
Indene(1,2,3-cd)pyrene	193395		Scrap tire, open burning	Tires in experimental burn hut		0.193 lb/ton tire	Sum of PAH analy on liq extrat. of XAD-2 test & filter compont, shred condition = 2" by 2" piece, burn rate=1.3 kg/hr, controlled	212
Indene(1,2,3-cd)pyrene	193395		Scrap tire, open burning	Tires in experimental burn hut		0.148 lb/ton tire	Sum of PAH analy on liq extrat. of XAD-2 test & filter compont, shred condition = 2" by 2" piece, burn rate=1.1 kg/hr, controlled	212
Indene(1,2,3-cd)pyrene	193395		Scrap tire, open burning	Tires in experimental burn hut		0.135 lb/ton tire	Sum of PAH analy on liq extrat. of XAD-2 test & filter compont, shred condition = 2" by 2" piece, burn rate=1.7 kg/hr, controlled	212
Indene(1,2,3-cd)pyrene	193395		Scrap tire, open burning	Tires in experimental burn hut		0.070 lb/ton tire	Sum of PAH analy on liq extrat. of XAD-2 test & filter compont, shred condition = 2" by 2" piece, burn rate=2.3 kg/hr, controlled	212
Iron	15438310	25	Wood combustion, industrial	Horizontal return tube	10200906	194.7 lb/10E12 Btu heat input	Sample results, 1 plant, wood flowrate = .514 kg/s, boiler has 3-pass design w/flyash reinjection, uncontrolled	176
Iron	15438310	25	Wood combustion, industrial	Balanced draft wickes stoker-fired industrial boiler	10200906	0.0084 lb/ton fuel or >0.24 ng/J	Dry wood, one plant, particulate control w/mechanical collector (cyclone), wood feed rate 0.29 kg/s, boil. eff. 55.3%	177
Iron	15438310	25	Wood combustion, industrial	Balanced draft wickes stoker-fired industrial boiler	10200906	0.0104 lb/ton fuel or >0.39 ng/J	Green wood, one plant, particulate control w/mechanical collector (cyclone), wood feed rate 0.54 kg/s, boil. eff. 61.3%	177
Iron	15438310	2951	Asphaltic concrete production	Plant stack	305002	3.72 x 10E-7 lb/ton concrete	Uncontrolled from a single plant, avg. of 2 values, range is 2.22 x 10E-7 - 5.21 x 10E-7 lb/ton	170
Iron	15438310	2951	Asphaltic concrete production	Plant stack	305002	4.73 x 10E-9 lb/ton concrete	Controlled (unspecified) from a single plant, avg. of 2 values, range is 3.08 x 10E-9 - 6.38 x 10E-9 lb/ton	170
Iron	15438310	806	Hospital waste incineration	Incinerator	315020	<0.0103 lb/ton feed	Uncontrolled, average emission factor based on 3 facilities	167
Isobutyraldehyde	78842		Wood combustion, residential	Fireplace		2.8 lb/ton wood burned	Uncontrolled, average emission factor based on source tests	58
Isobutyraldehyde	78842		Wood combustion, residential	Woodstove		3 lb/ton wood burned	Uncontrolled, average emission factor based on source tests	58
Lead	7439921		Coal combustion, industrial	Pulverized coal watertube boiler	10200202	0.0086 lbs/10E6 BTU heat input	Uncontrolled emissions	189
Lead	7439921		Coal combustion, industrial	Spreader stoker watertube boiler	10200204	0.0086 lbs/10E6 BTU heat input	Uncontrolled emissions	189

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POLLUTANT	CAS NUMBER	SIC CODE	INDUSTRIAL PROCESS	EMISSION SOURCE	SCC CODE	EMISSION FACTOR	NOTES	REFERENCE
Selenium	7782492	4911	Coal combustion, utility	Pulverized dry bottom boiler, lignite coal	10100301	13.21 lb/10E12 Btu	Controlled by ESP, based on reported emissions data and engineering judgement	54
Selenium	7782492	4911	Coal combustion, utility	Pulverized wet bottom boiler, lignite coal	10100301	10.66 lb/10E-12 Btu	Controlled by ESP, based on reported emissions data and engineering judgement	54
Selenium	7782492	4911	Coal combustion, utility	Stoker boiler, anthracite coal	10100102	83.71 lb/10E12 Btu	Controlled by multicyclones, based on reported emissions data and engineering judgement	54
☆ Selenium	7782492	4911	Oil combustion, utility	Tangential-fired, residual oil	101004	4.638 lb/10E12 Btu	Controlled by ESP, based on reported emissions data and engineering judgement	54 ✓
Selenium	7782492	4911	Oil combustion, utility	Tangential-fired, residual oil	101004	23.42 lb/10E12 Btu	Uncontrolled, based on reported emissions data and engineering judgement	54
Selenium	7782492	4911	Oil combustion, utility	Wall furnace, residual oil	101004	4.638 lb/10E12 Btu	Controlled by ESP, based on reported emissions data and engineering judgement	54
Selenium	7782492	4911	Oil combustion, utility	Wall furnace, residual oil	101004	23.42 lb/10E12 Btu	Uncontrolled, based on reported emissions data and engineering judgement	54
Selenium	7782492	4953	Municipal waste combustion	Mass burn unit	501001	4 x 10E-4 lb/ton feed	Calculated from three tests, average of range, uncontrolled, likely to exclude Se in vapor phase	21
Selenium	7782492	4953	Municipal waste combustion	Mass burn unit	501001	6 x 10E-5 lb/ton feed	Calculated from three tests, average of range, ESP, likely to exclude Se in vapor phase	21
Selenium	7782492	4953	Municipal waste combustion	RDF unit	501001	4 x 10E-4 lb/ton refuse	Calculated from max value of three tests, controlled with wet scrubber	19
Selenium	7782492	4953	Sewage sludge incineration	Fluidized-bed furnace	50100506	8 x 10E-4 lb/ton dry sludge	One test, scrubber	101
Selenium	7782492	4953	Sewage sludge incineration	Fluidized-bed incinerator	50200506	4 x 10E-5 lb/ton sludge	Calculated with 3.1 x 10E-4 lb/day, 1323 lb sludge/hr, 10 hr/day	20
Selenium	7782492	4953	Sewage sludge incineration	Multiple hearth furnace	50100506	0.0032 lb/ton dry sludge	Average of four tests, scrubber	101
Silicon tetrafluoride	7783611	2819	Hydrofluoric acid manufacture	Tail gas	30101206	30 lb/ton acid	Uncontrolled, average of data for three plants	97
Silicon tetrafluoride	7783611	2819	Hydrofluoric acid manufacture	Tail gas	30101206	0.3 lb/ton acid	Caustic scrubber, average of data for three plants	97
Silver	7440224	226	Woven fabric finishing	Heat setting	330001	2.6 x 10E-5 lb/ton fabric	Uncontrolled, based on test data	52
Silver	7440224	226	Woven fabric finishing	Tenter frames - resin finishing	330001	3.8 x 10E-4 lb/ton fabric	Uncontrolled, average of four tests	52
Silver	7440224	226	Woven fabric finishing	Thermosol dyeing	330001	0.0012 lb/ton fabric	Uncontrolled, average of two tests	52

INDUSTRIAL PROCESS	SIC CODE	EMISSION SOURCE	SCC CODE	POLLUTANT	CAS NUMBER	EMISSION FACTOR	NOTES	REFERENCE
Nonferrous metals production	3341	Melt furnace at permanent magnet alloy facility	304	Nickel	7440020	2 lb/ton of nickel charged	Controlled by fabric filter, based on engineering judgement	110
Nonferrous metals production	3341	Melt furnace at superalloy facility	304	Nickel	7440020	2 lb/ton of nickel charged	Controlled by fabric filter, based on engineering judgement	110
Nonylphenol production	2869	Fugitive emissions	301	Phenol	108952	0.38 lb/ton used	From engineering estimates	13
Nonylphenol production	2869	General emissions	301	Phenol	108952	1.6 lb/ton used	From engineering estimates	13
Nonylphenol production	2869	Storage	407084	Phenol	108952	0.02 lb/ton used	From engineering estimates	13
Oil and coal combustion	49	Stack - particulate	102	Polychlorinated dibenzo-p-dioxins, total		1.34 x 10E-4 lb/ton	No penta homologue included, one location, TCDD detection = 4 x 10E-5 lb/ton	119
Oil and coal combustion	49	Stack - particulate	102	2,3,7,8-Tetrachlorodibenzo-p-dioxin	1746016	Not detectable	One location, detection limit = 2 x 10E-5 lb/ton	119
Oil combustion		Fuel oil		Ammonia	7664417	0.8 lb/1000 gallons fuel oil burned	Sources emitting > 100 tons NH3/year	179
Oil combustion		Distillate oil-fired boiler, util/commerc/industr/residential	1	Arsenic	7440382	4.2 lb/10E12 Btu	Uncontrolled, calculated based on engineering judgement	34
Oil combustion		Distillate oil-fired boiler, util/commerc/industr/residential	1	Arsenic	7440382	2.06 lb/10E12 Btu	Controlled with multiclone, calculated based on engineering judgement	34
Oil combustion		Distillate oil-fired boiler, util/commerc/industr/residential	1	Arsenic	7440382	0.50 lb/10E12 Btu	Controlled with ESP, calculated based on engineering judgement	34
Oil combustion		Distillate oil-fired boiler, util/commerc/industr/residential	1	Arsenic	7440382	0.42 lb/10E12 Btu	Controlled with scrubber, calculated based on engineering judgement	34
Oil combustion		Residual oil-fired boiler, util/commerc/industr/residential	1	Arsenic	7440382	19 lb/10E12 Btu	Uncontrolled, calculated based on engineering judgement	34
Oil combustion		Residual oil-fired boiler, util/commerc/industr/residential	1	Arsenic	7440382	9.31 lb/10E12 Btu	Controlled with multiclone, calculated based on engineering judgement	34

INDUSTRIAL PROCESS	SIC CODE	EMISSION SOURCE	SCC CODE	POLLUTANT	CAS NUMBER	EMISSION FACTOR	NOTES	REFERENCE
Oil combustion		Distillate oil-fired boiler, util/commerc/industr/residential	1	Cadmium	7440439	7.45 lb/10E12 Btu	Controlled with multiclone, calculated based on engineering judgement	34
Oil combustion		Distillate oil-fired boiler, util/commerc/industr/residential	1	Cadmium	7440439	1.58 lb/10E12 Btu	Controlled with ESP, calculated based on engineering judgement	34
Oil combustion		Distillate oil-fired boiler, util/commerc/industr/residential	1	Cadmium	7440439	0.63 lb/10E12 Btu	Controlled with scrubber, calculated based on engineering judgement	34
Oil combustion		Residual oil-fired boiler, util/commerc/industr/residential	1	Cadmium	7440439	15.7 lb/10E12 Btu	Uncontrolled, calculated based on engineering judgement	34
Oil combustion		Residual oil-fired boiler, util/commerc/industr/residential	1	Cadmium	7440439	46.84 lb/10E12 Btu	Controlled with multiclone, calculated based on engineering judgement	34
Oil combustion		Residual oil-fired boiler, util/commerc/industr/residential	1	Cadmium	7440439	9.90 lb/10E12 Btu	Controlled with ESP, calculated based on engineering judgement	34
Oil combustion		Residual oil-fired boiler, util/commerc/industr/residential	1	Cadmium	7440439	3.96 lb/10E12 Btu	Controlled with scrubber, calculated based on engineering judgement	34
Oil combustion		Distillate oil-fired boiler, util/commerc/industr/residential	1	Chromium	7440473	47.5 lb/10E12 Btu	Uncontrolled, calculated based on engineering judgement	34
Oil combustion		Distillate oil-fired boiler, util/commerc/industr/residential	1	Chromium	7440473	27.8 lb/10E12 Btu	Controlled with multiclone, calculated based on engineering judgement	34
Oil combustion		Distillate oil-fired boiler, util/commerc/industr/residential	1	Chromium	7440473	13.92 lb/10E12 Btu	Controlled with ESP, calculated based on engineering judgement	34
Oil combustion		Distillate oil-fired boiler, util/commerc/industr/residential	1	Chromium	7440473	3.84 lb/10E12 Btu	Controlled with scrubber, calculated based on engineering judgement	34

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INDUSTRIAL PROCESS	SIC CODE	EMISSION SOURCE	SCC CODE	POLLUTANT	CAS NUMBER	EMISSION FACTOR	NOTES	REFERENCE
Oil combustion		Residual oil-fired boiler, util/commerc/industr/residential	1	Chromium	7440473	21 lb/10E12 Btu	Uncontrolled, calculated based on engineering judgement	34
Oil combustion		Residual oil-fired boiler, util/commerc/industr/residential	1	Chromium	7440473	12.18 lb/10E12 Btu	Controlled with multiclone, calculated based on engineering judgement	34
Oil combustion		Residual oil-fired boiler, util/commerc/industr/residential	1	Chromium	7440473	6.09 lb/10E12 Btu	Controlled with ESP, calculated based on engineering judgement	34
Oil combustion		Residual oil-fired boiler, util/commerc/industr/residential	1	Chromium	7440473	1.68 lb/10E12 Btu	Controlled with scrubber, calculated based on engineering judgement	34
Oil combustion		Distillate oil-fired boiler, util/commerc/industr/residential	1	Copper	7440508	280 lb/10E12 Btu	Uncontrolled, calculated based on engineering judgement	34
Oil combustion		Distillate oil-fired boiler, util/commerc/industr/residential	1	Copper	7440508	165.2 lb/10E12 Btu	Controlled with multiclone, calculated based on engineering judgement	34
Oil combustion		Distillate oil-fired boiler, util/commerc/industr/residential	1	Copper	7440508	42 lb/10E12 Btu	Controlled with ESP, calculated based on engineering judgement	34
Oil combustion		Distillate oil-fired boiler, util/commerc/industr/residential	1	Copper	7440508	25.2 lb/10E12 Btu	Controlled with scrubber, calculated based on engineering judgement	34
Oil combustion		Residual oil-fired boiler, util/commerc/industr/residential	1	Copper	7440508	278 lb/10E12 Btu	Uncontrolled, calculated based on engineering judgement	34
Oil combustion		Residual oil-fired boiler, util/commerc/industr/residential	1	Copper	7440508	165.2 lb/10E12 Btu	Controlled with multiclone, calculated based on engineering judgement	34
Oil combustion		Residual oil-fired boiler, util/commerc/industr/residential	1	Copper	7440508	42.0 lb/10E12 Btu	Controlled with ESP, calculated based on engineering judgement	34

