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March 3, 2003

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BUREAU OF AIR REGULATION

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Florida Department of Environmental Protection
New Source Review Section
2600 Blair Stone Road MS 5505
Tallahassee, FL 32399-2400

Attention: Mr. A. A. Linero, P.E. Administrator

RE: NEW HOPE POWER PARTNERSHIP, PROJECT NO. 0990332-016-AC (PSD-FL-196M)

Dear Mr. Linero:

On October 4, 2002, the Department issued a request for additional information (RAI) for New Hope Power Partnership's (NHPP's) air construction permit application to increase the annual heat input limitation of the Okeelanta Cogeneration Plant. The purpose of this correspondence is to provide responses to the Department's requests. The responses to each item in the RAI are provide below.

Comment 1: New Hope Power Partnership (NHPP) requests an increase in heat input from 715 MMBtu per hour to 760 MMBtu per hour. Please provide supporting information that this is within the manufacturer's maximum continuous rated capacity for the cogeneration boilers. What affect will this have on power generation given the current 74.9 MW plant capacity? From the application, it appears that the flue gas flow rate and velocity will increase. Based on actual data, what is the current flue gas flow rate and velocity?

Response: NHPP requests an increase in heat input from 715 MMBtu per hour to 760 MMBtu per hour based on a feed water temperature reduction. The feedwater temperature reduction is the result of taking the last feedwater heater on each boiler out of service. The reduction in feed water temperature results in a need for more heat input to produce the same amount of steam (see the following table). The ABB-Combustion Engineering, Inc. cogeneration boilers are each designed for a maximum design pressure of 1,725 psig and a superheater steam pressure and temperature (at the main steam stop valve outlet) of 1,500 psig and 950 F, respectively. These design steam conditions will be maintained. Therefore the requested increase in heat input is within the manufacturer's maximum continuous rated capacity for the cogeneration boilers.

	Heat Input (MMBtu/hr)	Feedwater		Steam			Steam Rate [a] (lb/hr)
		Temp. (°F)	Enthalpy (Btu/lb)	Temp. (°F)	Pressure (psig)	Enthalpy (Btu/lb)	
Current	717.9	403	378.1	950	1,500	1,450.0	455,418
Future	748.2	360	332.9	950	1,500	1,450.0	455,418

[a] Assumes 68% thermal efficiency when burning bagasse.

A slightly higher maximum heat input of 760 MMBtu/hr is requested as a safety factor.

Because the requested additional heat input will be used to produce the same amount of steam, there will be no impact on power generation capacity of the plant.

Based on actual data, the current flue gas flow rate and velocity for biomass firing is presented in Table 6-3 of the application. The estimated gas flow and temperature representative of the higher heat input rate can also be found in Table 6-3.

Comment 2: NHPP requests that the total heat input restriction of 11.5 x 10^{+06} MMBtu per year be removed. This limit established an annual capacity factor of approximately 58% for the plant. Palm Beach County was a nonattainment county for the pollutant ozone during the initial application. It appears that a determination of the Lowest Achievable Emission Rate (LAER) for emissions of volatile organic compounds was avoided by limiting the plant capacity. Why did the original application request a limit on heat input? Please comment and discuss.

Response: The original request for a limit on heat input equal to 11.5 x10^6 MMBtu/yr was based on the design of the facility, taking into account both the crop-season and off-season operation. Recently, the plant's performance has improved and the 11.5 x10^6 MMBtu/yr limit has been approached. Therefore, it is desired to increase the current facility cap. Since PSD review will be triggered by any relaxation of the current cap, it is in the facility's interest to request 8,760 hours of operation for each boiler to allow for the most flexibility of operation during both the crop and off-crop seasons.

Comment 3: Attachment NH-EU2-C: The "List of Applicable Regulations" in the application states that 40 CFR 60.46a(i) is "non-applicable". However, the units were recently modified to fire natural gas so the NSPS NO_x limit specified in 40 CFR 60.44a(d) should apply. The attachment also lists Rules 62-296.405 (boiler > 250 MMBtu/hour) and 62-296.410 (carbonaceous fuel burning equipment) as "non-applicable". The Department disagrees and believes these are applicable requirements. Please comment.

Response:
The requirements of 40 CFR 60.44a(d) only apply to units that were constructed or reconstructed after July 1, 1997. This provision does not apply to units for which modification was commenced after July 1, 1997. This was clarified in a final rule published on August 14, 2001 in the Federal Register.

We also do not believe that the conversion to natural gas firing triggered "modification" under the NSPS. A modification occurs when a physical change or change in the method of operation increases a pollutant regulated under the NSPS on a lb/hr basis. The conversion to gas firing did not result in an increase in NO_x, SO_2 or PM on an hourly basis. In the Technical Evaluation and Preliminary Determination (TE&PD) issued by the Department on Dec. 4, 2000 (permit no. 0990332-013-AC/PSD-FL-196L), the Department states "When firing natural gas, hourly emissions of carbon monoxide, particulate matter, sulfur dioxide, and volatile organic compounds are expected to decrease." It is further stated "hourly emissions of nitrogen oxides are not expected to increase either." (reference page 3 of TE&PD).

Although on page 8 of the TE&PD the Department states that 60.44a(d)(2) applies, we believe that this is incorrect and the NO_x limit in 60.44a(a) applies, i.e., 0.20 lb/MMBtu. In support of this position, we reference a permit issued last year for FPL's Manatee Plant (permit No. 0810010-007-AC). This permit authorized natural gas firing for two 800-MW oil-fired units. The maximum heat input of the existing units on oil was 8,650 MMBtu/hr each. Natural gas burners were to be installed to allow up to 5,670 MMBtu/hr each unit on gas. The NO_x emissions limit for natural gas was set equal to the existing limit for oil firing, i.e., 0.3 lb/MMBtu, ensuring that hourly NO_x emission were not increasing. NSPS was not triggered by this change.

Department Rule 62-296.100, Purpose and Scope, states:

> "Standards for any "new" facility or emissions unit shall be the federal standards of performance for new stationary sources adopted by reference at Rule 62-296.204.800(7), F. A. C., unless a different or more stringent standard is established in Rules 62-296.401 through 62-296.417, F. A. C."

NHPP believes that there is nothing in Rules 62-296.405 or 296.410 that is more stringent or different than the NSPS Subpart Da. The NHPP boilers would be classified as "new" sources under Rule 296.405. The sole requirement for new sources under Rule 296.405 is to meet the applicable the NSPS, either Subpart D or Subpart Da.

The NHPP boilers would be classified as "new" sources under Rule 296.410. The requirement for new sources under Rule 296.410 is to meet a visible emissions limit and a PM emissions limit. However, both of those limits are less stringent that the respective Subpart Da limits.

Accordingly, Rules 296-405 and 296.410 do not apply to the NHPP boilers.

<u>Comment 4:</u> **Please provide the missing Attachment NH-FI-C3 (Process Flow Diagram).**

<u>**Response:**</u> See Attachment A.

<u>Comment 5:</u> **The floor for a NO_x BACT determination is established in Subpart Da, the New Source Performance Standards for electric generating steam units for which construction commenced after September 18, 1978. 40 CFR 60.44a(1) specifies a NO_x standard of 1.6 lb/MW-hr gross energy output, based on a 30-day rolling average. (This regulation was revised on April 10, 2001.) Please verify that the requested NO_x controls for the cogeneration boilers are capable of achieving this level of emissions.**

<u>**Response:**</u> The correct citation for the NO_x limit of 1.6 lb/MW-hr gross energy output is actually 40 CFR 60.44a(d)(1). However, as described in response to Comment 3 above, the NO_x standard under 40 CFR 60.44a(d)(1) is not applicable to the NHPP boilers. Nevertheless, we have addressed this comment.

As seen in Table 2-1 of the application, the proposed emission limit for NO_x for all fuels is based on a 30-day rolling average of 0.15 lb/MMBtu heat input. NSPS Subpart Da specifies a NO_x standard of 1.6 lb/MW-hr gross energy output, based on a 30-day rolling average. Per Subpart Da, gross energy output for a cogeneration unit is equal to the sum of the electrical output and one half of the steam energy. The equivalent limit based on gross energy output is equal to 1.59 lb/MW-hr. See Attachment B for detailed calculations. Therefore the NO_x controls for the cogeneration boilers meet the 40 CFR 60.44a(d)(1) emission limit, although not applicable to NHPP.

As discussed in the response to Comment 3 above, 60.44a(d)(1) only applies to newly constructed or reconstructed units. As a result, this provision does not apply to the modification requested by NHPP

Comment 6: Notwithstanding New Hope Power Partnership's preference, please provide each requested pollutant limit in terms of *ppmvd at 7% O_2*, which is equivalent to the requested limits in terms of *lb/MMBtu* limit for each fuel.

Response: See Attachment C for equivalent emissions for each gaseous pollutant for which a limit is requested. Note that NHPP is not requesting emission limits for natural gas or No. 2 fuel oil firing, except for NO_x, which is required under the NSPS.

Comment 7: NO_x BACT Review

a. **Please provide a top-down BACT review for all NO_x emissions control technologies ranked according to control effectiveness. In addition to SCR and SNCR, include other control options such as an SNCR/SCR hybrid system, combustion modifications, overfire air, reburn with natural gas, etc. Combinations of these technologies should also be explored. (Information provided by Hamon Research Cottrell's web site states that a hybrid SNCR/SCR system allows an easier retrofit requiring low catalyst volume resulting in low capital costs. Several of the other technologies were alluded to in the May 21st, 2002 EPRI presentation provided with the application. Combinations of technologies are briefly mentioned in the May 2002 DOE/NETL Pittsburgh Conference on SNCR and SCR, also provided with the application.**

Response: See Attachment D

b. **Table 2-3 lists the potential annual NO_x emissions as 1498 tons per year from the three-cogeneration boilers based on an SNCR-controlled emission factor 0.15 lb/MMBtu. Assuming a 40% reduction in NO_x emissions from SNCR (the original design control efficiency), the uncontrolled NO_x emission factor would be 0.25 lb/MMBtu. Table 5-3 uses an uncontrolled NO_x emission factor of 0.26 lb/MMBtu and shows an estimated NO_x reduction from SCR of 539 tons per year, based on a 90% capacity. The cost effectiveness calculation is based on a 70% control efficiency, but the vendor quote is based on a 90% control efficiency. The vendor quote also assumes an inlet exhaust of 210 ppmvd @ 15% O_2, which appears to be much higher than 0.25 lb/MMBtu. Please explain the discrepancies and calculate the annual NO_x reduction based upon the information provided to the vendor (inlet of 210 ppmvd @ 15% O_2 and an outlet of 21 ppmvd @ 15% O_2). Also, please assume full operation (8,760 hours per year) as requested by NHPP.**

Response: The emission factor of 0.26 lb/MMBtu is based on EPA AP-42, Fifth Edition, Volume 1, Bagasse and Wood Fired Boiler Emission Factors (50% Bagasse/50% Wood). The following demonstrates the calculation.

AP-42 (BAGASSE)	Units
1.2	lb NO_x/ton bagasse
211,111	lb bagasse/hour
105.5555	ton bagasse/hour
126.6666	lb NO_x/hour
760	MMBtu/hour
0.167	lb NO_x/MMBtu
AP-42 (WOOD)	**Units**
0.22	lb NO_x/MMBtu, Wood Chips
0.49	lb NO_x/MMBtu, Dry Wood
0.355	lb NO_x/MMBtu, average
Calculated Biomass Factor (50% Bagasse/50% Wood)	
0.26	lb NO_x/MMBtu, average

SCR has been determined to be technically infeasible for the project and the vendor quote has been retracted and therefore the submitted economic analysis is no longer valid. See Attachment E.

c. **Was the vendor provided a detailed description of the existing NHPP cogeneration boilers including boiler design, existing control equipment, process flow diagrams, varying flue gas temperatures, fuels, exhaust characteristics and composition? If not, please provide the information and request a revised vendor cost quote.**

Response: Yes, the vendor was provided a detailed description of the existing NHPP cogeneration boilers including boiler design, existing control equipment, process flow diagrams, varying flue gas temperatures, fuels, exhaust characteristics and composition. See Attachment E.

d. **NHPP states that the SCR system would be placed after the ESP to prevent fouling from the particulate laden gas stream. Please provide supporting information from the vendor that justifies the very limited catalyst guarantee (10,000 hours) with placement of the SCR in cleaned flue gas after the existing ESP.**

Response: See Attachment E. SCR has been determined to be technically infeasible for the project.

e. **NHPP states that it will be necessary to install a reheat system (100 MMBtu per hour) to raise the flue gas temperature into the proper operating range of the catalyst for the proposed SCR system. This results in a cost of more than $2.6 million, which is the bulk of the annual operating costs. Please provide additional information that supports: the need for a reheat system; the estimated size of the reheat system (100 MMBtu per hour); and the type of catalyst selected and its operating range. The SCR vendor states that SCR can be effective in an operating range of 400°F to over**

1,000°F depending on the catalyst used. Please provide supporting documentation of the actual flue gas exhaust temperatures at the boiler exhaust, the mechanical dust collectors (inlet/outlet) and the ESP (inlet/outlet).

Response: See Attachment E. SCR has been determined to be technically infeasible for the project.

f. The vendor quote for SCR includes freight. Please revise cost effectiveness calculations accordingly.

Response: See Attachment E. SCR has been determined to be technically infeasible for the project.

g. An ammonia cost of $580 per ton of aqueous ammonia appears very high. Available information suggests that actual ammonia costs will be less than $200 per ton of aqueous ammonia. Please provide supporting information and adjust the cost effectiveness estimate accordingly.

Response: See Attachment G, a cost quote for delivery of 19% aqueous ammonia has been obtained from Tanner Industries, Inc. See Attachment C. The quoted delivered cost per ton of 19% aqueous ammonia is $495/ton, compared to the previously estimated $580/ton. However, it should be recognized that the cost of ammonia continually fluctuates with the cost of natural gas. Natural gas is a key component in the production of ammonia. Therefore, if the price of natural gas rises, the price of ammonia will rise correspondingly.

h. Please provide information to support and justify the 25% contingency factor used to determine capital costs.

Response: See Attachment E. SCR has been determined to be technically infeasible for the project.

i. Information provided by Hamon Research Cottrell's web site suggests that boiler temperature mapping can be used to optimize the urea injection grid. Please provide a quote from the original equipment manufacturer (or Hamon Research Cottrell) to enhance the existing SNCR system for additional NO_x control.

Response: The temperature window for SNCR is very important because outside of it either more ammonia slips through the system or more NO_x is generated than is being chemically reduced. The SNCR system on the cogeneration boilers have already been optimized for reduced NO_x emissions. plant management performed a urea optimization on the boilers in 1998. Given the variability of the fuel and fuel mixture, temperature mapping would not be appropriate for the NHPP cogeneration boilers.

Comment 8: PM BACT Review

a. **Please provide a top-down BACT review for PM emissions ranked according to control effectiveness. Support statements regarding costs with vendor quotes and standard cost effectiveness analysis. Identify and include any enhancements to the existing ESP controls (additional fields, etc) that can be made to reduce the potential particulate matter increase of 181 tons per year.**

Response: See Attachment H.

b. **Please provide a cost estimate from the original ESP equipment manufacturer (or Southern Research Institute) for enhancing the existing ESP to provide an additional level of control.**

Response: The original ESP equipment manufacturer was Flakt, which is now Alstom. Alstom has been contacted repeatedly to obtain a cost estimate with no success. However, it has been confirmed that the existing configuration of the ESP system lacks sufficient space for the addition of another field. Because sufficient space does not exist in the current configuration of the cogeneration boilers, the construction of an additional field for the ESPs would result in the following extremely costly retrofits:

- Construction of a separate field for each ESP and tie-in to the existing ESP;
- Destruction of the existing stacks;
- Construction of new free-standing stacks;
- Relocation of existing ID fans;
- Construction of new duct work; and
- Other supporting equipment and structures.

For these reasons, the addition of another field is considered infeasible for the project, even lacking a vendor quote.

c. **Please obtain a vendor cost quote for the "Compact Hybrid Particulate Collector (COHPAC)" system, which is a hybrid ESP/baghouse add on control system offered by Hamon Research Cottrell, Inc. According to their web site, a high air-to-cloth ratio fabric filter can be added to an existing ESP system to increase control efficiencies above 99.9%. This system could also be used as part of the spray dryer SO_2 scrubbing system. Please comment.**

Response: Hamon Research Cottrell, Inc was contacted for a cost estimate for a COHPAC system resulting in no response. Nevertheless, as was the case for the addition of another field in the ESP, a COHPAC system would require the following extremely costly retrofit operations:

- Construction of a fabric filter unit to tie in to each ESP;
- Destruction of the existing stacks;
- Construction of new free-standing stacks;
- Relocation of existing ID fans;
- Construction of new duct work; and
- Other supporting equipment and structures.

For these reasons, COHPAC is considered infeasible for the project, even lacking a vendor quote.

Comment 9: SO_2 BACT Review

a. **Please provide supporting information from the vendors that a baghouse would be necessary in addition to the existing ESP. Please provide a cost estimate from the original equipment manufacturer (or Southern Research Institute) for enhancing the existing ESP to provide this additional level of control.**

Response: In applications involving spray dryer technology for FGD, the particulate collector is downstream and is considered an integral part of the FGD system. The spray dryer FGD operates by atomizing droplets of water and lime, which reacts with SO_2 and acid gases. The mechanism is such that the water is evaporated in the process, leaving a dry, spent lime material in the flue gases. Therefore, the spray dryer FGD system must have an appropriate means of particulate-matter collection. As described in the Air & Waste Management Association's Air Pollution Engineering Manual, "Not only is a well-designed particulate-matter control system needed to meet particulate-matter and opacity emissions requirements, but it can help to meet acid-gas-removal requirements. Acid gases are removed when the flue gas comes into contact with lime-containing particles and encounters the collected particulate matter in the fabric filter or ESP." Therefore, it is appropriate to include the cost of the fabric filter in the FGD BACT cost analysis.

See response to Comment 8(b) for enhancing the existing ESP to provide additional control.

b. **The additional fluorides that would be removed due to a scrubber were included in the emissions reductions and cost effectiveness calculations. Please include the additional particulate matter that would be removed with the baghouse.**

Response: See Attachment I for revised cost effectiveness calculations.

c. **Please estimate the emissions of hydrochloric acid from the cogeneration boilers and include emissions reductions in the cost effectiveness calculations.**

Response: NHPP does not have any hydrochloric acid (HCl) stack test data for its boilers. There are no available hydrochloric acid emission factors for bagasse combustion. However, such emissions are expected to be very low. For purposes of the BACT analysis only, HCl emissions for wood combustion can be estimated based on AP-42 emission factors for wood residue combustion. Based on the estimated biomass makeup of 50% bagasse and 50% wood residue and a heat input of 760 MMBtu/hr hydrochloric acid emissions can be estimated as follows:

0.019	AP-42 lb/MMBtu for wood residue
760	MMBtu/hr biomass firing
50%	wood makeup of biomass
380	MMBtu/hr from wood
7.22	lb HCL/hr
7884	hr/yr based on a 90% capacity factor
28.5	TPY HCL

It is emphasized that this estimate may not be representative of actual HCl emissions from the NHPP boilers. As described previously, NHPP has no actual HCl test data for its boilers.

d. The vendor quote for FGD includes freight. Please revise cost effectiveness calculations accordingly.

Response: See Attachment I for revised cost effectiveness calculations.

e. Please provide information to support and justify the 25% contingency factor used to determine capital costs. Was the vendor provided a detailed description of the existing cogeneration boilers including design, existing control equipment, process flow diagrams, temperatures, fuels, exhaust characteristics and composition?

Response: The 25% contingency factor was based on retrofit application. Per the EPA OAQPS Cost Control Manual, Sixth Edition, "the most subjective part of a cost estimate occurs when the control system is to be installed on an existing facility. Unless the original designer had the foresight to include additional floor space and room between components for new equipment, the installation of retrofitted pollution control devices can impose an additional expense to "shoe-horn" the equipment into the right location." The provided 25% contingency factor covers unexpected modifications that may result in a retrofit application. Modifications may occur that affect the following areas:

- Auxiliary Equipment
- Handling and Erection
- Piping, Insulation, and Painting
- Site Preparation
- Off-Site Facilities
- Engineering, and
- Lost Production

Regardless of any quote received at this level of evaluation, a 25% contingency factor is appropriate for this retrofit application.

