Memorandum

Florida Department of Environmental Protection

TO: Michael G. Cooke, Division of Air Resources Management

THROUGH: Trina Vielhauer, Bureau of Air Regulation
Al Linero, New Source Review Section

FROM: Jeff Koerner, New Source Review Section

DATE: October 22, 2003

SUBJECT: Project No. 0990332-016-AC
Draft Air Permit No. PSD-FL-196(O)
New Hope Power Partnership, Okeelanta Cogeneration Plant
Increased Heat Input Rates

This project authorizes increases in the hourly and annual heat input rates for the three existing boilers at the Okeelanta Cogeneration Plant. The existing boilers fire a blend of bagasse and wood as the primary fuel with natural gas and distillate oil as restricted alternate fuels for startup and supplemental use. Each unit employs the following add-on air pollution control equipment: mechanical dust collectors to remove heavy fly ash; electrostatic precipitators to remove fine particulate matter; and a urea-based selective non-catalytic reduction system to reduce nitrogen oxide emissions. Emissions of carbon monoxide and organic compounds are minimized by the high boiler temperatures and good combustion practices. Emissions of sulfur dioxide and sulfuric acid mist are minimized by the use of very low sulfur fuels. Each boiler is required to continuously monitor and record emissions of carbon monoxide, nitrogen oxides, sulfur dioxide, and opacity.

These changes provide flexibility to operate the cogeneration units without a synthetic restriction (8760 hours per year). The Department distributed an "Intent to Issue Permit" package on July 31, 2003. The Public Notice was published in The Palm Beach Post on September 24, 2003. The Public Notice included a brief discussion of New Hope Power Partnership's possible future plans to add a new steam turbine-electrical generator, which would bring the total steam-generated electrical power production capacity to about 140 MW. As stated in the Public Notice, the additional production capacity requires approval through the power plant site certification process and a revision of the PSD permit. No petitions for administrative hearings or extensions of time to petition for an administrative hearing were filed.

Day #90 is November 6, 2003. I recommend your approval of the attached Final Permit for this project.

Attachments

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

NOTICE OF FINAL PERMIT

In the Matter of an
Application for Permit by:

New Hope Power Partnership
Okeelanta Cogeneration Plant
8001 U.S. Highway 27 South
South Bay, FL 33493

Authorized Representative:
Mr. Rodney Williams, Plant Manager

Project No. 0990332-016-AC
Air Permit No. PSD-FL-196(O)
Okeelanta Cogeneration Plant
Increased Heat Input Rates
Palm Beach County, Florida

Enclosed is Final Air Permit No. PSD-FL-196(O), which authorizes increases to the hourly and annual heat input rates for the three existing boilers at the Okeelanta Cogeneration Plant, which is located off U.S. Highway 27 approximately six miles south of South Bay in Palm Beach County, Florida. As noted in the attached Final Determination, only minor changes and clarifications were made.

This permit is issued pursuant to Chapter 403, Florida Statutes. Any party to this order has the right to seek judicial review of it under Section 120.68 of the Florida Statutes by filing a notice of appeal under Rule 9.110 of the Florida Rules of Appellate Procedure with the clerk of the Department of Environmental Protection in the Office of General Counsel (Mail Station #35, 3900 Commonwealth Boulevard, Tallahassee, Florida, 32399-3000) and by filing a copy of the notice of appeal accompanied by the applicable filing fees with the appropriate District Court of Appeal. The notice must be filed within thirty (30) days after this order is filed with the clerk of the Department.

Executed in Tallahassee, Florida.

Trina L Vielhauer

Trina Vielhauer, Chief
Bureau of Air Regulation

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this Notice of Final Permit (including the Final permit) was sent by certified mail (*) and copies were mailed by U.S. Mail before the close of business on 10/29/03 to the persons listed:

Mr. Rodney Williams, New Hope Power*
Mr. James Meriwether, New Hope Power
Mr. David Buff, Golder Associates Inc.
Mr. David Dee, Landers & Parsons
Mr. James Stormer, PBCHD
Mr. Ron Blackburn, SD Office
Mr. Gregg Worley, EPA Region 4 Office
Mr. John Bunyak, NPS

Clerk Stamp

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

Victoria Gibson / October 29, 2003
(Clerk) (Date)

FINAL DETERMINATION

PERMITTEE

New Hope Power Partnership
Okeelanta Cogeneration Plant
8001 U.S. Highway 27 South
South Bay, FL 33493

PERMITTING AUTHORITY

Florida Department of Environmental Protection
Division of Air Resources Management
Bureau of Air Regulation
New Source Review Section
2600 Blair Stone Road, MS #5505
Tallahassee, Florida, 32399-2400

PROJECT

Project No. 0990332-016-AC
Air Permit No. PSD-FL-196(O)

This permit authorizes increases to the hourly and annual heat input rates for the three existing boilers at the Okeelanta Cogeneration Plant, which is located off U.S. Highway 27 approximately six miles south of South Bay in Palm Beach County, Florida.

NOTICE AND PUBLICATION

The Department distributed an "Intent to Issue Permit" package on July 31, 2003. The applicant published the "Public Notice of Intent to Issue" in The Palm Beach Post on September 24, 2003. The Department received the proof of publication on October 6, 2003. No petitions for administrative hearings or extensions of time to petition for an administrative hearing were filed.

COMMENTS

The Department received comments on the draft permit from New Hope Power Partnership (NHPP). The Department also received a response from the Palm Beach County Health Department regarding NHPP's comments and requested changes to the draft permit. The following summarizes all comments, the Department's response, and any resulting changes.

PLACARD PAGE (PAGE 1)

Project and Location: The applicant requests removal of reference to 74.9 MW electrical generating capacity because it has no relationship to air emissions. If NHPP decides to increase power generation beyond 74.9 MW, it will address the change through the power plant site certification process.

PBCHD Response: If NHPP objects to the limit on power generation, they should consider applying for a power plant site certification.

Department's Response: The Department notes that the limit on steam-generated power of "74.9 MW" was included in the PSD permit for the original construction of the cogeneration plant. The applicant has recently divulged plans to apply for increased power generating capacity through the power plant site certification process. The description of the maximum generating capacity was not changed. The PSD permit may be modified through the power plant site certification process.

SECTION I. GENERAL INFORMATION

Facility Description (Page 2): The applicant requests revision of the first sentence to, "*For PSD purposes*, the facility consists of two adjacent plants."

Department's Response: The Department added the following sentence to this paragraph, "The cogeneration plant, sugar mill, and sugar refinery are all considered a single facility for purposes of the PSD and Title V regulatory programs." In addition, the ARMS identification numbers were included for each plant.

Regulatory Classification, Title III (Page 2): The applicant requests revision of the classification description to, "*Based on the Title V operation permit, the facility may have emissions of hazardous air pollutants (HAPs) at levels greater than the major source thresholds.*"

PBCHD Response: Major source classification for criteria pollutants and hazardous air pollutants are based on potential emissions, which implies an educated suspicion and not certainty. The draft language is appropriate.

Department's Response: Based on the application and available information, the cogeneration plant is a potential major source of HAP emissions. The classification was revised to, "The existing facility is a *potential* major source of hazardous air pollutants (HAPs)."

Regulatory Classification, NSPS (Page 2): The applicant requests deletion of the reference to Subpart Db applicability, which applies to Okeelanta Corporation's Boiler 16. Boiler 16 is not part of the cogeneration plant.

Department's Response: The Subpart Db reference is for Boiler 16, which is part of Okeelanta Corporation's sugar mill. However, the "Regulatory Classification" section of the permit pertains to the facility as a whole, which consists of both the cogeneration plant and the sugar mill. No change was made.

SECTION II. ADMINISTRATIVE REQUIREMENTS

Title V Permit Revision (Page 4): The applicant requests up to 180 days to submit an application to revise the Title V air operation permit.

PBCHD Response: There does not appear to be any justification for a longer period in which to submit an application such as construction, additional testing, etc.

Department's Response: The Department revised the requirement as follows: "Pursuant to Rule 62-213.420(1)(a)2, F.A.C., the permittee shall submit an application for a revised Title V air operation permit at least ninety (90) days before the expiration of this permit, but no later than 180 days after commencing operation. In accordance with Rule 62-213.412(2), F.A.C., the permittee may immediately implement the changes authorized by this air construction permit after submitting the application for a revised Title V air operation permit to the Permitting Authority and providing copies of the application to EPA Region 4 and each Compliance Authority."

SECTION III. EMISSIONS UNIT SPECIFIC CONDITIONS, COGENERATION BOILERS

1. **Generating Capacity (Page 5)**: The applicant requests deletion of the last three sentences in the paragraph, which deal with the 74.9 power generating capacity.

   Department's Response: The Department did not revise the restriction on maximum generating capacity. As discussed above, this condition may be modified through the power plant site certification process.

2. **Boiler Design (Page 5)**: The applicant requests rewording of second sentence to, "Natural gas and distillate oil are fired at startup *and shutdown, when necessary to ensure good combustion,* to supplement biomass fuel, and for periods when the biomass fuel supply is interrupted."

   Department's Response: The condition was revised as requested.

5. **Control Equipment (Page 5)**: To correct a typographical error, the applicant requests revision of the first bullet item to, "Four burners are installed with one in each corner *of* the boiler."

   Department's Response: The condition was revised as requested.

10. **Permitted Capacity (Page 7)**: The applicant requests addition of the following sentence, "The operating hours of the cogeneration boilers are not restricted."

Department's Response: The condition was revised as requested.

16. **Emissions Standards, Particulate Matter (Page 8)**: The applicant requests maintaining the current particulate matter standard of 0.03 lb/MMBtu instead of the proposed lower standard of 0.026 lb/MMBtu. The applicant notes that the boilers have tested as high as 0.025 lb/MMBtu. Given the variability in fuel quality, boiler operation, and ESP performance over time, the applicant does not believe that the new standard provides enough "margin for compliance".

PBCHD Comment: The proposed BACT standard for particulate matter emissions is also a surrogate for metal HAP emissions as is the case in the proposed industrial boiler MACT regulations. The fact that a single emissions test failed to provide a comfortable margin of compliance should have no bearing on the BACT determination.

Department's Response: Recent BACT determinations have established particulate matter emission standards much lower than *0.03* lb/MMBtu for solid fuel fired boilers. The "0.026 lb/MMBtu" standard was established giving consideration to the proposed industrial boiler MACT and the existing controls for the cogeneration boilers (mechanical dust collectors and electrostatic precipitators). Based on the 12 stack test results provided with NHPP's comments, the Department notes that *all* tests demonstrate compliance with the proposed BACT standard. In fact, 8 of the 12 test results are *half* of the proposed BACT standard or less ($\leq$ 0.013 lb/MMBtu), which would indicate that NHPP has the capability to effectively control particulate matter emissions to meet the standard. The proposed standard was not changed.

16. **Emissions Standards, Volatile Organic Compounds (Page 8)**: The applicant requests retaining the current VOC standard of 0.06 lb/MMBtu. The applicant believes that the proposed BACT standard (0.05 lb/MMBtu) is too stringent given recent compliance tests, which showed Boiler C with VOC emissions of 0.058 lb/MMBtu. The applicant indicates that, although this may not be typical of VOC emissions, it is reflective of the variability due to fuel quality and boiler operation.

PBCHD Comment: Out of thirty previous stack tests, the highest measured emission rate was 0.036 lb/MMBtu. From the recent tests conducted in January of 2003, only the third run (1-hour of data) for Boiler C showed emissions higher than this rate at 0.117 lb/MMBtu. Again, the fact that a single emissions test failed to provide a comfortable margin of compliance should have no bearing on the BACT determination.

Department's Response: The Department established the proposed standard as BACT for VOC emissions based on the boiler design and "good combustion and operating practices". The application provided 21 VOC stack tests for the cogeneration boilers conducted when firing bagasse and/or wood. All of the tests show compliance with the proposed standard of 0.05 lb/MMBtu. The highest tested rate in this data was 0.036 lb/MMBtu, which is 28% below the proposed BACT standard. In fact, 20 of the 21 stack test results are *less than half* of the proposed BACT ($\leq$ 0.025 lb/MMBtu). Again, this would indicate that NHPP has the capability to effectively control volatile organic compounds to meet the standard using "good combustion and operating practices". The fact that a recent test for Boiler C showed a VOC emission rate of 0.058 lb/MMBtu does not provide overwhelming evidence to change the proposed BACT standard. The tests conducted during the same time frame for identical Boilers A and B indicated VOC emission rates of 0.0027 and 0.0057 lb/MMBtu, which are at least 10 times lower than that for Boiler C. Combined with the previous tests, this indicates that 21 of the 23 stack tests are *less than half* of the proposed BACT ($\leq$ 0.025 lb/MMBtu). The recent test for Boiler C appears to be an outlier resulting from the third run, perhaps indicating that good combustion conditions were not maintained. The proposed standard was not changed.

16. **Emissions Standards, Footnote "a" (Page 9)**: The applicant requests deletion of the requirement to also record and report CO emission in terms of "ppmvd corrected to 3% oxygen", which are the same units as the proposed industrial boiler MACT standard. The applicant believes that significant costs will be incurred

to upgrade the software. The applicant notes that it is premature to report CO emissions in these terms because the final MACT standard may change significantly from the proposed form.

Department's Response: The Department believes that it is important to gather this data prior to final promulgation of the industrial boiler MACT standards. This information will be an important aid in determining whether the existing boilers are capable of maintaining compliance with MACT standard or in the development of new control techniques. The existing CEMS already gathers the basic information. The cost of adding this recorded parameter will be minimal. The condition was not changed.

16. **Emissions Standards, Footnote "f" (Page 9)**: The applicant requests clarification that VOC emissions should be reported as carbon.

    Department's Response: The previous version of this PSD permit required reporting VOC emissions in terms of "propane" not carbon. The condition was not changed.

19. **Stack Test Requirements, Test Methods (Page 13)**: For Method 25A, the applicant requests clarification that VOC emissions should be reported as carbon.

    Department's Response: The previous version of this PSD permit required reporting VOC emissions in terms of "propane" not carbon. The condition was not changed.

21. **Quarterly Reports (Page 13)**: The applicant requests deletion of the requirement to report 12-month rolling heat input rates because there is no longer an annual heat input rate limit.