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INDUSTRIAL PROCESS	SIC CODE	EMISSION SOURCE	SCC CODE	POLLUTANT	CAS NUMBER	EMISSION FACTOR	NOTES	REFERENCE
Oil combustion		Residual oil-fired boiler, util/commerc/industr/residential	1	Copper	7440508	25.2 lb/10E12 Btu	Controlled with scrubber, calculated based on engineering judgement	36
Oil combustion		Oil-fired boiler or furnace, util/commerc/industr/residential	1	Formaldehyde	50000	405 lb/10E12 Btu	Uncontrolled, based on emissions testing	36
Oil combustion		industrial, commercial, and residential boilers	1	Lead	7439921	8.9 lb/10E12 Btu	Uncontrolled, calculated based on engineering judgement, assumed use distillate oil	36
Oil combustion		Utility boiler	101004	Lead	7439921	28 lb/10E12 Btu	Uncontrolled, calculated based on engineering judgement, assumed use residual oil	36
Oil combustion		Distillate oil-fired boiler, util/commerc/industr/residential	1	Manganese	7439965	14 lb/10E12 Btu	Controlled with scrubber, calculated based on engineering judgement	36
Oil combustion		Distillate oil-fired boiler, util/commerc/industr/residential	1	Manganese	7439965	6.44 lb/10E12 Btu	Controlled with multiclone, calculated based on engineering judgement	36
Oil combustion		Distillate oil-fired boiler, util/commerc/industr/residential	1	Manganese	7439965	3.08 lb/10E12 Btu	Controlled with ESP, calculated based on engineering judgement	36
Oil combustion		Distillate oil-fired boiler, util/commerc/industr/residential	1	Manganese	7439965	1.54 lb/10E12 Btu	Controlled with scrubber, calculated based on engineering judgement	36
Oil combustion		Residual oil-fired boiler, util/commerc/industr/residential	1	Manganese	7439965	26 lb/10E12 Btu	Uncontrolled, calculated based on engineering judgement	36
Oil combustion		Residual oil-fired boiler, util/commerc/industr/residential	1	Manganese	7439965	11.96 lb/10E12 Btu	Controlled with multiclone, calculated based on engineering judgement	36
Oil combustion		Residual oil-fired boiler, util/commerc/industr/residential	1	Manganese	7439965	5.72 lb/10E12 Btu	Controlled with ESP, calculated based on engineering judgement	36

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INDUSTRIAL PROCESS	SIC CODE	EMISSION SOURCE	SCC CODE	POLLUTANT	CAS NUMBER	EMISSION FACTOR	NOTES	REFERENCE
Oil combustion		Distillate oil-fired boiler, util/commerc/industr/residential	1	Nickel	7440020	47.6 lb/10E12 Btu	Controlled by ESP, based on engineering Judgement	36
Oil combustion		Distillate oil-fired boiler, util/commerc/industr/residential	1	Nickel	7440020	6.8 lb/10E12 Btu	Controlled by scrubber, based on engineering Judgement	36
Oil combustion		Residual oil-fired boiler, util/commerc/industr/residential	1	Nickel	7440020	1260 lb/10E12 Btu	Uncontrolled, based on engineering Judgement	36
Oil combustion		Residual oil-fired boiler, util/commerc/industr/residential	1	Nickel	7440020	642.6 lb/10E12 Btu	Controlled by multiclone, based on engineering Judgement	36
Oil combustion		Residual oil-fired boiler, util/commerc/industr/residential	1	Nickel	7440020	352.8 lb/10E12 Btu	Controlled by ESP, based on engineering Judgement	36
Oil combustion		Residual oil-fired boiler, util/commerc/industr/residential	1	Nickel	7440020	50.4 lb/10E12 Btu	Controlled by scrubber, based on engineering Judgement	36
Oil combustion		Cast iron sectional boilers, distillate oil	10300501	Polycyclic organic matter		34.5 lb/10E12 Btu	Uncontrolled, home heating application	114
Oil combustion		Distillate watertube boilers	10300501	Polycyclic organic matter		0.278 lb/10E12 Btu heat input	Uncontrolled	114
Oil combustion		Hot air furnace, distillate oil	10300501	Polycyclic organic matter		0.324 lb/10E12 Btu	Uncontrolled, same reference also lists <15.4 for same boiler/fuel type	114
Oil combustion		Scotch marine boilers, distillate oil	10300501	Polycyclic organic matter		41.04 lb/10E12 Btu	Uncontrolled	114
Oil combustion	49	Flue gas	1	2,3,7,8-Tetrachlorodibenzofuran		Not detectable	Low ash, 2% sulfur oil, sampled after heat exch., before ESP, 2378-TCDD detec. limit=<0.67-<1.3ng/m3	119
Oil combustion	49	Boiler flue gas	1	2,3,7,8-Tetrachlorodibenzo-p-dioxin	1746016	Not detectable	Low ash, 2% sulfur oil, sampled after heat exch., before ESP, 2378-TCDD detec. limit=<4.2-<7.9 ng/m3	119
Oil combustion, commercial		Scotch marine boilers, residual oil	10300401	Polycyclic organic matter		2.203 lb/10E12 Btu heat input	Uncontrolled, represents benzo(a)pyrene only	114

PB81-225559

Emissions Assessment of Conventional Stationary Combustion Systems: Volume V: Industrial Combustion Sources

TRW, Inc.
Redondo Beach, CA

Prepared for

Industrial Environmental Research Lab.
Research Triangle Park, NC

1981

U.S. Department of Commerce
National Technical Information Service

TABLE 18. TRACE ELEMENT EMISSION FACTORS AND MEAN AMBIENT SEVERITY FACTORS FOR RESIDUAL OIL-FIRED INDUSTRIAL BOILERS

Trace element	Concentration (ppm)	Emission factor (pg/J)	Ambient[a] severity factor
Aluminum (Al)	3.8	87	0.002
Arsenic (As)	0.8	18	1.1
Boron (B)	0.41	9.4	<0.001
Barium (Ba)	1.26	28.8	0.008
Beryllium (Be)	0.08	1.8	0.11
Bromine (Br)	0.13	3.0	<0.001
Calcium (Ca)	14	320	0.002
Cadmium (Cd)	2.27	51.9	0.64
Chlorine (Cl)	12	274	0.012
Cobalt (Co)	2.21	50.5	0.12
Chromium (Cr)	1.3	30	2.7
Copper (Cu)	2.8	64	0.638
Fluorine (F)	0.12	2.7	<0.001
Iron (Fe)	18	411	0.05
Mercury (Hg)	0.04	0.9	0.002
Potassium (K)	34	777	0.48
Lithium (Li)	0.06	1.4	0.006
Magnesium (Mg)	13	297	0.006
Manganese (Mn)	1.33	30.4	<0.001
Molybdenum (Mo)	0.9	21	<0.081
Sodium (Na)	31	708	0.034
Nickel (Ni)	42.2	964	7.8
Phosphorus (P)	1.1	25	0.004
Lead (Pb)	3.5	80	0.066
Antimony (Sb)	0.44	10	0.002
Selenium (Se)	0.7	16	0.010
Silicon (Si)	17.5	400	0.004
Tin (Sn)	6.2	142	0.004
Strontium (Sr)	0.15	3.4	<0.001
Thorium (Th)	<0.001	0.02	<0.001
Uranium (U)	0.7	16	0.22
Vanadium (V)	160	3656	0.90
Zinc (Zn)	1.26	28.8	<0.001

[a] Based on a firing rate of 50 x 10^9 J/hr.

TABLE 31. ESTIMATED TRACE ELEMENT EMISSION FACTORS AND AMBIENT SEVERITY FACTORS FOR BITUMINOUS COAL-FIRED BOILERS

	Pulverized[a]				Spreader stoker[b]			
	Uncontrolled		Controlled[c]		Uncontrolled		Controlled[c]	
	Emission factor (ng/J)	Mean ambient severity[d]	Emission factor (ng/J)	Mean ambient severity[d]	Emission factor (ng/J)	Mean ambient severity[e]	Emission factor (ng/J)	Mean ambient severity[e]
Aluminum	397	4.8	119	1.4	304	2.7	91	0.81
Antimony	0.2	0.049	0.048	0.05	0.15	0.027	0.037	0.081
Arsenic	1.2	2.9	0.35	0.87	0.92	1.7	0.27	0.51
Barium	4.2	1.0	1.25	0.30	3.2	0.57	0.96	0.17
Beryllium	0.1	6.1	0.031	1.8	0.077	8.5	0.024	1.1
Boron	4.1	0.050	1.24	0.015	3.1	0.29	0.95	0.087
Bromine	0.34	0.059	0.34	0.018	0.34	0.34	0.34	0.10
Cadmium	0.08	0.20	0.024	0.060	0.061	0.11	0.018	0.033
Calcium	263	6.4	78.8	1.9	201	3.7	60.3	1.1
Chlorine	33.9	1.4	33.9	0.42	33.9	0.80	33.9	0.24
Chromium	2.6	6.3	0.77	1.9	2.0	3.6	0.59	1.1
Cobalt	0.4	0.98	0.11	0.30	0.31	0.56	0.084	0.17
Copper	1.1	0.13	0.32	0.039	0.84	0.074	0.24	0.022
Fluorine	13.5	0.83	4.06	0.25	10.3	0.47	3.1	0.14
Iron	393	9.6	118	2.9	301	5.4	90.3	1.6
Lead	0.9	0.73	0.28	0.22	0.69	0.42	0.21	0.13
Lithium	1.13	6.3	0.34	1.9	0.86	3.6	0.26	1.1
Magnesium	57	0.70	17.2	0.21	43.6	0.40	13.2	0.12
Manganese	1.8	0.044	0.54	0.013	1.38	0.025	0.41	0.008
Mercury	0.007	0.017	[illegible]	0.005	0.007	0.010	0.007	0.003
Molybdenum	0.5	0.012	0.15	0.004	0.38	0.007	0.11	0.002
Nickel	2.9	3.5	0.87	1.1	2.2	2.0	0.67	0.60
Phosphorus	4.9	5.9	1.48	1.8	3.7	3.4	1.1	1.0
Potassium	53	3.2	15.8	0.96	40.5	1.8	12.1	0.54
Selenium	0.3	0.18	0.10	0.054	0.23	0.10	0.077	0.03
Silicon	711	8.6	213	2.6	544	4.8	163	1.5
Sodium	24	1.2	7.16	0.36	18.4	0.68	5.48	0.20
Strontium	7.0	0.28	2.1	0.084	5.4	0.16	1.6	0.048
Thorium	0.06	0.17	0.02	0.051	0.05	0.10	0.01	0.030
Tin	0.5	0.012	0.15	0.004	0.38	0.007	0.11	0.002
Uranium	0.04	0.024	0.012	0.007	0.03	0.014	0.009	0.004
Vanadium	1.3	0.32	0.38	0.096	0.99	0.18	0.29	0.054
Zinc	2.0	0.048	0.61	0.014	1.5	0.027	0.47	0.008

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[a] Calculated from data in Reference 28, Table 59.

[b] Calculated from emission factors of bituminous, pulverized, dry-bottom boilers and the ratio of published EPA emission factors for pulverized, dry-bottom boilers and spreader stokers.

[c] Cyclone

[d] Based on a heat capacity of 100 GJ/hr.

[e] Based on a heat capacity of 50 GJ/hr.

AIR TOXIC EMISSIONS FROM WOOD FIRED BOILERS

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ABSTRACT

California's new Air Toxic "HOT SPOTS" law (AB 2588) requires the identification and quantification of air toxic emissions from all major industrial plants. Under the sponsorship of the Timber Association of California, operators of wood fired boilers formed a pooled test program, to consolidate this testing effort and reduce testing costs. Several types of boilers using differing wood fuel mixes and a wide range of emission control equipment configurations have been tested for their release of air toxic substances. The organization of this pooled test program is described, source testing methodology is reviewed, and air toxic emission factors for eleven wood fired boilers are presented.

KEYWORDS

Air Pollution
Boilers
Cogeneration
Combustion
Fly Ash
Pollution Testing
Power Plants
Toxicity
Wood Fuel

INTRODUCTION

In 1987 the California State Legislature passed regulations directing all large industrial facilities to inventory and report the amount of air toxic materials released from their process stacks or from other plant fugitive emission areas. This Legislation required the inventory procedure to be based upon actual stack source tests or verified emission factor data. The plants were required to prepare and submit AIR TOXIC EMISSION INVENTORY PLANS to the individual air pollution control districts prior to August 1, 1989. These INVENTORY PLANS were to consider a listing of 326 toxic substances and were needed for any facility identified as emitting in excess of 25 tons per year of any of the criteria pollutants; particulate matter, sulfur oxides, nitrogen oxides, or hydrocarbons. Smaller plants were brought into the inventory program one year later. The AIR TOXIC EMISSION INVENTORY PLANS were reviewed by the air districts and were approved or revised prior to the start of testing. Emission source testing was to be completed and final AIR TOXIC EMISSION INVENTORY REPORTS were to be filed with the air districts by June 1, 1990. Based upon data contained in these Reports, the individual facilities were prioritized by the air districts for potential carcinogenic health risks or other health risks. Facilities classified as "High Priority" are now preparing air emission risk assessments which will be made available for public disclosure.

The Air Toxic Emission Inventory Program was designed to evaluate all possible air toxic emission release points, but the major focus of the inventory was placed upon combustion type processes, because they present the largest potential for release of large volumes of air emissions at oil refineries, chemical plants, utility boilers, lime kilns, smelters, kraft pulp mills and a vast array of fuel burning operations.

The air toxic substances evaluated in the wood fired boiler testing program included toxic metals, benzene, aldehydes, phenolics, polycyclic aromatic hydrocarbons (PAH's), dioxins and dibenzofurans.

EMISSION INVENTORY PROGRAM

The California State Legislature had established an extremely optimistic time schedule to accomplish the Air Toxic Program, considering the large number of industrial facilities operating in California.

August 1, 1989 ----	File Inventory Plans
June 1, 1990 ----	File Inventory Reports
December 1,1990 ---	Prioritize Facilities
May 1, 1991 ----	File Risk Assessments

The time schedule for this enormous air toxic inventory effort placed extreme financial and manpower resource demands upon industry to test thousands of air emission release points throughout California. Manpower demands placed upon testing firms capable of performing the needed source tests were further strained. There were too few testing firms to perform the source tests and many of these firms were not familiar with the specific testing procedures required to measure a vast array of substances by new source testing methods still being developed by the California Air Resources Board (CARB). This resource squeeze was extended to the few laboratory firms in the state qualified to perform the test analyses. Needless to say, the cost of source testing and laboratory analyses succumbed to the law of supply and demand. Source testing and laboratory charges began to escalate to where a complete air toxic emission test project for a single plant stack could cost as much as 60,000 dollars.