Comment 10: Revised Vendor Cost Quotes: For revised cost quotes, please provide the vendors with detailed descriptions of the existing plant, boilers, control equipment, fuels, configuration, flue gas characteristics, etc. Provide this information must with the revised cost quotes.

Response: Revised vender quotes have been developed with detailed descriptions of the existing plant, boilers, control equipment, fuels, configuration, flue gas characteristics, etc.

Comment 11: VOC Emissions: Based on test data, actual VOC emissions are less than 50 tons per year. As requested, the proposed project would result in potential VOC emissions of nearly 600 TPY.

a. The net VOC emissions increase is above the 40 ton per year PSD significant emission rate. Please provide a top-down BACT analysis for the control of VOC emissions. Such analysis should include such options as charcoal filtration, activated carbon injection, and catalytic oxidation.

Response: See Attachment J.

b. **The net VOC emissions increase is also above the 100 tons per year threshold, which requires an ambient impact analysis. Please discuss available options and techniques for addressing modeling concerns regarding VOC emissions and ozone impacts. Please contact Cleve Holladay at 850/921-8986 to discuss related modeling issues.**

<u>**Response:**</u> Cleve Holladay has been contacted regarding the potential VOC increase. If VOC emissions are significant, additional analysis for ozone could include air dispersion modeling or submittal of existing ambient data. However, as discussed in the response to Comment 11.a, based on actual emissions the estimated increase in VOC emissions is less than 40 TPY. Therefore, based on actual emissions, an ozone analysis would not be required.

<u>Comment 12</u>: **EPA and NPS: The Department is awaiting comment from EPA Region 4 and the NPS. We will forward any comments or requests for information submitted by these agencies as soon as possible.**

<u>**Response:**</u> NHPP will respond to additional comments from EPA and NPS as the Department requests.

Please feel free to call James Meriwether, New Hope Power Partnership, at (561) 993-1003, or Dave Buff, Golder Associates Inc., at (352) 336-5600, if you have any questions or comments concerning this additional information. We believe this information adequately responds to the RAI, and that the application can now be deemed complete.

Sincerely,

GOLDER ASSOCIATES INC.

David A. Buff

David A. Buff, P. E., Q. E. P.
Principal Engineer
Florida P. E. #19011
SEAL

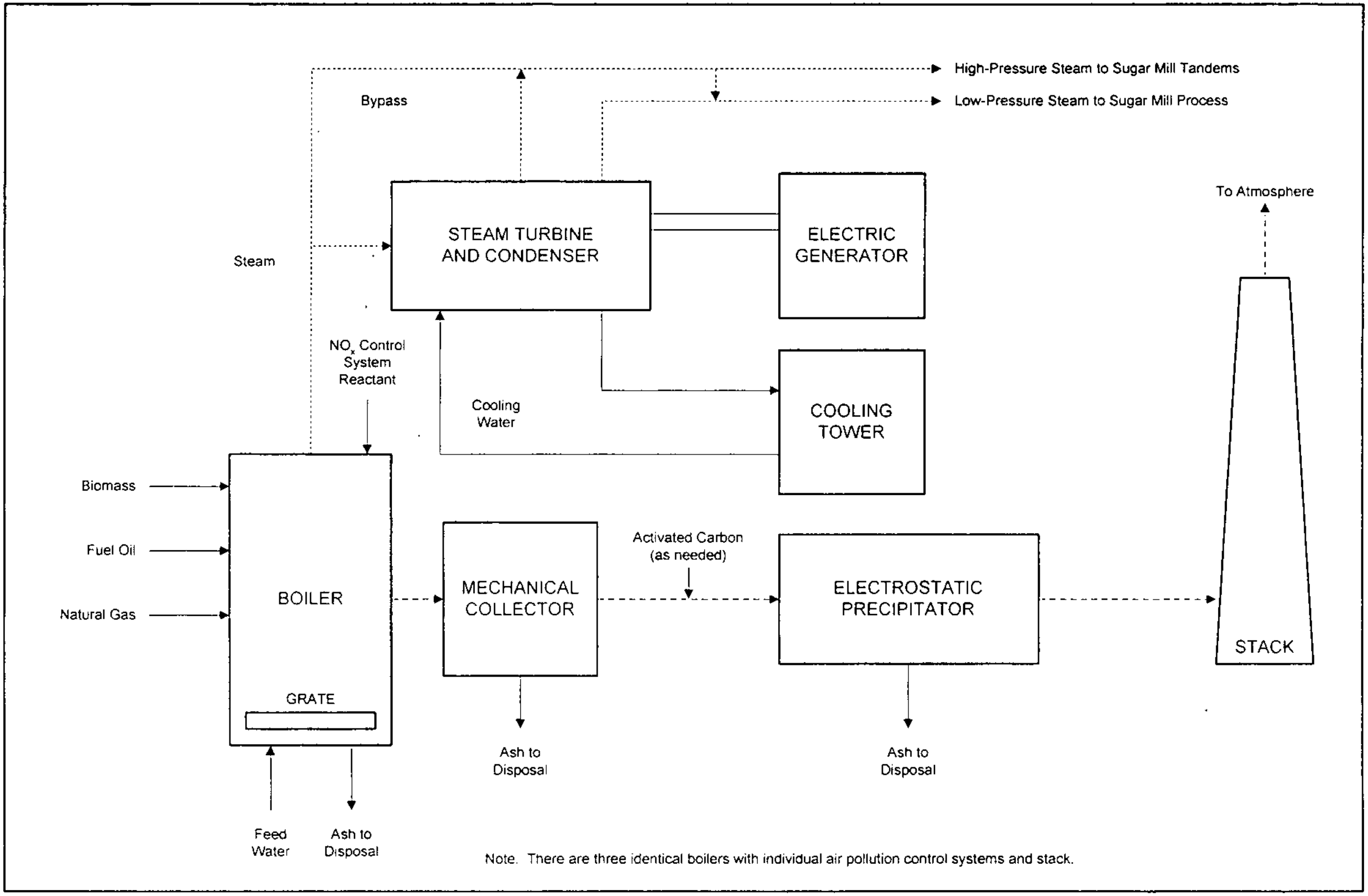
DB/DTL/jkw/nav

Enclosures

cc: R. Blackburn, DEP
J. Meriwether, NHPP
W. Tarr, Florida Crystals
G. Cepero, Florida Crystals
D. Dee, Landers & Parsons
D. Larocca, Golder
G. Kaiser
C. Holladay
G. Worrell, PBCHD
G. Little, EPA
G. Bunyak, NPS

ATTACHMENT A

PROCESS FLOW DIAGRAM



Attachment NH-FI-C3
Simplified Flow Diagram
New Hope Power Partnership Cogeneration Facility
South Bay, FL

Process Flow Legend
Solid/Liquid ⟶
Steam ⋯⋯▸

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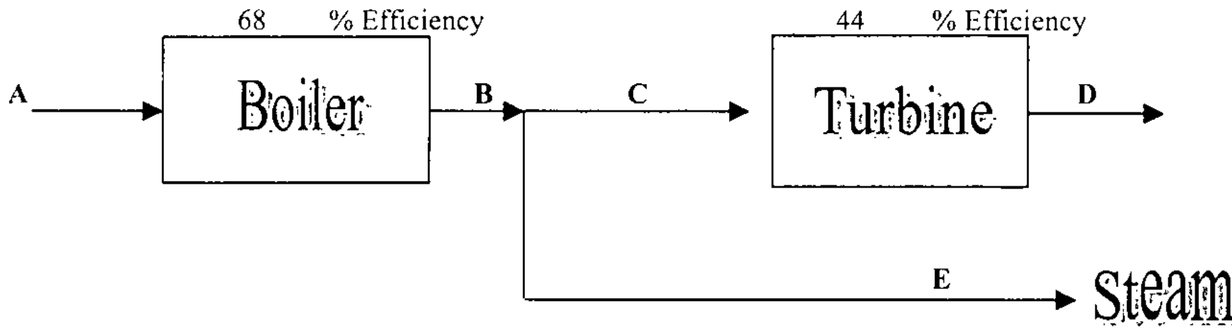
ATTACHMENT B

NO_x LB/MW-HR CALCULATION

NSPS Subpart Da - NOx lb per MW-Hr



Assumed Boiler/Turbine
30 % Total Efficiency

Case 1= 37.45 MW
Case 2= 25 MW
1MW = 3.4129 MMBtu/hr
Case 1= 127.81 MMBtu/hr
Case 2= 85.32 MMBtu/hr

Case 1 = Two Cogeneration Units in operation generating a total of 75 MW.
Case 2 = Three Cogeneration Units in operation generating a total of 75 MW.

	A MMBtu/hr	**B=(A*.68)** MMBtu/hr	**C=(D/.44)** MMBtu/hr	**D** MMBtu/hr	**E=(B-C)** MMBtu/hr
Case 1	760	516.8	289.71	127.81	227.09
Case 2	760	516.8	193.40	85.32	323.40

	Permit Limit NOx lb/(Input-MMBtu)	Subpart Da Gross Energy Output* MMBtu/hr	Equivalent NOx lb/(Output-MMBtu)	Equivalent NOx** lb/(MW-hr)
Case 1	0.15	241.36	0.4723	1.61
Case 2	0.15	247.02	0.4615	1.58
			Average	1.59

* Subpart Da Gross Energy Output = (Electrical Output + 1/2 Steam Energy)
** 1 MMBtu = 0.2928 MW-hrs

ATTACHMENT C

EQUIVALENT EMISSION RATES IN PPMVD @ 7% O_2

Table C-1. Equivalent Concentration-Based Emissions for NHPP Cogeneration Boilers Firing Biomass

Pollutant	Averaging Time	Maximum Emission Rate (lb/MMBtu)	Conversion Factor[a] ((lb/dscf)/ppm)	Equivalent Concentration lb/dscf[b]	Equivalent Concentration ppmvd @ 7% O_2
SO_2	3-hr	0.3	1.660E-07	2.16E-05	130
	24-hr	0.2	1.660E-07	1.44E-05	87
	Annual (12-month rolling)	0.06	1.660E-07	4.32E-06	26
NO_x	24-hr	0.2	1.194E-07	1.44E-05	121
	Annual (30-day rolling)	0.15	1.194E-07	1.08E-05	90
CO	1-hr (cold)	6.5	7.258E-08	4.68E-04	6,446
	1-hr (normal)	1.0	7.258E-08	7.20E-05	992
	8-hr (cold)	4.5	7.258E-08	3.24E-04	4,462
	8-hr (normal)	1.0	7.258E-08	7.20E-05	992
	Annual (12-month rolling)	0.35	7.258E-08	2.52E-05	347
VOC (as methane)	3-hr Compliance Test	0.06	4.159E-08	4.32E-06	104
Fluorides (as HF)	3-hr Compliance Test	7.0E-04	5.185E-08	5.04E-08	0.97

[a] Conversion factors for SO_2 and NO_x from 40 CFR 60 Appendix A-Method 19. All other factors converted based on the ratio of their molecular weights to SO_2.

[b] Based on the oxygen-based F factor for wood (40 CFR 60-Appendix A--Method 19) at standard conditions 68 °F and 760 mm Hg: $C_d = E(20.9\text{-}\%O2)/(20.9*Fd)$

Where, Cd = pollutant concentration (lb/scf)

E = pollutant emission rate (lb/MMBtu)

Fd = F factor = 9,240 dscf/MMBtu

Table C-2. Equivalent Concentration-Based Emissions for NHPP Cogeneration Boilers Firing Fuel Oil

Pollutant	Averaging Time	Maximum Emission Rate (lb/MMBtu)	Conversion Factor[a] ((lb/dscf)/ppm)	Equivalent Concentration lb/dscf[b]	Equivalent Concentration ppmvd @ 7% O_2
SO_2	All	0.05	1.660E-07	3.62E-06	22
NO_x	24-hr	0.2	1.194E-07	1.45E-05	121
	Annual (30-day rolling)	0.15	1.194E-07	1.09E-05	91
CO	All	1	7.258E-08	7.24E-05	997
VOC (as methane)	All	0.03	4.159E-08	2.17E-06	52

[a] Conversion factors for SO_2 and NO_x from 40 CFR 60 Appendix A-Method 19. All other factors converted based on the ratio of their molecular weights to SO_2.

[b] Based on the carbon dioxide-based F factor for fuel oil (40 CFR 60-Appendix A--Method 19) at standard conditions 68 °F and 760 mm Hg: $C_d = E(20.9\text{-}\%O2)/(20.9{*}Fd)$

Where, Cd = pollutant concentration (lb/scf)

E = pollutant emission rate (lb/MMBtu)

Fd = F factor = 9,190 dscf/MMBtu

Table C-3. Equivalent Concentration-Based Emissions for NHPP Cogeneration Boilers Firing Natural Gas

Pollutant	Averaging Time	Maximum Emission Rate (lb/MMBtu)	Conversion Factor[a] ((lb/dscf)/ppm)	Equivalent Concentration lb/dscf[b]	Equivalent Concentration ppmvd @ 7% O_2
SO_2	All	0.0058	1.660E-07	4.43E-07	3
NO_x	24-hr	0.20	1.194E-07	1.53E-05	128
	Annual (30-day rolling)	0.15	1.194E-07	1.15E-05	96
CO	All	0.08	7.258E-08	6.11E-06	84
VOC (as methane)	All	0.0053	4.159E-08	4.05E-07	10

[a] Conversion factors for SO_2 and NO_x from 40 CFR 60 Appendix A-Method 19. All other factors converted based on the ratio of their molecular weights to SO_2.

[b] Based on the carbon dioxide-based F factor for fuel oil (40 CFR 60-Appendix A--Method 19) at standard conditions 68 °F and 760 mm Hg: C_d = E(20.9-%O2)/(20.9*Fd)

Where, Cd = pollutant concentration (lb/scf)

E = pollutant emission rate (lb/MMBtu)

Fd = F factor = 8,710 dscf/MMBtu

ATTACHMENT D

NO_x BACT ANALYSIS

ATTACHMENT D

NO_x BACT ANALYSIS

INTRODUCTION

NHPP has three ABB-Combustion Engineering Inc. model VU-40 steam generating boilers. Each unit is designed for balanced draft furnace operation and fires primarily bagasse and wood chips (biomass) on a continuous ash discharge (CAD) spreader stoker. The CAD stoker configuration is designed to provide maximum combustion efficiency, reduced emissions, and quick response to boiler load changes, reliability, and serviceability. Bagasse and wood are conveyed to the boilers from the storage area and utilize a common feed system. The feed system incorporates a rotating feeder and pneumatic distributor. The rotating feeder, which is located away from the boiler and in front of the boiler front wall, fluffs the bagasse and wood chips.

From the feeder, the fuel is dropped into the discharge chute to the pneumatic distributor and is injected into the furnace above the grate. Lighter particles burn in suspension. Fuel not combusted in suspension falls to the grate to complete the process. This system promotes burning in suspension to improve combustion efficiency and reduce emissions.

The boilers utilize tangential overfire air to promote vigorous mixing of the combustion gases to maximize combustion efficiency and reduce pollutant emissions. Located in the four corners, the overfire air system injects hot air at high velocities into the furnace. In addition, the stoker design incorporates multiple undergrate zones for proper air distribution of air across the entire grate surface. This design allows for optimization of fuel combustion and also reduces pollutant emissions.

Additional air pollution control equipment serving each boiler consists of mechanical dust collectors and electrostatic precipitators (ESP) to control PM and heavy metal emissions, a selective non-catalytic reduction (SNCR) system for the control of NO_x emissions, and a carbon injection system for mercury (Hg) control. The following is provided as a top-down BACT analysis for NO_x emissions from the cogeneration boilers.

CONTROL TECHNOLOGY FEASIBILITY

The technically feasible NO_x controls for the cogeneration boilers are shown in Table D-1. As shown in the table, there are six types of NO_x abatement methods with various techniques within each method. Each available technique is listed with its associated efficiency estimate, identified as feasible or infeasible, and ranked based on control efficiency. Of the six categories of control, sorbents, chemical reduction of NO_x, and reducing peak temperature (Methods 1, 4, and 6) are the most common.

Potential Control Method Descriptions

Removal of Nitrogen from Fuel

Ultra-Low Nitrogen Fuel -- The primary fuel combusted in the cogeneration boilers is biomass consisting of bagasse and wood. Combustion of bagasse and wood results in emission of NO_x much lower than conventional fossil fuels due to the characteristically low levels of nitrogen associated with these fuels. The No. 2 fuel oil and natural gas backup fuels are also inherently low in nitrogen. Therefore, NHPP's cogeneration boilers are currently controlling NO_x emissions through the use of low nitrogen content fuels.

Oxidation of NO_x with Subsequent Adsorption

- Inject Oxidant -- The oxidation of nitrogen to its higher valence states makes NO_x soluble in water. When this is done a gas absorber can be effective. Oxidants that have been injected into the gas stream are ozone, ionized oxygen, or hydrogen peroxide. This NO_x reduction technique has not been demonstrated on large-scale boilers or with biomass combustion, and as such is not considered technically feasible for the NHPP cogeneration boilers.
- Non-Thermal Plasma Reactor (NTPR) -- This technique generates electron energies in the gas stream that generate gas-phased radicals, such as hydroxyl (OH) and atomic oxygen (O) through collision of electrons with water and oxygen molecules present in the flue gas stream. In the flue gas stream, these radicals oxidize NO_x to form nitric acid (HNO_3), which can then be condensed out through a wet condensing precipitator. NTPR has not been demonstrated on large-scale boilers or with biomass combustion, and as such is not considered technically feasible for the NHPP cogeneration boilers.

Chemical Reduction of NO_x

- Selective Catalytic Reduction (SCR) -- SCR uses a catalyst to react injected ammonia to chemically reduce NO_x. The catalyst has a finite life in flue gas and some ammonia slips through without being reacted. SCR has historically used precious metal catalysts, but can now also use base metal and zeolite catalyst materials. Catalyst poisoning due to biomass combustion renders SCR as not technically feasible for NO_x control for the NHPP cogeneration boilers. A discussion of the technical infeasibility of SCR is presented in Attachment E.
- Selective Non-Catalytic Reduction (SNCR) -- In SNCR, ammonia or urea is injected within the boiler or in ducts in a region where the flue gas temperature is between 900°C and 1,100°C (1,652 to 2,012°F). This technology is based on temperature ionizing the ammonia or urea instead of using a catalyst or non-thermal plasma. The temperature window for SNCR is very important because outside of it either more ammonia slips through the system or more NO_x is generated than is being chemically reduced. Adding additional controls for reducing peak temperature in the boiler may reduce thermal NO_x formation in the combustion zone, but may alter the temperature profile of the furnace and as a result alter the control of NO_x through the SNCR system. SNCR has been demonstrated as a feasible technology for biomass combustion and is currently employed as an add-on control device for the NHPP cogeneration boilers. The system achieves 40% to 50% NO_x reduction.
- $SCONO_x$™ -- An integration of proven, proprietary, patented catalytic oxidation and absorption technology, $SCONO_x$™ is recognized by the EPA as a pollution control technology that has been "Demonstrated in Practice," and is to be evaluated as an available control technology in the environmental impact of emissions of new Combined Cycle Gas Turbine power plants. There are only two applications currently utilizing $SCONO_x$™, these facilities are 30 MW co-generation unit with a GE LM 2500 gas turbine as the prime mover and a dual-fueled, 5 MW Solar Taurus turbine powered cogeneration system. $SCONO_x$™ has not been designed for or implemented on a biomass fired boiler. Therefore, it was not considered further.

Reducing Residence Time at Peak Temperature

- Air Staging of Combustion -- Combustion air is divided into two streams. The first stream is mixed with fuel in a ratio that produces a reducing flame. The second stream is injected downstream of the flame and makes the net ratio slightly excess air compared to the stoichiometric ratio. The stoker design of the NHPP cogeneration boilers incorporates multiple undergrate zones for proper air distribution of air across the entire grate surface. This design allows for optimization of fuel combustion and also reduces pollutant emissions.

In addition, the NHPP cogeneration boilers utilize over fire air, which acts as air staging of combustion.