    Department's Response: The Department agrees and removed the requirement to keep records of the 12-month rolling heat input limit.

OTHER CHANGES

The section titled "Relevant Documents" was moved from Page 3 to Page 2. The only other changes made were corrections to minor typographical and formatting errors.

CONCLUSION

The Department considers the changes described above to be minor revisions and not substantial in nature. The final action of the Department is to issue the permit with the changes described above.

Department of
Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

PERMITTEE

New Hope Power Partnership
Okeelanta Cogeneration Plant
8001 U.S. Highway 27 South
South Bay, FL 33493

Authorized Representative:
Mr. Rodney Williams, Plant Manager

Air Permit No. PSD-FL-196(O)
Project No. 0990332-016-AC
Okeelanta Cogeneration Plant
SIC No. 4911
Palm Beach County

PROJECT AND LOCATION

The original PSD permit authorized the construction of a biomass and fossil fuel-fired 74.9 MW cogeneration plant adjacent to Okeelanta Corporation's sugar mill and refinery. The original PSD permit expired on July 1, 1996. The permittee obtained several previous permit modifications that extended some construction-related activities as well as revised specific conditions of the permit. This permit modification authorizes an increase in the hourly heat input rate from 715 to 760 MMBtu per hour per boiler and removes the previous limit on the annual heat input rate ($11.5 \times 10^{+06}$ MMBtu per year) for the three boilers combined. As a result of the changes, BACT determinations were required for emissions of carbon monoxide, fluorides, lead, nitrogen oxides, particulate matter, sulfur dioxide, sulfuric acid mist, and volatile organic compounds. In addition, Condition No. 15 was revised to simply require permanent shutdown of the existing Okeelanta sugar mill boilers, which were part of the netting analysis for the original project.

The cogeneration plant is located off U.S. Highway 27 approximately six miles south of South Bay in Palm Beach County, Florida. The UTM coordinates are Zone 17, 524.90 km East, and 2940.10 km North. The map coordinates are latitude 26° 35' 00" N and longitude 80° 45' 00" W.

STATEMENT OF BASIS

This PSD air pollution construction permit is issued under the provisions of Chapter 403 of the Florida Statutes (F.S.), and Chapters 62-4, 62-204, 62-210, 62-212, 62-296, and 62-297 of the Florida Administrative Code (F.A.C.) and Title 40, Part 52, Section 21 of the Code of Federal Regulations. Specifically, this permit is issued pursuant to the requirements for the Prevention of Significant Deterioration (PSD) of Air Quality, Rule 62-212.400, F.A.C. The permittee is authorized to perform the proposed work and operate the installed equipment in accordance with the conditions of this permit, the conditions of the Title V operation permit, and as described in the application, approved drawings, plans, and other documents on file with the Department.

CONTENTS

Michael G. Cooke

10/27/03

Michael G. Cooke, Director
Division of Air Resources Management

Effective Date

FACILITY DESCRIPTION

The facility consists of two adjacent plants. Okeelanta Corporation (ARMS ID No. 0990005) operates a sugar mill (SIC No. 2061) and sugar refinery (SIC No. 2062) including packaging and transshipment activities. New Hope Power Partnership (ARMS ID No. 0990332) operates a 74.9 net MW cogeneration plant that provides process steam for the sugar mill/refinery and generates electricity for sale to the power grid (SIC 4911). The cogeneration plant, sugar mill, and sugar refinery are all considered a single facility for purposes of the PSD and Title V regulatory programs. This permit addresses the cogeneration plant, which consists of the following emissions units.

ID	Emission Unit Description
001	Cogeneration Boiler A (760 MMBtu per hour)
002	Cogeneration Boiler B (760 MMBtu per hour)
003	Cogeneration Boiler C (760 MMBtu per hour)
004	Material handling and storage

REGULATORY CLASSIFICATION

Title III: The existing facility is a potential major source of hazardous air pollutants (HAPs).

Title IV: The existing facility does not operate any units subject to the acid rain provisions of the Clean Air Act.

Title V: The existing facility is a Title V major source of air pollution in accordance with Chapter 213, F.A.C.

PSD: The existing facility is a PSD major source of air pollution with respect to Rule 62-212.400, F.A.C.

PPSC: The existing facility is not subject to Chapter 62-17, F.A.C. for Power Plant Site Certification because it produces less than 75 MW of steam-generated electrical power.

NSPS: The existing facility operates units subject to the New Source Performance Standards in 40 CFR 60, including Subparts Da and Db (boilers) and Subpart Kb (fuel storage tanks).

PERMITTING AUTHORITY

All documents related to PSD applications for permits to construct or modify shall be submitted to the Bureau of Air Regulation of the Florida Department of Environmental Protection (DEP) at 2600 Blair Stone Road (MS #5505), Tallahassee, Florida 32399-2400. All documents related to applications for permits to operate the cogeneration plant shall be submitted to the Air Resource Section of the Department's South District Office at P.O. Box 2549, Fort Myers, Florida 33902-2549. Copies of all such documents shall be submitted to the Air Pollution Control Section of the Palm Beach County Health Department at P.O. Box 29, West Palm Beach, Florida 33402-0029.

COMPLIANCE AUTHORITY

All documents related to compliance activities such as reports, tests, and notifications shall be submitted to the Air Pollution Control Section of the Palm Beach County Health Department at P.O. Box 29, West Palm Beach, Florida 33402-0029. Copies of all such documents shall be submitted to the Air Resources Section at the South District Office of the Florida Department of Environmental Protection (DEP) at 2295 Victoria Avenue, Suite 364 in Fort Myers, Florida 33902-2549.

RELEVANT DOCUMENTS

The documents listed below are not a part of this permit; however, they are specifically related to this permitting action and are on file with the Department.

- Air Permit No. PSD-FL-196 issued September 27, 1993 and all subsequent modifications.
- Permit application received on September 6, 2002 and all related correspondence to make complete.

APPENDICES

The following Appendices are attached as part of this permit.

Appendix A. Citation Format

Appendix B. General Conditions

Appendix C. Standard Requirements

Appendix D. Final BACT Determinations

Appendix E. Continuous Monitor Requirements

CITATION FORMAT

Appendix A of this permit describes the format used to cite applicable rules, regulations, and permitting actions.

1. General Conditions: The permittee is subject to, and shall operate under, the attached General Conditions listed in Appendix B of this permit. General Conditions are binding and enforceable pursuant to Chapter 403 of the Florida Statutes. [Rule 62-4.160, F.A.C.]

2. Applicable Regulations, Forms and Application Procedures: Unless otherwise indicated in this permit, the construction and operation of each subject emissions unit shall be in accordance with the capacities and specifications stated in the application. The facility is subject to all applicable provisions of: Chapter 403 of the Florida Statutes (F.S.); Chapters 62-4, 62-204, 62-210, 62-212, 62-213, 62-296, and 62-297 of the Florida Administrative Code (F.A.C.); and the Title 40, Parts 51, 52, and 60 of the Code of Federal Regulations (CFR), adopted by reference in Rule 62-204.800, F.A.C. The terms used in this permit have specific meanings as defined in the applicable chapters of the Florida Administrative Code. The permittee shall use the applicable forms listed in Rule 62-210.900, F.A.C. and follow the application procedures in Chapter 62-4, F.A.C. Issuance of this permit does not relieve the permittee from compliance with any applicable federal, state, or local permitting or regulations. [Rules 62-204.800, 62-210.300 and 62-210.900, F.A.C.]

3. Permit Expiration: The original expiration date for the construction of this plant was July 1, 1996. Construction of the cogeneration plant is complete and commercial operation has commenced. This revised permit does not authorize any additional construction. The expiration date of this revised permit is September 1, 2004 strictly for the purpose of processing a Title V air permit revision to incorporate these changes. All physical construction is complete. [Rule 62-4.210(2), F.A.C.]

4. Effective Date: The effective date of the modified PSD permit is specified on the placard page (page 1).

5. Relaxations of Restrictions on Pollutant Emitting Capacity: If a previously permitted facility or modification becomes a facility or modification which would be subject to the preconstruction review requirements of this rule if it were a proposed new facility or modification solely by virtue of a relaxation in any federally enforceable limitation on the capacity of the facility or modification to emit a pollutant (such as a restriction on hours of operation), which limitation was established after August 7, 1980, then at the time of such relaxation the preconstruction review requirements of this rule shall apply to the facility or modification as though construction had not yet commenced on it. [Rule 62-212.400(2)(g), F.A.C.]

6. New or Additional Conditions: For good cause shown and after notice and an administrative hearing, if requested, the Department may require the permittee to conform to new or additional conditions. The Department shall allow the permittee a reasonable time to conform to the new or additional conditions, and on application of the permittee, the Department may grant additional time. [Rule 62-4.080, F.A.C.]

7. Modifications: No emissions unit or facility subject to this permit shall be constructed or modified without obtaining an air construction permit from the Department. Such permit shall be obtained prior to beginning construction or modification. [Rules 62-210.300(1) and 62-212.300(1)(a), F.A.C.]

8. Title V Permit Revision: Pursuant to Rule 62-213.420(1)(a)2, F.A.C., the permittee shall submit an application for a revised Title V air operation permit at least ninety (90) days before the expiration of this permit, but no later than 180 days after commencing operation. In accordance with Rule 62-213.412(2), F.A.C., the permittee may immediately implement the changes authorized by this air construction permit after submitting the application for a revised Title V air operation permit to the Permitting Authority and providing copies of the application to EPA Region 4 and each Compliance Authority. To apply for a revised Title V operation permit, the applicant shall submit the appropriate application form, compliance test results, and such additional information as the Department may by law require. As necessary, the application shall include a Compliance Assurance Monitoring Plan. The application shall be submitted to the Department's South District Office with copies to the Compliance Authority. [Rules 62-4.030, 62-4.050, 62-4.220, 62-213.412, and 62-213.420, F.A.C.]

This section of the permit addresses the following emissions units.

Emissions Units 001, 002, and 003: Cogeneration Boilers A, B, and C *Description*: Each unit is a biomass-fired spreader stoker steam boiler manufactured by Zurn and designed to produce approximately 506,100 pounds per hour of steam at 1500 psig and 975° F. *Fuels and Capacity*: The primary fuel is biomass (760 MMBtu per hour), which includes bagasse from the adjacent sugar mill and clean wood material delivered to the plant by area subcontractors. Auxiliary fuels include natural gas (605 MMBtu per hour) and very low sulfur distillate oil (490 MMBtu per hour). *Controls*: Pollution control equipment includes low-NOx burners for gas firing, a selective non-catalytic reduction system to reduce nitrogen oxides emissions, mechanical dust collectors and an electrostatic precipitator to reduce particulate matter emissions, and an activated carbon injection system to reduce potential mercury emissions. Good operating practices and the efficient combustion of clean, low-sulfur fuels minimizes emissions of carbon monoxide, sulfuric acid mist, sulfur dioxide, and volatile organic compounds. *Stack Parameters*: Exhaust gases exit a 10 feet diameter stack that is at least 199 feet tall and with a volumetric flow rate of approximately 319,000 acfm at 352° F.
Emissions Unit 004: Material handling and storage including unloading operations, stockpiles, transfer operations, conveyors, screens, crushers, hoppers, silos, and storage tanks.

CONSTRUCTION DETAILS

1. Generating Capacity: Construction of the proposed cogeneration plant shall reasonably conform to the plans described in the application. The plant shall be designed, constructed, and operated such that the generating capacity does not exceed 74.9 net megawatt (MW) based on a 1-hour average. The owner or operator shall not modify the cogeneration plant in any way that would cause the plant to exceed the limit on maximum net generating capacity. The hourly average net generation rate shall be recorded and retained for at least 5 years.

2. Boiler Design: The cogeneration boilers shall consist of spreader stoker units designed to fire biomass as the primary fuel with pipeline natural gas and distillate oil as auxiliary fuels. Natural gas and distillate oil are fired at startup and shutdown, when necessary to ensure good combustion, to supplement biomass fuel, and for periods when the biomass fuel supply is interrupted. No other fuels are authorized. *{Permitting Note: Each boiler was originally designed to fire low sulfur coal as an emergency backup fuel, but no transfer, crushing, or storage systems were ever installed. The permittee shall obtain a permit modification before firing any other fuel (including coal) not specifically authorized by this permit.}*

3. Stack: Each boiler shall have an individual stack that is at least 199 feet tall. The permanent stack sampling facilities for each stack must comply with Rule 62-297.345, F.A.C.

4. Process Monitors: Each boiler shall be equipped with instruments to measure the fuel feed rate, heat input, steam production, steam pressure, and steam temperature. Appendix E identifies minimum requirements for monitoring equipment.

5. Control Equipment: Each boiler shall be equipped with:
   - Low-NOx natural gas burners rated for no more than 0.15 pounds of NOx per MMBtu of heat input. Four burners are installed with one in each corner of the boiler. The maximum heat input rate from all four burners is 605 MMBtu per hour.
   - Mechanical dust collectors consisting of four, large diameter, multi-tube modules with airfoil vanes or equivalent equipment. The mechanical dust collectors shall be installed and maintained as pre-control devices prior to each electrostatic precipitator and designed for a removal efficiency of at least 85% of the particulate matter greater than 10 microns in size (assuming a specific gravity of 2.00).
   - An electrostatic precipitator (ESP) designed for at least 98 percent removal of particulate matter.

- A selective non-catalytic reduction (SNCR) system designed for at least 40 percent removal of NOx.
- A carbon injection system (or equivalent) for potential control of mercury emissions.

6. Continuous Monitors: For each cogeneration boiler, the permittee shall install, calibrate, maintain, and operate continuous emissions monitoring systems (CEMS) and continuous opacity monitoring systems (COMS) to measure and record emissions of carbon monoxide (CO), nitrogen oxides (NOx), opacity, oxygen (O_2), and sulfur dioxide (SO_2) in a manner sufficient to demonstrate compliance with the standards of this permit. The opacity monitor shall be placed in the ductwork between the electrostatic precipitator and the stack or in the stack. Appendix E identifies minimum requirements for monitoring systems.