Fortunately, one safety valve was built into this inventory process by the State Legislature, allowing groups of like or similar process operations to "pool" their resources, test representative prototype air emission processes, develop air toxic emission factors and apply these prototype factors to similar facilities participating in the test pool. Although this procedure reduced the source testing costs and manpower demands, it imposed another layer of governmental review upon the process. The test approval process was extended from the individual air districts to the California Air Resources Board, adding another layer of

TABLE 2

EMISSIONS OF AIR TOXIC METALS FROM WOOD FIRED BOILERS

BOILER NUMBER	1	2	3	10	4	5	6	7	8	9	11
BOILER TYPE	FUEL CELL	FUEL CELL	DUTCH OVEN	AIR INJ	DUTCH OVEN	STOKER	STOKER	STOKER	STOKER	STOKER	FLUID BED
STEAM RATE (Mlb/hr)	6	68	50	43	37	90	118	136	164	167	92
PARTICULATE CONTROL	CYCLONE	MC	MC	MC	WS	WS	WS	ESP	ESP	ESP	ESP
SUBSTANCE	EMISSION FACTORS (e) parts per million by weight (ug/g particulate)										
ARSENIC	8	5	29	4	72	230	565	0 <240>	92	0 <240>	0 <45>
BERYLLIUM	0	0	0	0	0	0	0	0	0	0	0
CADMIUM	1	28	8	8	19	36	8	172	190	0 <240>	29
CHROMIUM	18	33	14	25	35	518	74	0 <1440>	206	0 <480>	168
HEX CHROME	0 <187>	25	7	29	0 <120>	0 <140>	0 <150>	0 <3840>	0 <755>	0 <1180>	0 <513>
COPPER	67	257	182	133	380	514	558	1756	928	903	550
LEAD	187	24	114	63	780	1270	302	890	617	981	258
MANGANESE	653	12077	7690	6550	4260	3530	1990	53900	12795	13150	7360
NICKEL	5	62	33	38	290	130	55	1520	1423	0 <1920>	467
SELENIUM	0	0	0	0	0	0	0	0	0	0	430
ZINC	180	2043	1430	1250	8460	8910	6200	25900	10200	6290	3230
MERCURY(ug/dscm)(f)	0	0.3	2.4	0	0	0.5	0.9	0	0.4	0.3	0

NOTES (e) Expressed as Front Half Particulate Catch Only
(f) Mercury is expressed as micrograms per dry standard cubic meter
< > Indicates Detection Limit for this Metal

TABLE 3

EMISSIONS OF AIR TOXIC ORGANICS FROM WOOD FIRED BOILERS

BOILER NUMBER	1	2	3	4	5	6	7	8	9	10	11
BOILER TYPE	FUEL CELL	FUEL CELL	DUTCH OVEN	DUTCH OVEN	STOKER	STOKER	STOKER	STOKER	STOKER	AIR INJ	FLUID BED
CARBON MONOXIDE:ppm	20	2500	220	600	220	1200	1000	500	300	2100	250
HYDROCARBONS:ppm	25	12	20	NM	9	40	25	35	6	35	NM
ORGANIC SUBSTANCE EMISSIONS. parts per billion by volume at 12 percent carbon dioxide											
FORMALDEHYDE	724	760	530	72	490	417	310	1020	260	139	21
ACETALDEHYDE	384	140	130	21	90	132	33	240	40	0	14
BENZENE	0	10	25	315	87	1270	212	490	79	930	8
PHENOLS	NT	<1	NT	<1	11	NT	NT	6	<1	NT	NT
POLYCYCLIC AROMATIC HYDROCARBON EMISSIONS microgrannms per dry standard cubic meter at 12% CO^2											
NAPHTHALENE	611	BP	29	45	312	179	BP	286	120	BP	330
ACENAPHTHYLENE	0	0.28	3.90	1.59	0.31	24.7	7.27	0.49	0	5.19	0.07
ACENAPHTHENE	0	0.01	0.12	0	0.10	1.90	0.01	0	0	0.50	0
FLUORENE	0.80	0.03	0.70	0.07	0.06	5.55	0.19	0	0	0.13	0.02
PHENANTHRENE	3.70	0.42	2.18	2.69	0.23	29.5	6.66	0.18	0	6.21	0.48
ANTHRACENE	0.16	0.01	0.14	0.14	0.02	1.77	0.19	0	0	0.27	0
FLUORANTHENE	0.75	0.39	0.98	2.47	0.08	10.6	1.39	0.03	0.01	5.07	0.21
PYRENE	0.40	0.24	1.29	3.61	0.10	6.83	1.15	0.04	0	6.53	0.05
*BENZO(A)ANTHRACENE	0	0	0	0.04	0	0.75	0	0	0	0.04	0.01
CHRYSENE	0	0.05	0	0.06	0.01	0	0	0	0	0.13	0.02
*BENZO(B&K)FLUORANTHENE	0	0.12	0.15	0.04	0.06	0.86	0	0	0.07	0	0
*BENZO(A)PYRENE	0	0.01	0	0	0	0	0	0	0	0	0
*BENZO(GHI)PERYLENE	0	0.01	0.06	0.06	0	0	0	0	0	0.41	0
*DIBENZ(AH) ANTHRACENE	0	0	0	0	0	0	0	0	0	0	0
*INDENO(123CD)PYRENE	0	0.01	0	0	0	0	0	0	0	0.07	0

NOTES NT--Not Tested NM--Instrument Inoperative BP--Blank Problems
* Classified as a Carcinogen by CARB

TABLE 5

DIOXIN AND DIBENZOFURAN EMISSIONS FROM WOOD FIRED BOILERS
CALIFORNIA AIR RESOURCES BOARD STUDY - 1988

BOILER ID	A	B	C	D(REG)	D(BLND)
BOILER TYPE	FUEL CELL	FUEL CELL	FLUID BED	STOKER	STOKER
PARTICULATE CONTROL	MULTICLONE	MC & ESP	MC & ESP	MULTICLONE & ESP	

DIOXIN AND DIBENZOFURAN FACTORS

(Expressed as the 2,3,7,8 TCDD equivalent using California DHS Factors)

DIOXINS & FURANS: ng/dscm at 12 percent carbon dioxide in exhaust gas					
DIOXINS	0.037	0.004	0.022	0.013	0.006
FURANS	0.538	0.221	0.561	0.789	0.179
TOTAL 2,3,7,8 EQUIV	0.575	0.225	0.583	0.802	0.185

****

(Expressed as the 2,3,7,8 TCDD equivalent using EPA Factors)

DIOXINS & FURANS: ng/dscm at 12 percent carbon dioxide in exhaust gas					
DIOXINS	0.023	0.002	0.023	0.011	0.003
FURANS	0.231	0.135	0.209	0.643	0.088
TOTAL 2,3,7,8 EQUIV	0.254	0.137	0.232	0.654	0.091

BEST AVAILABLE COPY

PM Speciated Emission Factor Profile

Profile Name : Wood-Fired Boiler
Profile Number : 12704
Data Quality : B/D

Control Device : Wet Scrubber
Reference(s) : 149
Data Source : Average of 3 replicates. Dilution sampler with 2-stage virtual impactor.

SCC Code : 10200902
SCC Name : EXTCOMB BOILER
SCC Name : INDUSTRIAL
SCC Name : WOOD/BARK WASTE
SCC Name : WOOD/BARK>50K STM

Emission Factor Units: LBS PER TONS BURNED

Mass Fraction Data -		(0-2.5)	(0-6)	(0-10)
	Size Interval (um) :	(0-2.5)	(0-6)	(0-10)
	Mass Fraction :	0.980	0.980	0.980

Total Particulate Matter -

	Species		Emission Factors			
CAS Number	No	Sym	0-2.5 um	2.5-10 um	0-10 um	Total Particulate
7440-41-7	4	Be	0.00141	0.00000	0.00141	NA
7440-42-8	5	B	0.01764	0.00000	0.01764	NA
7782-41-4	9	F	0.11290	0.00000	0.11290	0.16380
7440-23-5	11	Na	0.51227	0.00000	0.51227	NA
7439-95-4	12	Mg	0.08044	0.00000	0.08044	NA
7429-90-5	13	Al	0.09949	0.00000	0.09949	0.11542
7440-21-3	14	Si	0.06421	0.00000	0.06421	0.08460
7723-14-0	15	P	0.05363	0.00000	0.05363	0.06163
7704-34-9	16	S	0.18346	0.00000	0.18346	0.19742
7782-50-5	17	Cl	1.43942	0.00000	1.43942	1.40616
7440-09-7	19	K	1.15013	0.00000	1.15013	1.11636
7440-70-2	20	Ca	0.26107	0.00000	0.26107	0.29664
7440-32-6	22	Ti	0.00339	0.00000	0.00339	0.00403
7440-62-2	23	V	0.00035	0.00000	0.00035	0.00065
7440-47-3	24	Cr	0.00056	0.00000	0.00056	0.00065
7439-96-5	25	Mn	0.02399	0.00000	0.02399	0.02686
7439-89-6	26	Fe	0.06915	0.00000	0.06915	0.07711
7440-48-4	27	Co	0.00423	0.00000	0.00423	NA
7440-02-0	28	Ni	0.00035	0.00000	0.00035	0.00036
7440-50-8	29	Cu	0.00261	0.00000	0.00261	0.00238
7440-66-6	30	Zn	0.04516	0.00000	0.04516	0.04327
7440-38-2	33	As	0.00198	0.00000	0.00198	0.00180
7782-49-2	34	Se	0.00014	0.00000	0.00014	0.00014
7726-95-6	35	Br	0.01277	0.00000	0.01277	0.01260
7440-17-7	37	Rb	0.00318	0.00000	0.00318	0.00324
7440-24-6	38	Sr	0.00247	0.00000	0.00247	0.00288

PM Speciated Emission Factor Profile continued (profile 12704)

	Species		Emission Factors			
CAS Number	No	Sym	0-2.5 um	2.5-10 um	0-10 um	Total Particulate
7440-67-7	40	Zr	0.00056	0.00000	0.00056	0.00079
7439-98-7	42	Mo	0.00176	0.00000	0.00176	0.00216
7440-05-3	46	Pd	0.00028	0.00000	0.00028	0.00043
7440-22-4	47	Ag	0.00049	0.00000	0.00049	0.00072
7440-43-9	48	Cd	0.00014	0.00000	0.00014	0.00050
7440-74-6	49	In	0.00071	0.00000	0.00071	0.00108
7440-31-5	50	Sn	0.00092	0.00000	0.00092	0.00137
7440-36-0	51	Sb	0.00169	0.00000	0.00169	0.00209
7440-39-3	56	Ba	0.00388	0.00000	0.00388	0.00626
7439-91-0	57	La	0.00459	0.00000	0.00459	0.00742
7440-45-1	58	Ce	0.00028	0.00000	0.00028	0.00036
7439-97-6	80	Hg	0.01454	0.00000	0.01454	0.01512
7439-92-1	82	Pb	0.09173	0.00000	0.09173	NA
	201	OC	0.39514	0.00000	0.39514	0.50904
	202	EC	0.32458	0.00000	0.32458	0.32040
	203	SO4	0.49392	0.00000	0.49392	0.52452
	204	NO3	0.00600	0.00000	0.00600	0.00965

Profile Number : 12704
Profile Name : Wood-Fired Boiler
Profile Quality : B/D

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149 Cooper, J. A., C. A. Frazier, and J. E. Houck. Seattle-Tacoma Aerosol Characterization Study (STACS). Draft Final Report to the Puget Sound Air Pollution Control Agency by NEA, Inc. 1983.

REPORT NO.: 192-91-10

PROJECT: 1121-001

DATE: February 28, 1991

TYPE: EMISSION TEST REPORT

EMISSION TEST RESULTS
NO. 1 AND 2 BARK BOILERS
AND NO. 1, 2, AND 3 RECOVERY BOILERS
SEMINOLE KRAFT CORPORATION
JACKSONVILLE, FLORIDA

AUTHOR: Jeffrey W. Burdette

FIELD TEAM: J. Burdette, K. Krick, D. Prater, C. Johnson, T. Drake, J. Morgan, D. Bellware

PREPARED FOR:
Seminole Kraft Corporation
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Jacksonville, FL 32218

TABLE 2.1.3
NO.1 BARK BOILER
METALS SUMMARY

Run No.	1	2	3	4	5	AVG
Date	1/7/91	1/8/91	1/8/91	1/8/91	1/8/91	
Stack Flow Rate, dscfm	95,609	99,961	96,893	92,695	99,450	96,922
Sample Volume, dscf	30.123	37.070	37.302	39.347	42.390	37.246
ANTIMONY (Sb)						
Quantity Collected, ug	0.0	0.0	0.0	0.0	0.0	0.0
Concentration, ug/dscf	0.0	0.0	0.0	0.0	0.0	0.0
Emission Rate, lb/hr	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
ARSENIC (As)						
Quantity Collected, ug	0.0	0.0	0.0	0.0	0.0	0.0
Concentration, ug/dscf	0.0	0.0	0.0	0.0	0.0	0.0
Emission Rate, lb/hr	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
BARIUM (Ba)						
Quantity Collected, ug	8.0	30.0	257.0	0.0	0.0	59.0
Concentration, ug/dscf	0.3	0.8	6.9	0.0	0.0	1.6
Emission Rate, lb/hr	0.0034	0.0107	0.0882	0.0000	0.0000	0.0205
BERYLLIUM (Be)						
Quantity Collected, ug	0.0	0.0	0.0	0.0	0.0	0.0
Concentration, ug/dscf	0.0	0.0	0.0	0.0	0.0	0.0
Emission Rate, lb/hr	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CADMIUM (Cd)						
Quantity Collected, ug	6.0	2.0	7.0	2.0	0.0	3.4
Concentration, ug/dscf	0.2	0.1	0.2	0.1	0.0	0.1
Emission Rate, lb/hr	0.0025	0.0007	0.0024	0.0006	0.0000	0.0013
CHROMIUM (Cr)						
Quantity Collected, ug	10.0	11.0	8.0	5.0	5.0	7.8
Concentration, ug/dscf	0.3	0.3	0.2	0.1	0.1	0.2
Emission Rate, lb/hr	0.0042	0.0039	0.0027	0.0016	0.0016	0.0028
COPPER (Cu)						
Quantity Collected, ug	17.0	23.0	21.0	21.0	19.0	20.2
Concentration, ug/dscf	0.6	0.6	0.6	0.5	0.4	0.5
Emission Rate, lb/hr	0.0071	0.0082	0.0072	0.0065	0.0059	0.0070
LEAD (Pb)						
Quantity Collected, ug	32.0	34.0	30.0	26.0	28.0	30.0
Concentration, ug/dscf	1.1	0.9	0.8	0.7	0.7	0.8
Emission Rate, lb/hr	0.0134	0.0121	0.0103	0.0081	0.0087	0.0105