- Fuel Staging of Combustion -- This is staging of combustion using fuel instead of air. Fuel is divided into two streams. The first stream feeds primary combustion that operates in a reducing fuel to air ratio. The second stream is injected downstream of primary combustion, causing the net fuel to air ratio to be only slightly oxidizing. Excess fuel in primary combustion dilutes heat to reduce temperature. The second stream oxidizes the fuel while reducing the NO_x to N_2.
- Inject Steam -- Injection of steam causes the stoichiometry of the mixture to be changed and dilutes calories generated by combustion. These actions cause combustion temperature to be lower and in-turn reduces the amount of thermal NO_x formed.

Reducing Peak Combustion Temperature

- Flue Gas Recirculation (FGR) -- Recirculation of cooled flue gas reduces combustion temperature by diluting the oxygen content of the combustion air and by causing heat to be diluted in a greater mass of flue gas. Heat in the flue gas can be recovered by a heat exchanger. This reduction of temperature lowers the NO_x concentration that is generated. If combustion temperature is held below 1,400°F, the thermal NO_x formation will be negligible. The NHPP cogeneration boiler's CAD stoker grate is designed with convective cooling resulting in grate operating temperatures below 1,400°F.
- Reburn -- In a boiler outfitted with reburn technology, a new set of natural gas burners are installed above the main burners. Natural gas is injected to form a fuel-rich, oxygen-deficient combustion zone above the main firing zone. Nitrogen oxides, created by the combustion process in the main portion of the boiler, travel upwards into the reburn zone and are converted to molecular nitrogen. The technology requires no catalysts, chemical reagents, or changes to the already existing burners. Typical reburn systems also incorporate redesign of the combustion air system to provide less excess air (LEA). Natural gas reburn is a feasible technology for the NHPP cogeneration boilers, however implementation would require new burners and a redesign of the existing fuel system and the resulting change in furnace characteristics would likely affect the NO_x removal performance of the existing SNCR urea injection system. In addition a reburn system would require displacement of approximately 20% of biomass with natural gas, which would result in a natural gas cost of approximately $4.5 million per year, while resulting in only 25% reduction of NO_x emissions. See Attachment F.
- Over Fire Air (OFA) -- When the primary combustion process uses a fuel-rich mixture, use of OFA completes the combustion. Because the mixture is always off-stoichiometric when combustion is occurring, the combustion temperature is suppressed. After all other stages of combustion, the remainder of the fuel is oxidized in the overfire air. NHPP's cogeneration boilers utilize tangential overfire air to promote vigorous mixing of the combustion gases to maximize combustion efficiency and reduce pollutant emissions. Located in the four corners, the overfire air system injects hot air at high velocities into the furnace.
- Less Excess Air (LEA) -- Excess airflow in combustion zone has been correlated to the amount of NO_x generated. Limiting the net excess airflow under 2% can strongly limit NO_x content of the flue gas. The NHPP cogeneration boilers utilize a biomass-fired system with pneumatic distributor for fuel feed system.
- Combustion Optimization -- Combustion optimization refers to the active control of combustion. Active combustion control measures seek to find optimum combustion efficiency and to control combustion at that efficiency. The NHPP's cogeneration boilers

have been optimized for combustion efficiency. However, the variable nature of biomass results in constant changes to optimization points.

- Low NO_x Burners (LNB) -- A LNB provides a stable flame that has several different zones. For example, the first zone can be primary combustion. The second zone can be a fuel reburning zone with fuel added to chemically reduce NO_x. The third zone can be the final combustion in low excess air to limit the temperature. This is not an option for biomass-fired system with pneumatic distributors for the fuel feed system. In this system, the fuel is dropped into the discharge chute to the pneumatic distributor and is injected into the furnace above the grate. Lighter particles burn in suspension. Fuel not combusting in suspension, falls to the grate to complete the process. However, NHPP does utilize low-NO_x burners for oil and natural gas firing.

ECONOMIC, ENVIRONMENTAL AND ENERGY IMPACTS

NHPP's cogeneration boilers are currently utilizing a combination of NO_x control technologies that result in the highest emissions reductions that are technically feasible and have been demonstrated on biomass-fired boilers (refer to Table D-1). Additional NO_x controls resulting in emission levels lower than current BACT levels would result in an unreasonable economic burden for NHPP. Nevertheless, a cost analysis is provided for the addition of a natural gas reburn system for further NO_x reduction of 25%.

Economic Analysis

The year 2003 vendor cost quote and control cost analyses of natural gas reburn (NGR) for the cogeneration boilers are provided Attachment F. The total estimated capital cost of NGR for one cogeneration boiler is $856,000. Based on the vendor quote with a NO_x control efficiency of 25%, the total annualized cost of applying NGR is estimated at $4,661,281. The resulting cost effectiveness of adding NGR with this level of control is estimated at over $41,000 per ton of NO_x removed.

For this system the baseline emissions were estimated based on 0.15 lb/MMBtu, equivalent to the current emission limit. A capacity factor of 90 percent was assumed for both baseline and maximum future emissions, since it is not feasible for the cogeneration boilers to operate at 100 percent capacity factor year-around. The high operating costs are a result of the requirement to replace 20% of the biomass with natural gas.

Environmental Impacts

As shown in Table 6-11 of the application, the maximum predicted annual NO_2 impacts for the proposed project are less than half of the EPA Class II significant impact level of 1.0 $\mu g/m^3$. In addition, the maximum predicted annual NO_2 impact on the EPA Class I area is only 4.7% of the EPA Class I significant impact level of 0.1 $\mu g/m^3$. The addition of natural gas reburn would result in an insignificant reduction of ambient impacts that are already below EPA significance levels for both Class I and II areas.

Energy Impacts

Significant energy penalties occur with natural gas reburn. As discussed previously, natural gas reburn will require the displacement of 20% of the biomass fuel with natural gas. As a result, annual natural gas fuel costs will be nearly $4,500,000 based on a natural gas cost of $5/Mcf.

BACT SELECTION
As summarized in the application, a review was performed of previous BACT determinations for similar biomass-fired industrial and electric utility boilers listed in the RACT/BACT/LAER Clearinghouse on EPA's web page. From this information, BACT determinations issued within the last 10 years (i.e., since 1992) were identified. A summary of these BACT determinations was presented in Appendix D, Table D-3, of the application. Note that one fluidized bed biomass boiler located in California (SAI Energy, Inc.) was not included in the table because of the distinct difference between NHPP's spreader stoker boilers and a fluidized bed boiler.

Aside from one exception, previous BACT determinations for NO_x have ranged from 0.14 to 0.46 lb/MMBtu. The one exception is a limit of 0.10 lb/MMBtu limit for Multitrade Limited Partnership in Virginia. The Multitrade limit was issued over 10 years ago. In comparison to the NHPP cogeneration facility, Multitrade Limited Partnership operates as a peaking plant that burns 100-percnet wood fuels. The NHPP facility burns a mixture of bagasse and wood, No. 2 fuel oil, and natural gas, and operates at a very high capacity factor. Since Multitrade operates as a peaking plant with limited hours of operation per year, and higher generated revenue, higher urea usage and therefore a lower NO_x limit is technically and economically feasible for this facility.

For NHPP, the existing combination of SNCR, tangential OFA, low nitrogen fuel (wood & bagasse), along with the boiler's water-wall heat absorption, resulting in lower peak gas temperatures, can achieve the maximum amount of emissions reduction that is economically feasible, is technically feasible, and is demonstrated in practice. Additional controls should be rejected as BACT for the NHPP cogeneration boilers for the following reasons:

- Additional controls to reduce gas temperature and therefore reduce thermal NO_x formation may result in decreased performance of the SNCR system, which is designed to operate within a specific temperature window.
- NHPP's cogeneration boilers currently utilize all four of the technically feasible NO_x abatement methods identified for stokers and spreader grates, identified by EPA's Technical Bulletin, *"Nitrogen Oxides (NO_x), Why and How They are Controlled."* These methods include the following:
  - Removal of Nitrogen (Combustion of Biomass Fuel)
  - Chemical Reduction of NO_x (SNCR)
  - Reducing Residence Time at Peak Temperature (Boiler design)
  - Reducing Peak Temperature (Water wall heat absorption)

  The fifth NO_x abatement method, and not used by NHPP's cogeneration boilers, is oxidation of NO_x with subsequent absorption. This method has not been demonstrated on large boilers or on the combustion of bagasse.
- SCR has been determined to be technically infeasible because biomass combustion produces high levels of potassium, sodium, and phosphorous in the flue gas stream. The presence of these substances in the flue gas causes catalyst poisoning, leading to catalyst deactivation.
- The requested NO_x permit limit of 0.15 lb/MMBtu is representative of previous BACT determinations for NO_x, which range from 0.14 to 0.46 lb/MMBtu
- Additional control with natural gas reburn results in high annual costs and low emission reduction potential, with a cost effectiveness of over $41,000 per ton of NO_x removed.

Therefore, the proposed NO_x BACT limit for NHPP is based on the existing combination of SNCR, tangential OFA, low nitrogen fuel (bagasse), along with the boiler's water-wall heat absorption and operating experience at the cogeneration facility. The proposed NO_x limit is a 30-day rolling NO_x

standard of 0.15 lb/MMBtu when firing an authorized fuel. This is consistent with the 30-day averaging period specified in NSPS Subpart Da and represents a much lower limit than the NSPS (0.60 lb/MMBtu for solid fuel and 0.20 lb/MMBtu for gas and oil firing).

Table D-1. NHPP Cogeneration Boilers NO_x Control Technolgy Feasibility

NOx Abatement Method	Technique Now Available	Estimated Efficiency	Feasible and Demonstrated (Y/N)	Rank Based on Control Efficiency	Employed by NHPP (Y/N)
1. Removal of nitrogen from fuel	Ultra-Low Nitrogen Fuel	No Data	Y	4	Y
2. Oxidation of NOx with subsequent absorption.	Inject Oxidant	60 - 80%	N	NTF	N
	Non-Thermal Plasma Reactor (NTPR)	60 - 80%	N	NTF	N
3. Chemical reduction of NOx	Selective Catalytic Reduction (SCR)	35 - 80%	N	NTF	N
	Selective Non-Catalytic Reduction (SNCR)	35 - 50%	Y	1	Y
	$SCONO_X$™	35 - 80%	N	NTF	N
4. Reducing residence time at peak temperature	Air Staging of Combustion	50 - 65%	Y	2	Y
	Fuel Staging of Combustion	50 - 65%	Y	2	N
	Inject Steam	50 - 65%	Y	2	N
5. Reducing peak combustion temperature	Flue Gas Recirculation (FGR)	15 -25%	Y	3	N
	Natural Gas Reburning (NGR)	15 -25%	Y	3	N
	Over Fire Air (OFA)	15 -25%	Y	3	Y
	Less Excess Air (LEA)	15 -25%	Y	3	N
	Combustion Optimization	15 -25%	Y	3	Y
	Reduce Air Preheat	15 -25%	Y	3	N
	Low NOx Burners (LNB) - biomass	15 -25%	Y	NTF	N
	-oil/gas	15 -25%	Y	3	Y

NTF = Not Technically Feasible

ATTACHMENT E

TECHNICAL FEASIBILITY OF SCR

ATTACHMENT E

TECHNICAL FEASIBILITY OF SCR

An investigation into the feasibility and associated cost of using SCR for NHPP's biomass fired cogeneration boilers has been performed. The results of this investigation lead to the conclusion that SCR is technically infeasible for application to biomass-fired boilers, and therefore, technically infeasible for application to NHPP's cogeneration boilers, as described below.

Previously, a cost analysis was submitted to FDEP based on a cost quote from SCR vendor Hamon Research Cottrell (Hamon). All of the other vendors we contacted declined to provide a cost quote, citing their inability to provide SCR for a biomass-fired unit. Continued discussions between Hamon and their catalyst suppliers has resulted in Hamon's retraction of their cost quote. Hamon's catalyst supplier, Ceram, has stated that the presence of potassium, sodium, and phosphorus in the gas stream, as a result of biomass combustion, will deactivate the catalyst at an unreasonably high rate. Ceram also stated that they know of no SCR in commercial operation, fired with biomass, which shows good performance. For these reasons, Hamon has cancelled their cost quote and recommended the use of SNCR for the NHPP boilers.

SCR has been determined to be technically infeasible for the following reasons (refer to the following pages for all documentation):

- Biomass combustion produces high levels of potassium, sodium, and phosphorous in the flue gas stream. The potassium, sodium, and phosphorous in the flue gas causes catalyst poisoning, leading to catalyst deactivation. Hamon's catalyst supplier, Thomas Nagle of Ceram, stated "The catalyst will be strongly deactivated by potassium, sodium, and phosphorous."
- There exists no successful commercial experience of SCR applied to biomass-fired boilers. Therefore, Golder was unable to find a vendor with any experience with designing or installing an SCR system for wood or bagasse-fired boilers. The only vendor (Hamon) that provided a cost quote for SCR for the cogeneration boilers withdrew the quote after more carefully reviewing the PM loading and metals content in the flue gas. Hamon states "...we have queried catalyst manufacturers in order to determine the applicability of SCR on boilers using biomass as fuel. All of those who we spoke with indicated that SCR was not applicable to this application and declined to quote their products...The reason SCR would not function in this case is that the fuel contains metals which act as poisons for the catalyst, unacceptably reducing its effective life. This is true whether the SCR is a stand alone system or if a hybrid system using SCR in conjunction with SNCR were employed."

  The following vendors also stated that they do not provide SCR for biomass-fired boilers, and declined to bid on this project:
  - Engelhard Corp.
  - Babcock & Wilcox
  - Wheelabrator A.P.C.

  Haldor Topsoe, a catalyst supplier, was willing to supply a cost quote for the catalyst for an SCR applied to biomass cogeneration boilers, but they have no experience with bagasse or wood alone or bagasse and wood fired in combination. Flemming Hansen of Haldor Topsoe stated "Regarding the use of SCR on biomass fired boilers...the main issue is the alkalis, predominantly potassium in the biomass. Potassium is a severe catalyst poison and can in worst-case scenario cause complete deactivation within a few thousand hours of operation...we don't have any experience with bagasse."

- Swedish pilot plants have experienced unacceptable deactivation rates of the catalyst. Data from the first several years of operation have indicated that the catalyst for a wood-fired boiler deactivates about 3 to 4 times faster than similar coal-fired boilers. The CHEC Research Centre in Denmark studied a pilot plant and "found that by co-combustion of coal with biomass or separate biomass combustion, SCR catalysts deactivate at an unacceptable rate." Also posted on the website for Chemical Engineering II, Center for Chemistry and Chemical Engineering, Lund Institute of Technology, Lund University, Sweden, it is stated "Four larger Swedish plants are using the SCR technique in combination with bio-fuel combustion...The experiences from the first few years on stream show a relatively fast deactivation...using 100% wood as fuel."
- An EPA (1999) NO_x Control Technical Bulletin (EPA 456/F-99-006R) only lists SNCR as control technology for wood fired boilers.
- EPA's Air Pollution Control Cost Manual (Sixth Edition) only lists coal, distillate oil, residual oil, and natural gas as potential fuels for SCR applications for industrial boilers.
- Literature regarding the application of SCR for biomass-fired boilers has indicated problems with catalyst deactivation. A technical paper entitled "Effects of Fuel Characteristics on SCR Installations" was authored by Dr. W. Scott Hinton, P.E., of Foster Wheeler and presented at the US DOE National Energy Technology Laboratory's 2002 Conference on Selective Catalytic Reduction (SCR) and Selective Non-Catalytic Reduction (SNCR) for NO_x Control. The summary states "Specialty fuels such as waste or biomass present a challenge for SCR technology due to the relatively little worldwide experience on these unusual fuels...Biomass, due to high levels of constituents such as sodium and potassium, has been problematic in terms of catalyst poisoning and the resulting shortened catalyst life." Refer to the attached paper summary.
- Another technical paper presented at the 2001 Air & Waste Management Association (A&WMA) conference by Dr. E. Joseph Duckett, P.E. and David Mysko, P.E., of Eichleay Engineers, Inc., states "SCR operates most efficiently at temperatures between 575 and 800 degrees F and when flue gas is relatively free of particulate matter, which tends to contaminate or "poison" the catalytic surfaces...Within the industrial sector, SCR has been applied primarily to gas or oil-fired units due to the low particulate emissions and resultant low probability of catalyst plugging with using these fuels." Biomass flue gases have high particulate content.

In summary, SCR is technically infeasible for the NHPP cogeneration boilers.

HAMON

October 22, 2002

Ms. Fawn Howard
Golder Associates Inc.
Gainsville, Florida

Subject: Florida Crystal
NOx Emissions Control Project
HR-C Proposal No. P-6171

Dear Ms. Howard:

At your urging we have reviewed our offer for three SCR systems for Florida crystal. As such, we have investigated the use of SCR on boilers which were fueled by wood and other biomass. In particular, we have queried catalyst manufacturers in order to determine the applicability of SCR on boilers using biomass as fuel. All of those who we spoke to indicated that SCR was not applicable to this application and declined to quote their products. I will attach an e-mail from one of the catalyst vendors which states his position and which lists several references to SCR on biomass. The reason SCR would not function in this case is that the fuel contains metals which act as poisons for the catalyst, unacceptably reducing its effective life. This is true whether the SCR is a stand alone system or if a hybrid system using SCR in conjunction with SNCR were employed.

As a result, we must recant our earlier budgetary proposal for SCR's for the cogeneration boilers which were to burn biomass. Since the package boiler will burn natural gas or fuel oil, SCR will be applicable and I attach our revised proposal for just the package boiler. We have provided two alternatives, one for flue gas at a temperature of 410 degrees F and a second for flue gas at a temperature of 700 deg F.

We would like to indicate also, that should temperatures on the order of 1800 deg F be available somewhere in the cogeneration boilers, SNCR would be applicable. Modest NOx reductions on the order of 40% would be achievable with this process.

Sincerely,

Hamon Research-Cottrell

Alfred J. Drabnis
Proposal Manager

Howard, Fawn

From: DRABNIS Alfred [alfred.drabnis@hamon.com]
Sent: Monday, October 21, 2002 1:46 PM
To: 'fhoward@golder.com'
Cc: GIALANELLA Mario
Subject: FW: P-6171

Fawn,

I am forwarding this to you per Mario Gialanella's request. Mr. Nagl indicates that SCR on biomass has not been successful. It lists three websites which can be accessed which support this statement.

I will work up a revised proposal on the package boiler and forward it to
you shortly.

Regards,

Al Drabnis

-----Original Message-----
From: Nagl Thomas [mailto:Thomas-Nagl@ceram.net]
Sent: Tuesday, September 24, 2002 1:04 PM
To: DRABNIS Alfred
Cc: Aumann Michael; Orehovsky Kurt; Campbell Lynn; Holscher Greg; Diego
Mosca (E-Mail)
Subject: AW: P-6171

Dear Al,

Thank you for your prompt response.
As far as we know there is no SCR in commercial operation fired with biomass
which shows good performance.
The catalyst will be strong deactivated by potassium, sodium and phosphorus.
Most of the proper working projects are pilot plants.
Please find below some papers concerning this topic.
http://www.chec.kt.dtu.dk/research/labfacilities/scrmasnedo.htm
http://www.fetc.doe.gov/publications/proceedings/02/scr-sncr/hintonsummary.p
df http://www.chemeng.lth.se/pk/english/projects/deactivation.htm We will
discuss the design of this catalyst internally and please expect an answer
end of this week.
Best regards,
Thomas

PORZELLANFABRIK FRAUENTHAL GmbH
Phone: +43-(0)3462-2000-201
Fax: +43-(0)3462-2000-311
E-mail: thomas-nagl@ceram.net

CHEC Research Centre
Combustion and Harmful Emission Control

Home

Laboratory facilities

Laboratories
Pilot scale laboratories

Experimental setups

Jet Bubbling Reactor
High temperature oven
Flow reactor setup
Low temperature corrosion
Fluidized/fixed bed reactor
SCR pilot plant
SCR Masnedø
Desulphurization pilot plant
Solid fuel flow reactor
Full scale measurements

Analytical equipment

Heating stage microscope
Particle size analyzer
TGA/STA
Ion chromatograph
BET and Hg porosimetry
High Temperature viscometer
FTIR

SCR Masnedo

Selective catalytic reduction of NO by NH3 is the most common method of flue gas cleaning on coal fired power plants. However, it has been found that by co-combustion of coal with biomass or separate biomass combustion, SCR catalysts deactivate at an unacceptable rate. An experimental setup exposing SCR catalyst to a real biomass flue gas is established at Masnedø CHP.