7. Good Combustion Practices: An oxygen meter shall be installed for each unit to continuously monitor a representative sample of the flue gas. The oxygen monitor shall be used with automatic feedback or manual controls to continuously optimize air/fuel ratio parameters. Depending on the fuel quality and existing combustion conditions, the operator shall provide sufficient excess air to ensure good combustion within the boiler. The application to revise the Title V operation permit shall identify "good combustion practices" for the cogeneration boilers to minimize pollutant emissions during startup, operation, and shutdown. The document "Use of Flue Gas Oxygen Meter as BACT for Combustion Controls" shall be used as a guide. Good combustion controls shall also include the following:

   - Maintain improved combustion controls to provide efficient tuning of air/fuel control instrumentation.
   - Maintain rotary pocket-style wood feeders with efficient air seal to minimize intrusion of ambient air.
   - Maintain effective water level controls in bottom ash system to prevent intrusion of ambient air.
   - Mix biomass fuel to provide a consistent fuel blend.
   - Maintain the flue gas oxygen content to provide efficient combustion for the existing conditions.
   - When necessary to enhance poor combustion, reduce the biomass feed rate below the maximum rate.
   - When necessary to enhance poor combustion, co-fire natural gas or distillate oil.

8. O&M Plans: The application to revise the Title V operation permit shall include an operation and maintenance plan consisting of at least the following items.

   a. For the cogeneration boilers, electrostatic precipitators (ESP), selective non-catalytic reduction (SNCR) systems, activated carbon injection (ACI) mercury control systems, and silo fabric filters, identify: the capacities, design efficiencies, pollutant emission rates, general operational description of equipment, key design and operating parameters, expected operating range of each key parameter, monitoring of key parameters, frequency of monitoring (instantaneous, continual, or continuous), and actions taken to return key parameters to within the expected operating ranges. The plan shall also specify good operating practices to promote efficient boiler combustion, startup and shutdown procedures for the boilers and control systems to minimize emissions, and precautions to prevent fugitive particulate matter emissions. *{Permitting Note: Operation outside of the specified operating range for any monitored parameter would not be a violation by itself. However, continued operation outside of a specified operating range without corrective action may be considered circumvention of the air pollution control equipment or methods.}*

   b. For the selective non-catalytic reduction (SNCR) systems identify an alternate NOx emissions control plan based on previous monitoring data that shall be implemented in case the NOx monitoring system is down. The plan shall identify the minimum urea injection rate that has demonstrated continuous compliance with the NOx emissions standard at various load conditions.

9. Materials Handling Controls: For the fly ash handling and mercury control system reactant storage systems:

   a. The particulate matter filter control system for the storage silos shall be designed to achieve an outlet dust loading of no greater than 0.01 grains per actual cubic feet of exhaust.

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

OPERATIONAL RESTRICTIONS

10. Permitted Capacity: The cogeneration boilers shall be constructed and operated in accordance with the capabilities and specifications described in the application. The maximum heat input rate to each cogeneration boiler shall not exceed 760 MMBtu/hr when burning 100 percent biomass, 605 MMBtu/hr when burning 100 percent natural gas, and 490 MMBtu/hr when burning 100 percent very low sulfur distillate oil. The steam production of each boiler shall not exceed an average of 506,100 pounds per hour at 1,500 psig and 975°F. The operating hours of the cogeneration boilers are not restricted (8760 hours per year).

11. Primary Fuel: The primary fuel for the plant shall be biomass, which shall consist of bagasse and authorized wood material. Bagasse is the fibrous vegetative residue remaining after the sugarcane milling process. Authorized wood material is clean construction and demolition wood debris, yard trash, land clearing debris, and other clean cellulose and vegetative matter. Each cogeneration boiler shall combust no more than 30% by weight yard waste (yard trash) on a calendar quarter basis that is defined as a municipal solid waste (MSW) in 40 CFR 60.51a. The biomass fuel used at the cogeneration plant shall not contain hazardous substances, hazardous wastes, biomedical wastes, or garbage. The fuel used at the cogeneration plant shall not contain special wastes, except wood, lumber, trees, tree remains, bagasse, cane tops and leaves, and other clean vegetative and cellulose matter. The permittee shall perform a daily visual inspection of any wood material or similar vegetative matter that has been delivered to the plant for use as fuel. Any shipment observed to contain prohibited materials shall not be used as fuel, unless such materials can be readily segregated and removed from the wood material and vegetative matter.

    The permittee shall design and implement a management and testing program for the wood material and other materials delivered to the plant for fuel. The program shall be designed to keep painted and chemically treated wood, household garbage, toxic or hazardous non-biomass and non-combustible waste material, from being burned at this plant. The program shall provide for the routine inspection and/or testing of the fuel at the originating wood yard sites as well as at the cogeneration site, to ensure that the quantities of painted or chemically treated wood in the fuel are minimized. Based on the analysis of a composite sample, wood material containing more than 70.7 ppm arsenic or 83.3 ppm chromium or 62.8 ppm copper shall not be burned. Fuel scheduled for burning shall be inspected daily. At a minimum, the fuel management program shall include the following sampling and analyses:

    a. At least twice each month, the permittee shall have separate analyses conducted on an as-fired wood sample and an as-fired bagasse sample for the following: heating value (modified ASTM D3286, Btu/lb, dry), carbon content (modified ASTM D5373, percent by weight, dry), sulfur content (modified ASTM D4239 Method C, percent by weight, dry), and moisture content (modified ASTM D3173, percent by weight). In addition the wood sample shall be analyzed for copper, chromium, and arsenic in accordance with Methods 3050/6010 (EPA Method SW-846) and reported in ppm by weight, dry. Samples shall be taken at least two weeks apart.

    b. At least once each month, the permittee shall have an analysis conducted on a composite sample of fly ash and bottom ash for arsenic, copper, and chromium in accordance with the procedures described in EPA Method SW-846, *Test Methods for Evaluating Solid Waste, Physical/Chemical Methods* (40 CFR 261, Appendix III). The analytical results from ash testing shall be used in conjunction with those from the as-fired wood samples to evaluate the effectiveness of the fuel management program in removing chemically treated wood from the biomass fuel. The permittee shall dispose of all ash generated on site in accordance with the applicable state and federal regulations.

    c. Analytical results of the as-fired biomass fuels and ash sampling shall be summarized and provided in the quarterly report to the Compliance Authority.

    The ash and fuel management program shall become part of the Title V operation permit.

12. Auxiliary Fuel: The cogeneration boilers shall fire only distillate oil and pipeline natural gas as auxiliary fuels. Distillate oil shall be new No. 2 oil with a maximum sulfur content of 0.05 percent sulfur by weight as determined by the appropriate test method listed in 40 CFR 60.17. "New" oil is oil that has been refined from crude oil and that has not been used in any manner that may contaminate it. Each boiler may startup solely on pipeline natural gas or distillate oil.

13. Fossil Fuel Limitation: The firing of fossil fuels (distillate oil and natural gas) shall be less than 25 percent of the total heat input to each cogeneration boiler during any calendar quarter.

14. Fuel Records: The permittee shall maintain a daily log of the amounts and types of fuels used. The amount, heating value, and sulfur content of each fuel oil delivery shall be kept in a log for at least five years. For each calendar month, the actual monthly SO_2 emissions and the 12-month rolling total SO_2 emissions shall be determined and kept in a log.

15. Permanent Shutdown: Sugar mill boiler Nos. 4, 5, 6, 10, 11, 12, 14, and 15 shall remain permanently shutdown and rendered incapable of operation. *{Permitting Note: Okeelanta Corporation's Boiler No. 16 may operate in accordance with modified Permit No. PSD-FL-169(A).}* [Rule 62-212.400, F.A.C.]

EMISSIONS LIMITING STANDARDS

16. Emissions Standards: Based on the maximum permitted heat input to each cogeneration boiler, stack emissions shall not exceed the standards specified in the following table:

Pollutant	Averaging Period	Emissions Standards per Boiler [i]	
		lb/MMBtu	lb/hr
Carbon Monoxide (CO) [a]	30-day rolling CEMS avg.	0.50	380.0
	12-month rolling CEMS avg.	0.35	
Nitrogen Oxides (NOx) [b]	30-day rolling CEMS avg.	0.15	114.0
Sulfur Dioxide (SO_2) [c]	24-hour rolling CEMS avg.	0.20	152.0
	30-day rolling CEMS avg.	0.10	
	12-month rolling CEMS avg.	0.06	
Stack Opacity [d]	6-minute block COMS avg. (Alternative: EPA Method 9)	≤ 20% opacity, except for one 6-minute block per hour that is ≤ 27% opacity	
Particulate Matter (PM/PM_{10}) [e]	3-run test avg.	0.026	19.8
Volatile Organic Compounds (VOC) [f]	3-run test avg.	0.05	38.0
Mercury [g]	3-run test avg.	5.4×10^{-06}	NA
Lead and Fluorides [h]	The BACT determination for lead and fluoride emissions is the use of fuels containing low levels of these compounds (bagasse, wood, distillate oil, and natural gas) and prospective removal with the fly ash by the mechanical dust collectors and electrostatic precipitators.		

a. Compliance shall be determined by data collected from the required CO CEMS in terms of "lb/MMBtu of heat input". The 30-day rolling average shall be determined by calculating the arithmetic average of all hourly emission rates for 30 successive boiler operating days and be consistent with the NOx monitoring requirements below. Compliance with the 12-month standard shall be based on the rolling average for each consecutive 12-month period. In addition, the CO CEMS shall record CO emissions in terms of "ppmvd corrected to 3% oxygen" for each 1-hour block average and each 24-hour block average (daily average). *{Permitting Note: CO emissions data recorded and reported in terms of "ppmvd corrected to 3% oxygen" are for informational purposes only.}*

b. Compliance shall be determined by data collected from the required NOx CEMS in terms of "lb/MMBtu of heat input". The 30-day rolling average shall be determined by calculating the arithmetic average of all hourly emission rates for 30 successive boiler operating days and the requirements of 40 CFR 60.13, 60.44a, 60.46a, 60.47a, 60.48a, and 60.49a. A boiler-operating day is any day in which any authorized fuel is fired.

c. Compliance with the SO_2 standards shall be determined by data collected from the required SO_2 CEMS in terms of "lb/MMBtu of heat input". The 24-hour average shall be determined by calculating the arithmetic average of all valid hourly emission rates for 24 successive boiler-operating hours. The 30-day rolling average shall be determined by calculating the arithmetic average of all hourly emission rates for 30 successive boiler-operating days and the requirements of 40 CFR 60.13, 60.43a, 60.46a, 60.47a, 60.48a, and 60.49a. Compliance with the 12-month standard shall be based on the rolling average for each consecutive 12-month period. Valid SO_2 hourly averages shall not be excluded from any compliance average. *{Permitting Note: Potential emissions of sulfuric acid mist are minimized by the effective control of SO_2 emissions with the firing of low sulfur fuels. For reporting purposes, sulfuric acid mist emissions shall be estimated as 6% of the total measured SO_2 emissions.}*

d. Continuous compliance with the opacity standard shall be determined by data collected from the required COMS in terms of "percent opacity" based on 6-minute block averages. Alternatively, compliance may also be determined by conducting EPA Method 9 observations.

e. Compliance with the particulate matter standards shall be determined by the average of three test runs conducted in accordance with EPA Method 5. For purposes of reporting PM_{10} emissions, it shall be assumed that all particulate matter emitted is PM_{10}.

f. Compliance with the VOC standards shall be determined by the average of three test runs conducted in accordance with EPA Method 25A based on propane. In addition, the permittee may choose to conduct EPA Method 18 concurrently with EPA Method 25A to deduct emissions of methane and ethane from the measured VOC emissions. Otherwise, all emissions measured by EPA Method 25A shall be considered "volatile organic compounds".

g. Compliance with the mercury standards shall be determined by the average of three test runs conducted in accordance with EPA Method 101A or 29. Emissions in excess of this standard shall be a violation of the permit. In addition, if two or more cogeneration boilers exceed the annual mercury emission limit, the permittee shall reactivate the carbon injection system for all three units within 30 days of the stack test report due date. The minimum carbon injection rate shall be at least 7 pounds per hour. Within 60 days of the stack test report due date, the permittee shall submit to the permitting and compliance authorities a mercury testing protocol designed to establish an effective carbon injection rate to control mercury emissions. Within 60 days of receiving approval for the mercury testing protocol by the permitting authority, the permittee shall begin the approved testing program. At a minimum, the permittee shall submit a full engineering report summarizing the uncontrolled emissions, controlled emissions, fuels, operating capacities, and recommending a minimum activated carbon injection rate to control mercury emissions.

h. The particulate matter standard is also a surrogate standard for lead emissions. *{Permitting Note: For reporting purposes, average lead emissions are expected to be 2.6×10^{-05} lb/MMBtu and average fluoride emissions are expected to be 1.9×10^{-04} lb/MMBtu when firing bagasse/wood.}*

i. Each boiler shall comply with the standards when firing any combination of authorized fuels. The "lb/hour" rates are based on the highest emission standard shown for that pollutant. Required compliance tests shall be performed in accordance with the requirements of Condition No. 19. The cogeneration boilers are also subject to the new source performance standards (NSPS Subpart Da) for new electric utility steam generating units. These requirements include the general provisions of Subpart A in 40 CFR 60, as well as the following source-specific applicable requirements: 60.40a

(Applicability and Designation of Affected Facility); 60.41a (Definitions); 60.42a (Standards for Particulate Matter); 60.43a (Standard for Sulfur Dioxide); 60.44a (Standard for Nitrogen Oxides); 60.46a (Compliance Provisions); 60.47a (Emissions Monitoring); 60.48a (Compliance Determination Procedures and Methods); and 60.49a (Reporting Requirements). The cogeneration boilers are also subject to Rule 62-296.405(2), F.A.C. (Fossil Fuel Steam Generators with more than 250 MMBtu per Hour of Heat Input), Rule 62-296.410, F.A.C. (Carbonaceous Fuel Burning Equipment), and Rule 62-296.570, F.A.C. (Reasonably Available Control Technology Requirements for Major VOC and NOx Facilities).