(continued)

TABLE 2.1.3 (CONTINUED)
NO.1 BARK BOILER
METALS SUMMARY

Run No.	1	2	3	4	5	AVG
Date	1/7/91	1/8/91	1/8/91	1/8/91	1/8/91	
Stack Flow Rate, dscfm	95,609	99,961	96,893	92,695	99,450	96,922
Sample Volume, dscf	30.123	37.070	37.302	39.347	42.390	37.246
MANGANESE (MN)						
Quantity Collected, ug	29.0	24.0	19.0	24.0	24.0	24.0
Concentration, ug/dscf	1.0	0.6	0.5	0.6	0.6	0.7
Emission Rate, lb/hr	0.0122	0.0086	0.0065	0.0075	0.0074	0.0084
MERCURY (Hg)						
Quantity Collected (FH), u	0.0	0.0	0.0	0.0	0.0	0.0
Quantity Collected (KMn	0.0	0.0	0.0	1.7	1.1	0.6
Concentration, ug/dscf	0.0	0.0	0.0	0.0	0.0	0.0
Emission Rate, lb/hr	0.0000	0.0000	0.0000	0.0005	0.0003	0.0002
NICKEL (Ni)						
Quantity Collected, ug	33.0	42.0	30.0	60.0	36.0	40.2
Concentration, ug/dscf	1.1	1.1	0.8	1.5	0.8	1.1
Emission Rate, lb/hr	0.0138	0.0150	0.0103	0.0187	0.0112	0.0138
PHOSPHORUS (P)						
Quantity Collected, ug	145.0	197.0	156.0	180.0	199.0	175.4
Concentration, ug/dscf	4.8	5.3	4.2	4.6	4.7	4.7
Emission Rate, lb/hr	0.0608	0.0702	0.0536	0.0560	0.0617	0.0605
SELENIUM (Se)						
Quantity Collected, ug	0.0	0.0	0.0	0.0	0.0	0.0
Concentration, ug/dscf	0.0	0.0	0.0	0.0	0.0	0.0
Emission Rate, lb/hr	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
SILVER (Ag)						
Quantity Collected, ug	38.0	32.0	0.0	0.0	0.0	14.0
Concentration, ug/dscf	1.3	0.9	0.0	0.0	0.0	0.4
Emission Rate, lb/hr	0.0159	0.0114	0.0000	0.0000	0.0000	0.0055
THALLIUM (Tl)						
Quantity Collected, ug	0.0	0.0	0.0	0.0	0.0	0.0
Concentration, ug/dscf	0.0	0.0	0.0	0.0	0.0	0.0
Emission Rate, lb/hr	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
ZINC (Zn)						
Quantity Collected, ug	378.0	508.0	457.0	446.0	447.0	447.2
Concentration, ug/dscf	12.5	13.7	12.3	11.3	10.5	12.1
Emission Rate, lb/hr	0.1586	0.1810	0.1569	0.1389	0.1386	0.1548

TABLE 2.2.3
NO. 2 BARK BOILER
METALS SUMMARY

Run No.	1	2	3	AVG
Date	1/9/91	1/9/91	1/9/91	
Stack Flow Rate, dscfm	81,699	79,254	81,372	80,775
Sample Volume, dscf	36.816	34.592	34.709	35.372
ANTIMONY (Sb)				
Quantity Collected, ug	0.0	0.0	0.0	0.0
Concentration, ug/dscf	0.0	0.0	0.0	0.0
Emission Rate, lb/hr	0.0000	0.0000	0.0000	0.0000
ARSENIC (As)				
Quantity Collected, ug	0.0	0.0	0.0	0.0
Concentration, ug/dscf	0.0	0.0	0.0	0.0
Emission Rate, lb/hr	0.0000	0.0000	0.0000	0.0000
BARIUM (Ba)				
Quantity Collected, ug	34.0	36.0	4.0	24.7
Concentration, ug/dscf	0.9	1.0	0.1	0.7
Emission Rate, lb/hr	0.0100	0.0109	0.0012	0.0074
BERYLLIUM (Be)				
Quantity Collected, ug	0.0	0.0	0.0	0.0
Concentration, ug/dscf	0.0	0.0	0.0	0.0
Emission Rate, lb/hr	0.0000	0.0000	0.0000	0.0000
CADMIUM (Cd)				
Quantity Collected, ug	2.0	3.0	2.0	2.3
Concentration, ug/dscf	0.1	0.1	0.1	0.1
Emission Rate, lb/hr	0.0006	0.0009	0.0006	0.0007
CHROMIUM (Cr)				
Quantity Collected, ug	9.0	8.0	17.0	11.3
Concentration, ug/dscf	0.2	0.2	0.5	0.3
Emission Rate, lb/hr	0.0026	0.0024	0.0053	0.0034
COPPER (Cu)				
Quantity Collected, ug	21.0	25.0	14.0	20.0
Concentration, ug/dscf	0.6	0.7	0.4	0.6
Emission Rate, lb/hr	0.0062	0.0076	0.0043	0.0060
LEAD (Pb)				
Quantity Collected, ug	52.0	42.0	18.0	37.3
Concentration, ug/dscf	1.4	1.2	0.5	1.0
Emission Rate, lb/hr	0.0153	0.0127	0.0056	0.0112

(continued)

TABLE 2.2.3 (CONTINUED)
NO. 2 BARK BOILER
METALS SUMMARY

Run No.	1	2	3	AVG
Date	1/9/91	1/9/91	1/9/91	
Stack Flow Rate, dscfm	81,699	79,254	81,372	80,775
Sample Volume, dscf	36.816	34.592	34.709	35.372
MANGANESE (MN)				
Quantity Collected, ug	29.0	39.0	44.0	37.3
Concentration, ug/dscf	0.8	1.1	1.3	1.1
Emission Rate, lb/hr	0.0085	0.0118	0.0136	0.0113
MERCURY (Hg)				
Quantity Collected (FH), ug	0.0	0.0	0.0	0.0
Quantity Collected (KMnO4	1.2	0.0	0.0	0.4
Concentration, ug/dscf	0.0	0.0	0.0	0.0
Emission Rate, lb/hr	0.0004	0.0000	0.0000	0.0001
NICKEL (Ni)				
Quantity Collected, ug	36.0	38.0	24.0	32.7
Concentration, ug/dscf	1.0	1.1	0.7	0.9
Emission Rate, lb/hr	0.0106	0.0115	0.0074	0.0098
PHOSPHORUS (P)				
Quantity Collected, ug	201.0	218.0	233.0	217.3
Concentration, ug/dscf	5.5	6.3	6.7	6.2
Emission Rate, lb/hr	0.0589	0.0660	0.0722	0.0657
SELENIUM (Se)				
Quantity Collected, ug	0.0	0.0	0.0	0.0
Concentration, ug/dscf	0.0	0.0	0.0	0.0
Emission Rate, lb/hr	0.0000	0.0000	0.0000	0.0000
SILVER (Ag)				
Quantity Collected, ug	0.0	0.0	0.0	0.0
Concentration, ug/dscf	0.0	0.0	0.0	0.0
Emission Rate, lb/hr	0.0000	0.0000	0.0000	0.0000
THALLIUM (Tl)				
Quantity Collected, ug	0.0	0.0	0.0	0.0
Concentration, ug/dscf	0.0	0.0	0.0	0.0
Emission Rate, lb/hr	0.0000	0.0000	0.0000	0.0000
ZINC (Zn)				
Quantity Collected, ug	426.0	517.0	370.0	437.7
Concentration, ug/dscf	11.6	14.9	10.7	12.4
Emission Rate, lb/hr	0.1249	0.1565	0.1146	0.1320

APPENDIX B

DERIVATIONS OF EMISSION FACTORS FOR BASELINE EMISSIONS FOR EXISTING FACILITY

All pollutant emissions are expressed in terms of lb/MMBtu, lb/ton/ or lb/lb steam for bagasse, and in terms of lb/1000 gal for fuel oil. The basis for the emission factors is presented below.

A. BAGASSE

1. PM: Emission factors are determined from PM stack tests and measured steam production.

For a given boiler:

Total lb steam/yr x Btu bagasse/Btu total x lb PM/lb steam
x ton/2,000 lb = total PM (TPY) bagasse

where lb PM/lb steam is computed as follows:

PM (lb/hr) test ÷ average steam (lb/hr)test = lb PM/lb steam

A test was conducted on each boiler in 1990 and 1991. PM emissions and steam production were measured.

Activity factors for bagasse are equivalent to total steam production multiplied by the Btu contribution of bagasse with respect to total Btu input for steam generation.

Sample calculation:

Boiler No. 4, 1991

40.28 PM (lb/hr)test ÷ 115,754 Avg Steam(lb/hr)test
= $3.48\text{x}10^{-4}$ lb PM/lb steam

Btu bagasse = 72,531 tons bagasse x 2,000 lb/ton x 4250 Btu/lb bagasse
= $6.165\text{x}10^{11}$ Btu bagasse
Btu total = $6.165\text{x}10^{11}$ + (76,517 gal oil x 150,000 Btu/gal oil)
= $6.280\text{x}10^{11}$ Btu total

PM (TPY) = $2.8436\text{x}10^{8}$ lb steam/yr x 6.165/6.280 = $2.792\text{x}10^{8}$ lb steam/yr due to bagasse

0.000348 lb PM/lb steam x $2.792\text{x}10^{8}$ x 1 ton/2,000 lb
= 48.57 TPY

2. SO_2: Industry data indicate an average of 0.006% sulfur (dry basis) and 50% moisture in bagasse. This is equivalent to 0.003%, wet basis. Test data also

indicate SO_2 removal in the wet scrubbers when burning bagasse, estimated at 60%. The emission factor is:

1 ton bagasse x 2,000 lb/ton x 0.00003 lb S/lb x 2 lb SO_2/lb S x (1-0.60)
=0.048 lb/ton.

Sample calculation: Activity factor = 731,158 tons bagasse/yr

SO_2 (TPY) = 0.048 lb/ton x 731,158 TPY bagasse x ton/2,000 lb
= 17.5 TPY

3. NO_x: The emission factor used is an average of emission factors taken between industry test data (KBN, 1990) for traveling gate boilers for bagasse and EPA AP-42.

Industry test data (KBN, 1990) range up to 0.33 lb NO_x/MMBtu
EPA-42 : 0.14 lb/MMBtu
Average = (0.33 + 0.14)/2 = 0.235 lb NO_x/MMBtu

Sample calculation: 731,158 TPY bagasse x 2,000 lb/ton x 4,250 Btu/lb
= 6.2148×10^6 MMBtu

1991-1992 Crop Year: Activity Factor = 6.2148×10^6 MMBtu

NO_x (TPY) = 6.2148×10^6 MMBtu x 0.235 lb/MMBtu x ton/2,000 lb
= 730.2 TPY

4. CO: The emission factor used is based upon industry test data. The emission factor is 29 lb/ton.

Sample calculation:

1991-1992 Crop Year: Activity Factor = 731,158 tons bagasse

CO (TPY) = 731,158 tons bagasse x 29 lb/ton bagasse x ton/2,000 lb
= 10,601.8 TPY

5. VOC: The emission factor used is based on a compilation of industry stack test data. The emission factor is 1.02 lb/ton.

Sample calculation:

1991-1992 Crop Year: Activity Factor = 731,158 ton bagasse

VOC (TPY) = 731,158 ton bagasse x 1.02 lb/ton x ton/2,000 lb
= 372.9 TPY

6. **Hg**: Bill Patrick, LSU, obtained 17 samples of dead sugar cane leaves in Oct.-Dec, 1991. The average Hg content was 0.068 ppm Hg (dry), or 0.033 ppm at 51.7% moisture. These are considered to be representative of bagasse, which is dead sugar cane stalks. The resulting emission factor is:

2,000 lb/ton x 0.033 ppm (wet) = $6.6\text{x}10^{-5}$ lb/ton (wet)

Sample calculation:

1991-1992 Crop Year: Activity Factor = 731,158 tons bagasse

Hg(TPY) = $6.60\text{x}10^{-5}$ lb/ton x 731,158 TPY x ton/2,000 lb

= 0.02413 TPY

7. **Lead**: No emission factor is available for bagasse. Tests conducted at Seminole Kraft Corporation (SKC) in Jacksonville, Florida (1990) provide an emission factor for lead from wood-fired boilers with a wet scrubber. The emission factor is 0.00077 lb/ton.

Sample calculation: Activity Factor = 731,158 tons bagasse

Lead (TPY) = 0.00077 lb/ton x 731,158 TPY x ton/2,000 lb = 0.2815 TPY

8. **Beryllium, Fluoride**: No detectable amounts of beryllium were measured during the SKC emission tests on wood-fired boilers in 1990. An emission factor for fluorides is not available for wood- or bagasse-fired boilers.

9. **Sulfuric Acid Mist**: From EPA Publication AP-42, sulfuric acid mist emissions are equivalent to 3 percent of SO_2 emissions. This factor was used directly to convert total SO_2 emissions into sulfuric acid mist emissions.

B. <u>No. 6 Fuel Oil</u>:

1. **PM**: The emission factor is taken from EPA AP-42 using a 2.5% sulfur content by weight. This is the sulfur content of oil burned at Okeelanta.

AP-42: 28 lb PM/1,000 gal

Sample calculation:

1991 Boilers 4-15: Activity Factor= 3,351.20 thousand gal

PM (TPY) = 28 lb/1,000 gal x 3,351.20 (1,000 gal)/yr x ton/2,000 lb

= 46.92 TPY

2. **SO_2, NO_x, CO, VOC**: The emission factors are based on EPA AP-42.

SO_2: 392.5 lb/1,000 gal (157 x 2.5)

NO_x: 67 lb/1,000 gal

CO: 5 lb/1,000 gal

VOC: 0.76 lb/1,000 gal

Sample calculation:

1991-1992 Crop Year Boilers 4-15: Activity Factor = 2,937.531 thousand gal

SO_2 (TPY) = 392.5 x 2,937.531 ÷ 2,000 = 576.5 TPY

3. **Hg**: The emission factor is based on average Hg content of No. 6 fuel oil. The emission factor is 0.00055 lb/1,000 gal

Sample calculation: Activity Factor = 2,937.531 thousand gallons/yr

Hg (TPY) = 0.00055 lb/1,000 gal x 2,937.531 (1,000 gal)/yr x ton/2,000 lb
= 0.00081 TPY

4. **Beryllium, Lead**: The emission factors are obtained from Toxic Air Pollutant Emission Factors , Second Edition EPA publication EPA-450/2-90-011 (1990).