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CHEC Research Centre
Combustion and Harmful Emission Control

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SCR (Selective Catalytic Reduction) pilot plant

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Laboratories
Pilot scale laboratories

Experimental setups
Jet Bubbling Reactor
High temperature oven
Flow reactor setup
Low temperature corrosion
Fluidized/fixed bed reactor
SCR pilot plant
SCR Masnedø
Desulphurization pilot plant
Solid fuel flow reactor
Full scale measurements

Analytical equipment
Heating stage microscope
Particle size analyzer
TGA/STA
Ion chromatograph
BET and Hg porosimetry
High Temperature viscometer
FTIR

Selective catalytic reduction of NO by NH3 is the most common method of flue gas cleaning on coal-fired power plants. However, it has been found that by co-combustion of coal with biomass or separate biomass combustion, SCR catalysts deactivate at an unacceptable rate. A pilot scale reactor for testing the activity of catalyst elements for Selective Catalytic Reduction of NO by NH3 has been established.

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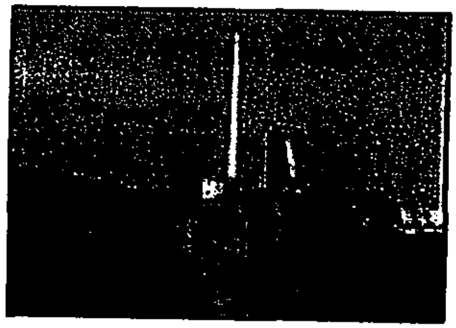
Last updated 02-04-01

SCR-catalysts in Biofuelled Power-stations



The SCR technique is interesting for removal of NO_x since it gives the highest NO_x reduction of all commercially available technologies (80-90 %). It also gives a relatively small ammonia slip and no nitrous oxide emission. This is valid when the catalyst is in good condition. The SCR technique has become the dominant deNO_x technology when coal is used as fuel with an expected catalyst lifetime of at least 3-5 years. Because the cost of exchange of catalyst modules is the dominating part of the operation costs it is imperative, both for the economy and the performance, that decrease in lifetime of the catalyst ('deactivation') can be minimised. If it's possible to limit the deactivation to the degree experienced at coal combustion the SCR gives a higher net income from the NO_x fee system when applied to a 125 MWth boiler compared e.g. to the SNCR technique.

Four larger Swedish plants are using the SCR technique in combination with bio fuel combustion and these plants is one of the first references in the world for SCR in combination with this fuel. The experiences from the first years on stream show a relatively fast deactivation. In this project the cause and the extent of catalyst deactivation has been investigated when using 100 % wood as fuel. The trend of deactivation has been studied as a function of the flue gas temperature, the type of catalyst and the type of combustion technique used. The field tests has been performed in a CFB boiler in Norrköping firing forest residues and in a boiler in Jordbro firing pulverised wood (PC). Samples of four different commercial catalyst types have been installed in a test rig connected to the convection section of the boiler.

The results after 2100 hours show a large difference in deactivation trend between the two plants; when using a conventional honeycomb catalyst 80 % of the original activity remains in the CFB boiler but only 20 % remains in the PC boiler. The deactivation in the CFB boiler is about 3 to 4 times faster than what is expected for a conservative design for a coal fired boiler. The results show that the general deactivation trend is similar for the plate and the honeycomb catalyst types. With a catalyst optimised for bio fuels the deactivation rate was about 2/3 compared to the conventional catalyst. At a working temperature of 315 °C the deactivation was not as rapid as at 370 °C. The amount of easily dissolved potassium increases on the surface of the catalyst, especially in the PC boiler, and this is probably the cause of deactivation. The total amount of potassium in the flue gas is about 5 times higher in the CFB boiler compared to the PC boiler. This indicates that only a certain form of potassium attacks the catalyst and that the total alkali content of the fuel is not a good indicator on the deactivation tendency.

The potassium on the catalyst dissolves in water and sulphuric acid. A wash of deactivated catalyst samples with water resulted in higher activity than for the fresh samples if the washing was complemented by sulphatisation by sulphur dioxide. After a sulphatisation procedure with only 500 ppm SO_2 the activity was regained to at least 90 % even for heavily deactivated samples. The combination of sulphatisation, periodical washing, lower temperature and use of an optimised catalyst are very promising measures increase the catalyst lifetime and to decrease the operation costs for SCR in bio fuel fluidised bed based power plants. Therefore, a thorough investigation of these measures is warranted.

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This page was last updated 1999-05-04

From: Flemming Hansen [mailto:FGH@topsoe.com]
Sent: Friday, June 07, 2002 5:48 PM
To: 'fhoward@golder.com'
Cc: Torben Slabiak; Gloria Dixon
Subject: Use of SCR in Biomass fired boiler project No 0137678

Dear Ms. Howard,

Regarding the use of SCR on biomass fired boilers it is our experience that this is best done after the particulate removal e.g. ESP or baghouse.
The main issue is the alkalis predominately potassium in the biomass.
Potassium is a
severe catalyst poison and can in worst case scenario cause complete deactivation within a
few thousand hours of operation. In case of co-firing wood
with coal a portion of the potassium will be adsorbed on the fly ash in stead of the catalyst and the deactivation appears to be less and something we can design around.
For cofirng straw and coal there is no real benefit however and we would believe
that to be the case for bagasse and coal as well, although we don't have any experience with bagasse.

For bagasse and wood firing it is therefore our recommendation that the SCR is installed downstream the bag house or ESP as they will
minimize any poisoning from the potassium in the fluegas.

Should this be of interest then we will be pleased to study the cases further and present a budget cost for the SCR.

Sincerely,

Flemming Hansen
Sales Manager DeNOx Catalysts
Haldor Topsoe, Inc.
Tel.: 281-228-5120
Fax: 281-228-5129

EFFECTS OF FUEL CHARACTERISTICS ON SCR INSTALLATIONS

W. Scott Hinton, Ph.D., P.E.
Foster Wheeler Energy Corporation, 1612 Smuggler's Cove Circle, Gulf Breeze, FL 32563
E-mail: shinton@wshinton.com; Telephone (850)-936-0037; Fax: (850)-936-0064

SUMMARY

The recent implementation of SCR technology to various combustion processes has demonstrated the strong effect that fuel characteristics have on the SCR installation. The general fuel selection, such as gas, oil, or coal will influence the basic design of the facility in terms of ability to cope with ash, soot, sulfur etc., thus affecting parameters such as catalyst pitch, materials of construction, and general size and layout. Specific fuel parameters such as the presence of catalyst poisons, unusual trace elements, or unfavorable particulate will strongly affect the specific facility design. Alternate fuels, even though combusted for a relatively short period of time, may govern the overall design of an SCR facility due to the strong adverse impacts during their short burn durations. Traditionally, clean natural gas has represented the least demanding fuel case for an SCR, with installation difficulty increasing as fuels become heavier, progressing through light to heavy fuel oil, residual refinery fuels, high rank to low rank coals, and finally special solid fuels such as municipal wastes, industrial wastes, or biomass. These ranks of difficulty are not strict, however, as the adverse characteristics of one particular fuel may outweigh the adverse impacts of another fuel that generally represents a more difficult application. For instance, a coal-fired installation with high-rank, low-poison coal may actually be less demanding than an installation burning a heavy fuel oil with high contaminant and particulate levels. For convenience, the discussions are divided three categories; 1) gaseous fuels, consisting of natural gas and various process gases, 2) liquid fuels, consisting of various ranks of refined petroleum fuels and residual distillation products, and 3) solid fuels, consisting of cokes, coals, wastes, and biomass.

Gaseous fuels have traditionally consisted primarily of clean natural gas, but in recent years process or syn-gas installations have become more common. These installations may present a variety of problems for SCR technology due to fuel constituents such as sulfur, fine particulate, and various heavy metals. These applications must be treated on a case-by-case basis to fully determine the potential for adverse impacts on the SCR catalyst. In many cases insufficient information is available to fully determine the impacts and testing may be required to determine parameters such as trace flue gas constituents and total particulate levels.

Various ranks of fuel oils are combusted in both conventional boilers and gas turbines. As with process gases, these fuels may range widely in terms of sulfur content and metals content. In addition, the particular fuel and combustion process will determine the amount of fine particulate or soot that may be formed, thus dictating catalyst geometry and the need for sootblowing. Vanadium content in fuel oils is of special concern due to the high SO_2 oxidation rates that may occur with the build-up of vanadium on the catalyst. This phenomenon, along with fuel sulfur level, will impact the acceptable ammonia slip level and minimum operating temperature for any given facility.

SCR applied to coal-fired facilities has traditionally been an area of focus for the industry. Coal characteristics such as ash content, sulfur levels, and trace metals content will influence the specific catalyst design and overall installation design greatly. As more detailed operating histories are gained for various coals, optimum SCR specifications are being developed which minimize the cost of NOx removal. Currently the most crucial coal parameters evaluated are ash content, sulfur concentration, and arsenic and calcium levels. These parameters, along with operating temperature and gas velocities, will dictate the catalyst formulation and geometry. The coal characteristics will also influence parameters such as specified maximum ammonia slip, ductwork design, and equipment design for corrosion resistance.

Specialty fuels such as waste or biomass present a challenge for SCR technology due to the relatively little worldwide experience on these unusual fuels. Materials such as municipal solid waste will contain a wide variety of potential catalyst poisons, both known and unknown. This limits the ability to predict catalyst life and to properly compare the economics of SCR technology to other NOx reduction technologies. Biomass, due to high levels of constituents such as sodium and potassium, has been problematic in terms of catalyst poisoning and the resulting shortened catalyst life. Blending of various specialty fuels with traditional fuels such as coal has been proposed as an advantageous solution, but little long-term data is available to fully assess the impacts of these fuel blends. As with many fuels, the exact impact of specialty fuels on SCR must be evaluated on a case-by-case basis, and in many circumstances the exact effects on the SCR process may be unknown.

Advanced NO_x Controls for Industrial Sources

Paper No. 28 Session No. EI-3a

E. Joseph Duckett, Ph.D., P.E. and David Mysko, P.E.
Eichleay Engineers, Inc., 6585 Penn Avenue, Pittsburgh, PA 15206-4407

ABSTRACT

Federal regulatory pressure to reduce urban ambient ozone concentrations has lead to a series of proposed new state regulations limiting emissions of nitrogen oxides (NO_X). Although many of the regulatory pressures for NO_X reduction have focused on electric utility power plants, the new regulations also affect selected industrial sources, primarily existing large industrial boilers. New industrial sources face even tighter NO_X emission limits required to demonstrate Best Available Control Technology (BACT) or Lowest Achievable Emission Rate (LAER). After briefly reviewing the regulatory pressures affecting industrial sources, this paper overviews the technologies available for NO_X control from industrial sources. Both combustion sources and non-combustion NO_X sources are discussed. The principal technologies covered are: low NO_X burners; selective catalytic reduction; and wet chemical scrubbing. An illustration of a facility-wide control system optimization to minimize costs under a cap and trade program is presented.

INTRODUCTION

Air emissions of nitrogen oxides (NO_X) are generated by both combustion and non-combustion sources. Not too many years ago, as recently as the late 1980's, NO_X emissions were almost exclusively associated with automobiles and electric utility power plants. Even more recently, through the mid-1990's, most of the regulatory attention for NO_X control from stationary sources was still focused on fossil fuel-fired power plants within the electric utility industry. This is reflected in the Acid Deposition Control provisions (Title IV) of the 1990 Clean Air Act Amendments which restricted NO_X emissions from existing coal-fired boilers, but only at utility power plants.

NO_x emissions are regulated from at least three directions. The primary purpose of NO_X emission control is to reduce ambient concentrations of tropospheric (ground level) ozone. NO_X in the presence of volatile organic compounds (VOC's), heat and sunlight, enters into a complex series of photochemical reactions resulting in the production of ozone, a primary constituent of urban "smog". The U.S. EPA established a National Ambient Air Quality Standard (NAAQS) for ozone and has determined that several areas within the U.S. (primarily urban areas) are not in attainment with this ambient standard. These non-attainment areas are required to develop emission control programs to restrict NO_X emissions. Title I (Section 184) of the same 1990 Amendments to the Clean Air Act created a 12-state "Ozone Transport Region" within the northeastern United States. Within these entire states, a multi-phased program is required to restrict NO_X and other emissions.

SCR operates most efficiently at temperatures between 575 and 800 degrees F and when the flue gas is relatively free of particulate matter, which tends to contaminate or "poison" the catalytic surfaces. In some cases reheating of the flue gas is needed to meet temperature requirements, impacting the cost of the system. To avoid reheat requirements, some manufacturers are currently developing or have already developed special low-temperature catalysts which can be used at temperatures as low as 400 degrees F. Because catalysts lose their effectiveness over time due to "poisoning" or clogging of catalyst pores, they must be replaced periodically. On large boilers, it has been reported that catalyst replacement may be necessary every 1 to 5 years, depending on the application and the level of contaminants in the fuel.

Until recent years, SCR had seen very limited application on boilers in the U.S. Most of the industrial applications of this control technology had been in Japan, where much of the original SCR technology development took place. [11] Within the industrial sector, SCR has been applied primarily to gas or oil-fired units due to the low particulate emissions and resultant low probability of catalyst plugging when using these fuels. Data from Japanese oil-fired industrial boilers retrofitted with SCR show NO_x reductions ranging from 85 to 90 percent. These units had controlled NO_x levels between 0.02 and 0.03 lb/MMBtu, operating with flue gas treatment temperatures of 575 to 700 degrees F. Results from tests conducted on three natural-gas and two coal-fired boilers with SCR showed more moderate reduction efficiencies of 53 to 80 percent. In summary, NO_x reduction efficiencies with SCR have been reported in the range between 53 and 90+ percent.

The retrofit of SCR to an existing boiler requires far more extensive modifications than does SNCR, as the SCR reactor must be placed in the existing flue gas path where the temperature is sufficiently high for efficient NO_x control. This is in addition to the required installation of reagent injectors and storage and control equipment.

NON-COMBUSTION NO_X CONTROL TECHNOLOGIES

Almost by definition, controls for non-combustion NO_x sources are not as temperature-based as controls for combustion sources. Four examples of control technologies for non-combustion sources are water scrubbing; chemical scrubbing; oxidation/reduction scrubbing and reagent substitution some NO_x control options for non-combustion sources are summarized in Table 3. Each of these approaches is discussed below.

Water Scrubbing

Because of the solubility of NO_2 in water, modest reductions in NO_x emissions can be achieved by simply scrubbing with water. The actual reduction in NO_x emissions is dependent on the proportion of NO_2 in the exhaust and vented gases. For mixed acid pickling in the stainless steel industry, NO_2 represents only about one-third of the total NO_x. With water scrubbing achieving a 50% removal efficiency for NO_2, this equates to a reduction of only about 15 percent from the total uncontrolled NO_x emission rate. [12]

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EPA AIR POLLUTION CONTROL COST MANUAL

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Office of Air Quality Planning and Standards
Research Triangle Park, North Carolina 27711

Ammonia sulfates also deposit on the fly ash. Ammonia content in the fly ash greater than 5 ppm can result in off-gassing which would impact the salabilty of the ash as a byproduct and the storage and disposal of the ash by landfill. [10] (See Chapter 1 SNCR)

Formation of Arsenic Oxide

Arsenic oxides (As_2O_3), formed during combustion of fuel containing arsenic, cause catalyst deactivation by occupying active pore sites. Coal burning boilers are particularly susceptible to arsenic poisoning. Limestone ($CaCO_3$) can be injected into the flue gas to generate the solid $Ca_3(AsO_4)_2$, which does not deposit on the catalyst and can be removed from the flue gas with a precipitator.

Retrofit Versus New Design

Retrofit of SCR on an existing boiler has higher capital costs than SCR installed on a new boiler system. The magnitude of the cost differential is a function of the difficulty of the retrofit. A large part of the capital costs are not impacted by retrofit including ammonia storage, vaporization, and injection equipment costs. The increase in cost is primarily due to modifications to existing ductwork, the cost of structural steel and reactor construction, auxiliary equipment costs, such as additional fans, and engineering costs. In addition, significant demolition and relocation of equipment may be required to provide space for the reactor. These costs can account for over 30% of the capital costs associated with SCR [9]. Retrofit costs for cyclone or wet bottom wall-fired boilers are somewhat higher than retrofit costs for dry bottom wall- or tangentially-fired boilers [4]. Differential retrofit cost for SCR in Germany is approximately 200 $ per MMBtu/hr (20 $/kW) [4].

Combustion Unit Design and Configuration

Boiler size is one of the primary factors that determines the SCR system capital costs. In addition, boiler configuration influences SCR costs. Boiler configurations that split the flue gas flow for two or more air preheaters and/or particulate removal systems require more than one SCR reactor. Additional reactors substantially increase capital costs. Boiler operations that have varying operating load, frequent startup/shutdowns, or seasonal operations require an SCR bypass. Additional ductwork, dampers, and control systems increase the SCR system capital costs. The SCR system may require modifications to draft fans and/or installation of additional fans. This increases both capital and operating costs of the SCR system. In addition, boiler and duct modifications may be required for implosion protection to accommodate increased draft requirements. [9]

Fuel Source

Industrial boilers use coal, distillate oil, residual oil, and natural gas. The fuel type and grade affects the SCR design and, therefore, the capital costs of the SCR system. Fuels

United States
Environmental Protection
Agency
Air

Office of Air Quality
Planning and Standards
Research Triangle Park, NC 27711

EPA 456/F-99-006R
November 1999

EPA

TECHNICAL BULLETIN

NITROGEN OXIDES (NOx), WHY AND HOW THEY ARE CONTROLLED

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Table 16: Unit Costs for NO_x Control Technologies for Non-Utility Stationary Sources

Source Type/Fuel Type	Control Technology	Percent Reduction (%)	Ozone Season Cost Effectiveness ($1990/ton) Small*	Large*
ICI Boilers - Coal/Wall	SNCR	40	1,870	1,380
ICI Boilers - Coal/Wall	LNB	50	3,490	2,600
ICI Boilers - Coal/Wall	SCR	70	2,910	2,450
ICI Boilers - Coal/FBC	SNCR - Urea	75	1,220	910
ICI Boilers - Coal/Stoker	SNCR	40	1,810	1,350
ICI Boilers - Coal/Cyclone	SNCR	35	1,480	1,110
ICI Boilers - Coal/Cyclone	Coal Reburn	50	3,730	710
ICI Boilers - Coal/Cyclone	NGR	55	3,730	710
ICI Boilers - Coal/Cyclone	SCR	80	1,840	1,560
ICI Boilers - Residual Oil	LNB	50	940	1,020
ICI Boilers - Residual Oil	SNCR	50	5,600	1,950
ICI Boilers - Residual Oil	LNB + FGR	60	2,670	920
ICI Boilers - Residual Oil	SCR	80	3,460	1,840
ICI Boilers - Distillate Oil	LNB	50	2,810	4,950
ICI Boilers - Distillate Oil	SNCR	50	10,080	3,520
ICI Boilers - Distillate Oil	LNB + FGR	60	5,960	1,810
ICI Boilers - Distillate Oil	SCR	80	6,480	3,460
ICI Boilers - Natural Gas	LNB	50	1,950	1,560
ICI Boilers - Natural Gas	SNCR	50	8,400	2,930
ICI Boilers - Natural Gas	LNB + FGR	60	6,110	1,420
ICI Boilers - Natural Gas	OT + WI	65	1,620	760
ICI Boilers - Natural Gas	SCR	80	5,190	2,770
ICI Boilers - Wood/Bark/Stoker	SNCR - Urea	55	2,090	1,430
ICI Boilers - Wood/Bark/FBC	SNCR - Ammonia	55	1,660	1,210
ICI Boilers - MSW/Stoker	SNCR - Urea	55	2,610	1,830
ICI Boilers - Process Gas	LNB	50	1,950	1,560
ICI Boilers - Process Gas	LNB + FGR	60	6,110	1,420
ICI Boilers - Process Gas	OT + WI	65	1,620	760
ICI Boilers - Process Gas	SCR	80	4,990	2,570
ICI Boilers - Coke	SNCR	40	1,870	1,380
ICI Boilers - Coke	LNB	50	3,490	2,600
ICI Boilers - Coke	SCR	70	2,910	2,450
ICI Boilers - LPG	LNB	50	2,810	4,950
ICI Boilers - LPG	SNCR	50	10,000	3,440
ICI Boilers - LPG	LNB + FGR	60	5,960	1,810
ICI Boilers - LPG	SCR	80	6,240	3,220
ICI Boilers - Bagasse	SNCR - Urea	55	2,090	1,430
ICI Boilers - Liquid Waste	LNB	50	940	1,020
ICI Boilers - Liquid Waste	SNCR	50	5,560	1,910
ICI Boilers - Liquid Waste	LNB + FGR	60	2,670	920
ICI Boilers - Liquid Waste	SCR	80	3,320	1,710
Internal Combustion Engines - Oil	IR	25	1,840	1,160

ATTACHMENT F

NATURAL GAS REBURN COST ANALYSIS

Table F-1. Cost Effectiveness of Natural Gas Reburn, NHPP

Cost Items	Cost Factors[a]	Cost per Cogeneration Boiler ($)
DIRECT CAPITAL COSTS (DCC):		
Purchased Equipment Cost (PEC)		
Basic Process	Vendor quote[b]	500,000
Engineering Study	Vendor quote[b]	100,000
Taxes	Florida sales tax, 6%	30,000
Total DCC:		630,000
INDIRECT CAPITAL COSTS (ICC):		
Contractor Fees	10% of PEC	63,000
Performance test	1% of PEC	6,300
Contingencies	25% of PEC	157,500
Total ICC:		226,800
TOTAL CAPITAL INVESTMENT (TCI):	DCC + ICC	856,800
DIRECT OPERATING COSTS (DOC):		
(1) Operating Labor		
Operator	8 hours/week, $16/hr, 52 weeks/yr	$6,656
Supervisor	15% of operator cost	998
(2) Maintenance	Engineering estimate, 5% of Basic Process Cost	25,000
(3) Natural Gas Cost	Displace 20% of Biomass with Natural Gas	4,493,880 [c]
Total DOC:		4,526,534
INDIRECT OPERATING COSTS (IOC):		
Overhead	60% of oper. labor & maintenance	19,593
Property Taxes	1% of total capital investment	8,568
Insurance	1% of total capital investment	8,568
Administration	2% of total capital investment	17,136
Total IOC:		53,865
CAPITAL RECOVERY COSTS (CRC):	CRF of 0.0944 times TCI (20 yrs @ 7%)	80,882
ANNUALIZED COSTS (AC):	DOC + IOC + CRC	4,661,281
BASELINE NO_x EMISSIONS (TPY) :	0.15 lb/MMBtu; 760 MMBtu/hr; 8,760 hr/yr ; 90% capacity factor	449.4 [d]
MAXIMUM NO_x EMISSIONS (TPY) :	25% reduction	337.1
REDUCTION IN NO_x EMISSONS (TPY):		112.4
COST EFFECTIVENESS:	$ per ton of NO_x Removed	41,489

Footnotes:

[a] Unless otherwise specified, factors and cost estimates reflect OAQPS Cost Manual, Section 3, Sixth edition.