{Permitting Note: Appendix D identifies the final BACT determinations for the cogeneration boilers.}

17. Material Handling: The following conditions apply to the biomass, ash, and activated carbon handling facilities.

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

    b. Water sprays, chemical wetting agents, and/or stabilizers shall be applied to storage piles, handling equipment, unenclosed transfer points, etc. during dry periods and as necessary to prevent visible emissions. When adding, moving or removing material from the storage pile, visible emissions of no more than 20% opacity are allowed.

    c. The mercury control system reactant storage silos shall be maintained at a negative pressure while operating with the exhaust vented to a filter control system. Visible emissions from any storage silo shall not exceed 5 percent opacity based on a 6-minute block average. A visible emissions test (EPA Method 9) shall be performed at least annually for each silo that is loaded with carbon during the federal fiscal year.

STARTUP, SHUTDOWN, AND MALFUNCTION

18. Startup, Shutdown, and Malfunction Requirements: The permittee shall comply with the following requirements regarding periods of startup, shutdown, and malfunction for each cogeneration boiler.

    a. *Definitions*

        1) Excess emissions are emissions of pollutants in excess of those allowed by any applicable air pollution rule of the Department, or by a permit issued pursuant to any such rule or Chapter 62-4, F.A.C. The term applies only to conditions that occur during startup, shutdown, or malfunction. [Rule 62-210.200(106), F.A.C.]

        2) Startup is the commencement of operation of a boiler which has shut down or ceased operation for a period of time sufficient to cause temperature, pressure, chemical or pollution control device imbalances, which may result in excess emissions. Periods of startup for each boiler shall end once steam generation reaches 150,000 pounds per hour. A cold startup is a startup after the boiler has been shutdown for 24 hours or more. A warm startup is a startup after the boiler has been shutdown for less than 24 hours.

        3) Shutdown is the cessation of the operation of a boiler for any purpose after steam generation drops below 150,000 pounds per hour.

        4) Malfunction is any unavoidable mechanical and/or electrical failure of air pollution control equipment or process equipment or of a process resulting in operation in an abnormal or unusual manner. [Rule 62-210.200(160), F.A.C.]

    b. *Prohibition*: Excess emissions which are caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure which may reasonably be prevented during startup, shutdown, or malfunction shall be prohibited. Emissions data recorded during such preventable periods shall be included in the compliance averages. [Rule 62-210.700(4), F.A.C.]

c. *Monitoring Data Exclusion*: Each continuous monitoring system shall operate and record data during all periods of operation (including startup, shutdown, and malfunction) except for continuous monitoring system breakdowns, repairs, calibration checks, and zero and span adjustments. Provided the operators implement best operational practices to minimize the amount and duration of emissions, the following conditions apply. Pursuant to Rules 62-210.700(1) and (5), F.A.C., these conditions consider the variations in operation of the cogeneration boilers.

1) Natural gas or distillate oil shall be fired during startup prior to energizing the electrostatic precipitator (ESP). Once the operating temperature recommended by the ESP manufacturer is maintained (approximately 340° F to 350 ° F), it shall be placed on line and the boiler shall comply with the opacity standard specified in Condition No. 16. The ESP shall be on line and functioning properly before firing any biomass. The opacity limit does not apply when the ESP is off line due to warm startup, cold startup, or shutdown. No more than twenty 6-minute block averages of opacity monitoring data shall be excluded in a 24-hour period due to documented malfunctions.

2) Hourly CO and NOx emission rate values collected during startup, shutdown, or documented malfunction may be excluded from the 30-day and/or 12-month compliance averages. No more than six hourly emission rate values (CO or NOx) shall be excluded in a 24-hour period due to a cold startup. No more than three hourly emission rate values (CO or NOx) shall be excluded in a 24-hour period due to a warm startup. No more than two hourly emission rate values (CO or NOx) shall be excluded in a 24-hour period due to a malfunction. No more than two hourly emission rate values (CO or NOx) shall be excluded in a 24-hour period due to a shutdown. For each cogeneration boiler, no more than 183 hourly emission rate values shall be excluded during any calendar quarter.

3) All valid hourly SO_2 emission rate values shall be included in all of the compliance averages. [40 CFR 60.46a and 60.49a]

4) To "document" a malfunction, the operator shall notify the Compliance Authority within one working day of the malfunction by phone, facsimile, or electronic mail. The notification shall include the date and time of malfunction, a description of the malfunction and probable cause, steps to taken to minimize emissions, and actions taken to correct the problem. [Rules 62-210.700(6) and 62-4.130, F.A.C.]

d. *Reporting*: In conjunction with the annual operating report, the permittee shall identify the number of startups, the number of shutdowns, and the number of malfunctions that occurred during the year for each boiler. For each boiler's CO and NOx monitors, the report shall identify the annual hours of emission data excluded from the compliance determination due to each type of incident (startups; shutdowns; and documented malfunctions).

[Rule 62-210.700, F.A.C.; Rule 62-4.070(3), F.A.C.; 40 CFR 60.8; and 40 CFR 60.46a]

COMPLIANCE METHODS AND REPORTING

19. Stack Test Requirements

a. *Initial Tests*: Initial tests were initially required for emissions of mercury, particulate matter, and volatile organic compounds. The Department may require these initial tests to be repeated if major physical or operational changes are made that affect main components such as the boiler, fuels, and/or pollution control equipment.

b. *Annual Tests*: At least once during each federal fiscal year, the permittee shall conduct compliance tests for emissions of mercury, particulate matter, and volatile organic compounds.

c. *Renewal Tests*: Within the 12-month period prior to submitting an application to renew the Title V air operation permit, the permittee shall conduct compliance tests for emissions of, mercury, particulate matter, and volatile organic compounds. Tests shall be conducted at five-year intervals.

d. *Test Procedures*: The emission compliance tests shall be conducted in accordance with the provisions of Chapter 62-297, F.A.C., 40 CFR 60.46a (NSPS Subpart Da), and as summarized in Appendix C of this permit. The permittee shall notify the Compliance Authority in writing at least 30 days prior to any initial NSPS performance tests and at least 15 days prior to any other required tests. The biomass fuel feed for each test run shall consist of at least 45% wood materials by weight. Testing of emissions shall be conducted with each cogeneration boiler operating at permitted capacity, which is defined as a heat input rate between 684 and 760 MMBtu/hour and firing 100% biomass. If it is impracticable to test at permitted capacity, a cogeneration boiler may be tested at less than the maximum permitted capacity; in this case, subsequent operation is limited to 110 percent of the test rate until a new test is conducted. Within three days of completing a test below permitted capacity, the permittee shall provide written notification of the restricted operational capacity to the Compliance Authority. Once the unit is so limited, operation at higher capacities is allowed for no more than 15 consecutive days for the purpose of additional compliance testing to regain the authority to operate at the permitted capacity. [Rule 62-297.310(7)(a)9, F.A.C. and 40 CFR 60.7, 60.8]

e. *Test Methods*: Compliance with the emission limits specified in this permit shall be demonstrated using EPA Methods, as contained in 40 CFR Part 60 (Standards of Performance for New Stationary Sources), or 40 CFR Part 61 (National Emission Standards for Hazardous Air Pollutants).

EPA Method	Description
1	Selection of sample site and velocity traverses
2	Stack gas flow rate when converting concentrations to or from mass emission limits
3A	Gas analysis when needed for calculation of molecular weight or percent O_2
4	Moisture content when converting stack velocity to dry volumetric flow rate for use in converting concentrations in dry gases to or from mass emission limits
5	Particulate matter emissions
6 or 6C	Sulfur dioxide emissions
7 or 7E	Nitrogen oxide emissions
9	Visible emissions determination of opacity *{Permitting Note: Although each unit is required to monitor opacity with a COMS, visible observations may also be used to demonstrate compliance.}*
10	Carbon monoxide emissions
12	Inorganic lead emissions
19	Calculation of sulfur dioxide and nitrogen oxide emission rates
25A	Volatile organic compounds emissions *{Permitting Note: EPA Method 18 may be conducted concurrently with EPA Method 25A to deduct emissions of methane and ethane from the measured VOC emissions. Otherwise, all emissions measured by EPA Method 25A shall be considered "volatile organic compounds".*
29	Multiple metals emissions
101A	Particulate and gaseous mercury emissions

No other methods may be used to demonstrate compliance unless prior written approval is received from the Department. Other applicable testing requirements are included in Appendix C of the permit. The permittee shall use CEMS and COMS data to demonstrate compliance with the emissions standards for CO, NOx, opacity, and SO_2. [Rules 62-204.800 and 62-297.100, F.A.C.; 40 CFR 60, Appendix A]

20. Continuous Monitor Requirements: The permittee shall demonstrate compliance with the emissions standards for CO, NOx, opacity, and SO_2 based on data collected from the continuous emissions monitoring systems (CEMS) and continuous opacity monitoring systems (COMS) required for each cogeneration boiler.

Appendix E specifies the minimum requirements for monitoring equipment.

21. Quarterly Reports: For each cogeneration boiler, the permittee shall submit a quarterly report for each required continuous emissions and opacity monitoring system in accordance with the requirements specified in Appendix E of this permit. The permittee shall also submit a quarterly summary of the fuel analyses, fuel usage, and equipment malfunctions. For each malfunction, the report shall identify the cause (if known), and corrective actions taken. The quarterly reports and summaries shall be submitted to the Compliance Authority no later than 30 days following each calendar quarter.

22. Annual Operating Report: The permittee shall submit an annual report that summarizes the actual operating rates and emissions from this facility. Annual operating reports shall be submitted to the Compliance Authority by March 1st of each year. Along with this report, the permittee shall also submit a summary of CO emissions from each cogeneration boiler in terms of "ppmvd corrected to 3% oxygen based on a 24-hour average (day)" for each operational day. [Rule 62-210.370(2), F.A.C.]

CONTENTS

CITATION FORMAT

The following examples illustrate the format used in the permit to identify applicable permitting actions and regulations.

REFERENCES TO PREVIOUS PERMITTING ACTIONS

Old Permit Numbers

Example: Permit No. AC50-123456 or Air Permit No. AO50-123456

Where: "AC" identifies the permit as an Air Construction Permit
"AO" identifies the permit as an Air Operation Permit
"123456" identifies the specific permit project number

New Permit Numbers

Example: Permit Nos. 099-2222-001-AC, 099-2222-001-AF, 099-2222-001-AO, or 099-2222-001-AV

Where: "099" represents the specific county ID number in which the project is located
"2222" represents the specific facility ID number
"001"identifies the specific permit project
"AC" identifies the permit as an air construction permit
"AF" identifies the permit as a minor federally enforceable state operation permit
"AO" identifies the permit as a minor source air operation permit
"AV" identifies the permit as a Title V Major Source Air Operation Permit

PSD Permit Numbers

Example: Permit No. PSD-FL-317

Where: "PSD" means issued pursuant to the Prevention of Significant Deterioration of Air Quality
"FL" means that the permit was issued by the State of Florida
"317" identifies the specific permit project

RULE CITATION FORMATS

Florida Administrative Code (F.A.C.)

Example: [Rule 62-213.205, F.A.C.]

Means: Title 62, Chapter 213, Rule 205 of the Florida Administrative Code

Code of Federal Regulations (CFR)

Example: [40 CFR 60.7]

Means: Title 40, Part 60, Section 7

GENERAL CONDITIONS

The permittee shall comply with the following general conditions from Rule 62-4.160, F.A.C.

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

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

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

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

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

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

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

   a. Have access to and copy and records that must be kept under the conditions of the permit;
   b. Inspect the facility, equipment, practices, or operations regulated or required under this permit, and,
   c. Sample or monitor any substances or parameters at any location reasonably necessary to assure compliance with this permit or Department rules.

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

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

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

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

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

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

10. The permittee agrees to comply with changes in Department rules and Florida Statutes after a reasonable time for compliance, provided, however, the permittee does not waive any other rights granted by Florida Statutes or Department rules.

11. This permit is transferable only upon Department approval in accordance with Florida Administrative Code Rules 62-4.120 and 62-730.300, F.A.C., as applicable. The permittee shall be liable for any non-compliance of the permitted activity until the transfer is approved by the Department.

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

13. This permit also constitutes:

    a. Determination of Best Available Control Technology (X);
    b. Determination of Prevention of Significant Deterioration (X); and
    c. Compliance with New Source Performance Standards (X).

14. The permittee shall comply with the following:

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

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

    c. Records of monitoring information shall include:

        1) The date, exact place, and time of sampling or measurements;
        2) The person responsible for performing the sampling or measurements;
        3) The dates analyses were performed;
        4) The person responsible for performing the analyses;
        5) The analytical techniques or methods used; and
        6) The results of such analyses.

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

{Permitting Note: Unless otherwise specified by permit, the following conditions are generally applicable to all emissions units.}

EMISSIONS AND CONTROLS

1. Plant Operation - Problems: If temporarily unable to comply with any of the conditions of the permit due to breakdown of equipment or destruction by fire, wind or other cause, the permittee shall notify each Compliance Authority as soon as possible, but at least within one working day, excluding weekends and holidays. The notification shall include: pertinent information as to the cause of the problem; steps being taken to correct the problem and prevent future recurrence; and, where applicable, the owner's intent toward reconstruction of destroyed facilities. Such notification does not release the permittee from any liability for failure to comply with the conditions of this permit or the regulations. [Rule 62-4.130, F.A.C.]
2. Circumvention: The permittee shall not circumvent the air pollution control equipment or allow the emission of air pollutants without this equipment operating properly. [Rule 62-210.650, F.A.C.]
3. Excess Emissions Prohibited: Excess emissions caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure that may reasonably be prevented during startup, shutdown or malfunction shall be prohibited. [Rule 62-210.700(4), F.A.C.]
4. Excess Emissions - Notification: In case of excess emissions resulting from malfunctions, the permittee shall notify the Department or the appropriate Local Program in accordance with Rule 62-4.130, F.A.C. A full written report on the malfunctions shall be submitted in a quarterly report, if requested by the Department. [Rule 62-210.700(6), F.A.C.]
5. VOC or OS Emissions: No person shall store, pump, handle, process, load, unload or use in any process or installation, volatile organic compounds or organic solvents without applying known and existing vapor emission control devices or systems deemed necessary and ordered by the Department. [Rule 62-296.320(1), F.A.C.]
6. Objectionable Odor Prohibited: No person shall cause, suffer, allow or permit the discharge of air pollutants, which cause or contribute to an objectionable odor. [Rule 62-296.320(2), F.A.C.]
7. General Visible Emissions: No person shall cause, let, permit, suffer or allow to be discharged into the atmosphere the emissions of air pollutants from any activity equal to or greater than 20 percent opacity. [Rule 62-296.320(4)(b)1, F.A.C.]
8. Unconfined Particulate Emissions: During the construction period, unconfined particulate matter emissions shall be minimized by dust suppressing techniques such as covering and/or application of water or chemicals to the affected areas, as necessary. [Rule 62-296.320(4)(c), F.A.C.]