The emission factors are: Lead = 0.0042 lb/1,000 gal
Beryllium = 0.000038 lb/1,000 gal

Sample calculation: Activity Factor = 2,937.531 thousand gallons/yr

Lead (TPY) = 0.0042 lb/1,000 gal x 2,937.531 (1,000 gal)/yr x ton/2,000 lb
= 0.0062 TPY

5. **Fluoride**: The emission factor is obtained from Emissions Assessment of Conventional Stationary Combustion Systems: Volume V EPA Publication EPA 600/7-81-0-003 (1981). The emission factor is 0.018 lb/1000 gal

Sample calculation: Activity Factor = 2,937.531 thousand gallons/yr

Fluoride (TPY) = 0.018 lb/1,000 gal x 2,937.531 (1,000 gal)/yr
x ton/2,000 lb = 0.026 TPY

9. **Sulfuric Acid Mist**: From EPA Publication AP-42, sulfuric acid mist emissions are equivalent to 3 percent of SO_2 emissions.

Sample calculation: Activity Factor = SO_2 (1991-1992) = 576.5 TPY

Sulfuric Acid Mist (TPY) = 576.5 x 0.03 = 17.30 TPY

C. TOTAL EMISSIONS

Total emissions for each pollutant is the sum of emissions due to bagasse firing and emissions due to fuel oil firing. For PM10, industry test data indicate approximately 90% of PM emissions are PM10:

$$PM10 = PM(TSP) \times 0.90$$

Table B-1. Baseline Particulate Emissions for Okeelanta Corporation

	No. 6 Oil				Bagasse				
Source Description	Particulate Emission Factor (lb/1000 gal)	Ref	Activity Factor (1000 gal/yr)	Particulate Emissions (TPY)	Particulate Emission Factor (lb PM/lb steam)	Ref	Activity Factor (#steam/yr)	Particulate Emissions (TPY)	Total Particulate Emissions (TPY)
1991									
Boiler No. 4	28	1	76.52	1.07	3.48E-04	2	2.792E+08	48.57	49.64
Boiler No. 5	28	1	233.17	3.26	4.71E-04	2	3.391E+08	79.83	83.10
Boiler No. 6	28	1	241.63	3.38	3.85E-04	2	1.690E+08	32.54	35.92
Boiler No. 10	28	1	397.90	5.57	4.07E-04	2	2.752E+08	55.96	61.53
Boiler No. 11	28	1	370.44	5.19	4.03E-04	2	3.409E+08	68.70	73.89
Boiler No. 12	28	1	489.54	6.85	3.11E-04	2	3.955E+08	61.50	68.36
Boiler No. 14	28	1	779.64	10.91	3.39E-04	2	4.180E+08	70.94	81.86
Boiler No. 15	28	1	762.37	10.67	3.66E-04	2	3.182E+08	58.24	68.92
			3,351.20	46.92			2.535E+09	476.30	523.22
1990									
Boiler No. 4	28	1	43.94	0.62	3.22E-04	2	1.974E+08	31.81	32.42
Boiler No. 5	28	1	67.23	0.94	3.81E-04	2	3.170E+08	60.46	61.40
Boiler No. 6	28	1	165.04	2.31	1.55E-04	2	1.834E+08	14.19	16.50
Boiler No. 10	28	1	252.29	3.53	3.86E-04	2	2.716E+08	52.43	55.96
Boiler No. 11	28	1	183.64	2.57	3.76E-04	2	3.153E+08	59.27	61.84
Boiler No. 12	28	1	344.42	4.82	3.11E-04	2	3.253E+08	50.55	55.37
Boiler No. 14	28	1	546.08	7.65	2.36E-04	2	3.209E+08	37.81	45.46
Boiler No. 15	28	1	336.82	4.72	2.98E-04	2	2.969E+08	44.30	49.02
			1,939.46	27.15			2.228E+09	350.82	377.97
Average									
Boiler No. 4				0.84	-	-	-	40.19	41.03
Boiler No. 5				2.10	-	-	-	70.15	72.25
Boiler No. 6				2.85	-	-	-	23.37	26.21
Boiler No. 10				4.55	-	-	-	54.19	58.75
Boiler No. 11				3.88	-	-	-	63.98	67.86
Boiler No. 12				5.84	-	-	-	56.03	61.86
Boiler No. 14				9.28	-	-	-	54.38	63.66
Boiler No. 15				7.69	-	-	-	51.27	58.96
Boiler No. 16 *									23.10
								Total	473.69

References/Notes:

1. Compilation of Air Pollutant Emission Factors AP-42, Section 1.3. Oil sulfur content is 2.5% by weight.
2. Emission factors from stack tests and steam production during tests.

* This boiler is permitted but just began operation in July 1992. Baseline emissions are therefore equivalent to the maximum permitted emission rate.

Table B-2. Computation of Baseline PM Emission Factors from stack tests

Blr #	1991 data Avg Steam flow (#/hr)	1991 data Part emis (#/hr)	1991 data Emis Factor (#part/#steam)	1990 data Avg Steam flow (#/hr)	1990 data Part emis (#/hr)	1990 data Emis Factor (#part/#steam)
4	115,754	40.28	3.48E-04	97,289	31.36	3.22E-04
5	107,323	50.54	4.71E-04	124,081	47.33	3.81E-04
6	74,687	28.77	3.85E-04	102,831	15.92	1.55E-04
10	94,831	38.57	4.07E-04	96,757	37.35	3.86E-04
11	98,715	39.79	4.03E-04	123,652	46.48	3.76E-04
12	137,107			125,501	39.00	3.11E-04
14	143,515	48.72	3.39E-04	143,035	33.71	2.36E-04
15	115,994	42.47	3.66E-04	93,002	27.75	2.98E-04

Note: No Particulate emission tests were available for Boiler 12 in 1991. Emission factor used is the same as Boiler No. 12 for 1990.

Table B-3. Activity Factors used in PM emission factor determination

	Bagasse		Oil			Total Steam (lbs)		
Blr #	tons	Btu	gals	Btu	Total Btu	Total	Bagasse	Oil
				1991				
4	72,531	6.17E+11	76,517	1.15E+10	6.28E+11	2.84E+08	2.79E+08	5.20E+06
5	87,597	7.45E+11	133,172	2.00E+10	7.65E+11	3.48E+08	3.39E+08	9.10E+06
6	46,825	3.98E+11	241,625	3.62E+10	4.34E+11	1.86E+08	1.70E+08	1.55E+07
10	75,915	6.45E+11	397,897	5.97E+10	7.05E+11	3.00E+08	2.75E+08	2.54E+07
11	91,454	7.77E+11	370,439	5.56E+10	8.33E+11	3.65E+08	3.41E+08	2.43E+07
12	106,470	9.05E+11	489,535	7.34E+10	9.78E+11	4.28E+08	3.96E+08	3.21E+07
14	111,028	9.44E+11	779,641	1.17E+11	1.06E+12	4.43E+08	3.94E+08	4.88E+07
15	90,685	7.71E+11	762,369	1.14E+11	8.85E+11	3.65E+08	3.18E+08	4.71E+07
				1990				
4	53,478	4.55E+11	43,736	6.56E+09	4.61E+11	2.03E+08	2.00E+08	2.89E+06
5	85,607	7.28E+11	67,228	1.01E+10	7.38E+11	3.21E+08	3.17E+08	4.39E+06
6	50,370	4.28E+11	165,043	2.48E+10	4.53E+11	1.94E+08	1.83E+08	1.06E+07
10	74,910	6.37E+11	252,293	3.78E+10	6.75E+11	2.88E+08	2.72E+08	1.61E+07
11	86,591	7.36E+11	183,639	2.75E+10	7.64E+11	3.27E+08	3.15E+08	1.18E+07
12	91,232	7.75E+11	344,424	5.17E+10	8.27E+11	3.46E+08	3.25E+08	2.16E+07
14	93,148	7.92E+11	546,075	8.19E+10	8.74E+11	3.54E+08	3.21E+08	3.32E+07
15	84,322	7.17E+11	336,824	5.05E+10	7.67E+11	3.18E+08	2.97E+08	2.09E+07

Notes: Heating value of No. 6 Fuel Oil = 150,000 Btu/gal
Heating value of bagasse = 4,250 Btu/lb

Table B-4. Baseline SO2 Emissions for Okeelanta Corporation

	No. 6 Fuel Oil				Bagasse				
Crop Year	SO2 Emission Factor (lb/1000 gal)	Ref.	Activity Factor (1000 gal/yr)	Annual SO2 Emissions (TPY)	SO2 Emission Factor (lb/ton)	Ref.	Activity Factor (TPY)	Annual SO2 Emissions (TPY)	Total SO2 Emissions (TPY)
1991-1992									
Boilers 4-15	392.5	1	2,937.531	576.5	0.048	2	731,158	17.5	594.0
1990-1991									
Boilers 4-15	392.5	1	3,160.529	620.3	0.048	2	688,747	16.5	636.8
Average									
Boilers 4-15				598.372				17.0	615.4
Boiler 16*									132.9
								Total=	748.3

References/Notes:

1. Compilation of Air Pollutant Emission Factors, AP-42, Section 1.3, September 1988, with an oil sulfur content of 2.5% by weight.

2. Based on a sulfur content for bagasse of 0.006% by weight, dry basis, 50% moisture as fired and a control system efficiency of 60% Activity factor is based on wet bagasse fired.

* This boiler is permitted but just began operation in July 1992. Baseline emissions are therefore equivalent to the maximum permitted emission rate.

Table B-5. Baseline NOx Emissions for Okeelanta Corporation

	No. 6 Fuel Oil				Bagasse					Total Annual Emissions (TPY)
Crop Year	NOx Emission Factor (lb/1000 gal)	Ref.	Activity Factor (1000 gal/yr)	Annual NOx Emissions (TPY)	NOx Emission Factor (lb/MMBtu)	Ref.	Activity Factor (TPY)	Activity Factor (Btu/yr)	Annual Emissions (TPY)	
1991-1992										
Boilers 4-15	67	1	2,937.531	98.4	0.235	2	731,158	6.21E+12	730.2	828.7
1990-1991										
Boilers 4-15	67	1	3,160.529	105.9	0.235	2	688,747	5.85E+12	687.9	793.8
Average										
Boilers 4-15				102.1					709.1	811.2
Boiler 16*										77.5
									Total=	888.7

References/Notes:

1. Compilation of Air Pollutant Emission Factors, AP-42, Section 1.3, September 1988.
2. Based on average between AP-42 emission factor and industry test data for bagasse fired boilers.

* This boiler is permitted but just began operations in July 1992. Baseline emission are therefore equivalent to the maximum permitted emission rate.

Table B-6. Baseline CO Emissions for Okeelanta Corporation

Crop Year	No. 6 Fuel Oil CO Emission Factor (lb/1000 gal)	Ref.	Activity Factor (1000 gal/yr)	Annual CO Emissions (TPY)	Bagasse CO Emission Factor (lb/ton)	Ref.	Activity Factor (TPY)	Annual CO Emissions (TPY)	Total Annual CO Emissions (TPY)
1991-1992									
Boilers 4-15	5	1	2,937.531	7.3	29	2	731,158	10,601.8	10,609.1
1990-1991									
Boilers 4-15	5	1	3,160.529	7.9	29	2	688,747	9,986.8	9,994.7
Average									
Boilers 4-15				7.6				10,294.3	10,301.9
Boiler 16*									86.1
								Total=	10,388.0

References/Notes:

1. Compilation of Air Pollutant Emission Factors, AP-42, Section 1.3, September 1988.

2. Based on sugar industry test data.

* This boiler is permitted but just began operation in July 1992. Baseline emissions are therefore equivalent to the maximum emission rate.

Table B-7. Baseline VOC Emissions for Okeelanta Corporation

	No. 6 Fuel Oil				Bagasse				
Crop Year	VOC Emission Factor (lb/1000 gal)	Ref.	Activity Factor (1000 gal/yr)	Annual VOC Emissions (TPY)	VOC Emission Factor (lb/ton)	Ref.	Activity Factor (TPY)	Annual VOC Emissions (TPY)	Total Annual VOC Emissions (TPY)
1991-1992									
Boilers 4-15	0.76	1	2,937.531	1.1	1.02	2	731,158	372.9	374.0
1990-1991									
Boilers 4-15	0.76	1	3,160.529	1.2	1.02	2	688,747	351.3	352.5
Average									
Boilers 4-15				1.16				362.1	363.2
Boiler 16*									38.7
								Total=	401.9

References/Notes:

1. Compilation of Air Pollutant Emission Factors, AP-42, Section 1.3, September 1988.

2. Based on a compilation of stack test data for bagasse fired boilers.

* This boiler is permitted but just began operation in July 1992. Baseline emissions are therefore equivalent to the maximum permitted emission rate.

Table B-8. Baseline Mercury Emissions for Okeelanta Corporation

	No. 6 Fuel Oil				Bagasse				
Crop Year	Hg Emission Factor (lb/1000 gal)	Ref.	Activity Factor (1000 gal/yr)	Annual Hg Emissions (TPY)	Hg Emission Factor (lb/ton)	Ref.	Activity Factor (TPY)	Annual Hg Emissions (TPY)	Total Hg Emissions (TPY)
1991-1992									
Boilers 4-15	0.00055	1	2,937.531	0.00081	6.6E-05	2	731,158	0.02413	0.02494
1990-1991									
Boilers 4-15	0.00055	1	3,160.529	0.00087	6.6E-05	2	688,747	0.02273	0.02360
Average									
Boilers 4-15				0.00084				0.02343	0.02427
Boiler 16*									0.00130
								Total=	0.0256

References/Notes:

1. Based on average Hg content of No. 6 fuel oil.
2. Based on a mercury content of dead cane leaves of 0.068 ppm (dry) and 51.7% moisture. No removal credit taken for wet scrubbers. Activity factor is based on wet bagasse.

* This boiler is permitted but just began operation in July 1992. Baseline emissions are therefore equivalent to the maximum permitted emission rate.