[b] 2003 Coen cost quote, 2 units = $1,000,000, includes materials, installation, and start-up.

[c] Operational costs of reburn includes displacing 20% of the solid fuel with natural gas, natural gas cost $5/mcf, wood fuel cost is $2.5/MMBtu, bagasse cost is $0.0/MMBtu, and Biomass makeup based on 50% wood and 50% bagasse.

[d] Based on SNCR emission of 0.15 lb/MMBtu

COEN

Clean combustion. Powerful results.

January 22, 2003

To: Golder Associates Inc.
6421 NW 23rd Street, Suite 500
Gainesville, FL 32653-1500

Phone: (352) 336-5600
FAX: (352) 336-6603

Attention: Mr. David T. Larocca

Reference: Coen Proposal No. 03-30-003

Subject: New Hope Power Okeelanta, FL
Application of reburn technology on bagasse and woodwaste fired VU40 boilers

Dear Mr. Larocca,

Thank you for the information that you sent us on the New Hope Power Okeelanta and Osceola cogeneration units. Our preliminary review indicates that reburn does indeed have the potential for achieving the modest NOx reductions required to permit the capacity increase, and is an effective way to use the gas burners installed last year. In this letter, we would like to give you the results of our initial review and a proposal on how to move forward in investigating the costs and benefits of applying reburn technology to the Okeelanta cogeneration units.

Coen has teamed-up with TIAX on numerous re-burn and gas cofire projects over the past 10 years. TIAX markets reburn and gas cofire retrofits under the brand name "Acurex Energy" as described on the website www.cofire.com.

Reburn technology or cofiring requires a set of natural gas burners and over fire air ports above the grate where the biomass is combusted. Natural gas is injected to form a fuel-rich, oxygen-deficient combustion zone above the main firing zone. The technology achieves a reduction of NOx by converting the nitrogen-oxides, created by the combustion process in the lower portion of the boiler, into molecular nitrogen. Additional air to complete the burnout of all combustibles is then injected above the gasburner level. The amount of NOx reduction achieved with reburn depends on how rich the substoichiometric zone is operated. This in turn depends on ensuring that complete burnout is achieved in the overfire air zone above the reburn zone

Gas cofiring also yields additional benefits resulting from improved combustion including efficiency gains due to reduced moisture losses, lower excess air, improved carbon utilization, and enhanced equipment lifetime. Finally, cofiring can provide immediate recovery from interruptions in solid fuel availability and fuel feed, and from combustion problems.

Coen added natural gas burners to two of the three boilers in 2001. The burners were installed in the tangential SOFA ports approximately 20 ft above the grate. The maximum heat release of the burners is 400 MMBtu/hr. In our review, we assumed using the new burners and the SOFA ports for both gas injection and overfire air injection, to avoid costly modifications of the waterwall and air ducting.

NOx reduction benefits

Initial review of the drawings leads us to estimate that a NOx reduction of 15 – 25% is possible. This number is limited by the proximity of the gas injection and OFA injection location since we will use the SOFA/natural gas burner set-up. The gas cofiring rate should be less than 30% of the total heat input, with exact magnitude depending on reduction targets to ensure compliance.

To be able to give a firm expected NOx reduction number Coen/TIAX will have to perform an engineering study that would include the following:

- Identify regulatory constraints to satisfy permitting requirements for capacity increase
- Investigate natural gas and OFA injection locations and patterns.
- A site visit to review the installation and effect of damper settings and gather process data.
- Run a reburn NOx prediction model
- Performing Fluent CFD modeling on the furnace mixing/cofire-reburn combustion process.
- Determine required changes/modifications to the installation and scope of the retrofit.
- Prepare a study report with options and costs to ensure NOx compliance with the capacity upgrade.

The study report will include a firm NOx guarantee and +/- 10% budget quote including scope of the retrofit, materials installation and start-up.

Budget price for the engineering study by Coen/TIAX is:................................**$100,000.**

Costs of Reburn

As the scope of the retrofit has not yet been determined, it is difficult to give an indication of the costs involved. Anticipated modifications would be:

- Redirecting and modification of gas nozzles
- Redirecting and modification of air buckets
- Balancing of combustion air flows
- Addition of steam nozzles in gas buckets for increased momentum and mixing

In addition, there will be an extended start-up with Coen and TIAX engineers supporting New Hope Power operations personnel in tuning the system for optimum NOx reduction and combustion performance.

A preliminary rough estimate of the total project costs of materials, installation and start-up for two (2) boilers is:... **$ 1,000,000.**

Operational costs of reburn could include displacing 20% of the solid fuel with natural gas –This operational cost increase will be partly compensated by an increased efficiency due to lower excess air and improved solid fuel utilization.

We hope that the above information is helpful and look forward to further work with you on this project.

If you have any questions, or would like to discuss this letter then please feel free to contact me at 650-686-3384.

Kind Regards,
COEN COMPANY, INCORPORATED

Stephan Bergmans,
Sr. Application Engineer
Direct tel. No. (650) 686-3384

CC: Howard Mason, TIAX LLC
Sam Harman, H.C.Claymoore
Wes Schulze, Coen Company

ATTACHMENT G

AMMONIA COST ANALYSIS

TANNER INDUSTRIES, INC.
735 DAVISVILLE RD., THIRD FLOOR, SOUTHAMPTON, PA 18966-3200
215-322-1238 FAX 215-322-7725
www.tannerind.com

Mr. Dave Larocca
Golder Associates
6241 NW. 23rd St.
Gainesville,Fl 32653

via facsimile: 352-336-6603

Dear Mr. Larocca

Per your request, we are pleased to supply the following quotation for truckloads of **19% Ammonium Hydroxide** for delivery to Palm Beach Power in Palm Beach Florida

$ 495.00 per ton of contained anhydrous ammonia delivered.
Minimum: 45,000 pounds.
Terms: Net cash in 30 days.
Price includes 2 hours unloading time

We appreciate the opportunity to quote on your business.

If you have any questions, or if we may be of further service, please call.

Very truly yours,
Tanner Industries, Inc.

Thomas P Hearn
Director Of Sales

/edc

cc:

ATTACHMENT H

PM/PM_{10} BACT ANALYSIS

ATTACHMENT H

PM/PM_{10} BACT ANALYSIS

PROPOSED CONTROL TECHNOLOGY

Emissions of PM/PM10 from the cogeneration units will occur due to combustion of biomass, No. 2 fuel oil, and natural gas. Particulate matter emissions are currently controlled by mechanical cyclone dust collectors and electrostatic precipitators (ESPs). The dust collectors were installed during the year 2000, and are located immediately following each boiler's air preheater, prior to the ESP. The proposed BACT for PM/PM_{10} is based on the following control techniques:

- Mechanical cyclone dust collector; and
- Electrostatic Precipitator (ESP).

The proposed PM/PM_{10} emission limit is based on the current limit of 0.03 lb/MMBtu. Maximum PM/PM_{10} emissions for all three (3) cogeneration boilers combined will be limited to 68.4 lb/hr and 299.59 TPY after the increase in facility heat input. The maximum emissions are based on biomass firing.

BACT ANALYSIS

As part of the BACT analysis, a review was performed of previous PM/PM_{10} BACT determinations for industrial and electric utility boilers listed in the RACT/BACT/LAER Clearinghouse on EPA's web page. A summary of BACT determinations for biomass-fired industrial and electric utility boilers from this review were presented in Appendix D, Table D-1 of the application. Determinations issued during the last ten years were shown in the table.

From the review of previous BACT determinations, it is evident that PM/PM_{10} BACT determinations for biomass-fired industrial and electric utility boilers have typically been based on cyclone/ESP technology or baghouse technology. BACT determinations have been in the range of 0.03 lb/MMBtu to 0.15 lb/MMBtu of PM/PM_{10} emissions.

CONTROL TECHNOLOGY FEASIBILITY

The technically feasible PM/PM_{10} controls for the cogeneration units are shown in Table H-1. As shown in Table H-1, there are five types of PM/PM10 abatement methods, with various techniques within each method. Each available technique was listed with its associated efficiency estimate, identified as feasible or infeasible, and ranked based on control efficiency.

Potential Control Method Descriptions

Fuel Techniques

Fuel substitution, or fuel switching, is a common means of reducing emissions from combustion sources, such as electric utilities and industrial boilers. It involves replacing the current fuel with a fuel that emits less of a given pollutant when burned.

For fuel substitution to be practical, there must be a suitable replacement fuel available at an acceptable cost. NHPP's primary fuel for the cogeneration boilers is biomass, a large portion of which is a byproduct of the sugar mill's operations. Therefore, substitution of the fuel would result in an unacceptable cost.

Pretreatment
The performance of particulate control devises can often be improved through pretreatment of the gas stream. For PM control devices, pretreatment consists of the following techniques:

- Settling Chambers,
- Elutriators,
- Momentum Separators,
- Mechanically-Aided Separators, and
- Cyclones.

Of these five techniques, cyclones offer the most control efficiency, typically in the range of 60 to 90%. All of the other techniques have control efficiencies less than 30%.

Cyclones use inertia to remove particles from a spinning gas stream. Within a cyclone, the gas stream is forced to spin within a usually conical-shaped chamber. The gas spirals down the cyclone near the inner surface of the cyclone tube. At the bottom of the cyclone the gas turns and spirals up through the center of the tube and out the top of the cyclone.

Particles in the gas stream are forced toward the cyclone walls by centrifugal forces. For particles that are large, typically greater than 10 microns, inertial momentum overcomes the fluid drag forces so that the particles reach the cyclone walls and are collected. For smaller particles, the fluid drag forces are greater than the momentum forces and the particles follow the gas out of the cyclone. Inside the cyclone, gravity forces the large particles down the sidewalls of the cyclone to a hopper where they are collected.

NHPP's cogeneration boilers are currently utilizing mechanical dust cyclones before each ESP. The cyclones efficiency is estimated at 80 percent based on ash generation quantities.

Electrostatic Precipitators (ESPs)
Collection of PM by electrostatic precipitators involves the ionization of the gas stream passing through the ESP; the charging, migration, and collection of particles on oppositely charged surfaces; and the removal of particles from the collection surfaces. There are two basic types of ESPs: dry and wet. In dry ESPs, the particulate is removed by rappers, which vibrate the collection surface, dislodging the particles and allowing them to fall down. Wet ESPs use water to rinse collection surfaces of collected particles.

Electrostatic precipitators have several advantages when compared with other control devices. They are very efficient collectors, even for small particles, with greater than 99% control efficiency. ESPs can also treat large volumes of gas with a low pressure drop. ESPs can operate over a wide range of temperatures and generally have low operating cost. The disadvantages of ESPs are large capital cost, large space requirements and difficulty in controlling particles with high resistivity.

NHPP's cogeneration boilers are currently utilizing dry ESP systems. The existing configuration of the ESP system does not have sufficient space for the addition of another field for enhancement of the PM collection efficiency. In order to add an additional field to the existing ESPs, the destruction of the existing stacks, construction of new stacks, and relocation of existing ID fans and other supporting equipment and structures would be required.

Fabric Filters
Baghouses, or fabric filters, utilize porous fabric to filter cake an airstream. They include types such as reverse-air, shaker, and pulse-jet baghouses. The dust that accumulates on the surface of the filter aids in the filtering of fine dust particles. PM/PM_{10} control efficiencies for fabric filters are typically greater than 99 percent.

During fabric filtration, dusty gas is drawn through the fabric by forced-draft fans. The fabric is responsible for some filtration, but more significantly it acts as support for the dust layer that accumulates. The layer of dust, also known as a filter cake, is a highly efficient filter, even for submicron particles. Woven fabrics rely on the filtration of the dust cake much more than the felted fabrics.

Fabric filters offer high efficiencies, are flexible to treat many types of dusts and a wide range of volumetric gas flow rates. In addition, fabric filters can be operated with low-pressure drop. Some potential disadvantages are; high temperatures can damage fabric bags, and also have a potential for fire or explosion. This is especially an issue with biomass-fired boiler, where the biomass particles are light and not as easily collected in mechanical collectors. Additionally, high moisture content flue gas may result in "plugging" of the baghouse due to moisture condensation in the filter cake. For these reasons fabric filters are not considered feasible for the project.

Wet Scrubbers
Wet scrubbers are systems that involve particle collection by contacting the particles to a liquid, usually water. The aerosol particles are transferred from the gaseous airstream to the surface of the liquid by several different mechanisms. Wet scrubbers create a liquid waste that must be treated prior to disposal. PM/PM_{10} control efficiencies for wet scrubbing systems range from about 50 to 95 percent, depending on the type of scrubbing system used. Typical wet scrubbers are as follows:

- Spray Chamber,
- Packed-Bed,
- Impingement Plate,
- Mechanically-Aided,
- Venturi,
- Orifice, and
- Condensation.

The advantages of wet scrubbers compared to other PM collection devises are that they can collect flammable and explosive dusts safely, absorb gaseous pollutants, and collect mists. Scrubbers can also cool hot gas streams. The disadvantages are the potential for corrosion and freezing and the potential of water and solid waste pollution problems.

<u>Economic Analysis</u>
NHPP currently utilizes mechanical cyclone dust collectors and ESPs to control PM/PM_{10}. This combination of control equipment results in the highest control efficiency determined to be feasible for the project. As described previously, fabric filters are not feasible due to the high moisture content of the flue gas as well as potential fire hazards. Therefore a detailed economic analysis of other control technologies is not presented. Additional PM/PM_{10} control equipment would result in an unacceptable economic burden for NHPP.

BACT SELECTION

In conclusion, the NHPP proposed PM/PM_{10} emission limit is reasonable based on previous BACT determinations for similar facilities and the highly efficient PM/PM_{10} control of the existing dust collectors and ESP.

Any additional or different add-on control PM/PM_{10} control equipment is not appropriate for the cogeneration boilers. Such control equipment would result in significant capital costs, including construction of new stacks, and would also result in significant lost revenue during the construction period. Therefore, the proposed PM/PM_{10} BACT limit of 0.03 lb/MMBtu is based on the mechanical cyclone dust collector and ESP.

Table H-1. NHPP Cogeneration Boilers PM/PM_{10} Control Technolgy Feasibility

PM Abatement Method	Technique Now Available	Estimated Efficiency	Feasible and Demonstrated (Y/N)	Rank Based on Control Efficiency	Employed by NHPP (Y/N)
Fuel Techniques	Fuel Substitution	NA	Y	7	N
Pretreatment	Settling Chambers	< 10%	Y	6	N
	Elutriators	< 10%	Y	6	N
	Momentum Separators	10 - 20%	Y	5	N
	Mechanically-Aided Separators	20 - 30%	Y	4	N
	Cyclones	60 - 90%	Y	3	Y
Electrostatic Precipitators(ESP)	Dry ESP	>99%	Y	1	Y
	Wet ESP	>99%	Y	1	N
	Wire-Plate ESP (Dry or Wet)	>99%	Y	1	N
	Wire-Pipe ESP (Dry or Wet)	>99%	Y	1	N
Fabric Filters	Shaker-Cleaned	>99%	N	NTF	N
	Reverse-Air	>99%	N	NTF	N
	Pulse-Jet	>99%	N	NTF	N
Wet Scrubbers	Spray Chambers	50 - 95 %	Y	2	N
	Packed-Bed	50 - 95 %	Y	2	N
	Impingement Plate	50 - 95 %	Y	2	N
	Mechanically-Aided	50 - 95 %	N	NTF	N
	Venturi	50 - 95 %	Y	2	N
	Orifice	50 - 95 %	Y	2	N
	Condensation	50 - 95 %	Y	2	N

NTF = Not Technically Feasible

ATTACHMENT I

FGD COST ANALYSIS WITH
PM, HF AND HCl EMISSIONS

Table 1-1. Cost Effectiveness of Lime Spray Drying FGD for SO_2, PM, HF, and HCL Control, NHPP Cogeneration Boiler (One Unit)
Vendor: Wheelabrator APC

Cost Items	Cost Factors[a]	Cost per Cogen Boiler ($)
DIRECT CAPITAL COSTS (DCC):		
Purchased Equipment Cost (PEC)		
Absorber + lime storage/delivery + Fabric Filter	Vendor quote[b]	3,960,000
Taxes	Florida sales tax, 6%	237,600
Total PEC:		4,197,600
Direct Installation	Vendor quote[b]	2,900,000
Items Excluded From Vendor Quote:		
Ductwork	100 ft @ $106/ft	10,000
FGD waste conveyors	Estimate	50,000
Foundations	12% of PEC	503,712
Water/air/electrical supply & piping	10% of PEC	419,760
Thermal insulation and lagging	Estimate	50,000
ID Fan	Estimate	100,000
Total Direct Installation:		4,033,472
Total DCC (PEC + Direct Installation):		8,231,072
INDIRECT CAPITAL COSTS (ICC)		
Engineering	2% of PEC (for excluded items)	83,952
Construction and field expenses	2% of PEC (for excluded items)	83,952
Contractor Fees	2% of PEC (for excluded items)	83,952
Startup	1% of PEC	41,976
Performance test	1% of PEC	41,976
Contingencies	25% of PEC (for retrofit application)	1,049,400
Total ICC:		1,385,208
TOTAL CAPITAL INVESTMENT (TCI):	DCC + ICC	9,616,280
DIRECT OPERATING COSTS (DOC):		
(1) Operating Labor		
Operator	0.5 hr/shift, $16/hr, 8760 hrs/yr	8,760
Supervisor	15% of operator cost	1,314
(2) Maintenance		
Operator	0.5 hr/shift, $16/hr, 8760 hrs/yr	8,760
Supervisor	15% of operator cost	1,314
(3) Operating Materials		
Reagent	48 lbs/hr, $65/ton	13,666
(4) Electriciy	700 KW, $0.04/KW-hr	245,280
(5) Dry Waste Disposal	103 lbs/hour, $30/ton	13,534
Total DOC:		292,628
INDIRECT OPERATING COSTS (IOC)		
Overhead	60% of oper. labor & maintenance	12,089
Property Taxes	1% of total capital investment	96,163
Insurance	1% of total capital investment	96,163
Administration	2% of total capital investment	192,326
Total IOC:		396,740
CAPITAL RECOVERY COSTS (CRC):	CRF of 0.0944 times TCI (20 yrs @ 7%)	907,777
ANNUALIZED COSTS (AC):	DOC + IOC + CRC	1,597,145
BASELINE EMISSIONS (TPY):	0.06 (lb SO_2)/MMBtu,	179.8
760 MMBtu/hr, 90% capacity factor	0.03 (lb PM/PM10)/MMBtu	89.9
	0.0007 (lb HF)/MMBtu; and	2.1
	0.019 (lb HCL)/MMBtu wood comb (380 MMBtu/hr)	28.46
Total		300.2
MAXIMUM EMISSIONS (TPY):	90% SO_2 reduction	17.98
	PM/PM10 @ 0.02 lb/MMBtu	60.22
	90% HF reduction	0.21
	90 % HCL reduction	2.85
Total		81.2
REDUCTION IN SO2, PM/PM10, HF, AND HCL EMISSONS (TPY)		218.9
COST EFFECTIVENESS:	$ per ton of pollutants Removed	7,295

Footnotes:

[a] Unless otherwise specified, factors and cost estimates reflect OAQPS Cost Manual, Section 5, Fifth edition.