TESTING REQUIREMENTS

9. Operating Rate During Testing: Testing of emissions shall be conducted with the emissions unit operating at permitted capacity. Permitted capacity is defined as 90 to 100 percent of the maximum operation rate allowed by the permit. If it is impractical to test at permitted capacity, an emissions unit may be tested at less than the maximum permitted capacity; in this case, subsequent emissions unit operation is limited to 110 percent of the test rate until a new test is conducted. Once the unit is so limited, operation at higher capacities is allowed for no more than 15 consecutive days for the purpose of additional compliance testing to regain the authority to operate at the permitted capacity. [Rule 62-297.310(2), F.A.C.]
10. Calculation of Emission Rate: For each emissions performance test, the indicated emission rate or concentration shall be the arithmetic average of the emission rate or concentration determined by each of the three separate test runs unless otherwise specified in a particular test method or applicable rule. [Rule 62-297.310(3), F.A.C.]
11. Test Procedures: Tests shall be conducted in accordance with all applicable requirements of Chapter 62-297, F.A.C.
    a. *Required Sampling Time.* Unless otherwise specified in the applicable rule, the required sampling time for each test run shall be no less than one hour and no greater than four hours, and the sampling time at each sampling point shall be of equal intervals of at least two minutes. The minimum observation period for a visible emissions compliance test shall be thirty (30) minutes. The observation period shall include the period during which the highest opacity can reasonably be expected to occur.

b. *Minimum Sample Volume.* Unless otherwise specified in the applicable rule or test method, the minimum sample volume per run shall be 25 dry standard cubic feet.

c. *Calibration of Sampling Equipment.* Calibration of the sampling train equipment shall be conducted in accordance with the schedule shown in Table 297.310-1, F.A.C.

[Rule 62-297.310(4), F.A.C.]

12. Determination of Process Variables

a. *Required Equipment.* The owner or operator of an emissions unit for which compliance tests are required shall install, operate, and maintain equipment or instruments necessary to determine process variables, such as process weight input or heat input, when such data are needed in conjunction with emissions data to determine the compliance of the emissions unit with applicable emission limiting standards.

b. *Accuracy of Equipment.* Equipment or instruments used to directly or indirectly determine process variables, including devices such as belt scales, weight hoppers, flow meters, and tank scales, shall be calibrated and adjusted to indicate the true value of the parameter being measured with sufficient accuracy to allow the applicable process variable to be determined within 10% of its true value.

[Rule 62-297.310(5), F.A.C.]

13. Sampling Facilities: The permittee shall provide stack testing facilities and sampling locations in accordance with Rule 62-297.310(6), F.A.C.

14. Test Notification: The permittee shall notify the Compliance Authority in writing at least 30 days prior to any initial NSPS performance tests and at least 15 days prior to any other required tests. [Rule 62-297.310(7)(a)9, F.A.C. and 40 CFR 60.7, 60.8]

15. Special Compliance Tests: When the Department, after investigation, has good reason (such as complaints, increased visible emissions or questionable maintenance of control equipment) to believe that any applicable emission standard contained in a Department rule or in a permit issued pursuant to those rules is being violated, it shall require the owner or operator of the emissions unit to conduct compliance tests which identify the nature and quantity of pollutant emissions from the emissions unit and to provide a report on the results of said tests to the Department. [Rule 62-297.310(7)(b), F.A.C.]

RECORDS AND REPORTS

16. Records Retention: All measurements, records, and other data required by this permit shall be documented in a permanent, legible format and retained for at least five (5) years following the date on which such measurements, records, or data are recorded. Records shall be made available to the Department upon request. [Rules 62-4.160(14) and 62-213.440(1)(b)2, F.A.C.]

17. Annual Operating Report: The permittee shall submit an annual report that summarizes the actual operating rates and emissions from this facility. Annual operating reports shall be submitted to the Compliance Authority by March 1st of each year. [Rule 62-210.370(2), F.A.C.]

18. Emissions Performance Test Reports: A report indicating the results of any required emissions performance test shall be submitted to each Compliance Authority no later than 45 days after completion of the last test run. The test report shall provide sufficient detail on the tested emission unit and the procedures used to allow the Department to determine if the test was properly conducted and if the test results were properly computed. At a minimum, the test report shall provide the applicable information listed in Rule 62-297.310(8)(c), F.A.C. [Rule 62-297.310(8), F.A.C.]

PSD Applicability

The existing facility is located in Palm Beach County, an area that is in attainment with (or designated as unclassifiable for) all air pollutants subject to a National Ambient Air Quality Standard (NAAQS). The cogeneration plant is classified as a fossil fuel-fired steam electric plant, which is one of the 28 PSD Major Facility Categories identified in Table 62-212.400-1, F.A.C. Potential emissions from the plant are greater than 100 tons per year for at least one regulated pollutant. As such, the facility is "major" with respect to the Prevention of Significant Deterioration (PSD) of Air Quality. The proposed project will result in net emissions increases that are greater than the PSD significant emission rates identified in Table 62-212.400-2, F.A.C. for the following pollutants: carbon monoxide, nitrogen oxides, particulate matter, sulfur dioxide, volatile organic compounds, lead, fluorides, and sulfuric acid mist. Therefore, the project is subject to PSD preconstruction review and the Department makes the following determinations of Best Available Control Technology (BACT) for these pollutants.

Final BACT Determinations

In accordance with Rule 62-212.400, F.A.C., the Department determines that the following standards represent the Best Available Control Technology (BACT) for the existing biomass-fired cogeneration boilers.

Pollutant	BACT Standards for Each Cogeneration Boiler		
	Averaging Period	lb/MMBtu	lb/hr
Carbon Monoxide (CO) *Based on "good combustion practices".*	30-day rolling CEMS avg.	0.50	380.0
	12-month rolling CEMS avg.	0.35	
Nitrogen Oxides (NOx) *Based on the application of SNCR.*	30-day rolling CEMS avg.	0.15	114.0
Sulfur Dioxide (SO_2) *Based on "low sulfur fuels". The SO_2 standards are also surrogate standards for sulfuric acid mist (SAM) emissions.*	24-hour rolling CEMS avg.	0.20	152.0
	30-day rolling CEMS avg.	0.10	
	12-month rolling CEMS avg.	0.06	
Opacity *Based on application of mechanical dust collectors and electrostatic precipitator.*	6-minute block COMS avg. (Alternative: EPA Method 9)	≤ 20% opacity, except for one 6-minute block per hour that is ≤ 27% opacity	
Particulate Matter (PM) *Based on application of mechanical dust collectors and electrostatic precipitator.*	3-run test avg.	0.026	19.8
Volatile Organic Compounds (VOC) *Based on "good combustion practices".*	3-run test avg.	0.05	38.0
Lead (Pb) and Fluorides (Fl) *Based on "low lead/fluoride fuels".*	BACT is the use of fuels containing low levels of these compounds (bagasse, wood, distillate oil, and natural gas) and prospective removal with the fly ash by the mechanical dust collectors and electrostatic precipitators. The particulate matter standard shall also serve as a surrogate standard for lead.		

The Department's technical review and rationale for the BACT determinations are presented in Technical Evaluation and Preliminary Determination issued concurrently with the draft permit for this project.

Determination By:

Jeffery J. Koerner — 10-22-03

Jeff Koerner, P.E., Project Engineer — (Date)
New Source Review Section

Recommended By:

Trina L Vielhauer — 10/27/03

Trina Vielhauer, Chief — (Date)
Bureau of Air Regulation

Approved By:

Michael G. Cooke — 10/27/03

Michael G. Cooke, Director — (Date)
Division of Air Resources Management

CONTINUOUS MONITOR REQUIREMENTS

{Permitting Note: The following summarizes the basic monitoring requirements for the cogeneration boilers.}

1. Process and Control Parameters: The permittee shall install, calibrate, maintain, and operate continuous monitoring systems to measure and record the following process and control equipment parameters:

   a. *Power Output.* The net power generation (MW) delivered for sale to the electrical power grid shall be continuously monitored and recorded in 1-hour block averages.

   b. *Fuel Feed Rate.* Fuel flow meters equipped with totalizers are required to monitor and record the fuel feed rates for distillate oil (gallons) and natural gas (million cubic feet). Biomass feed rates (tons of bagasse and tons of wood) shall be calculated and recorded based on actual fuel flows. The permittee shall continuously monitor the fuel throughput rates based on the fuel flow monitors and calculate the actual heat input rates (24 hour average) for each fuel during each day of operation.

   c. *Steam Parameters.* Each cogeneration boiler shall be equipped with monitors to measure and record the steam temperature (° F), steam pressure (psig), and steam production (pounds).

   d. *Urea Injection Rate (SNCR System).* The urea injection rate shall be continuously monitored and recorded for each cogeneration boiler. The urea injection rate shall be compared to actual NOx emissions data recorded by the CEMS. The permittee shall identify minimum urea injection rates for various load conditions that ensure compliance with the NOx standards. Should the NOx CEMS be unavailable, the urea injection rate shall be maintained at an appropriate minimum level.

   e. *Activated Carbon Injection Rate (Mercury Control System).* If the mercury injection system is reactivated, the carbon injection rate shall be continuously monitored and recorded. Based on the testing required in this permit, the permittee shall identify and maintain minimum carbon injection rates to ensure effective control of mercury emissions.

   The permittee shall maintain written procedures for inspecting, calibrating, and maintaining the process and control monitoring equipment. [Rules 62-4.070 and 62-212.400(BACT), F.A.C.]

2. CEMS and COMS: For each cogeneration boiler, the permittee shall install, calibrate, maintain, and operate continuous emissions monitors (CEMS) and continuous opacity monitors (COMS) to measure and record emissions of carbon monoxide (CO), nitrogen oxides (NOx), oxygen (O_2), sulfur dioxide (SO_2), and opacity in a manner sufficient to demonstrate compliance with the standards of this permit.

   a. *Performance Specifications.* Each monitor shall be located in the ductwork between the electrostatic precipitator and the stack (or in the stack) to obtain emissions measurements representative of actual stack emissions. Each CEMS and COMS shall comply with the corresponding performance specifications that identify location, installation, design, performance, and reporting requirements.

      (1) Opacity shall comply with Performance Specification 1 in Appendix B of 40 CFR 60.

      (2) NOx and SO_2 CEMS shall comply with Performance Specification 2 in Appendix B of 40 CFR 60. The SO_2 reference method for the annual RATA shall be EPA Method 6 (or 6C) in Appendix A of 40 CFR 60. The NOx reference method for the annual RATA shall be EPA Method 7 (or 7E) in Appendix A of 40 CFR 60.

      (3) O_2 CEMS shall comply with Performance Specification 3 in Appendix B of 40 CFR 60. The O_2 reference method for the annual RATA shall be EPA Method 3A Appendix A of 40 CFR 60.

      (4) CO CEMS shall meet Performance Specification 4 or 4A in Appendix B of 40 CFR 60. The CO reference method for the annual RATA shall be EPA Method 10 in Appendix A of 40 CFR 60.

   b. *Data Collection.* Each CEMS and COMS shall record emissions data at all times including episodes of startup, shutdown, and malfunction. Emissions data recorded during periods of startup, shutdown, or malfunction may only be excluded from the compliance averages in accordance with the requirements specified in Section III of this permit. To the extent practicable, the permittee shall minimize the duration of data excluded for startup, shutdown and malfunctions.

      Each CEMS shall be designed and operated to sample, analyze, and record emissions data evenly spaced over a 1-hour period. Each 1-hour average shall be computed using at least one data point in each fifteen minute quadrant of the 1-hour block during which the unit combusted fuel. Notwithstanding this requirement, each 1-hour average shall be computed from at least two data points separated by a minimum of 15 minutes. All valid measurements or data points collected during a 1-hour block shall be used to calculate the 1-hour emission averages. CO, NOx, and SO_2 CEMS shall express the 1-hour emission averages in terms of "lb/MMBtu of heat input". O_2 CEMS shall express the 1-hour emission average in terms of "percent by volume". A 30-day rolling emission average shall be the average of all valid 1-hour emission averages collected during the 30-day period. A 12-month rolling emission average shall be the average of all valid 1-hour emission averages collected during the 12-month period. NOx and SO_2 CEMS shall comply with NSPS Subpart Da in 40 CFR 60.

Each COMS shall be designed and operated to complete a minimum of one cycle of sampling and analyzing for each successive 10-second period and one cycle of data recording for each successive 6-minute period. Opacity shall be recorded in 6-minute block averages.

c. *Quality Assurance Procedures.* Each CEMS shall comply with the applicable quality assurance procedures specified in Appendix F of 40 CFR 60. These procedures include methods such as calibration, calibration drift, data recording, accuracy assessment, calculations, audit procedures, preventive maintenance, corrective actions, and reporting.

d. *Monitor Availability.* Monitor availability shall not be less than 95% in any calendar quarter. In the event 95% availability is not achieved, the permittee shall provide the Department with a report identifying the problems in achieving 95% availability and a plan of corrective actions that will be taken to achieve 95% availability. The permittee shall implement the reported corrective actions within the next calendar quarter. Failure to take corrective actions or continued failure to achieve the minimum monitor availability shall be violations of this permit.

e. *Other Applicable Requirements*: Each CEMS shall comply with the following applicable requirements Rules 62-204.800 and 62-297.520, F.A.C. (Continuous Monitor Performance Specifications); 40 CFR 60.13 (Subpart A - Monitoring Requirements); 40 CFR 60.47a (Subpart Da - Emissions Monitoring); 40 CFR 60.48a (Subpart Da - Compliance Determination Procedures and Methods); 60.49a (Subpart Da - Reporting Requirements).

f. *Quarterly Reports*: For each cogeneration boiler, the permittee shall submit the report on the following page to summarize each required continuous emissions and opacity monitoring system. The authorized representative shall certify that the information provided in each quarterly report is true, accurate, and complete to the best of his/her knowledge. Each quarterly report is due no later than 30 days following the calendar quarter.