Table B-9. Baseline Beryllium Emissions for Okeelanta Corporation

	No. 6 Fuel Oil				Bagasse				
Crop Year	Beryllium Emission Factor (lb/1000 gal)	Ref.	Activity Factor (1000 gal/yr)	Annual Beryllium Emissions (TPY)	Beryllium Emission Factor (lb/ton)	Ref.	Activity Factor (TPY)	Annual Beryllium Emissions (TPY)	Total Beryllium Emissions (TPY)
1991-1992									
Boilers 4-15	0.000038	1	2,937.531	0.000055	0	2	731,158	0.0	0.000055
1990-1991									
Boilers 4-15	0.000038	1	3,160.529	0.000059	0	2	688,747	0.0	0.000059
Average									
Boilers 4-15				0.000057				0.0	0.000057
Boiler 16*									0.000340
									Total=0.000397

References/Notes:

1. Toxic Air Pollutant Emission Factors (EPA-450/2-90-011) (1990)
2. Emission tests for Seminole Kraft (1990) and TAPPI Proceedings (1990).

* This boiler is permitted but just began operation in July 1992. Baseline emissions are therefore equivalent to the maximum permitted emission rate.

Table B-10. Baseline Fluoride Emissions for Okeelanta Corporation

	No. 6 Fuel Oil				Bagasse				
Crop Year	Fluoride Emission Factor (lb/1000 gal)	Ref.	Activity Factor (1000 gal/yr)	Annual Fluoride Emissions (TPY)	Fluoride Emission Factor (lb/ton)	Ref.	Activity Factor (TPY)	Annual Fluoride Emissions (TPY)	Total Fluoride Emissions (TPY)
1991-1992									
Boilers 4-15	0.018	1	2,937.531	0.026	0	2	731,158	0.0	0.0260
1990-1991									
Boilers 4-15	0.018	1	3,160.529	0.028	0	2	688,747	0.0	0.0280
Average									
Boilers 4-15				0.027				0.0	0.0270
Boiler 16*									0.0170
								Total=	0.0440

References/Notes:

1. Emissions Assessment of Conventional Stationary Combustion Systems: Volume V:Industrial Combustion Sources EPA-600/7-81-0-003 (1981).

2. No emission factor for bagasse or wood is available.

* This boiler is permitted but just began operation in July 1992. Baseline emissions are therefore equivalent to the maximum permitted emission rate.

Table B-11. Baseline Lead Emissions for Okeelanta Corporation

	No. 6 Fuel Oil				Bagasse				
Crop Year	Lead Emission Factor (lb/1000 gal)	Ref.	Activity Factor (1000 gal/yr)	Annual Lead Emissions (TPY)	Lead Emission Factor (lb/ton)	Ref.	Activity Factor (TPY)	Annual Lead Emissions (TPY)	Total Lead Emissions (TPY)
1991-1992									
Boilers 4-15	0.0042	1	2,937.531	0.0062	0.00077	2	731,158	0.2797	0.2858
1990-1991									
Boilers 4-15	0.0042	1	3,160.529	0.0066	0.00077	2	688,747	0.2634	0.2701
Average									
Boilers 4-15				6.4E-03				0.3	0.2780
Boiler 16*									0.0038
								Total=	0.2818

References/Notes:

1. Toxic Air Pollutant Emission Factors (EPA-450/2-90-011) (1990).

2. No data available for bagasse; based on testing on wood fired boiler at Seminole Kraft Corp (1990)

* This boiler is permitted but just began operation in July 1992. Baseline emissions are therefore equivalent to the maximum permitted emission rate.

Table B-12. Summary of NO_x Emission Tests Performed on Bagasse Boilers in Florida

Unit	Boiler Type	Date	Steam Rate (lb/hr)	Heat Input Rate (MMBtu/hr)	Bagasse Burning Rate[a] (TPH wet)	NO_x Emissions		
						lb/hr	lb/MMBtu	lb/ton,wet
Atlantic Sugar Association								
Boiler 3	Horseshoe	03/19/80	92,868	160.2	22.25	27.7	0.17	1.24
Boiler 4	Horseshoe	03/18/80	91,833	158.4	22.00	31.8	0.20	1.45
Boiler 5	Traveling Grate	03/21/83	108,000	201	27.92	25.9	0.13	0.93
Boiler 5	Traveling Grate	03/21/83	98,000	183	25.42	15.7	0.09	0.62
Boiler 5	Traveling Grate	03/21/83	108,000	201	25.42	28.1	0.14	1.01
Boiler 5	Traveling Grate	03/21/83	107,000	200	27.78	32.0	0.16	1.15
Boiler 5	Traveling Grate	03/21/83	107,000	199	27.64	29.9	0.15	1.08
Boiler 5	Traveling Grate	02/20/87	NA	NA	NA	9.7	NA	NA
Boiler 5	Traveling Grate	02/20/87	NA	NA	NA	7.7	NA	NA
Boiler 5	Traveling Grate	02/20/87	NA	NA	NA	6.4	NA	NA
Boiler 5	Traveling Grate	02/28/88	NA	NA	NA	27.7	NA	NA
Boiler 5	Traveling Grate	01/11/89	119,500	219.9	30.54	18.3	0.08	0.60
Okeelanta								
Boiler 10	Horseshoe	04/10/80	97,667	168.5	23.40	17.7	0.11	0.76
Osceola Farms								
Boiler 6	Traveling Grate	12/09/86	150,000	290	40.28	16.8	0.06	0.42
Boiler 6	Traveling Grate	12/09/86	150,000	290	40.28	7.9	0.03	0.20
Boiler 6	Traveling Grate	12/09/86	150,000	290	40.28	12.8	0.04	0.32
Sugar Cane Growers Cooperative[b]								
Boiler 1	Traveling Grate	03/20/80	81,176	118.5	16.46	38.7	0.33	2.35
Boiler 2	Traveling Grate	03/20/80	94,500	137.9	19.15	37.3	0.26	1.84
Boiler 8	Traveling Grate	02/04/83	246,429	414	57.50	43.1	0.10	0.75
Boiler 8	Traveling Grate	02/04/83	243,250	406	56.39	29.2	0.07	0.52
Boiler 8	Traveling Grate	02/04/83	254,211	425	59.03	32.3	0.08	0.55
Boiler 8	Traveling Grate	01/27/89	248,000	425.2	39.81[c]	117.9	0.28	2.96
Boiler 8	Traveling Grate	01/27/89	251,408	431.0	40.36[c]	118.8	0.28	2.94
Boiler 8	Traveling Grate	01/27/89	249,375	427.5	40.03[c]	117.7	0.28	2.94
U.S. Sugar - Bryant								
Boiler 2	Vibrating Grate	02/26/80	155,000	267.4	37.14	14.9	0.06	0.40
Boiler 5	Vibrating Grate	02/03/89	253,253	566.2	80.95[d]	85.0	0.15	1.05
Boiler 5	Vibrating Grate	02/03/89	247,612	554.2	79.55[d]	71.6	0.13	0.90
Boiler 5	Vibrating Grate	02/03/89	253,881	568.2	81.33[d]	79.7	0.14	0.98
U.S. Sugar - Clewiston								
Boiler 1	Vibrating Grate	02/28/80	215,000	370.9	51.51	26.9	0.07	0.52
Boiler 4	Traveling Grate	12/23/85	262,500	561.4	76.2[d]	92.9	0.17	1.10
Boiler 4	Traveling Grate	12/23/85	266,000	562.7	76.3[d]	70.4	0.13	0.83
Boiler 4	Traveling Grate	12/23/85	251,407	532.3	72.4[d]	58.2	0.11	0.73

Note:
lb/hr = pounds per hour.
lb/MMBtu = pounds per million British thermal units.
lb/ton = pounds per ton.
MMBtu/hr = million British thermal units per hour.
NA = not available.
TPH = tons per hour.

[a] Assumed 3,600 Btu/lb average heat content for wet bagasse.

[b] Heat input and NO_x emissions due to oil burning excluded.

[c] Combination of residue/oil firing; oil firing constituted less than 7 percent of total heat input. Average heating value of wet residue assumed to be 5,340 Btu/lb.

[d] Based on actual reported data.

Table B-13. Summary of VOC Emission Tests Performed on Bagasse Boilers in Florida

Unit	Boiler Type	Date	Steam Rate (lb/hr)	Heat Input Rate (MMBtu/hr)	Bagasse Burning Rate[a] (TPH wet)	VOC Emissions		
						lb/hr	lb/MMBtu	lb/ton,wet
Atlantic Sugar								
Boiler 5	Traveling Grate	03/21/83	108,000	201	27.92	14.3	0.07	0.51
Boiler 5	Traveling Grate	03/21/83	98,000	183	25.42	14.6	0.08	0.57
Boiler 5	Traveling Grate	03/21/83	108,000	201	27.92	14.5	0.07	0.52
Boiler 5	Traveling Grate	02/20/87	NA	NA	NA	20.0	NA	NA
Boiler 5	Traveling Grate	02/28/88	NA	NA	NA	34.3	NA	NA
Boiler 5	Traveling Grate	01/11/89	119,500	219.9	30.54	25.2	0.12	0.82
Osceola Farms								
Boiler 6	Traveling Grate	12/18/86	160,000	310	43.06	79.0	0.25	1.83
Boiler 6	Traveling Grate	12/18/86	160,000	310	43.06	49.0	0.16	1.14
Sugar Cane Growers Cooperative								
Boiler 8	Traveling Grate	02/04/83	246,429	414	57.50	13.9	0.03	0.24
Boiler 8	Traveling Grate	02/04/83	243,250	406	56.39	26.8	0.07	0.48
Boiler 8	Traveling Grate	02/04/83	254,211	425	59.03	88.1	0.21	1.49
Boiler 8[b]	Traveling Grate	01/06/89	NA	425.2	39.81	35.8	0.08	0.90
						5.41[c]	0.01	0.14
Boiler 8[b]	Traveling Grate	01/06/89	NA	431.0	40.36	36.2	0.08	0.90
						12.7[c]	0.03	0.32
Boiler 8[b]	Traveling Grate	01/06/89	NA	427.5	40.03	111.4	0.26	2.78
						21.5[c]	0.05	0.54
U.S. Sugar - Bryant								
Boiler 5	Vibrating Grate	02/03/89	253,253	566.2	80.95[d]	102.8	0.18	1.27
Boiler 5	Vibrating Grate	02/03/89	253,881	568.2	81.33[d]	116.3	0.20	1.43
U.S. Sugar - Clewiston								
Boiler 4	Traveling Grate	12/23/85	262,500	561.4	76.2[d]	104.4	0.19	1.37
Boiler 4	Traveling Grate	12/23/85	266,000	562.7	76.3[d]	71.0	0.13	0.93
Boiler 4	Traveling Grate	12/23/85	251,407	532.3	72.4[d]	120.2	0.23	1.66

Note:
lb/hr = pounds per hour.
lb/MMBtu = pounds per million British thermal units.
lb/ton = pounds per ton.
MMBtu/hr = million British thermal units per hour.
NA = not available.
TPH = tons per hour.

[a] Calculated from reported heat input rate, assumed 3,600 Btu/lb average heat content for wet bagasse. Average heat value for wet residue is 5,340 Btu/lb.

[b] Residue was used as fuel source. Average heat value for wet residue is 5,340 Btu/lb.

[c] Sample analyzed by another analytical laboratory.

[d] Based on actual reported data.

Table B-14. Summary of CO Emission Tests Performed on Bagasse Boilers in Florida Using EPA Method 10

Unit	Boiler Type	Date	Steam Rate (lb/hr)	Heat Input Rate (MMBtu/hr)	Bagasse Burning Rate[a] (TPH wet)	CO Emissions lb/hr	CO Emissions lb/MMBtu	CO Emissions lb/ton,wet
U.S. Sugar - Bryant								
Boiler 5	Vibrating Grate	02/16/89	256,928	577.0	80.14	2,586.9	4.48	32.28
Boiler 5	Vibrating Grate	02/17/89	249,228	561.0	77.92	2,658.0	4.74	34.11
Boiler 5	Vibrating Grate	02/17/89	249,480	562.0	78.06	1,693.3	3.01	21.69
Osceola Farms								
Boiler 3	Traveling Grate	01/17/89	NA	NA	NA	NA	3.07	22.10
Boiler 3	Traveling Grate	12/05/89	NA	NA	NA	NA	0.81	5.83
Boiler 3	Traveling Grate	01/24/90	NA	NA	NA	NA	3.14	22.61
Boiler 6	Traveling Grate	01/16/89	NA	NA	NA	NA	5.42	39.02
Boiler 6	Traveling Grate	11/15/89	NA	NA	NA	NA	5.48	39.46
Boiler 6	Traveling Grate	02/02/90	NA	NA	NA	NA	5.93	42.70

Note:
lb/hr = pounds per hour.
lb/MMBtu = pounds per million British thermal units.
lb/ton = pounds per ton.
MMBtu/hr = million British thermal units per hour.
NA = not available.
TPH = tons per hour.

[a] Calculated from reported heat input rate, assumed 3,600 Btu/lb average heat content for wet bagasse.