[b] 2002 Wheelabrator APC cost quote, 2 units $7,920,000 material costs and $5,800,000 installation cost
Includes: Absorber, lime storage/delivery, fabric filter, ductwork from SDA to fabric filter, structural support, process piping and valves, and system control instrumentation.

Table 1-2. Cost Effectiveness of Lime Spray Drying FGD for SO_2, PM, HF, and HCL Control, NHPP Cogeneration Boiler (One Unit)
Vendor: Hamon Research-Cottrell

Cost Items	Cost Factors[a]	Cost per Cogen Boiler ($)
DIRECT CAPITAL COSTS (DCC):		
Purchased Equipment Cost (PEC)		
Absorber + lime storage/delivery + Fabric Filter	Vendor quote[b]	5,375,000
Taxes	Florida sales tax, 6%	322,500
Total PEC:		5,697,500
Direct Installation	Vendor quote[b]	3,200,000
Items Excluded From Vendor Quote:		
Ductwork	100 ft @ $106/ft	10,000
FGD waste conveyors	Estimate	50,000
Foundations	12% of PEC	683,700
Water/air/electrical supply & piping	10% of PEC	569,750
Thermal insulation and lagging	Estimate	50,000
ID Fan	Estimate	100,000
Total Direct Installation:		4,663,450
Total DCC (PEC + Direct Installation):		10,360,950
INDIRECT CAPITAL COSTS (ICC):		
Engineering	2% of PEC (for excluded items)	113,950
Construction and field expenses	2% of PEC (for excluded items)	113,950
Contractor Fees	2% of PEC (for excluded items)	113,950
Startup	1% of PEC	46,635
Performance test	1% of PEC	46,635
Contingencies	25% of PEC (for retrofit installation)	1,165,863
Total DCC:		1,600,982
TOTAL CAPITAL INVESTMENT (TCI):	DCC + ICC	11,961,932
DIRECT OPERATING COSTS (DOC):		
(1) Operating Labor		
Operator	0.5 hr/shift, $16/hr, 8760 hrs/yr	8,760
Supervisor	15% of operator cost	1,314
(2) Maintenance		
Operator	0.5 hr/shift, $16/hr, 8760 hrs/yr	8,760
Supervisor	15% of operator cost	1,314
(3) Operating Marterials		
Reagent	48 lbs/hr, $65/ton	13,666
(4) Electriciy	700 KW, $0.04/KW-hr	245,280
(5) Dry Waste Disposal	103 lbs/hour, $30/ton	13,534
Total DOC:		292,628
INDIRECT OPERATING COSTS (IOC):		
Overhead	60% of oper. labor & maintenance	12,089
Property Taxes	1% of total capital investment	119,619
Insurance	1% of total capital investment	119,619
Administration	2% of total capital investment	239,239
Total IOC:		490,566
CAPITAL RECOVERY COSTS (CRC):	CRF of 0.0944 times TCI (20 yrs @ 7%)	1,129,206
ANNUALIZED COSTS (AC):	DOC + IOC + CRC	1,912,400
BASELINE EMISSIONS (TPY):	0.06 (lb SO_2)/MMBtu,	179.8
760 MMBtu/hr, 90% capacity factor	0.03 (lb PM/PM10)/MMBtu	89.9
	0.0007 (lb HF)/MMBtu; and	2.1
	0.019 (lb HCL)/MMBtu wood comb. (380 MMBtu/hr)	28.46
Total		300.2
MAXIMUM EMISSIONS (TPY):	90% SO_2 reduction	17.98
	PM/PM10 @ 0.02 lb/MMBtu	60.22
	90% HF reduction	0.21
	90 % HCL reduction	2.85
Total		81.2
REDUCTION IN SO2, PM/PM10, HF, AND HCL EMISSONS (TPY)		218.9
COST EFFECTIVENESS:	$ per ton of pollutants Removed	8,735

Footnotes:

[a] Unless otherwise specified, factors and cost estimates reflect OAQPS Cost Manual, Section 5, Fifth edition.

[b] 2002 Hamon Research-Cottrell cost quote, 2 uints $10,750,000 material costs and $6,400,000 installation cost.
Includes: Absorber, lime storage/delivery, fabric filter, ductwork from SDA to fabric filter, structural support, process piping and valves, and system control instrumentation.

2.2 Spray Dryer Absorbers

The following numbered items comprise a description of the major equipment and services provided for each boiler for this project unless noted.

2.2.1 Spray Dryer Absorber
One (1) 100% capacity spray dryer absorber (SDA) vessel will be furnished with the following features described on a per absorber basis

2.2.1.1 Hopper
One (1) conical section hopper with a 60° internal cone angle

- Fabricated from 3/8" A-36 steel plate
- One (1) outlet duct
- One (1) 24"diameter quick opening access door
- Two (2) poke holes and strike plates, rodding device
- Hopper heaters with thermostatic control

2.2.1.2 Cylindrical and Lower Conical Section

- Fabricated from minimum 1/4" A-36 steel plate.
- 37'-0" diameter x 50'-0" high cylindrical section
- One (1) 2' x 4' bolted access door

2.2.1.3 Inlet Gas Distributor

- Specially designed scrolled configuration to provide initial pre-swirling of inlet flue gas.
- Manually adjustable inlet gas disperser vanes at the point of flue gas entry to optimize the gas flow pattern in the reaction chamber during mixing with the atomized spray.
- One (1) 2' x 4' bolted access door.

2.2.1.4 Rotary Atomizer
Each SDA vessel will be supplied with one (1) Anhydro rotary atomizer with the following features:

- Stainless steel construction for components coming in contact with the scrubbing liquid.
- Center rotating spindle assembly drive.

- Specially designed heat dissipating bearings providing two (2) point spindle support.
- Replaceable bearing cartridge design for rapid maintenance
- Automatic oil lubrication system servicing the upper and lower spindle bearings.
- Statically and dynamically balanced atomizer wheel machined from stainless steel with integral silicon carbide wear tiles and nozzles.
- Vertically mounted, high speed AC induction drive motor.
- Variable frequency drive system.
- Integral lifting bracket for complete atomizer removal.
- Maintenance stand for atomizer placement when removed from service.
- One (1) standby rotary atomizer unit complete with motors will be provided to serve as a reserve standby for two operating atomizer, i.e. one (1) per two (2) SDA vessels.

2.2.1.5 Atomizer Parts and Tools

- One (1) set of special tools for servicing the rotary atomizer unit

2.2.1.6 Atomizer Maintenance Removal System

- Checker plate service platform on top of the spray absorber gas distributor.
- Monorail beams supported form the building enclosure will be provided for mounting the atomizer maintenance and removal hoists
- One (1) common atomizer removal hoist electrically operated with motorized trolley to service each SDA.
- One (1) common electric hoist with motorized trolley providing atomizer unit lift-to-grade capacity.

2.3 Miscellaneous Components

2.3.1 Ductwork and Expansion Joints and Dampers

The following ductwork will be provided for each DFGD Subsystem:

SDA outlets to PJFF inlet manifolds

All ductwork will be fabricated from 3/16" minimum thickness ASTM A-36 steel plate with ASTM A-36 stiffeners. Fabric bellows-type expansion joints as required will be provided for the supplied ductwork

2.3.2 Stairs, Walkways and Platforms

Stairway access common to the SDA and PJFF as required for SDA and PJFF maintenance will be provided. Platforms will be provided to access instrument taps, and compartment inspection doors. Ladder and platform access to inlet ductwork test ports and lower access door will be provided.
Access facilities with the following features:

- ASTM A-36 structural steel walkway, framing and stringer support steel.
- 1-1/2" OD standard pipe handrailing, Schedule 40 pipe.
- Steel grating 1-1/4" x 3/16".
- Spray dryer absorber roof access platforms.

2.3.3 Support Steel

Structural support steel for the SDA, particulate collector, system ductwork, silos, miscellaneous equipment and access systems will be ASTM A-36 material.

2.3.4 System Piping

Carbon steel piping will be furnished to convey the lime slurry and service water to the SDA roof level areas.

2.3.5 Instrumentation and Control System Hardware

HRC will supply control logic information for the Owner to program his DCS unit which will be capable of operation and control of the spray dryer absorbers and fabric filter system interfacing with the lime preparation systems. Control and equipment status will be available from the Owner's DCS in the plant's main control room via the Owner's high-speed data highway.
Local instrumentation for operation and control of the DFGD system will be provided including field-mounted instrument racks as required.

2.3.6 Electrical Equipment

The motor control centers or power distribution equipment required to operate the proposed DFGD equipment are to be provided by others.

2.3.7 Surface Preparation and Painting

Un-insulated surface areas of the absorber, ductwork, access steel, support steel, ladders, walkways, and railing will receive surface preparation and cleaning and shop primer coating in accordance with HRC's standard specifications. Off the shelf equipment including electrical equipment will receive the manufacturer's standard paint system.

2.4 Lime Storage and Preparation System

One (1) complete system for receiving and storing bulk pebble lime, lime slurry preparation and storage equipment and pump station to pump the lime slurry to the SDA roof penthouses and rotary atomizers will be furnished to serve the FGD system needs of both boilers. This common system will serve all SDA vessels. This equipment will be arranged as a cylindrical self supporting structure beginning with the lime slurry storage tank and pump station at grade elevation; slakers, vibrating screens and lime feeders on the second level; and the integral lime storage silo above this point. This system will include the following basic features subject to the selected system supplier's standard package, except as noted:

2.4.1 Lime Storage

2.4.1.1 Storage Silo

- One (1) welded silo for pebble lime storage. Storage time is normally twenty-four (24) hours at the BMCR design conditions.
- 20" diameter combination manhole and pressure relief valve in the roof.
- High and low level indicators.
- 60° cone bottom with a manually operated knife gate.
- Electrical bin activator discharges to Y-chute with pneumatic slide gate valve at the inlet of each volumetric feeder.
- Roof access including ladder with cage from grade, roof handrail with toe plate and necessary transfer and service platforms.
- 4" diameter Schedule 40 fill pipe including truck connection, dust cap and limit switch on end of pipe.
- Roof-mounted vent filter.
- Shop prime painting of un-insulated surfaces.

2.4.2 Lime Slaking Equipment

2.4.2.1 Volumetric Screw Feeder

- Two (2) 120% capacity screw feeders
- Manually adjustable SCR drive and chute to slaker.

2.4.2.2 Lime Slakers

- Two (2) 120% vertical lime slakers (one to serve each boiler unit). Slaked milk of lime product will discharge to a vibrating screen (one per slaker) to facilitate grit removal prior to feeding into the common lime slurry storage tank.

2.4.2.3 Covered Slurry Storage Tank

- One (1) common 130,000-gallon slurry storage tank.
- Top mounted slow speed vertical mechanical mixer
- One (1) ultrasonic level sensor
- Inlet/outlet/drain connections.
- Access manhole in top.

2.4.2.4 Pump Station

- Four (4) 100% capacity 75 HP centrifugal 350 gpm slurry feed pumps, one (1) operating and one (1) standby for each boiler unit.
- Manual flush valves for pump and line flushing.
- Connecting piping internal to lime preparation system.

2.4.2.5 Local Control System

- Suppliers standard NEMA 4 lime slaker control panel with starters, PLC, switches, indicating lights and other components required for operation.

2.4.2.6 Miscellaneous

- Interior light fixtures.
- Wall mounted exhaust fans with automatic shutter.
- Heavy-duty electric heater for enclosure heating.

IV FABRIC FILTER

1.0 FABRIC FILTER TYPE

Hamon Research-Cottrell is proposing our patented, Low Pressure/High Volume (LPHV) Pulse jet fabric filter technology. The following describes the fabric filter and accessories offered for each boiler unless noted.

2.0 DESIGN CONDITIONS

Specific conditions which will be incorporated into the design are:

Flue Gas volumetric flow rate	326,000 acfm at actual conditions
Flue gas volume from spray absorbers	310,000 acfm
Operating temperature	160° F at spray absorber outlet
Design temperature	370°F
Excursion temperature	400°F for up to thirty (30) minutes
Operating pressure	-18" w.c. at air heater outlet
Design pressure	+35"/-35" w.c.
Transient pressure	+15/-35" w.c.
Inlet particulate loading	5.00 gr/acf

3.0 CONFIGURATION

Salient features of the fabric filter configuration are as indicated below:

Number of fabric filters	2
Number of compartments/fabric filter	6
No. bag bundles/compartment	1
No. of cleaning arms/bundle	3
No. bags/compartment	544
No. bags/fabric filter	3264
Bag length	23'-0"
Equivalent bag diameter (nominal)	4.9" Oval (approximately 2 ½" x 6")
Effective cloth area (sq. ft.): (with seams and cuffs deducted) Per bag Per compartment Per fabric filter	 27.59 15,008 90,050
Air-to-Cloth Ratio: Gross (on-line cleaning) Net (1 compartment off for maintenance)	 3.44 4.13
No. of pulse valves/compartment	1
No. of bags/pulse valve	544
Cleaning air blower system: No. of blowers Blower capacity Blower design pressure	 3 operating plus 1 spare per fabric filter 1,000 icfm/blower 16.2 psig

4.0 MATERIALS OF CONSTRUCTION

The materials of construction for the major components are shown below:

Fabric filter casing & partition walls	3/16" ASTM A36 plate with A-36 stiffeners
Fabric filter hoppers	3/16" ASTM A36 plate with A-36 stiffeners
Fabric filter tube sheet	¼" ASTM A36 plate with A-36 stiffeners
Fabric filter manifolds	3/16" ASTM A36 plate with A-36 stiffeners
Fabric filter inlet elbows	3/16" ASTM A36 plate with A-36 stiffeners
Bag material	18 oz. PPS
Bag cages	9 gauge mild steel, two piece construction with 10 vertical wires
Handrail and posts	1 1/2" Sch. 40 pipe
Toe plates	1/4" x 4" C.Q.M.S.
Grating & stair treads	1-1/4" x 3/16"

5.0 SYSTEM DESCRIPTION

Hamon Research-Cottrell is proposing it's **Low Pressure High Volume** (LPHV) fabric filtration technology to collect particulate from the flue gas exiting the spray absorbers. One (1) independent fabric filter casing, containing six (6) compartments is proposed. The filter bag cleaning system is designed for on-line cleaning which allows any one of the six (6) compartments to be isolated for maintenance. The proposed LPHV pulse jet cleaning system has successfully been utilized on many conventional baghouse installations. The general arrangement drawings of our proposed offering are attached.

5.1 Description of Operation

Our Low Pressure-High Volume pulse jet fabric filter utilizes a unique cleaning mechanism which provides on-line cleaning with the cleaning manifold continuously rotating at approximately 1 R.P.M. above the tube sheet.

The bags are oblong in shape and are arranged in concentric circles with regular spacing specific to each circle. The compactness of this arrangement is only possible with non-alignment of the bags in the radial direction. In the circumferential direction, the bag spacing is regular but specific to each row.

To more fully understand the low pressure, pulse jet system, you must realize that almost the full complement of the powerful cleaning flow is derived from the compartment's air reservoir. Figure 1 depicts an integral tank mounted design. For this proposal, we will be either offering a side mounted tank or an integral design. The low pressure system's nozzle can be

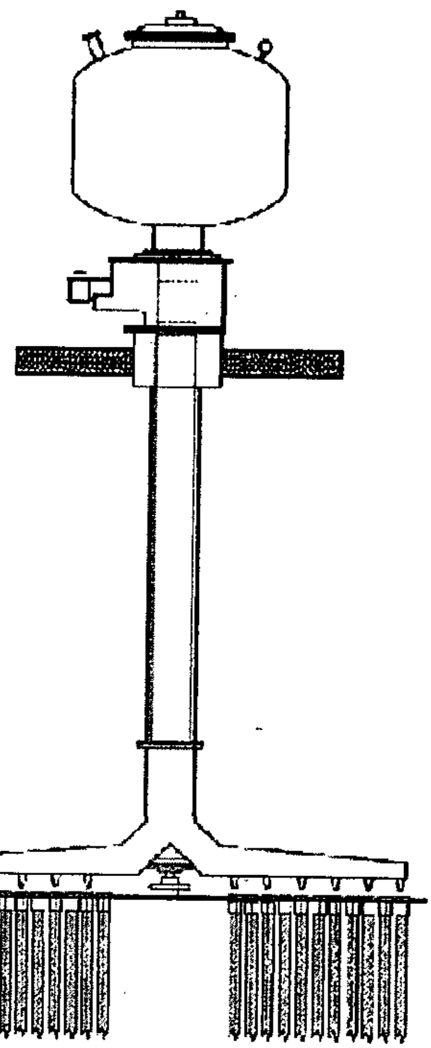


Figure 1

5.0 EQUIPMENT DESCRIPTION (CONTINUED)

5.1 Description of Operation (Continued)

located anywhere on the lengthwise centerline of the bag top, with some degree of "blockage" with the cage top, without detriment to the cleaning effectiveness. Unlike conventional pulse jets, relative position of the LPHV nozzle to bag is not critical. The cleaning air can be released from the reservoir, either by a preset timer, pressure drop initiated, or filter cake drag basis, (preferred) and directed to the manifold via a quick opening pilot assisted diaphragm valve.

The rotating manifold is supported on the tube sheet by a heavy duty, sealed thrust type bearing, designed for long life and low maintenance. The cleaning air distribution pipe and rotating manifold/nozzle assembly is designed such that pressure losses are kept to a minimum and stored energy in the reservoir is utilized to the fullest.

In addition to the primary cleaning action which is produced by an initial rapid fabric deceleration and dust cake dislodgment, the LPHV Pulse jet incorporates an additional feature which enhances fabric cleaning. The high volume of stored cleaning air flowing to the bags in the reverse direction provides a "Back-Flush", or reverse air cleaning effect, which augments the dynamic cleaning of the "pulse" itself. The cleaning air volume includes an extra margin for those cases where the nozzle may be located between bags.

The flue gas enters each compartment through the hopper. Entrance velocities are kept low, approximately 2,000 fpm in the NET condition, to minimize mechanical pressure drop and to also allow larger particulate to fall out into the hopper. This compartment entrance design, along with low can velocities, promotes reduced cleaning frequency, extending bag life and improving filtration efficiency.

Cleaning air will be delivered to each baghouse via two (2) 50% capacity, low pressure positive displacement blowers. A total of three (3) blowers will be provided, two (2) operating plus a spare.

The blowers for the fabric filter are connected by a common piping manifold system which feeds the clean air manifold reservoir tanks located at the baghouse roof level. The air reservoir tanks are sized to deliver a total air volume of 45.0 cu.ft. per pulse of cleaning air. The blowers will be located at grade.