CONTINUOUS MONITOR REQUIREMENTS

Facility Name	**ARMS ID No.**	**Title V Air Permit No.**
Okeelanta Cogeneration Plant	0990332	

Facility Address/Location

Located off U.S. Highway 27 South, approximately six miles south of South Bay in Palm Beach County, Florida

Emissions Unit Description	**Unit Operation in Calendar Quarter**
Spreader stoker boiler with maximum heat input of 760 MMBtu/hour ARMS EU ID No. ______ Cogeneration Boiler: ___ A ___ B ___ C	________ hours

Control Equipment

Mercury - activated carbon injection; Nitrogen Oxides – low NOx burners and selective non-catalytic reduction (NOx) system; Particulate Matter – mechanical dust collectors and electrostatic precipitators

Primary Fuel	**Auxiliary Fuels**
Biomass, which includes bagasse from adjacent sugar mill and wood material from area suppliers (clean construction and demolition wood debris, yard trash, land clearing debris, and other clean cellulose and vegetative matter)	Pipeline natural gas Distillate oil (≤ 0.05% sulfur by weight)

Pollutant Monitored *(Check one.)*	**Calendar Quarter of Operation Covered** *(Check one.)*
_____ CO _____ NOx _____ SO2 _____ Opacity	___ 1 ___ 2 ___ 3 ___ 4 for year _______

Continuous Monitor Information	**Emission Standards**
Manufacturer: ____________________	_______ lb/MMBtu of heat input, 24-hour rolling average
Model No. ____________________	_______ lb/MMBtu of heat input, 30-day rolling average
Date of last certification or audit: ____________	_______ lb/MMBtu of heat input, 12-month rolling average
	≤ 20% opacity, except for one 6-minute block per hour that is ≤ 27% opacity

Emission Data Summary	**CMS Performance Summary**
1. Duration of excess emissions in reporting period due to:	1. CMS downtime in reporting period due to:
a. Startup/shutdown .... _____	a. Monitor Equipment Malfunctions .... _____
b. Control equipment problems .... _____	b. Non-Monitor Equipment Malfunctions .... _____
c. Process problems .... _____	c. Quality Assurance Calibration .... _____
d. Other known causes .... _____	d. Other Known Causes .... _____
e. Unknown causes .... _____	e. Unknown Causes .... _____
2. Total duration of excess emissions .... _____	2. Total CMS Downtime .... _____
3. [Total duration of excess emissions] x (100%) .... _____ [Total source operating time]	3. [Total CMS Downtime] x (100%) .... _____ [Total source operating time]
Note: Report "excess emissions" as emission averages that are in excess of a permitted emissions standard. For gases, report excess emissions in terms of hours. For opacity, report excess emissions in terms of minutes.	*If monitor availability is not at least 95%, provide a report identifying the problems in achieving 95% availability and a plan of corrective actions that will be taken to achieve 95% availability*

Emissions Data Exclusion

1. Report the number of 1-hour emissions averages excluded the reporting period due to:
   a. Startup .... _____
   b. Shutdown .... _____
   c. Malfunction .... _____
   d. Total .... _____
2. On a separate page, summarize each malfunction event, the cause (if known), and corrective actions taken.
3. On a separate page, describe any changes to CMS, process or controls during last quarter.

7000 2870 0000 7028 3321

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

OFFICIAL USE

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

Postmark Here

Sent To
Rodney Williams
Street, Apt. No.; or PO Box No.
PO Box 9
City, State, ZIP+4
South Bay, FL 33493

PS Form 3800, May 2000 — See Reverse for Instructions

7000 2870 0000 7028 3482

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

OFFICIAL USE

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

Postmark Here

Sent To
Rodney Williams
Street, Apt. No.; or PO Box No.
PO Box 9
City, State, ZIP+4
S. Bay, FL 33493

PS Form 3800, May 2000 — See Reverse for Instructions

SENDER: *COMPLETE THIS SECTION*

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

1. Article Addressed to:

Mr. Rodney Williams
Plant Manager
New Hope Power Partnership
Post Office Box 9
South Bay, FL 33493

COMPLETE THIS SECTION ON DELIVERY

A. Received by *(Please Print Clearly)* Kathy Yerkes
B. Date of Delivery 11-21-03

C. Signature
X Kathy Yerkes
☐ Agent
☐ Addressee

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

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

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

2. Article Number *(Copy from service label)*
7000 2870 0000 7028 3482

PS Form 3811, July 1999 Domestic Return Receipt 102595-99-M-1789

SENDER: *COMPLETE THIS SECTION*

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

1. Article Addressed to:

Mr. Rodney Williams
Plant Manager
New Hope Power Partnership
Post Office Box 9
South Bay, FL 33493

COMPLETE THIS SECTION ON DELIVERY

A. Received by *(Please Print Clearly)*

B. Date of Delivery

C. Signature

X

☐ Agent
☐ Addressee

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

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

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

2. Article Number *(Copy from service label)*
7000 2870 0000 7028 3321

PS Form 3811, July 1999 Domestic Return Receipt 102595-99-M-1789

PLACE STICKER AT TOP OF ENVELOPE TO THE RIGHT OF RETURN ADDRESS

New Hope Power Partnership

Okeelanta Cogeneration Plant

P.O. Box 9
South Bay, FL 33493

Telephone (561)993-1010
Fax (561)992-7744

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OCT 06 2003
BUREAU OF AIR REGULATION

October 1, 2003

Department of Environmental Protection
Bureau of Air Regulation
New Source Review Section
Twin Towers Office Building
2600 Blair Stone Road
Mail Station #5505
Tallahassee, Florida 32399-2400

Attn: Jeff Koerner

Re: Project No. 0990332-016-AC
Draft Air Permit No. PSD-FL-196(O)
New Hope Power Partnership, Okeelanta Cogeneration Plant
Proof of Publication

Dear Mr. Koerner:

Please see the attached Proof of Publication for the above referenced modification of the Okeelanta Cogeneration Plant Air Construction Permit. The Public Notice of Intent was published in the Palm Beach Post on September 24, 2003. If you have any questions please contact me at (561) 993-1003.

Sincerely,

J. M. M.

James M. Meriwether
Environmental and Safety Manager

cc: Rodney Williams
Gus Cepero
Bill Tarr
David Buff
Ken Kosky
David Dee
C. Holladay
R. Blackburn, SD
G. [illegible], PBCHD
G. Worley, EPA
G. Bunyak, NPS

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THE PALM BEACH POST

Published Daily and Sunday
West Palm Beach, Palm Beach County, Florida

PROOF OF PUBLICATION

STATE OF FLORIDA
COUNTY OF PALM BEACH

Before the undersigned authority personally appeared **Tracey Diglio**, who on oath says that she is **Telephone Sales Supervisor** of The Palm Beach Post, a daily and Sunday newspaper published at West Palm Beach in Palm Beach County, Florida; that the attached copy of advertising, being **Notice** in the matter of **DEP #PSD-FL-196(O)** was published in said newspaper in the issues of **September 24, 2003**. Affiant further says that the said The Post is a newspaper published at West Palm Beach, in said Palm Beach County, Florida, and that the said newspaper has heretofore been continuously published in said Palm Beach County, Florida, daily and Sunday and has been entered as second class mail matter at the post office in West Palm Beach, in said Palm Beach County, Florida, for a period of one year next preceding the first publication of the attached copy of advertisement; and affiant further says that she/her has neither paid nor promised any person, firm or corporation any discount rebate, commission or refund for the purpose of securing this advertisement for publication in the said newspaper.

Tracey Diglio
____

Sworn to and subscribed before this 24th day of September, A.D. 2003

____

Personally known XX or Produced Identification______________________
Type of Identification Produced______________________________

NOTARY PUBLIC STATE OF FLORIDA
KAREN M McLINTON
MY COMMISSION # CC 979669
EXPIRES: Nov 15, 2004

NO. 7608915
PUBLIC NOTICE OF INTENT TO ISSUE PERMIT
MODIFICATION OF PSD AIR CONSTRUCTION PERMIT
STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
Project No. 0990332-016-AC
Draft Permit No. PSD-FL-196(O)
New Hope Power Partnership – Okeelanta Cogeneration Plant

The Department of Environmental Protection (Department) gives notice of its intent to issue an air construction permit modification to the applicant, New Hope Power Partnership. The applicant operates an existing cogeneration plant that is located approximately six miles south of South Bay on U.S. Highway 27 in Palm Beach County, Florida. The Okeelanta Cogeneration Plant's authorized representative is Mr. Rodney Williams, Plant Manager, and the mailing address is 8001 U.S. Highway 27 South, South Bay, FL 33493.

The applicant, applied to the Department for a permit to authorize increases in the hourly and annual heat input rates for the existing boilers at the Okeelanta Cogeneration Plant. The maximum hourly heat input rate will increase from 715 to 760 MMBtu per hour by taking the last feedwater heater on each unit out of service to reduce the feedwater temperature. The increase in the hourly heat input rate is within the manufacturer's maximum continuous steam rating for these units. The cogeneration plant's maximum potential annual heat input will increase from 11,500,000 to 19,970,000 MMBtu per year, which will relax a permit limit originally taken to avoid new source preconstruction review for several pollutants. The applicant requests the flexibility to operate the cogeneration units without synthetic operational restrictions.

The applicant has notified the Department of possible future plans to add a new steam turbine-electrical generator, which would increase the electrical generating capacity of the plant from 74.9 MW to approximately 140 MW. Such a future request would require application and review in accordance the Florida Electrical Power Plant Siting Act in Sections 403.501-403.518 of the Florida Statutes. Approval of such a request would require a revision of the PSD air permit.

The existing cogeneration plant is located in Palm Beach County, which is an area that is currently in attainment with (or designated as unclassifiable for) all pollutants subject to federal and state Ambient Air Quality Standards. The plant is a major facility with respect to the Prevention of Significant Deterioration (PSD) of Air Quality as defined in Rule 62-212.400, F.A.C. Based on the application, the project will result in the following potential increases in emissions in terms of "tons per year" (TPY): 2160 TPY of carbon monoxide (CO); 5 TPY of fluorides (Fl); 1.4 TPY of lead (Pb); 98 pounds per year of mercury (Hg); 741 TPY of nitrogen oxides (NOx); 181 TPY of particulate matter (PM/PM10); 20 TPY of sulfuric acid mist (SAM); 407 TPY of sulfur dioxide (SO_2); and 555 TPY of volatile organic compounds (VOC). Emissions of CO, Fl, Pb, NOx, PM/PM10, SAM, SO_2, and VOC exceed the PSD significant emission rates defined in Table 62-212.400-2, F.A.C. Therefore, the project is subject to PSD preconstruction review for these pollutants

PSD preconstruction review requires the Department to establish emissions standards that represent the Best Available Control Technology (BACT) for each PSD-significant pollutant. Based on reasonable assurances provided by the applicant and other available information, the Department establishes emissions standards in the draft permit based on the following BACT-level controls: CO and VOC – boiler design and good combustion practices; NOx – selective non-catalytic reduction (SNCR); SO_2 and SAM – low sulfur fuels; PM/PM_{10} – mechanical dust collectors followed by an electrostatic precipitator (ESP); Fl and Pb – authorized fuels containing only trace amounts of fluorides and with and prospective removal in the mechanical dust collectors/ESP.

As part of the PSD required preconstruction review, the Department reviewed the applicant's air quality analysis conducted for each PSD-significant pollutant. The analysis provides the Department with reasonable assurance that the project will not significantly contribute to or cause a violation of any state or federal ambient air quality standards. A refined analysis was required to evaluate the 3-hour and 24-hour SO_2 increments in the vicinity of the plant (Class II areas) and in the Everglades National Park (nearest PSD Class I area). The following table shows the maximum predicted for SO_2 impacts and PSD increments consumed by all sources in the area, including the project.

PSD CLASS II INCREMENT ANALYSIS – VICINITY OF THE PLANT

Pollutant
SO_2
Averaging Time
24-hr
Maximum Predicted Impact (µg/m3)
62
Impact Greater than Allowable Increment?
No
Allowable Increment (µg/m3)
91
Percent of Increment
68%
Averaging Time
3-hr
Maximum Predicted Impact (µg/m3)
218
Impact Greater than Allowable Increment?
No
Allowable Increment (µg/m3)
512
Percent of Increment
43%

PSD CLASS I INCREMENT ANALYSIS – EVERGLADES NATIONAL PARK

Pollutant
SO_2
Averaging Time
24-hr
Maximum Predicted Impact (µg/m3)
4.0
Impact Greater than Allowable Increment?
No
Allowable Increment (µg/m3)
5
Percent of Increment
80%
Averaging Time
3-hr
Maximum Predicted Impact (µg/m3)
12.2
Impact Greater than Allowable Increment?
No
Allowable Increment (µg/m3)
25
Percent of Increment
49%

Based on the analyses, the Department has reasonable assurance that the proposed project will not significantly contribute to or cause a violation of any Class I or Class II PSD increments.

The Department will issue the Final Permit with the proposed conditions unless a response received in accordance with the following procedures results in a different decision or significant change of terms or conditions. The Department will accept written comments and requests for public meetings concerning the proposed permit issuance action for a period of thirty (30) days from the date of publication of this Public Notice of Intent to Issue Permit. Written comments and requests for public meetings should be provided to the Department's Bureau of Air Regulation at 2600 Blair Stone Road, Mail Station #5505, Tallahassee, FL 32399-2400. Any written comments filed shall be made available for public inspection. If written comments received result in a significant change in the proposed agency action, the Department shall revise the proposed permit and require, if applicable, another Public Notice.

The Department will issue the permit with the attached conditions unless a timely petition for an administrative hearing is filed pursuant to Sections 120.569 and 120.57, F.S., before the deadline for filing a petition. The procedures for petitioning for a hearing are set forth below. Mediation is not available in this proceeding.