REFERENCES FOR APPENDIX B

PB91-126003

United States
Environmental Protection
Agency

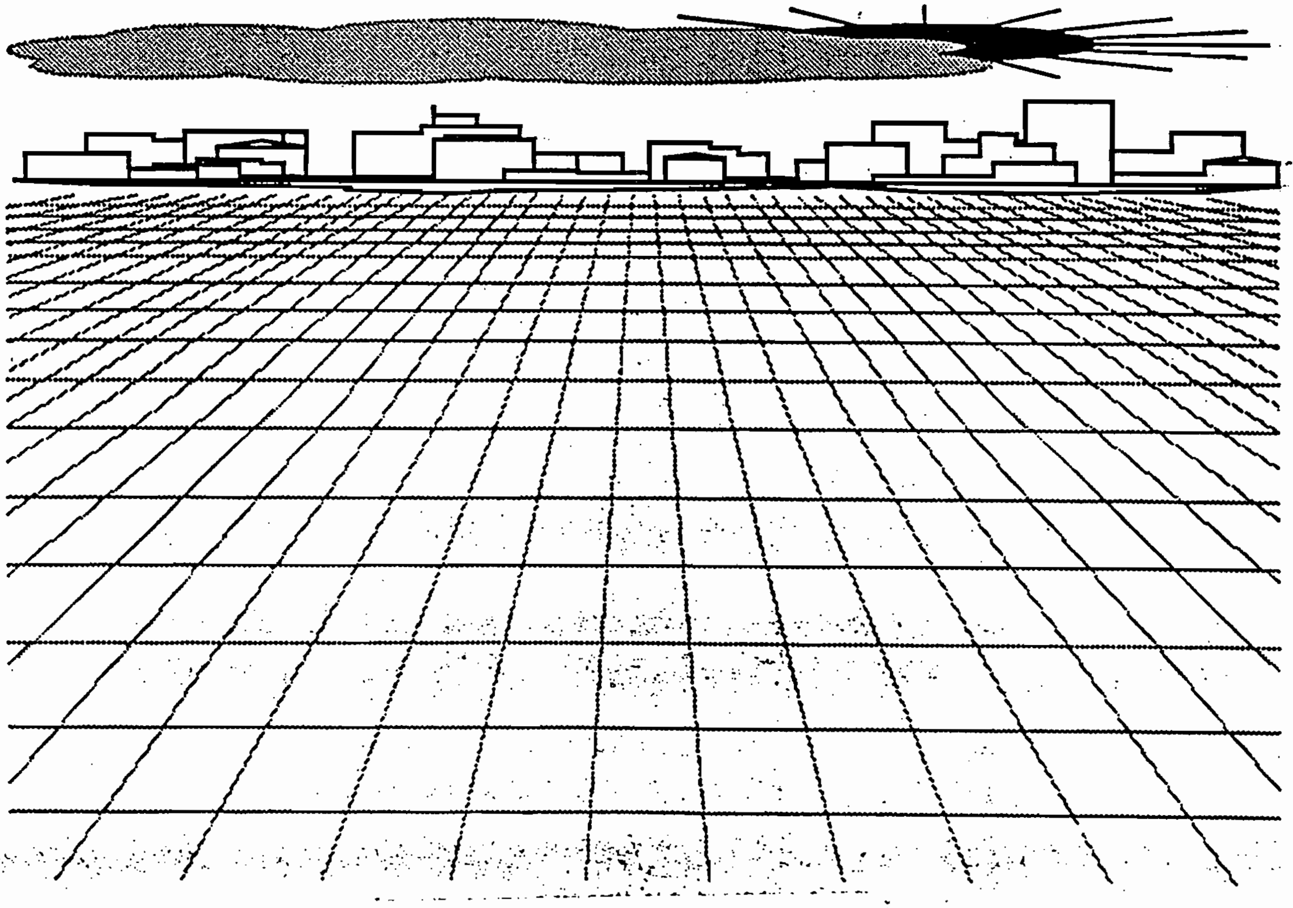
Office of Air Quality
Planning And Standards
Research Triangle Park, NC 27711

EPA-450/2-90-011
October 1990

AIR

EPA

TOXIC AIR POLLUTANT EMISSION FACTORS - A COMPILATION FOR SELECTED AIR TOXIC COMPOUNDS AND SOURCES, SECOND EDITION



POLLUTANT	CAS NUMBER	SIC CODE	INDUSTRIAL PROCESS	EMISSION SOURCE	SCC CODE	EMISSION FACTOR	NOTES	REFERENCE
Beryllium	7440417		Coal combustion, residential	Boilers fired by coal from rocky mountain region		15.2 lb/10E12 Btu	Uncontrolled, calculated based on engineering judgement	34
Beryllium	7440417		Coal combustion, residential	Lignite coal-fired boilers		27.5 lb/10E12 Btu	Uncontrolled, highly variable, calculated based on engineering judgement	34
Beryllium	7440417		Coal combustion, residential	Subbituminous coal-fired boilers		13.6 lb/10E12 Btu	Uncontrolled, highly variable, calculated based on engineering judgement	34
Beryllium	7440417		Internal combustion engines - stationary	Reciprocating engine - distillate oil fuel		0.069 lb/10E12 Btu	Uncontrolled emissions	213
Beryllium	7440417		Internal combustion engines - stationary	Gas turbine - distillate oil fuel		0.324 lb/10E12 Btu	Uncontrolled emissions	213
Beryllium	7440417		Oil combustion	Distillate oil-fired boiler, util/commerc/industr/residential	1	2.5 lb/10E12 Btu	Uncontrolled, calculated based on engineering judgement	34
Beryllium	7440417		Oil combustion	Distillate oil-fired boiler, util/commerc/industr/residential	1	1.58 lb/10E12 Btu	Controlled with multiclone, calculated based on engineering judgement	34
Beryllium	7440417		Oil combustion	Distillate oil-fired boiler, util/commerc/industr/residential	1	0.35 lb/10E12 Btu	Controlled with ESP, calculated based on engineering judgement	34
Beryllium	7440417		Oil combustion	Distillate oil-fired boiler, util/commerc/industr/residential	1	0.15 lb/10E12 Btu	Controlled with scrubber, calculated based on engineering judgement	34
Beryllium	7440417		Oil combustion	Residual oil-fired boiler, util/commerc/industr/residential	1	4.2 lb/10E12 Btu	Uncontrolled, calculated based on engineering judgement	34
Beryllium	7440417		Oil combustion	Residual oil-fired boiler, util/commerc/industr/residential	1	2.65 lb/10E12 Btu	Controlled with multiclone, calculated based on engineering judgement	34
Beryllium	7440417		Oil combustion	Residual oil-fired boiler, util/commerc/industr/residential	1	0.59 lb/10E12 Btu	Controlled with ESP, calculated based on engineering judgement	34

POLLUTANT	CAS NUMBER	SIC CODE	INDUSTRIAL PROCESS	EMISSION SOURCE	SCC CODE	EMISSION FACTOR	NOTES	REFERENCE
Indene	95136		Scrap tire, open burning	Tires in experimental burn hut		0.577 lb/ton tire	XAD-2 extracts w/MS analysis, Chunk condition = 1/4-1/6 of tire, burn rate = 2.3 kg/hr, uncontrolled	212
Indeno(1,2,3-cd)pyrene	193395		Scrap tire, open burning	Tires in experimental burn hut		0.193 lb/ton tire	Sum of PAH analy on liq extrat. of XAD-2 test & filter compont. shred condition = 2" by 2" piece, burn rate=1.3 kg/hr, controlled	212
Indeno(1,2,3-cd)pyrene	193395		Scrap tire, open burning	Tires in experimental burn hut		0.148 lb/ton tire	Sum of PAH analy on liq extrat. of XAD-2 test & filter compont. shred condition = 2" by 2" piece, burn rate=1.1 kg/hr, controlled	212
Indeno(1,2,3-cd)pyrene	193395		Scrap tire, open burning	Tires in experimental burn hut		0.135 lb/ton tire	Sum of PAH analy on liq extrat. of XAD-2 test & filter compont. shred condition = 2" by 2" piece, burn rate=1.7 kg/hr, controlled	212
Indeno(1,2,3-cd)pyrene	193395		Scrap tire, open burning	Tires in experimental burn hut		0.070 lb/ton tire	Sum of PAH analy on liq extrat. of XAD-2 test & filter compont. shred condition = 2" by 2" piece, burn rate=2.3 kg/hr, controlled	212
Iron	15438310	25	Wood combustion, industrial	Horizontal return tube	10200906	194.7 lb/10E12 Btu heat input	Sample results, 1 plant, wood flowrate = .514 kg/s, boiler has 3-pass design w/flyash reinjection, uncontrolled	176
Iron	15438310	25	Wood combustion, industrial	Balanced draft wickes stoker-fired industrial boiler	10200906	0.0084 lb/ton fuel or >0.24 ng/J	Dry wood, one plant, particulate control w/mechanical collector (cyclone), wood feed rate 0.29 kg/s, boil. eff. 55.3%	177
Iron	15438310	25	Wood combustion, industrial	Balanced draft wickes stoker-fired industrial boiler	10200906	0.0104 lb/ton fuel or >0.39 ng/J	Green wood, one plant, particulate control w/mechanical collector (cyclone), wood feed rate 0.54 kg/s, boil. eff. 61.3%	177
Iron	15438310	2951	Asphaltic concrete production	Plant stack	305002	3.72 x 10E-7 lb/ton concrete	Uncontrolled from a single plant, avg. of 2 values, range is 2.22 x 10E-7 - 5.21 x 10E-7 lb/ton	170
Iron	15438310	2951	Asphaltic concrete production	Plant stack	305002	4.73 x 10E-9 lb/ton concrete	Controlled (unspecified) from a single plant, avg. of 2 values, range is 3.08 x 10E-9 - 6.38 x 10E-9 lb/ton	170
Iron	15438310	806	Hospital waste incineration	Incinerator	315020	<0.0103 lb/ton feed	Uncontrolled, average emission factor based on 3 facilities	167
Isobutyraldehyde	78842		Wood combustion, residential	Fireplace		2.8 lb/ton wood burned	Uncontrolled, average emission factor based on source tests	58
Isobutyraldehyde	78842		Wood combustion, residential	Woodstove		3 lb/ton wood burned	Uncontrolled, average emission factor based on source tests	58
Lead	7439921		Coal combustion, industrial	Pulverized coal watertube boiler	10200202	0.0086 lbs/10E6 BTU heat input	Uncontrolled emissions	189
Lead	7439921		Coal combustion, industrial	Spreader stoker watertube boiler	10200204	0.0086 lbs/10E6 BTU heat input	Uncontrolled emissions	189

PB81-225559

Emissions Assessment of Conventional Stationary Combustion Systems: Volume V: Industrial Combustion Sources

TRW, Inc.
Redondo Beach, CA

Prepared for

Industrial Environmental Research Lab.
Research Triangle Park, NC

1981

U.S. Department of Commerce
National Technical Information Service
NTIS

TABLE 18. TRACE ELEMENT EMISSION FACTORS AND MEAN AMBIENT SEVERITY FACTORS FOR RESIDUAL OIL-FIRED INDUSTRIAL BOILERS

Trace element	Concentration (ppm)	Emission factor (pg/J)	Ambient[a] severity factor
Aluminum (Al)	3.8	87	0.002
Arsenic (As)	0.8	18	1.1
Boron (B)	0.41	9.4	<0.001
Barium (Ba)	1.26	28.8	0.008
Beryllium (Be)	0.08	1.8	0.11
Bromine (Br)	0.13	3.0	<0.001
Calcium (Ca)	14	320	0.002
Cadmium (Cd)	2.27	51.9	0.64
Chlorine (Cl)	12	274	0.012
Cobalt (Co)	2.21	50.5	0.12
Chromium (Cr)	1.3	30	2.7
Copper (Cu)	2.8	64	0.638
* Fluorine (F)	0.12	2.7	<0.001
Iron (Fe)	18	411	0.05
Mercury (Hg)	0.04	0.9	0.002
Potassium (K)	34	777	0.48
Lithium (Li)	0.06	1.4	0.006
Magnesium (Mg)	13	297	0.006
Manganese (Mn)	1.33	30.4	<0.001
Molybdenum (Mo)	0.9	21	<0.081
Sodium (Na)	31	708	0.034
Nickel (Ni)	42.2	964	7.8
Phosphorus (P)	1.1	25	0.004
Lead (Pb)	3.5	80	0.066
Antimony (Sb)	0.44	10	0.002
Selenium (Se)	0.7	16	0.010
Silicon (Si)	17.5	400	0.004
Tin (Sn)	6.2	142	0.004
Strontium (Sr)	0.15	3.4	<0.001
Thorium (Th)	<0.001	0.02	<0.001
Uranium (U)	0.7	16	0.22
Vanadium (V)	160	3656	0.90
Zinc (Zn)	1.26	28.8	<0.001

[a] Based on a firing rate of 50 x 10^9 J/hr.

APPENDIX C

COUNTY ZONING CONDITIONS FOR PROPOSED COGENERATION FACILITY

Board of County Commissioners
Karen T. Marcus, Chair
Carole Phillips, Vice Chair
Carol A. Roberts
Carol J. Elmquist
Mary McCarty
Ken Foster
Maude Ford Lee

County Administrator
Robert Weisman

Department of Planning, Zoning & Building

RECEIVED
SEP 0 2 1992
Carlton Fields - West Palm Beach
Gary M. Brandenburg

August 30, 1992

Gary Brandenburg, Esq.
Carlton, Field, Ward, Emmanuel,
  Smith & Culter, PA
P. O. Box 150
West Palm Beach, FL 33402

RE: PETITION NO. 92-14 - SPECIAL EXCEPTION
OKEELANTA CORP.

Dear Mr. Brandenburg:

At the Public Hearing on July 30, 1992, the Board of County Commissioners of Palm Beach County, Florida, officially approved your petition as advertised, subject to the attached list of tentative conditions. Please notify your Project Manager, in writing, within five (5) days if you believe there are any errors.

The next two deadlines for site plan certification are 12:00 noon, August 5, 1992, and 12:00 noon, August 17, 1992, for the August 31, 1992, and September 14, 1992, meetings, respectively. Site plan certification meetings commence at 9:00 a.m. in the Conference Room at 3400 Belvedere Road, West Palm Beach, Florida. The following documents must be submitted to this office before 12:00 noon on the deadline specified, for your plan to be considered at the next meeting:

1. Revised master/site plan upon which an exact copy of the Board approved conditions is shown. Site plan certification application is required with all petitions approved by the Board of County Commissioners.
2. Unity of Title/Control, Cross Access Agreement, or any other legal document in need of review for legal sufficiency.
3. Board of Adjustment variance relief, if required.
4. A Certificate of Concurrency or a Certificate of Exemption.

Should you have any questions or need additional assistance, please contact your Project Manager at 233-5034.

Very truly yours,

Roxanne M. Manning
Roxanne M. Manning, Zoning Director

RMM/bjw
Attachment

cc: Petition File, Project Manager, Ann Waters, K. C. Collette, R. Wheelihan, J. Choban, S. Hardy-Miller, D. Beasley, J. Dumas, J. MacGillis, L. Monroe, Minutes Department, J. Crawford, Barbara Bobsein

"An Equal Opportunity - Affirmative Action Employer"

3400 Belvedere Road West Palm Beach, Florida 33406 (407) 233-5000

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(4) Volatile Organic Compounds: 389.5
(5) Mercury: 0.0251
(6) With regard to sulfur dioxide emissions, the following conditions shall apply:

(a) If used, coal shall be of the low sulfur variety, and shall not exceed 0.7% sulfur by weight.