5.0 EQUIPMENT DESCRIPTION (CONTINUED)

5.1 Description of Operation (Continued)

The use of low pressure positive displacement blowers is a major improvement over the use of air compressors and dryers which are required for high pressure pulse jet designs. Air dryers are not required with positive displacement blowers because of the relatively low pressure. In addition, the cleaning air piping is not subject to freezing and/or condensation which can occur in high pressure compressed air lines in locations which are subject to cold ambient temperatures.

Blowers are more efficient and require less maintenance than compressor and air dryer systems.

A particular benefit of this unique technology is the requirement for fewer pulse cleaning air diaphragm valves. The LPHV technology requires only one "heavy duty" valve to clean 544 filter bags per bag bundle in each compartment. For this project, <u>only six (6) diaphragm valves</u> are required, that is, one per compartment. In contrast, a conventional pulse jet design could require at least 27 <u>valves per compartment</u> assuming a maximum of 20 bags per valve, equating to 162 <u>valves</u>. This would mean 162 high pressure pulse valves to inspect and maintain as opposed to only 6 valves with our low pressure design. In addition, the LPHV diaphragm valve, located outside the gas stream, is designed to last longer than conventional valves. A silencer is included over each diaphragm valve.

The volume of each cleaning air pulse is derived from theoretical gas laws as well as the number and length of bags being cleaned. The frequency of cleaning, and therefore the required flow rate of cleaning air, is determined from formulae derived from empirical data that has been gathered from an extensive amount of testing carried out at many pilot and full scale pulse jet installations.

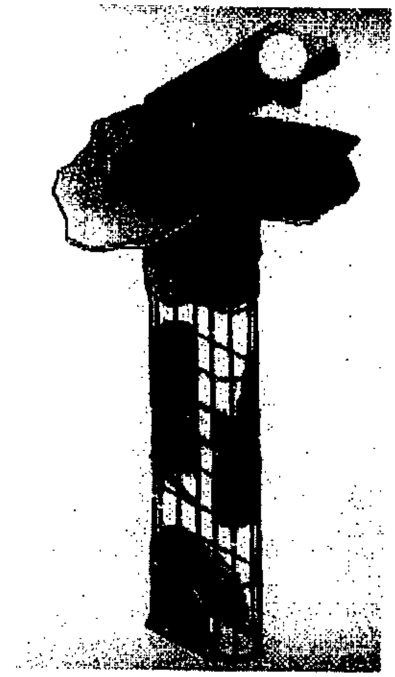
<u>Bag Inspection and Replacement</u>

A significant benefit of this cleaning method is the absence of blow pipes in the tube sheet area. This allows the bags and cages to be easily accessed for inspection or replacement. Only a single, trifurcated rotating manifold arm is located over each bundle of bags. This manifold arm can be easily moved should it happen to be stopped over the top of a failed bag. With only three rotating cleaning manifold arms in each compartment, inspection and maintenance costs in locating and replacing a potentially failed bag are greatly reduced.

5.0 EQUIPMENT DESCRIPTION (CONTINUED)

5.2 Filter Bags

Each compartment will contain one cylindrical bag bundle, with 544 filter bags installed plus an additional 33 (1%) bags supplied as spares. The filter bags for this project will be fabricated from heavy weight 18 oz/yd^2 nominal weight PPS.



The bags have an elongated cross section, which is essentially oblong with rounded ends to promote better movement and release of the dust. The bag/cage fixing method has been designed for ease of installation and maintenance. The bags are secured in the tube sheet by means of a stainless steel snap band that is sewn into the cuff of the bag. No tools are necessary for installation of the bags and/or cages.

5.3 Filter Bag Support Arrangement

The filter bag support cages correspond in cross section to the "oblong" shape of the bags and tube sheet openings. The outside dimensions of the cage are slightly smaller than the inside dimensions of the bag along with a tapered lower section to facilitate cage insertion into the bag and help promote more efficient bag cleaning.

Cages are constructed of heavy 9 gauge mild steel wires for **rigidity, durability** and **long life**. There are 10 vertical wires, secured by horizontal wires spaced at a minimum of 8" intervals. Cages are supplied in two (2) sections to reduce the need for inordinately high headroom in the roof weather enclosure or clean air plenum, thus reducing steel and weight. The cage sections are firmly held together by an interlocking clip arrangement and internal guide plates at the joint to achieve a smooth, rigid, and perfectly aligned connection. This cage design has been successfully used on similar pulse jet boiler applications. In addition to those cages required for the initial installation, an additional 33 cages (1%) are included as spares.

5.0 EQUIPMENT DESCRIPTION (CONTINUED)

5.4 Casing

The fabric filter casing will include the following design features and components:

- 3/16" A-36 steel
- Walk in plenum design for ease in bag inspections/replacements.
- Tube sheet of welded 1/4" A-36 steel, suitably reinforced
- Two (2) 24" x 60" mild steel access doors/compartment

5.5 Hoppers

Each fabric filter compartment will have a pyramidal hopper equipped with the following auxiliaries:

- Reinforced to support 3,500 lbs. of ash handling equipment.
- Flanged outlet opening, 12", 150 lb. shipped loose.
- One 24" mild steel access door with safety latch to prevent rapid full door opening.
- One (1) 4" diameter angled poke holes located near the hopper outlet.
- Two (2) 6" square strike plates.
- One (1) capacitance type hopper level detector, as manufactured by Drexel Brook or equal. An annunciation alarm will be provided to the control system.
- One (1) Eriez 55-P or equal vibrators. One NEMA 12 relay panel will be provided to accept signals from the ash handling system. Sequencing by others.

5.0 EQUIPMENT DESCRIPTION (CONTINUED)

5.5 Hoppers (Continued)

- Hopper heater system will include the following:

  ✓ Modular type heaters, as manufactured by HotFoil, Heat Trace, Thermon or equal. The heaters will be distributed on the bottom 1/3 of the hopper height.

  ✓ Throat heaters and poke hole heaters will be provided.

  ✓ NEMA 4 control panel will be provided in the hopper area for hopper heater control. The panel will contain feed circuit breakers, individual heater contactors, readout of hopper skin temperature and high/low temperature alarm.

5.6 Tube Sheet

The tube sheet for each compartment, complete with all stiffeners, will be shop fabricated from 1/4" thick plate to minimize deflection and insure that the highest standards of quality are maintained. Experience has shown that 3/16" thick tube sheets are not sufficient to prevent excessive deflection.

5.7 Dampers

The following dampers will be provided:

- One (1) pneumatically operated, low leak inlet louver damper per compartment with two limit switches for indication of damper open/closed position.
- One (1) pneumatically operated, low leak single disc outlet poppet damper per compartment, complete with two limit switches for indication of damper open/closed position.
- Four (4) pneumatically operated, double disc bypass poppet dampers per fabric filter, complete with two limit switches for indication of damper open/closed position.

5.0 EQUIPMENT DESCRIPTION (CONTINUED)

5.8 Support Steel

Support steel will be provided and installed for the fabric filter, as required. The fabric filter support structure will provide a clearance of approximately 6'-0" from the bottom of the hopper outlet flange to grade.

5.9 Slide Plates

Flat slide plates, as manufactured by Amscot or equal, will be provided between the fabric filter and support steel to accommodate thermal movement.

5.10 Access Doors

Mild steel access doors, 24" x 60", will be provided as follows:
- For entry into the walk in plenum

5.11 Access

Hamon Research-Cottrell will furnish the following access system:
- One walkway, 36" wide from common SDA/FF stairway to one end of the fabric filter.
- As a second means of egress, two caged ladders will be provided from grade to the fabric filter roof on the opposite end of the fabric filter.
- A platform will be provided for the full length of each fabric filter to allow access to the inlet damper actuators.
- A walkway will be provided above outlet manifold to the walk in plenum doors.

5.13 Instrumentation and Control

The baghouse will be controlled via the Owner's DCS system. HRC will provide a PLC and the instrumentation to allow the DCS to control the following
- Cleaning air blowers, spare blower will automatically start and alarm to the DCS if the primary blower fails
- Gear box drives for cleaning air manifold
- Inlet damper open/closed status
- Outlet poppet damper open/closed status
- Bypass poppet damper open/closed status
- Compartment ventilation system poppet damper open/closed status
- Cleaning air pressure control
- Baghouse on-line pulse-cleaning sequence
- Monitoring baghouse inlet and outlet temperature, overall differential pressure, blower and manifold drive motor starter status, manifold drive speed switch, and cleaning air pressure

5.0 EQUIPMENT DESCRIPTION (CONTINUED)

- Fabric filter inlet and outlet temperature.
- Fabric filter inlet and outlet pressure.

5.14 Paint

All surfaces which are exposed to flue gas or covered by insulation will not be painted.

The following surfaces will be cleaned per SSPC-SP6 and given one (1) shop coat of an inorganic zinc primer:

- access framing
- Ladders and cages
- Handrails
- monorail beam
- support steel

The following surfaces will be galvanized:

- grating and stair treads

The following manufactured components will be supplied with manufactures standard paint system:

- dampers & actuators
- PLC
- hoist
- instrumentation
- cleaning blowers

5.15 Model Study

A three dimensional model to 1:12 scale will be constructed of the AQC system. The scope will be from the spray dryer inlet to he fabric filter outlet.

The model study will identify pressure drop in the ductwork and AQS system and will be used to minimize dust drop out and to determine turning vane location in the ductwork. It will also be used to determine the optimal design of the internal flow control devices to provide good flow distribution to the bags, minimize pressure loss and undesirable dust buildups and to ensure that the baghouse hoppers have low velocity flow behavior to prevent dust re-entrainment. The model results will be displayed in a wide range of tabular and graphical formats including percent deviation maps, contour maps and histograms.

V TECHNICAL SERVICES

2.5.1 Erection Advisory Services

Erection advisory services will be made available on-site on a regular 8-hour day, 5-day workweek to advise on the recommended installation and erection procedures for the overall DFGD/Baghouse system. These services will be supplied on a per diem basis with the rates in effect at the time the service is provided.

2.5.1 System Start-up Service

Services of a startup engineer will be provided to start up and adjust the Hamon Research-Cottrell supplied equipment, witness performance tests and to instruct the operating personnel in the operation and maintenance of the equipment. This service can include:

- Visual inspection of erected system for general conformance with erection procedures and instruction.
- I&C checkout relative to proper operation and control of applicable components.
- Atomizer assembly direction.
- Basic startup inspection by lime and byproduct recycle preparation system suppliers.

These services will be supplied on a per diem basis with the rates in effect at the time the service is provided.

2.5.2 Operator Training Program

A formal training program will be conducted at the site to instruct the plant operators and maintenance personnel in the proper operation and maintenance procedures for the Hamon Research-Cottrell DFGD/Baghouse Systems and auxiliary equipment supplied. This service is included in price quoted.

VI TERMINATION POINTS

HRC will furnish equipment, materials, and services as described in the "Equipment Description" sections of this proposal. HRC's scope of supply terminates as follows:

- Spray dryer inlet flange connection as indicated on drawing number P-9030-001-002-B (Expansion joints by others).
- Fabric filter outlet duct connection as shown on drawing number P-9030-001-002-B (ID fan inlet. Expansion joints by others)
- Miscellaneous mechanical and electrical equipment - (i.e., control panel, structural steel base plate) - at the manufacturer's or MET's standard mounting base provisions.
- Access facilities at grade.
- Electrical connections at each component.
- Support steel at grade.
- Water - One main tie-in point for water near the lime slurry preparation plant.
- Hopper outlet flanges of fabric filter compartments.
- Delumper outlet flange on each SDA hopper outlet.
- Flange on top of recycle storage silo.
- Fill connection on lime storage silo.

VII ITEMS TO BE FURNISHED AND INSTALLED BY OTHERS

Hamon Research-Cottrell's scope of supply for materials and services is as described in this proposal. Equipment, materials, and services which are not included but are to be provided by others include the following. This list is not inclusive.

- Connecting ductwork except as noted above.
- Ductwork expansion joints as noted in the proposal.
- ID fans
- Stack.
- Permanent internal and external lighting.
- Byproduct removal, conveying and waste disposal storage system.
- Foundations and anchor bolts.
- Erection of all HRC supplied equipment and materials including erection labor, supervision, tools and required field construction equipment.
- Site demolition of existing equipment
- Field run power and I&C wiring, conduit, etc.
- Thermal insulation and lagging system.
- SDA & baghouse penthouse enclosure siding and roofing.
- Field finish painting.
- Start-up labor.
- Electrical power source.
- Electrical power distribution equipment and motor control centers
- Continuous emissions monitoring system.
- Site utilities including: water, power, lime, compressed air, and instrument air.
- Electrical/control equipment building.
- General plant control system(s).
- Other miscellaneous equipment or services required to complete the work.
- Licenses and permits.
- Precoat of filter bags prior to start up

VIII BUDGETARY PRICING

Material Unit 1 & 2 (F.O.B. jobsite, freight prepaid)........................$ 10,750,000

Optional Pricing

Installation/Erection Unit 1 & 2...$ 6,400,000

NOTES:

- The prices shown do not include any sales, use or gross receipts taxes. If these taxes become applicable, they are to be in addition to the above prices and to the account of Purchaser who shall indemnify Hamon Research-Cottrell for any taxes and additionally incurred costs due to Purchaser's failure to satisfy his tax obligations.
- Prices are budgetary.
- Installation/Erection budget price includes mechanical erection, control field wiring, field insulation, roof and hopper enclosure siding installation.

Wheelabrator Air Pollution Control Inc.

202 Canton Road, Suite 204
Cumming, GA 30040
USA

Phone 678.513.4555
Fax 678.513.4777
E-mail jjones@wapc.com

Jonathan P. Jones
Southern Regional Sales Manager

July 19, 2002

Golder Associates, Inc.

Attention: Ms. Fawn Howard
Staff Engineer

Subject: District Energy of St. Paul, Minnesota
WAPC Budget Proposal No. 02-5240-JJV

Dear Ms. Howard:

Thank you for considering Wheelabrator Air Pollution Control for your upcoming gas-scrubbing project.

Based on the data provided in your May 24, 2002 email, we offer the following budget and planning information. If available in the future, additional flue gas characterization data would be helpful to improve the accuracy of this estimate.

A two-fluid nozzle spray dryer absorber is utilized to atomize a lime slurry into the flue gas from your process. The slurry absorbs SO_2 and other acid gases from the flue gas while the heat of the flue gas evaporates the slurry water. The evaporation of the water cools the flue gas. The cooled flue gas is ducted to a pulse jet fabric filter where the dried reaction products and post-combustion particulate are collected. Some solid materials are also discharged from the spray dryer absorber.

Two (2) spray dryer absorbers (SDA) and two (2) fabric filter (FF) are proposed for the project. A slurry preparation system is provided including a storage silo mixing tank and pumps.

Attachment A summarizes the process parameters for the proposed equipment. Attachment B is a summary of the equipment and services to be offered.

WAPC estimate to design and supply a SDA/FF System:	**$7,920,000**
WAPC estimate for optional installation of above:	**$5,800,000**

The above price is provided for budget purposes only and is subject to the terms and conditions contained herein.

We trust that this information will assist you with your evaluation. Please contact me at the number above if you have any questions. We look forward to hearing from you.

Sincerely,

Jon Jones

sw5240.doc/cem

ATTACHMENT A – PROCESS PARAMETERS

1.	System Inlet Data (per boiler)		
1.1	Gas Flow Rate	326,000	ACFM
		213,000	SCFM
		960,000	lb/hr
1.2	Gas Temperature	340	°F
1.3	Mass Flow Rates		
	SO_2	152	lb/hr
1.4	Concentration		
	CO_2	17.8	vol % (estimated)
	O_2	4.5	vol % (estimated)
	N_2	71.4	vol % (estimated)
	H_2O	6.2	vol % (estimated)
	Pollutant Concentrations		
	SO_2	72	ppmv
2.	Expected Removal	90%	
2.1	Acid Gases	Outlet Residual	
	SO_2	7	ppm @ 7% O_2
2.2	Solid Particulate		lb/hr

ATTACHMENT B – DETAIL OF SUPPLY

1.0 Battery Limits

1.1 Flue Gas

Flue gas will enter the equipment at the spray dryer absorber inlet and be discharged at the fabric filter outlet flange. WAPC to provide expansion joints at the interface points.

1.2 Absorbent

Purchaser's self-unloading lime slurry truck will connect to WAPC's (dual) 4" storage silo tube connection.

1.3 Ash Disposal

Ash will be discharged from each of WAPC's spray dryer absorber live bin bottom discharges and from the fabric filter compartment hopper discharge flanges.

1.4 Structural Support and Foundations

WAPC to provide structural supports for supplied equipment. All equipment to be supported on Purchaser supplied foundations. Unless otherwise noted herein, WAPC's design assumes no loads will be transmitted to the WAPC supplied equipment from equipment supplied by Others.

1.5 Water

Purchaser will supply water and piping, both material and labor, at the following locations:

- city/process water for flushing at a flanged connection within slurry preparation silo
- dilution water process within slurry preparation silo
- potable water within slurry preparation silo
- potable water at base of spray dryer absorber

1.6 Instrument Air

Purchaser will supply instrument air (-30°F dew point) at a single point within 3 ft. of the lime slurry prep building at 80 PSIG.

1.7 Atomizing Air

WAPC will supply atomizing air the spray dryer absorber nozzle level.

1.8 Electrical

Purchaser to supply 480 V power to all WAPC-supplied panels and motor starters.

ATTACHMENT B – DETAIL OF SUPPLY

Purchaser to provide 110 V power to all panels.

1.9 Thermal Insulation and Lagging

All thermal insulation and lagging for fabric filter, spray dryer absorber, ductwork and piping (insulation and lagging), and installation labor is supplied by the Purchaser.

All insulated and non-insulated siding for the spray dryer/ absorber nozzle level enclosure and the absorbent preparation silo is supplied by Others.

1.10 Piping

All automatically actuated valves are provided by WAPC. All piping, manual valves, and fittings are provided by others.

1.11 Wiring and Lighting

All wiring and lighting installation labor and materials are provided by Others. Wiring materials include cable, conduit, tray, local disconnects, and enclosures.

1.12 Instrumentation and Control

WAPC will supply all local instrumentation for the equipment. The Purchaser will supply Continuous Emission Monitors (CEM's) to measure SO_2, O_2, and opacity at system inlet and outlet.

The equipment will be controlled from the WAPC supplied Microprocessor based control system.

ATTACHMENT B – DETAIL OF SUPPLY

2.0 Spray Dryer Absorber

Two (2) Wheelabrator Air Pollution Control Two-Fluid Nozzle Spray Dryer Absorber (SDA). SDA includes the following features:

2.1 Atomization Equipment per SDA

- Six (6) operating WAPC 5 x 6 mm two-fluid nozzles complete with shrouded lance assembly and hose connections
- one (1) spare nozzle and lance assembly
- atomizing air flow controllers and low flow switches
- liquid shutoff valves (solenoid activated)
- nozzle view ports
- nozzle silencers

2.1.1 Additional Equipment

final filter (plate type with motorized continuous cleaning)

2.2 Accessories

- nozzle level access doors (24" diameter)
- hopper access doors (24" diameter)
- hopper impactors (air operated)
- hopper hammer anvils and poke holes
- hopper heaters
- local instrumentation and control valves
- hopper level detector
- hopper discharge live bin bottom

2.3 Supports and Access

A. Support Steel

All equipment within the battery limits described above to be supported from WAPC designed and supplied support steel. Minimum hopper flange clearances will be 12' above grade.

B. Doors

- One (1) 24" dia. nozzle level inspection doors
- One (1) 20" x 54" hinged lower chamber inspection doors
- One (1) 24" dia. hinged hopper inspection doors
- One (1) 24" dia. outlet duct inspection doors

ATTACHMENT B – DETAIL OF SUPPLY

C. Access Walkways and Platforms

- 6' wide nozzle inspection platform, 360° around perimeter of vessel. (Platform constructed of 1/4" checkered floor plate with gutter at inside perimeter.)
- Lower chamber door access walkway.
- Hopper access platform.
- Hopper access platform.

D. Stairs

A common stair tower will be provided for access to both SDAs.

E. Caged Ladders

Caged ladders where required for emergency egress.