A person whose substantial interests are affected by the proposed permitting decision may petition for an administrative proceeding (hearing) under Sections 120.569 and 120.57, F.S. The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department at 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida, 32399-3000. Petitions filed by the permit applicant must be filed within fourteen (14) days of receipt of the notice of intent. Petitions filed by any persons other than those entitled to written notice under Section 120.60(3), F.S. must be filed within fourteen (14) days of publication of this Public Notice or within fourteen (14) days of receipt of the notice of intent, whichever occurs first. Under Section 120.60(3), F.S., however, any person who asked the Department for notice of agency action may file a petition within fourteen (14) days of receipt of that notice, regardless of the date of publication. A petitioner shall mail a copy of the petition to the applicant at the address indicated above at the time of filing. The failure of any person to file a petition within the appropriate time period shall constitute a waiver of that person's right to request an administrative determination (hearing) under Sections 120.569 and 120.57, F.S., or to intervene in this proceeding and participate as a party to it. Any subsequent intervention will be only at the approval of the presiding officer upon the filing of a motion in compliance with Rule 28-106.205, F.A.C.

A petition that disputes the material facts on which the Department's action is based must contain the following information: (a) The name and address of each agency affected and each agency's file or identification number, if known; (b) The name, address, and telephone number of the petitioner, the name, address, and telephone number of the petitioner's representative, if any, which shall be the address for service purposes during the course of the proceeding; and an explanation of how the petitioner's substantial interests will be affected by the agency determination; (c) A statement of how and when petitioner received notice of the agency action or proposed action; (d) A statement of all disputed issues of material fact. If there are none, the petition must so indicate; (e) A concise statement of the ultimate facts alleged, including the specific facts the petitioner contends warrant reversal or modification of the agency's proposed action; (f) A statement of the specific rules or statutes the petitioner contends require reversal or modification of the agency's proposed action; and (g) A statement of the relief sought by the petitioner, stating precisely the action petitioner wishes the agency to take with respect to the agency's proposed action.

A petition that does not dispute the material facts upon which the Department's action is based shall state that no such facts are in dispute and otherwise shall contain the same information as set forth above, as required by Rule 28-106.301, F.A.C.

Because the administrative hearing process is designed to formulate final agency action, the filing of a petition means that the Department's final action may be different from the position taken by it in this notice. Persons whose substantial interests will be affected by any such final decision of the Department on the application have the right to petition to become a party to the proceeding, in accordance with the requirements set forth above.

A complete project file is available for public inspection during normal business hours, 8:00 a.m. to 5:00 p.m., Monday through Friday, except legal holidays, at:

Dept. of Environmental Protection
Bureau of Air Regulation
New Source Review Section
Suite 4,
111 S. Magnolia Drive
Tallahassee, Florida 32301
Telephone: 850/488-0114

Dept. of Environmental Protection
South District Office
Air Resources Section
2295 Victoria Avenue,
Suite 364
Fort Myers, Florida
33901-3381
Telephone: 941/332-6975

Palm Beach County Health Dept.
Environmental Health and Engineering
Air Pollution Control Section
901 Evernia Street
West Palm Beach, Florida
33401
Telephone: 561/355-3136

The complete project file includes the application, Technical Evaluation and Preliminary Determination, Draft Permit, and the information submitted by the responsible official, exclusive of confidential records under Section 403.111, F.S. Interested persons may contact the Department's project engineer for additional information at the address and phone numbers listed above.

PUB: The Palm Beach Post
September 24, 2003

Department of Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

September 18, 2003

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. Rodney Williams, Plant Manager
New Hope Power Partnership
Okeelanta Cogeneration Plant
8001 U.S. Highway 27 South
South Bay, FL 33493

Re: Project No. 0990332-016-AC
Draft Air Permit No. PSD-FL-196(O)
New Hope Power Partnership, Okeelanta Cogeneration Plant
Increased Heat Input Rates – Revised Public Notice

Dear Mr. Williams:

On July 31, 2003, the Department issued a draft permit to increase the short term and long term heat input rates for the three existing boilers at the Okeelanta Cogeneration Plant. On August 19, 2003, we received a letter from your professional engineer of record (David Buff of Golder Associates Inc.) commenting and requesting changes to the draft permit. On August 19, 2003, New Hope Power Partnership informed the Department of possible future plans to add a new steam turbine-electrical generator, which would allow an additional 65 MW of steam-generated electrical power. As discussed, such a request requires application and review in accordance with the Florida Electrical Power Plant Siting Act in Sections 403.501-403.518 of the Florida Statutes. On September 4, 2003, the Department received a second letter from your professional engineer of record describing the possible future project to add new electrical generating capacity. Please be advised that approval of such a request would require a revision of the PSD air permit.

The Department requests that you publish the revised Public Notice of Intent to Issue Permit (Public Notice) as attached. The Public Notice must be published one time only, as soon as possible, in the legal advertisement section of a newspaper of general circulation in the area affected, pursuant to the requirements Chapter 50, Florida Statutes. Proof of publication, i.e., newspaper affidavit, must be provided to the Department's Bureau of Air Regulation office within seven days of publication. Failure to publish the notice and provide proof of publication may result in the denial of the permit.

Once the revised Public Notice is published, the Department will review your previously submitted comments and requests along with any comments received from other parties. If you have any questions, please contact A. A. Linero, Administrator of the New Source Review Section, at 850/921-9523 or Jeff Koerner, the project engineer, at 850/921-9536.

Sincerely,

Trina L Vielhauer

Trina Vielhauer, Chief
Bureau of Air Regulation

cc: Mr. James Meriwether, New Hope Power
Mr. David Buff, Golder Associates Inc.
Mr. James Stormer, PBCHD
Mr. Ron Blackburn, SD
Mr. Gregg Worley, EPA Region 4
Mr. John Bunyak, NPS

Enclosures

PUBLIC NOTICE OF INTENT TO ISSUE PERMIT
MODIFICATION OF PSD AIR CONSTRUCTION PERMIT

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

Project No. 0990332-016-AC
Draft Permit No. PSD-FL-196(O)

New Hope Power Partnership – Okeelanta Cogeneration Plant

The Department of Environmental Protection (Department) gives notice of its intent to issue an air construction permit modification to the applicant, New Hope Power Partnership. The applicant operates an existing cogeneration plant that is located approximately six miles south of South Bay on U.S. Highway 27 in Palm Beach County, Florida. The Okeelanta Cogeneration Plant's authorized representative is Mr. Rodney Williams, Plant Manager, and the mailing address is 8001 U.S. Highway 27 South, South Bay, FL 33493.

The applicant, applied to the Department for a permit to authorize increases in the hourly and annual heat input rates for the existing boilers at the Okeelanta Cogeneration Plant. The maximum hourly heat input rate will increase from 715 to 760 MMBtu per hour by taking the last feedwater heater on each unit out of service to reduce the feedwater temperature. The increase in the hourly heat input rate is within the manufacturer's maximum continuous steam rating for these units. The cogeneration plant's maximum potential annual heat input will increase from 11,500,000 to 19,970,000 MMBtu per year, which will relax a permit limit originally taken to avoid new source preconstruction review for several pollutants. The applicant requests the flexibility to operate the cogeneration units without synthetic operational restrictions.

The applicant has notified the Department of possible future plans to add a new steam turbine-electrical generator, which would increase the electrical generating capacity of the plant from 74.9 MW to approximately 140 MW. Such a future request would require application and review in accordance the Florida Electrical Power Plant Siting Act in Sections 403.501-403.518 of the Florida Statutes. Approval of such a request would require a revision of the PSD air permit.

The existing cogeneration plant is located in Palm Beach County, which is an area that is currently in attainment with (or designated as unclassifiable for) all pollutants subject to federal and state Ambient Air Quality Standards. The plant is a major facility with respect to the Prevention of Significant Deterioration (PSD) of Air Quality as defined in Rule 62-212.400, F.A.C. Based on the application, the project will result in the following potential increases in emissions in terms of "tons per year" (TPY): 2160 TPY of carbon monoxide (CO); 5 TPY of fluorides (Fl); 1.4 TPY of lead (Pb); 98 pounds per year of mercury (Hg); 741 TPY of nitrogen oxides (NOx); 181 TPY of particulate matter (PM/PM_{10}); 20 TPY of sulfuric acid mist (SAM); 407 TPY of sulfur dioxide (SO_2); and 555 TPY of volatile organic compounds (VOC). Emissions of CO, Fl, Pb, NOx, PM/PM_{10}, SAM, SO_2, and VOC exceed the PSD significant emission rates defined in Table 62-212.400-2, F.A.C. Therefore, the project is subject to PSD preconstruction review for these pollutants.

PSD preconstruction review requires the Department to establish emissions standards that represent the Best Available Control Technology (BACT) for each PSD-significant pollutant. Based on reasonable assurances provided by the applicant and other available information, the Department establishes emissions standards in the draft permit based on the following BACT-level controls: CO and VOC – boiler design and good combustion practices; NOx – selective non-catalytic reduction (SNCR); SO_2 and SAM – low sulfur fuels; PM/PM_{10} – mechanical dust collectors followed by an electrostatic precipitator (ESP); Fl and Pb – authorized fuels containing only trace amounts of fluorides and with and prospective removal in the mechanical dust collectors/ESP.

As part of the PSD required preconstruction review, the Department reviewed the applicant's air quality analysis conducted for each PSD-significant pollutant. The analysis provides the Department with reasonable assurance that the project will not significantly contribute to or cause a violation of any state or federal ambient air quality standards. A refined analysis was required to evaluate the 3-hour and 24-hour SO_2 increments in the vicinity of the plant (Class II areas) and in the Everglades National Park (nearest PSD Class I area). The following table shows the maximum predicted for SO_2 impacts and PSD increments consumed by all sources in the area, including the project.

PSD CLASS II INCREMENT ANALYSIS – VICINITY OF THE PLANT					
Pollutant	**Averaging Time**	**Maximum Predicted Impact ($\mu g/m^3$)**	**Impact Greater than Allowable Increment?**	**Allowable Increment ($\mu g/m^3$)**	**Percent of Increment**
SO_2	24-hr	62	No	91	68%
	3-hr	218	No	512	43%

NOTICE TO BE PUBLISHED IN THE NEWSPAPER

PSD CLASS I INCREMENT ANALYSIS – EVERGLADES NATIONAL PARK					
Pollutant	**Averaging Time**	**Maximum Predicted Impact ($\mu g/m^3$)**	**Impact Greater than Allowable Increment?**	**Allowable Increment ($\mu g/m^3$)**	**Percent of Increment**
SO_2	24-hr	4.0	No	5	80%
	3-hr	12.2	No	25	49%

Based on the analyses, the Department has reasonable assurance that the proposed project will not significantly contribute to or cause a violation of any Class I or Class II PSD increments.

The Department will issue the Final Permit with the proposed conditions unless a response received in accordance with the following procedures results in a different decision or significant change of terms or conditions. The Department will accept written comments and requests for public meetings concerning the proposed permit issuance action for a period of thirty (30) days from the date of publication of this Public Notice of Intent to Issue Permit. Written comments and requests for public meetings should be provided to the Department's Bureau of Air Regulation at 2600 Blair Stone Road, Mail Station #5505, Tallahassee, FL 32399-2400. Any written comments filed shall be made available for public inspection. If written comments received result in a significant change in the proposed agency action, the Department shall revise the proposed permit and require, if applicable, another Public Notice.

The Department will issue the permit with the attached conditions unless a timely petition for an administrative hearing is filed pursuant to Sections 120.569 and 120.57, F.S., before the deadline for filing a petition. The procedures for petitioning for a hearing are set forth below. Mediation is not available in this proceeding.

A person whose substantial interests are affected by the proposed permitting decision may petition for an administrative proceeding (hearing) under Sections 120.569 and 120.57, F.S. The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department at 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida, 32399-3000. Petitions filed by the permit applicant must be filed within fourteen (14) days of receipt of the notice of intent. Petitions filed by any persons other than those entitled to written notice under Section 120.60(3), F.S. must be filed within fourteen (14) days of publication of this Public Notice or within fourteen (14) days of receipt of the notice of intent, whichever occurs first. Under Section 120.60(3), F.S., however, any person who asked the Department for notice of agency action may file a petition within fourteen (14) days of receipt of that notice, regardless of the date of publication. A petitioner shall mail a copy of the petition to the applicant at the address indicated above at the time of filing. The failure of any person to file a petition within the appropriate time period shall constitute a waiver of that person's right to request an administrative determination (hearing) under Sections 120.569 and 120.57, F.S., or to intervene in this proceeding and participate as a party to it. Any subsequent intervention will be only at the approval of the presiding officer upon the filing of a motion in compliance with Rule 28-106.205, F.A.C.

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A complete project file is available for public inspection during normal business hours, 8:00 a.m. to 5:00 p.m., Monday through Friday, except legal holidays, at:

Dept. of Environmental Protection
Bureau of Air Regulation
New Source Review Section
Suite 4, 111 S. Magnolia Drive
Tallahassee, Florida 32301
Telephone: 850/488-0114

Dept. of Environmental Protection
South District Office
Air Resources Section
2295 Victoria Avenue, Suite 364
Fort Myers, Florida 33901-3381
Telephone: 941/332-6975

Palm Beach County Health Dept.
Environmental Health and Engineering
Air Pollution Control Section
901 Evernia Street
West Palm Beach, Florida 33401
Telephone: 561/355-3136

The complete project file includes the application, Technical Evaluation and Preliminary Determination, Draft Permit, and the information submitted by the responsible official, exclusive of confidential records under Section 403.111, F.S. Interested persons may contact the Department's project engineer for additional information at the address and phone numbers listed above.

NOTICE TO BE PUBLISHED IN THE NEWSPAPER

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

7001 0320 0001 3692 6105

OFFICIAL USE

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

Postmark Here

Sent To Rodney Williams
Street, Apt. No.; or PO Box No. PO Box 9
City, State, ZIP+4 South Bay, FL 33493

PS Form 3800, January 2001 — See Reverse for Instructions

SENDER: ***COMPLETE THIS SECTION***

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

1. Article Addressed to:

Mr. Rodney Williams
Plant Manager
New Hope Power Partnership
Okeelanta Cogeneration Plant
Post Office Box 9
South Bay, FL 33493

COMPLETE THIS SECTION ON DELIVERY

A. Received by *(Please Print Clearly)* Amanda Kinman
B. Date of Delivery 9-3-03

C. Signature
X Amanda Kinman
☐ Agent
☒ Addressee

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

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

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

2. 7001 0320 0001 3692 6105

PS Form 3811, July 1999 Domestic Return Receipt 102595-99-M-1789

Department of
Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

October 4, 2002

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Rodney Williams, Plant Manager
New Hope Power Partnership
8001 U.S. Highway 27, South
South Bay, FL 33493

Re: **Request for Additional Information**
Project No. 0990332-016-AC (PSD-FL-196B)
New Hope Power Partnership - Plant Capacity Increase

Dear Mr. Williams:

On September 6, 2002, the Department received your application and sufficient fee for an air construction permit to increase the capacity of the Okeelanta Cogeneration Plant. The application is incomplete. In order to continue processing your application, the Department will need the additional information requested below. Should your response to any of the below items require new calculations, please submit the new calculations, assumptions, reference material and appropriate revised pages of the application form.