PETITION 92-14

APPROVAL OF THE PETITION IS SUBJECT TO THE FOLLOWING CONDITIONS:

A. AIR QUALITY

1. Petitioner shall:

   a. Prior to initial start up, install all air pollution control devices and processes required by the Florida Department of Environmental Regulation (DERM), the United States Environmental Protection Agency (EPA), and as described in the environmental report attached hereto and made a part hereof (Exhibit A) to include, but not be limited to:

      (1) an electrostatic precipitator, designed for at least 98% removal of particulate matter or equivalent;

      (2) a thermal D-NOx system designed for at least 40% removal of oxides of nitrogen, or equivalent; and

      (3) an activated carbon injection system for control of mercury emissions, or equivalent.

   b. Continuously monitor and record exhaust gas opacity, oxides of nitrogen, and carbon monoxide.

   c. Test stack emissions according to DER and EPA standards at least once every six months for particular matter, oxides of nitrogen, carbon monoxide, sulfur dioxide, lead, mercury and volatile organic compounds for the first two years of operation. If the test results for the first two years of operations indicate the facility is operating in compliance with the terms of approval and of applicable permits and regulations, the test will thereafter occur as required by the respective DER and EPA permits, with the exception that stack emissions will be tested annually for mercury. In the event the results of the first two years of testing show non-compliance, then the frequency of testing shall continue to occur once every six months until the facility achieves a sustained two-year period of compliance.

   d. Not exceed the total actual annual emissions from the existing boilers and those currently permitted for construction at this facility. Except for particulate matter and sulfur dioxide, the following figures represent the best available estimates for the actual current emissions. These emissions, in tons per year, by pollutant, are:

(1)	Particulate Matter:	555.9
(2)	Oxides of Nitrogen:	855.0
(3)	Carbon Monoxide:	10,526.2
(4)	Volatile Organic Compounds:	389.5
(5)	Mercury:	0.0251

      (6) With regard to sulfur dioxide emissions, the following conditions shall apply:

         (a) If used, coal shall be of the low sulfur variety, and shall not exceed 0.7% sulfur by weight.

(b) Fuel oil shall be limited to low sulfur No. 2 distillate oil and shall not exceed 1% sulphur by weight.

(c) Coal consumption shall not exceed 25% of the total heat input in any calendar quarter.

(Paragraphs (d) through (h) apply to total sulfur dioxide emissions for the combined facilities of petitions 92-13 and 92-14.)

(d) Shall not exceed the current emissions of the proposed project (an average of 1000 tons of sulfur dioxide. If the life of the project exceeds thirty years, the total allowable lifetime emissions will be adjusted proportionately.)

(e) For the case that the Palm Beach County government makes available 200,000 tons of biomass fuel per year to the cogeneration facilities in Petitions 92-13 and 92-14, under the same terms and conditions as those in the existing Okeelanta/Palm Beach Solid Waste Authority Wood-waste Agreement, the petitioner shall:

1) not exceed 1500 tons of sulfur dioxide for that year.

2) not exceed an average of 1300 tons of sulfur dioxide for each five year incremental period.

(f) For the case that the Palm Beach County government cannot make available the 200,00 tons of biomass fuel per year to the cogeneration facilities in Petitions 92-13 and 92-14, the petitioner shall:

(1) not exceed 1700 tons of sulfur dioxide for that year.

(2) not exceed an average of 1500 tons of sulfur dioxide for each ten year incremental period.

(g) The allowable average sulfur dioxide emissions for the five and ten year incremental periods described above shall be calculated on a weighted average for any period in which both cases occur (years in which biomass is made available/years in which biomass is not made available.)

(h) Sulfur dioxide emissions shall include all emissions from the proposed projects in Petitions 92-13 and 92-14 and the currently existing boilers at the Okeelanta and Osceola facilities if in operation during initial project operation.

e. Employ all methods to control unconfined dust and particulate emissions, required by local, state and/or federal agencies.

f. Request in all applications to DER and EPA that the above conditions become part of the corresponding permits. (HEALTH)

2. 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 by the Petitioner to comply with state and federal air standards. (ZONING - Health)

3. With the exception of clearing for access roads, survey lines, construction trailers, equipment staging areas, fencing, and specific building sites, construction shall commence within 90 days after completion of clearing and grading. Any cleared zones or areas not necessary to the operation of the site shall be planted in grass within 90 days after establishment of finished grade. (ZONING)

4. The petitioner shall comply at all times with the requirements of all permits issued by all agencies having jurisdiction over the facility. (HEALTH - ERM)

B. <u>BUILDING AND SITE DESIGN</u>

1. Maximum total floor area shall be limited to 10% of the total lot area of the subject property. (BUILDING - Zoning)

2. Prior to site plan certification, the site plan shall be amended to indicate a maximum 6.6 acres building envelope on the site and the square footage to be contained therein. All construction and development of the principal structure and accessory facilities shall occur within this envelope. All accessory uses indicated on the site plan outside of the building envelope shall be subject to the requirements and regulations of Section 402.7(E)2(b) (Site Plan Review Committee Powers and Standards of Review). Uses and building locations within the envelope shall not be subject to this requirement. (ZONING)

C. <u>ENVIRONMENTAL RESOURCES MANAGEMENT</u>

1. Plans for all underground and above ground storage tanks must be approved by the Department of Environmental Resources Management prior to installation. The petitioner shall perform all necessary preventative measures to reduce the chances of contamination of the groundwater. Double walled tanks and piping with corrosion protection or their equivalent shall be a part of those measures. (BUILDING-ERM)

2. Secondary containment for stored Regulated Substances, including but not limited to fuels, oils, solvents, or other hazardous chemicals, is required. Department of Environmental Resources Management staff are willing to provide guidance on appropriate protective measures. (BUILDING-ERM)

3. All new excavated lakes shall possess a littoral shelf area. A littoral shelf shall be an area with a slope not greater six (6) feet horizontal to one (1) foot vertical, ranging in depth from ordinary high water (OHW) or the controlled water level (CWL) to four feet below OHW or

CWL. A minimum of 30% of the surface area of all lakes shall be planted with native aquatic vegetation on a minimum of three foot centers.

a. A littoral shelf planting plan and maintenance plan shall be submitted to the Department of Environmental Resources Management concurrent with Site Plan Review application and approved by ERM prior to Site Plan certification. This information shall also be provided on a mylar for the Zoning Division as part of the site plan application.(ERM)

b. Prior to the issuance of a Certificate of Occupancy and within three working days of the completion of littoral plantings ERM shall be notified. This planting shall not be credited as compensation required by wetland permits. (BUILDING-ERM)

D. EXOTIC SPECIES

1. Areas disturbed as a result of the construction of the cogeneration facility and transmission lines shall be continually maintained to be free of Brazilian Pepper, Australian Pine and Melaleuca. (ZONING)

E. ENGINEERING

1. The Developer shall provide discharge control and treatment for the stormwater runoff in accordance with all applicable agency requirements in effect at the time of the permit application. However, at a minimum, this development shall retain onsite the stormwater runoff generated by a three (3) year-one (1) hour storm with a total rainfall of 3 inches as required by the Permit Section, **Land Development Division**. The drainage system shall be maintained in an acceptable condition as approved by the County Engineer. In the event that the drainage system is not adequately maintained as determined by the County Engineer, this matter will be referred to the Code Enforcement Board for enforcement (COUNTY ENGINEER).

2. If required by the County Engineer or the South Florida Water Management District the Developer shall design the drainage system such that drainage from those areas which may contain hazardous or undesirable waste shall be separate from stormwater runoff from the remainder of the site (COUNTY ENGINEER).

F. HEALTH

1. Potable water supply for the proposed project is to be provided by a reverse osmosis non-transient non-community water supply system in accordance with Chapter 17-550 & 17-555, F.A.C. (HEALTH)

2. The industrial waste stream generated by this site shall be disposed of in accordance with all applicable Florida DER regulations. (HEALTH)

3. Cogeneration boiler fuels shall be limited to Biomass, as defined in Condition K.9. and fossil fuels. The use of fossil fuels shall be limited in accordance with conditions A.1.d.(6)(a), A.1.d.(6)(b) and A.1.d.(6)(c). The use of Biomass Wastes shall include provisions for the substantial exclusion of painted and chemically

treated wood, household garbage, toxic or hazardous materials or wastes and special wastes. This specification must be reviewed and approved by the Palm Beach County Public Health Unit prior to site plan approval. (HEALTH)

4. All fly ash and bottom ash from the facility which is produced during any period in which fossil fuels are used, and thereafter for a reasonable time shall be segregated and managed as set forth in the ash management plan. (HEALTH)

5. Prior to site plan approval, a detailed ash management plan shall be submitted by the petitioner and approved by the Palm Beach County Public Health Unit. This plan must detail contingencies plans, testing and monitoring of the ash, ash handling and disposal methods, planned spreading locations and identification of environmental impacts and proposed measures for mitigating these impacts. (HEALTH)

6. Prior to site plan approval, a detailed fuel management plan shall be submitted and approved by the Palm Beach County Public Health Unit. This plan shall detail location, size, handling procedures, transportation, dust control and fire protection. (HEALTH)

7. Prior to site plan approval, the petitioner shall identify all liquid waste streams and provide a complete physical and chemical characterization of the waste streams which shall include, at a minimum, the following information:

    a. A description of the source or process associated with the waste stream.

    b. Volume and flow rates.

    c. Physical parameters including temperature, pH, and total dissolved solids.

    d. Expected concentrations of pollutants or contaminants, including but not limited to, Nitrogen, Phosphorous and other nutrients, mercury, lead and other trace metals, volatile or semivolatile organic compounds, etc.

    e. A description and detail of any treatment system utilized.

    f. A description of the disposal or reuse method and identification of all points of discharge. (HEALTH)

8. Prior to site plan approval, a detailed domestic wastewater management plan shall be submitted and approved by the Palm Beach County Public Health Unit. (HEALTH)

9. Prior to site plan approval, a detailed storm water management plan shall be submitted by the petitioner to the South Florida Water Management District (SFWMD) and Palm Beach County Public Health Unit for review and approval. Staff shall coordinate its review with the SFWMD. (HEALTH)

10. Prior to site plan approval, a detailed industrial wastewater management plan must be submitted to the Department of Environmental Regulation (DER) and the Palm Beach County Public Health Unit for review and approval. Staff shall coordinate its review with the DER. (HEALTH)

11. Prior to site plan approval, all applicable environmental permits or applications for permits must be obtained or submitted. (HEALTH)

G. LANDSCAPING

1. Prior to site plan certification, the petitioner shall submit a Landscape Betterment Plan for review and approval by the Zoning Division. The Landscape Betterment Plan shall demonstrate conformance to all Landscape Code requirements and conditions of approval. (ZONING)

2. As an alternative, the petitioner may landscape the site and provide off-site improvements in accordance with the Unified Land Development Code, upon adoption. (ZONING)

H. LIGHTING

1. All outdoor lighting used to illuminate the premises and identification signs shall be of low intensity, shielded and directed downward. (BUILDING - CODE ENF)

I. PARKING

1. Vehicle parking shall be limited to the parking areas designated on the approved site plan. No parking of vehicles shall be permitted in landscaped areas, right-of-way or interior drives. (CODE ENF)

J. TRANSMISSION LINES

1. All transmission lines required by this facility are to be constructed in accordance with the National Electric Safety Code. (BUILDING)

2. All transmission lines leaving the site and required by this facility shall not exceed 138 KV. (BUILDING)

K. USE LIMITATIONS

1. Use of the site shall be limited as follows:

Land Area	66.46 acres
Total Floor Area	288,250 square feet
Maximum Total Floor Area	10%
Electrical Production	74.9 mega watt maximum
Fuel Storage Yard	45 acre max. net land area

2. Prior to site plan certification, the site plan shall be amended to indicate the location of a truck/vehicle wash facility. This wash facility shall utilize a 100% water recycling system. (ZONING/BUILDING)

3. There shall be no repair or maintenance of vehicles on site. (CODE ENF)

4. No outside storage of disassembled vehicles, or parts thereof, shall be permitted on site. (CODE ENF)

5. The maximum height, from grade to highest point, for all fuel storage areas shall not exceed fifty (50) feet. (BUILDING)

6. Onsite storage shall be contained within the area designated on Exhibit 48 and shall be processed and stored in a manner which controls fugitive and dust particulate emissions. (CODE ENF)

7. All vehicles utilizing public rights-of-way to carry biomass waste (i.e. vegetative matter) to the site shall be equipped, at a minimum, with covering or screens over top of the open bed of the vehicle to prevent the loss of material during transportation to the facility. (CODE ENF)

8. The storage of fuel on site shall be limited to the areas designated on the certified site plan and shall be limited to the storage of bagasse and biomass waste only. (CODE ENFORCEMENT)

9. "Biomass Waste", as referred to herein, shall mean bagasse, vegetative and woody matter, including material resulting from landscaping, maintenance, land clearing operations, clean wood, cellulose material, tree and shrub trimmings, grass clippings, palm fronds, trees, tree stumps, wood from land development operations, clean wood debris from demolition operations; it shall not include trash, garbage or sludge (FAC 17-701), biohazardous waste (17-712 FAC), or biological waste (17-712 FAC).

10. The existing boiler facilities shall be abandoned within three (3) years of commercial start up of the cogeneration facility and no later than January 1, 1999. The existing boilers and new facilities shall not be operated at the same time. (MONITORING/CODE ENFORCEMENT)

L. WATER SUPPLY

1. Construction shall not commence on the project site until it has been demonstrated to the satisfaction of the South Florida Water Management District that an acceptable and sustainable supply of water during drought periods is available to serve the project over and above that necessary to serve already approved development. (BUILDING - SFWMD)

2. The petitioner shall utilize all drought-tolerant plants in landscaping on the subject property. (ZONING)

3. The petitioner shall use water-saving plumbing fixtures and other water conserving devices in restrooms and employee locker rooms, as specified in the Water Conservation Act, Section 553.14, Florida Statutes. (BUILDING)

M. COMPLIANCE

1. As provided in the Palm Beach County Zoning Code, Sections 400.2 and 402.6, failure to comply with any of these conditions of approval at any time may result in:

   a. The denial or revocation of a building permit; the issuance of a stop work order; the denial of a Certificate of Occupancy on any building or structure; or the denial or revocation of any permit or approval for any developer-owner, commercial-owner, lessee, or user of the subject property; and/or

b. The revocation of the Special Exception and any zoning which was approved concurrently with the Special Exception as well as any previously granted certifications of concurrency or exemptions therefrom; and/or

c. A requirement of the development to conform with updated standards of development, applicable at the time of the finding of non-compliance, or the addition or modification of conditions reasonably related to the failure to comply with existing conditions. (MONITORING)

2. Appeals of any departmental-administrative actions hereunder may be taken to the Palm Beach County Board of Adjustment or as otherwise provided in the Palm Beach County Zoning Code. Appeals of any revocation of Special Exception, Rezoning, or other actions based on a Board of County Commission decision, shall be by petition for writ of certiorari to the Fifteenth Judicial Circuit. (MONITORING)

APPENDIX D

APPLICATION TO OPERATE/CONSTRUCT AIR POLLUTION SOURCES