Caged ladders from following points:

- nozzle inspection platform to chamber access platform
- chamber access door to hopper platform
- hopper access platform to grade

F. Enclosures

Enclosures for the following areas:

- nozzle access platform (insulated)

  Enclosures to be constructed of structural steel framing with siding and roofing. Siding and roofing are supplied as part of the insulation and lagging subcontract.

  Additional equipment provided includes:

- ventilation louvers
- ventilation fans
- man-door
- electric convection heaters
- eyewash station and safety shower

ATTACHMENT B – DETAIL OF SUPPLY

3.0 Fabric Filter (Pulse Jet)

Two (2) WAPC Jet III Pulse-Jet Fabric Filters complete as follows:

- Carbon steel construction- 10 ga housing, 3/16" - A-36 hoppers
- tubesheet for bag installation
- access at tubesheet/outlet damper level
- inlet/outlet plenums and dampers
- PPS felt bags
- cleaning system including pulse headers, pulse valves, manifolds, venturi, and timers
- local differential pressure gauges
- hopper level detectors
- hopper doors (24" diameter)
- housing doors (20" x 48" hinged)
- hopper heaters
- hopper impactors and poke tubes

4.0 Absorbent Preparation Equipment

One (1) Slurry Preparation and Delivery System designed to store and pump lime slurry slurry, complete with storage silo, storage tank, pumps, slakers and control panel. Silo and tank are preassembled in a 12 ft. dia. tube and shipped in two (2) major pieces; external equipment to the tube is shipped loose for field assembly. Pumps are shipped loose for field assembly (skid mounted and prepiped) for installation in a separate modular equipment building. Customer-supplied grit bin to be located outside enclosure. Purchaser will supply dilution water for the tank.

Equipment includes:

- paste type pug mill slaker
- lime slurry storage silo
- agitated slurry tank
- slurry pumps
- local instrumentation and control valves

5.0 Duct System

5.1 Ductwork

Constructed of 3/16" ASTM A-36 steel plate properly stiffened for +/- 35" WG static pressure. Ductwork to connect from spray dryer absorber outlets to inlet plenum of fabric filters.

5.2 Expansion Joints

Fabric-type expansion joints where determined necessary by WAPC including:

- spray dryer absorber outlet
- fabric filter inlet

6.0 Control System

Microprocessor board programmable logic controller for overall control of system including:

- Redundant processors
- Ethernet communication card
- Touchscreen panelview operator interface
- I/O modules with 20% spares
- Programming software
- NEMA 12 enclosure

All continuous emission monitoring (SO_2, opacity) will be provided by Others. WAPC will provide all local instrumentation for the equipment.

The following systems/components will be controlled from local panels:

- storage and slaking system (silo, tank)
- slurry pumps

ATTACHMENT B – DETAIL OF SUPPLY

7.0 Erection Services (Option)

7.1 Structural Erection

Structural erection of components supplied by WAPC including slurry preparation system spray dryer absorbers, fabric filters, ductwork, access walkways, and support steel.

7.2 Mechanical Installation

Installation of all mechanical items, including damper valves, mixing equipment and setting of all pumps, motors, and instrumentation.

7.3 Thermal Insulation

Thermal insulation and lagging of spray dryer absorbers, fabric filters and ductwork, including labor and materials. Insulated siding for all enclosures.

7.4 Piping

Labor and materials to install all slurry and water piping.

7.5 Electrical Wiring, Lighting and Heat Tracing

Labor and materials to install all electrical equipment and provide lighting within WAPC's Detail of Supply. Materials include cable, conduit, cable tray, lights, enclosures, lighting transformers and distribution panels.

Labor and materials to heat trace all external piping. Materials include electrical heat tracing, thermostats and local distribution panels.

Golder Associates, Inc.
South Florida Cogeneration Client

WAPC Budget Proposal No.02-5240-JJV
July 19, 2002

TERMS AND CONDITIONS OF EQUIPMENT AND ERECTION SALES

1. **ACCEPTANCE**

These Terms and Conditions of Sales form part of each Proposal submitted by Wheelabrator Air Pollution Control (WAPC) for the sale of Equipment described herein (Equipment) and Erection Services to Buyer. ANY CONTRACT MADE BY AND BETWEEN THE PARTIES IS EXPRESSLY CONDITIONED ON BUYER'S ASSENT TO THESE TERMS AND CONDITIONS AND TO WAPC'S REVIEW AND APPROVAL OF BUYER'S CREDIT. Unless otherwise stated herein, Buyer has thirty (30) days from the date of the Proposal to notify WAPC in writing of Buyer's offer to enter into a contract on the basis of this Proposal. Upon notification by WAPC from its office in Pittsburgh, Pennsylvania that it has accepted such offer by Buyer, this Proposal shall become a contract between Buyer and WAPC.

2. **WARRANTY**

WAPC warrants for a period equal to the lesser of (i) twelve (12) months after completion of the Work or (ii) eighteen (18) months after delivery of the Equipment (the "Warranty Period") that the Equipment and Work described herein will be free from defects in material and workmanship, will be of the kind and quality herein designated or described, and will conform to the specifications herein set forth. If within the Warranty Period, WAPC receives written notice promptly after the discovery of any nonconformance to the above warranties, WAPC shall correct each such defect, at its option, either by repairing or replacing any defective part(s). The liability of WAPC to Buyer arising out of the foregoing, whether under warranty, tort, contract, negligence, strict liability or otherwise, shall not in any case exceed the cost of correcting defects in the Equipment or Work and upon the expiration of said warranty, all such liability shall terminate. Except as otherwise expressly set forth herein, THERE ARE NO OTHER WARRANTIES, EXPRESS OR IMPLIED, INCLUDING THE WARRANTIES OF MERCHANTABILITY OR FITNESS FOR A PARTICULAR PURPOSE. Liability of WAPC under this warranty is conditioned upon the Equipment being handled, operated, and maintained in accordance with the written instructions provided or approved in writing by WAPC. The warranties specified above do not cover and WAPC makes no warranties which extend to damage due to deterioration or wear or failure occasioned by chemicals, abrasion, corrosion or erosion; Buyer's misapplication; abnormal conditions of temperature or dirt; or operation of the Equipment other than as instructed in writing. WAPC's sole responsibility, and Buyer's exclusive remedy hereunder, shall be limited to such repair or replacement as above provided.

3. **TAXES**

In addition to the price specified herein, Buyer shall pay any tax imposed by any governmental body on the sale, delivery, use or other handling of Equipment sold hereunder, the performance of the Work, or in connection with this Proposal or any transactions contemplated hereby.

4. **FORCE MAJEURE**

WAPC shall not be responsible for losses or damages to Buyer (or any third person) occasioned by delays in the performance or the nonperformance of any of WAPC's obligations or by loss of or damage to any of the Equipment specified in the Proposal when caused directly or indirectly by acts of God, acts of government or military authority, casualty, riot, acts of Buyer, strikes or other labor difficulties, shortages of labor, supplies, and transportation facilities or any other cause beyond WAPC's control. The schedule shall be adjusted in accordance with the impact of any such delay or postponement and the price shall be equitably adjusted to include all additional costs, including overheads, plus a reasonable profit thereon.

TERMS AND CONDITIONS OF EQUIPMENT AND ERECTION SALES

5. CANCELLATION

Buyer may cancel any contract resulting from this Proposal only upon written notice to WAPC and only upon such terms as will indemnify and reimburse WAPC for all loss or damage resulting therefrom, including, without limitation, WAPC's direct costs incurred, overhead, reasonable contract profits, costs, and expenses to which WAPC has become committed for fulfillment of the contract prior to cancellation, plus reasonable settlement expenses.

6. LAWS AND REGULATIONS

WAPC does not assume responsibility for compliance with federal, state, and local laws and regulations unless expressly set forth in WAPC's Proposal. All laws and regulations expressly referenced herein shall refer only to those editions or versions thereof in effect on the date of this Proposal. In the event of revisions or changes thereto subsequent to the date of this Proposal, WAPC assumes no responsibility or liability for compliance therewith. If Buyer desires a modification to the Equipment as a result of a revision or change in such laws or regulations, such modification shall be treated as a Change Order.

7. CHANGE ORDERS

The Buyer may make minor changes within the general scope of Work, to the plans or equipment specifications included in this Proposal by giving WAPC written notification thereof in a Change Order. WAPC shall submit to the Buyer in writing the changes required to the contract price and to the fabrication and erection schedule and other obligations resulting from such Change Order. WAPC shall have no obligation to proceed with such Change Order until WAPC and Buyer agree in writing to such changes in the contract provisions.

8. LIMITATION ON LIABILITY

Whether attributable to contract, tort, warranty, negligence, strict liability or otherwise, WAPC's responsibility for any claims, damages, losses or liabilities arising out of or related to its performance of this Proposal or the Equipment covered hereunder, including but not limited to any correction of Equipment defects under the Warranty or any applicable performance guarantees, shall not exceed the purchase price. IN NO EVENT SHALL WAPC BE LIABLE FOR ANY SPECIAL, INDIRECT, INCIDENTAL, CONSEQUENTIAL, OR PUNITIVE DAMAGES OF ANY CHARACTER, INCLUDING BUT NOT LIMITED TO, LOSS OF USE OF PRODUCTIVE FACILITIES OR EQUIPMENT, LOST PROFITS, GOVERNMENTAL FINES OR PENALTIES, PROPERTY DAMAGES, PERSONAL INJURIES OR LOST PRODUCTION, WHETHER SUFFERED BY BUYER OR ANY THIRD PARTY, IRRESPECTIVE OF WHETHER CLAIMS OR ACTIONS FOR SUCH DAMAGES ARE BASED UPON CONTRACT, TORT, WARRANTY, NEGLIGENCE, STRICT LIABILITY OR OTHERWISE.

9. PATENTS

WAPC assumes the expenses involved in the defense of suits brought in the U.S., (plus damages, profits and costs awarded against Buyer in such a suit,) on the charge that Equipment delivered hereunder and manufactured by WAPC and used in the manner for which it was sold constitutes in and of itself an infringement of a U.S. patent, in an amount not to exceed in the aggregate purchase price of the items or parts thereof found to directly infringe any such patent. If, as a result of any such suit, the use of the Equipment is enjoined, WAPC shall either procure for Buyer the right to use the Equipment or modify it so that it no longer infringes or replace it with non-infringing Equipment. WAPC's patent obligation is conditional upon Buyer notifying WAPC promptly in writing when such suit is brought or threatened and giving WAPC full authority, information and assistance for the defense of the suit and such patent obligation does not apply to any item, or part thereof, manufactured to Buyer's specifications, or to any product manufactured by use of WAPC Equipment and, as to such item or product, WAPC assumes no liability for patent infringement. Except as herein expressly set forth, WAPC does not assume any other obligation or liability in connection with patent infringement suits brought against Buyer or the user of the Equipment which may be delivered hereunder.

10. **PROPRIETARY MATERIAL**

All drawings, patterns, specifications and information included in this Proposal, and all information otherwise supplied by WAPC relating to the design, erection, operation, and maintenance of the Equipment is the proprietary and/or confidential material or information of WAPC. Buyer shall not disclose such material or information to others or allow others to use such material or information except as required for Buyer to obtain service for the Equipment.

11. **LICENSES AND PERMITS**

WAPC shall obtain required contractors' licenses. All other licenses and/or permits shall be supplied by Buyer.

12. **INSURANCE**

WAPC shall maintain the following insurance coverage during the erection schedule:

Workmen's Compensation as required by statute; and Employer's Liability with a limit of liability of $100,000.

Comprehensive General Liability including Completed Operations with the following limits:

Bodily Injury	$1,000,000 Each Occurrence
	$1,000,000 Aggregate
Property Damage	$1,000,000 Each Occurrence
	$1,000,000 Aggregate

Automobile Liability on all owned, leased and hired automobiles with the following limits:

Bodily Injury	$ 500,000 Each Person
	$1,000,000 Each Occurrence
Property Damage	$ 500,000 Each Occurrence

"All Risk" Builder's Risk Insurance on the entire Work including all equipment, material and supplies. This insurance shall include the interest of WAPC, the Buyer and all Subcontractors. WAPC's responsibility under this insurance shall cease and such coverage shall be cancelled upon WAPC's decision, in its sole discretion, that the Work is complete for the purpose of Builder's Risk Insurance Coverage. A Certificate of Insurance shall be furnished at the start of work.

13. **WAIVER OF SUBROGATION**

WAPC and Buyer shall waive their rights and their respective insurance carriers subrogation rights against each other with respect to property damage. In the event that the Buyer is not the Owner of the facilities where the Equipment is being erected, the Buyer agrees to include a provision in its contract with the Owner of such facilities requiring the Owner to supply WAPC with a written waiver of its rights of recovery and its insurance carrier's right of subrogation against WAPC as specified in this Article.

TERMS AND CONDITIONS OF EQUIPMENT AND ERECTION SALES

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14. ASSIGNMENT/SUBCONTRACT

WAPC may assign/subcontract all or any portion of the contract included in its Proposal.

15. ERECTION LABOR

All erection labor included in this Proposal is based on the labor working the first shift of the established working day, Monday through Friday (excluding holidays), and upon paying the local prevailing rates for the labor which is to be used for the erection of the proposed equipment.

16. INTERPRETATION AND ENFORCEMENT

Any contract resulting from this Proposal, shall be construed according to the laws of the Commonwealth of Pennsylvania without giving effect to the conflict of law provisions thereof and suit may be instituted for the enforcement thereof in any state or federal court situate in Pennsylvania.

17. BUYER'S SERVICES

ATTACHMENT J

BACT ANALYSIS FOR VOC

ATTACHMENT J

BACT ANALYSIS FOR VOC

PROPOSED CONTROL TECHNOLOGY

VOC emissions are proposed to be controlled through proper furnace design and good combustion practices including control of combustion air and temperature, distribution of fuel on the combustion grate, and proper control over the furnace loads and transient conditions.

The proposed VOC emission limit for the cogeneration boilers is 0.06 lb/MMBtu for biomass firing.

BACT ANALYSIS

As part of the BACT analysis, a review was performed of previous VOC BACT determinations for industrial and electric utility boilers listed in the RACT/BACT/LAER Clearinghouse on EPA's web page. A summary of the BACT determinations for biomass-fired industrial and electric utility boilers from this review are presented in Appendix D, Table D-5, of the application. The VOC emission limits for biomass-fired industrial and electric utility boilers range from 0.02 to 2.62 lb/MMBtu. This rather large range of emissions is due to differences in boiler design and operation, as well as fuel variability. From the review of previous determinations, it is evident that VOC BACT determinations for biomass-fired industrial and electric utility boilers have been good combustion practices and boiler design.

Control Technology Feasibility

The technically feasible VOC controls are shown in Table J-1. As shown, there are four types of VOC abatement methods. Each available technique is listed with its associated efficiency estimate, identified as feasible or infeasible, and ranked based on control efficiency.

Potential Control Method Descriptions

Refrigerated Condensors -- The most common types of condensers used are surface and contact condensers. In surface condensers, the coolant does not contact the gas stream. Most surface condensers in refrigerated systems are shell and tube type. Shell and tube condensers circulate the coolant through tubes. The VOC condenses on the outside surface of the tube. Plate and frame type heat exchangers are also used as condensers in refrigerated systems. In these condensers, the coolant and the vapor flow separately over thin plates. In either design, the condensed VOC vapors drain away to a collection tank for storage, reuse, or disposal.

Contact condensers cool the vapor stream by spraying either a liquid at ambient temperature or a chilled liquid directly into the gas stream.

Refrigerated condensers are used as air pollution control devises for treating emissions with high VOC concentrations (>5,000 ppmv), in applications involving gasoline bulk terminals, storage, etc. Refrigerated condensers are not technically feasible for reduction of VOC from industrial boilers, and as such are not technically feasible for the cogeneration boilers.

Carbon Adsorbers -- Adsorption is employed to remove VOC compounds from low to medium concentration gas streams. Adsorption is a phenomenon where gas molecules passing through a bed of solid particles are selectively held there by attractive forces which are weaker and less specific than thos of chemical bonds. During adsorption, a gas molecule migrates from the gas stream to the surface of the solid where it is held by physical attraction releasing energy, the heat of adsorption, which typically equals or exceeds the heat of condensation. Adsorption capacity of the solid for the gas tends to increase with the gas phase concentration, molecular weight, diffusivity, polarity, and boiling point. Gases form actual chemical bonds with the adsorbent surface groups. There are five types of adsorption techniques, (see Table 3).

Of the five techniques, fixed bed units are typically utilized for controlling continuous VOC containing streams from flow rates ranging from several hundred to several thousand cubic feet per minute. Based on the large flow rates of the cogeneration boilers (>300,000 acfm), carbon adsorption is not considered technically feasible.

Flare -- Flaring is a VOC control process in which the VOCs are piped to a remote, usually elevated, location and burned in an open flame in the open air using a specially designed burner tip and auxiliary fuel. Flares are not technically feasible for cogeneration boilers, due to the large gas flow rate and low heating value of the gas stream.

Incinerators -- The two basic types of incinerators are thermal and catalytic. Thermal systems may be direct flame incinerators with no energy recovery, flame incinerators with a recuperative heat exchanger, or regenerative systems that operate in a cyclic mode to achieve high energy recovery. Catalytic systems include fixed bed (packed bed or monolith) systems and fluid-bed systems, both of which provide for energy recovery. Catalytic systems are not an option for biomass combustion due to catalyst poisoning, and the large gas flow rate of the NHPP boiler.

As with the previous control devices, incinerators are usually implemented on sources of much higher VOC concentration and much lower flow rates than the cogeneration boilers. Additionally, it is estimated that to utilize thermal oxidation, each thermal oxidizer would require 16,700 SCFH or 146.3 MMSCF/year of natural gas, resulting in significant increased NO_x emission. For these reasons incineration is considered not feasible for the cogeneration boilers.

BACT SELECTION

In conclusion, New Hope Power is requesting an increase in heat input from 715 MMBtu per hour to 760 MMBtu per hour, and an increase in the facility cap on heat input from $11.5x10^{12}$ Btu per year for three cogeneration boilers to $19.97x10^{12}$ Btu per year. The proposed VOC limit is 0.06 lb/MMBtu for biomass combustion. As presented in Table 3-3 of the application, the net increase in permitted VOC emissions resulting from the proposed heat input increase and proposed increase in facility cap is 555 TPY for all three units.

However, actual VOC emissions are equal to 43.93 TPY based on year 2000 and 2001 data. Based on the average annual heat input of $10.5x10^{12}$ Btu per year, and an hourly heat input rate of 715 MMBtu/hour, the average actual VOC emission factor for 2000 and 2001 is 0.0084 lb/MMBtu. Based on an emission factor equal to 0.0084 lb/MMBtu, 8,760 hr/yr of operation and the proposed heat input rate of 760 MMBtu/hr, the future potential emissions are equal to 83.9 TPY, a net increase in actual VOC emissions of 39.97 TPY. Therefore based on actual emissions PSD review would not apply. VOC emissions have been shown to be variable depending on fuel and fuel mixture.

The VOC emission limits for biomass-fired industrial and electric utility boilers range from 0.02 to 2.62 lb/MMBtu. From the review of previous BACT determinations, it is evident that VOC BACT determinations have been based on good combustion practices and boiler design. The NHPP proposed emission limits are with in the range of previous determinations. Additional VOC controls resulting in emission levels lower than current BACT levels would result in an unreasonable economic burden for NHPP

Table J-1. NHPP Cogeneration Boilers VOC Control Technolgy Feasibility

VOC Abatement Method	Technique Now Available	Estimated Efficiency	Feasible and Demonstrated (Y/N)	Rank Based on Control Efficiency	Employed by NHPP (Y/N)
Refrigerated Condensors	Surface	Variable	N	NTF	N
	Contact	Variable	N	NTF	N
Carbon Adsorbers	Fixed Regenerative bed	Variable	N	NTF	N
	Disposable/Rechargeable Cannisters	Variable	N	NTF	N
	Traveling Bed Adsorbers	Variable	N	NTF	N
	Fluid Bed Adsorbers	Variable	N	NTF	N
	Chromatographic Baghouse	Variable	N	NTF	N
Destruction Controls	Flares	Variable	N	NTF	N
Incinerators	Thermal	>80%	N	NTF	N
	Catalytic	>80%	N	NTF	N

NTF = Not Technically Feasible