1. 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?
2. NHPP requests that the total heat input restriction of $11.5 \times 10^{+06}$ 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.
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 NOx 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.
4. Please provide the missing Attachment NH-FI-C3 (Process Flow Diagram).
5. The floor for a NOx 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 NOx 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 NOx controls for the cogeneration boilers are capable of achieving this level of emissions.

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.

7. NOx BACT Review

   a. Please provide a top-down BACT review for all NOx 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.)

   b. Table 2-3 lists the potential annual NOx 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 NOx emissions from SNCR (the original design control efficiency), the uncontrolled NOx emission factor would be 0.25 lb/MMBtu. Table 5-3 uses an uncontrolled NOx emission factor of 0.26 lb/MMBtu and shows an estimated NOx 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 NOx 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 (8760 hours per year) as requested by NHPP.

   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.

   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.

   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 1000° 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).

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

   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.

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

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 NOx control.

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.

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.

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.

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.

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.

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

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

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?

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.

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.

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.

12. 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.

The Department will resume processing your application after receipt of the requested information. Rule 62-4.050(3), F.A.C. requires that all applications for a Department permit must be certified by a professional engineer registered in the State of Florida. This requirement also applies to responses to Department requests for additional information of an engineering nature. For any material changes to the application, please include a new certification statement by the authorized representative or responsible official. You are reminded that Rule 62-4.055(1), F.A.C. now requires applicants to respond to requests for information within 90 days or provide a written request for an additional period of time to submit the information.

If you have any questions regarding this matter, please call me at 850/921-9523 or Jeff Koerner at 850/921-9536.

Sincerely,

A. A. Linero, P.E. Administrator
New Source Review Section

AAL/jfk

cc: Mr. James Meriwether, New Hope Power Partnership
Mr. David Buff, Golder Associates Inc.
Mr. Ron Blackburn, SD
Mr. James Stormer, PBCHD
Ms. Jeanneane Gettle, EPA Region 4
Mr. John Bunyak, NPS

Table H-1. Summary of SO_2 Sources Included in the Air Modeling Analysis, New Hope Power Partnership

AIRS Number	Facility	Units	Modeling ID Name	Relative Location X (m)	Relative Location Y (m)	Stack and Operating Parameters Height (m)	Diameter (m)	Temper. (K)	Velocity (m/s)	Emission Rate(g/s) 3-Hour	24-Hour	PSD Source? (EXP/CON)	Modeled in AAQS	Class II	Class I
0112545	El Paso Broward														
		Combined Cycle CT CC-1	EPBRCT1	583,700	2,905,500	41.1	5.79	359.3	61.13	0.46	0.46	CON	No [e]	No [e]	Yes
		Simple Cycle SC-1	EPBRSC1	583,700	2,905,500	41.1	5.79	862.0	146.96	0.46	0.46	CON	No [e]	No [e]	Yes
		Simple Cycle SC-2	EPBRSC2	583,700	2,905,500	41.1	5.79	862.0	146.96	0.46	0.46	CON	No [e]	No [e]	Yes
		Simple Cycle SC-3	EPBRSC3	583,700	2,905,500	41.1	5.79	862.0	146.96	0.46	0.46	CON	No [e]	No [e]	Yes
0710019	Lee County RRF PSD		LEECORRF	456,800	3,042,500	83.8	1.88	388.5	19.81	14.00	14.00	CON	No [e]	No [e]	Yes
0990568	Lake Worth Generating														
		4-GE Frame 7FA CTs & HRSG	LWGENCT	583,600	2,907,600	45.7	5.49	377.6	24.29	51.16	51.16	CON	No [e]	No [e]	Yes
0990594	El Paso Belle Glade														
		Combined Cycle CT CC-1	EPBGLCT	534,900	2,953,300	41.1	5.79	359.3	61.13	0.46	0.46	CON	No [e]	No [e]	Yes
		Simple Cycle SC-1	EPBGSC1	534,900	2,953,300	41.1	5.79	862.0	146.96	0.46	0.46	CON	No [e]	No [e]	Yes
		Simple Cycle SC-2	EPBGSC2	534,900	2,953,300	41.1	5.79	862.0	146.96	0.46	0.46	CON	No [e]	No [e]	Yes
		Simple Cycle SC-3	EPBGSC3	534,900	2,953,300	41.1	5.79	862.0	146.96	0.46	0.46	CON	No [e]	No [e]	Yes
	Palm Beach Power Corp.														
		Cogen Boiler 1	PBPCBLR1	544,400	2,967,400	60.7	2.44	419.3	24.87	28.73	19.15	CON	No [e]	No [e]	Yes
		Cogen Boiler 2	PBPCBLR2	544,400	2,967,400	60.7	2.44	419.3	24.87	28.73	19.15	CON	No [e]	No [e]	Yes
		Package Boiler	PACKBLR	544,400	2,967,400	22.9	1.52	483.2	22.86	1.47	1.47	CON	No [e]	No [e]	Yes
0510015	Southern Gardens Citrus - PSD														
		Peel Dryer	SGARDDRY	488	2,958	38.1	1.73	316.0	7.45	5.29	5.29	CON	No [e]	No [e]	Yes
		Boilers 1-3	SGARDBLR	488	2,958	16.8	1.22	478.0	14.22	6.88	6.88	CON	No [e]	No [e]	Yes
990021	Pratt & Whitney (United Technologies)														
		Heater	PRATARCH	509,600	2,954,200	15.2	0.91	810.9	143.73	13.99	13.99	CON	No [e]	No [e]	Yes
		Boiler BO-12	PRATBO12	509,600	2,954,200	4.6	0.76	533.2	6.92	0.51	0.51	CON	No [e]	No [e]	Yes
		A-10 Test Stand	PRATA10	509,600	2,954,200	5.8	4.17	410.9	106.68	0.55	0.55	No	Yes	No	No

Note:
EXP = PSD expanding source
CON = PSD consuming source
NO = Source does not affect PSD increment
ND = No data available

[a] Facilities or sources within facilities that operate only during the October 1 through April 31 crop season.

[b] Sugar mill sources that operate all year.

[c] Large source with emissions greater than 1,000 TPY included in the AAQS or PSD Class II modeling even though the source is located outside of the screening area.

[d] Represents worst case emissions for May 1 through September 31 off-crop season operation, and October 1-April 30 for on-crop season.
Updated from PSD modeling information, Golder Associates (7/18/00). Baseline data represents November 1 though April 30.

[e] Not included in AAQS or Class II modeling analyses because they screened out.

Table H-1. Summary of SO_2 Sources Included in the Air Modeling Analysis, New Hope Power Partnership

AIRS Number	Facility Units	Modeling ID Name	Relative Location X (m)	Relative Location Y (m)	Stack and Operating Parameters Height (m)	Diameter (m)	Temper. (K)	Velocity (m/s)	Emission Rate(g/s) 3-Hour	24-Hour	PSD Source? (EXP/CON)	Modeled in AAQS	Class II	Class I
0710000	FPL Fort Myers [c]													
	Unit 1 PSD	FMU1	567,100	3,056,500	91.8	2.90	422.0	29.90	-585.50	-585.50	EXP	No	Yes	Yes
	Unit 2 PSD	FMU2	567,100	3,056,500	121.2	5.52	408.0	19.20	-1334	-1334.0	EXP	No	Yes	Yes
	HRSGs 1 - 6	FMYHR1_6	567,100	3,056,500	38.1	5.79	377.6	14.2	3.86	3.9	CON	Yes	Yes	Yes
	Gas Turbines 1 -12	FMYGT112	567,100	3,056,500	9.75	4.42	797.0	35.7	649.2	649.2	NO	Yes	No	No
1110003	Fort Pierce Utilities [c]													
	Units 6&7	FTPIER67	594,200	2,960,600	45.7	2.19	408.2	12.50	77.87	77.87	NO	Yes	No	No
0550018	TECO-Phillips [c]													
	Steam Boiler	TECOSB	424,200	2,945,700	18.90	0.67	ND	ND	0.7	0.7	NO	No	No	No
	Diesel Generator Unit 1	TECO1	424,200	2,945,700	45.72	1.83	441.0	24.1	58.0	29.0	NO	Yes	No	No
	Diesel Generator Unit 2	TECO2	424,200	2,945,700	45.72	1.83	450.0	24.1	58.0	29.0	NO	Yes	No	No
0550004	TECO-Sebring/Dinner Lake [c]													
	Steam Boiler	DINNSB	464,300	3,035,400	22.9	1.83	394.3	5.79	37.78	37.78	CON	Yes	Yes	No
0610029	Vero Beach Power [c]													
	Unit 1	VERBU1	587,400	2,885,300	60.96	1.07	437.0	32.42	28.77	28.77	NO	Yes	No	No
	Unit 2	VERBU2	587,400	2,885,300	60.96	1.07	434.3	37.57	84.21	84.21	NO	Yes	No	No
	Unit 3	VERBU3	587,400	2,885,300	60.96	1.83	440.4	19.93	142.07	142.07	NO	Yes	No	No
	Unit 4	VERBU4	587,400	2,885,300	60.96	2.13	425.4	24.36	69.05	69.05	NO	Yes	No	No
	Unit 5 Simple Cycle CT	VERBU5	587,400	2,885,300	38.10	3.35	416.5	19.56	15.50	15.50	CON	Yes	Yes	No
0250348	Dade County RRF PSD													
	Units 1&2	DCRRF12	566,800	3,036,300	76.2	3.66	405.4	15.86	26.41	12.32	CON	No [e]	No [e]	Yes
	Units 3&4	DCRRF34	566,800	3,036,300	76.2	3.66	405.4	15.86	26.41	12.32	CON	No [e]	No [e]	Yes
0112515	Enron Pompano Beach Energy Center													
	3-170 MW CTs	ENPMPCT	580,100	2,883,300	24.4	5.49	847.0	47.06	39.16	39.16	CON	No [e]	No [e]	Yes
0110120	North Broward RRF PSD	NBCRRF	579,600	2,883,300	58.5	3.96	381.0	18.01	35.40	35.40	CON	No [e]	No [e]	Yes
0112534	Enron Deerfield Beach Energy Center													
	3-170 MW CTs	ENDFCT	592,800	2,943,700	24.4	5.49	847.0	47.06	39.16	39.16	CON	No [e]	No [e]	Yes

Table H-1. Summary of SO_2 Sources Included in the Air Modeling Analysis, New Hope Power Partnership

AIRS Number	Facility Units	Modeling ID Name	Relative Location X (m)	Relative Location Y (m)	Height (m)	Diameter (m)	Temper. (K)	Velocity (m/s)	Emission Rate(g/s) 3-Hour	Emission Rate(g/s) 24-Hour	PSD Source? (EXP/CON)	Modeled in AAQS	Modeled in Class II	Modeled in Class I
0850001	FPL Martin													
	Units 1&2	MART12	537,800	2,969,160	152.1	7.99	420.9	21.03	1743.79	1743.79	NO	Yes	No	No
	Aux Blr PSD	MARTAUX	537,800	2,969,160	18.3	1.10	535.4	15.24	12.90	12.90	CON	Yes	Yes	Yes
	Diesel Gens PSD	MARTGEN	537,800	2,969,160	7.6	0.30	785.9	39.62	0.51	0.51	CON	Yes	Yes	Yes
	Units 3&4 PSD	MART34	537,800	2,969,160	64.9	6.10	410.9	18.90	470.40	470.40	CON	Yes	Yes	Yes
	Unit 8	MART8	537,800	2,969,160	36.6	5.79	397.6	13.59	12.99	12.99	CON	Yes	Yes	Yes
0990234	Palm Beach Co. Resource Recovery[c]													
	1&2 PSD	PBCRRF	543,100	2,992,900	76.2	2.04	505.2	24.90	85.05	85.05	CON	Yes	Yes	Yes
0990568	Lake Worth Utilities[c]													
	Unit 3	LAKWTHU3	583,300	2,908,000	38.1	2.13	408.2	7.71	103.95	103.95	NO	Yes	No	No
	Unit 4	LAKWTHU4	583,300	2,908,000	35.1	2.29	418.2	17.00	129.85	129.85	NO	Yes	No	No
	Unit 5	LAKWTHU5	583,300	2,908,000	22.9	0.94	450.4	18.29	11.59	11.59	NO	Yes	No	No
	HRSG	LAKWTHHR	583,300	2,908,000	45.7	5.49	377.6	13.74	12.79	12.79	CON	Yes	Yes	Yes
0990042	FPL Riviera[c]													
	Units 3&4 at 2.5%s fuel oil	RIVU34	555,860	2,882,200	90.8	4.88	401.5	18.90	2113.65	2113.65	NO	Yes	No	No
0112119	South Broward RRF PSD [c]	SBCRRF	575,200	3,006,800	59.4	3.96	381.0	18.01	37.91	37.91	CON	Yes	Yes	Yes
0110037	FPL - Lauderdale [c]													
	CTs 1-4 PSD	LAUDU45	562,900	2,861,700	45.7	5.49	438.7	14.60	271.15	271.15	CON	Yes	Yes	Yes
	GT 1-12 (0.5% fuel oil)	LDGT1_12	562,900	2,861,700	13.7	2.37	733.2	114.31	552.80	552.80	NO	Yes	No	No
	GT 13-24 (0.5% fuel oil)	LDGT1324	562,900	2,861,700	13.4	4.75	733.2	28.43	552.80	552.80	NO	Yes	No	No
	4&5 PSD Baseline	FTLAU45B	562,900	2,861,700	46.0	4.27	422.0	14.63	-457.00	-457.00	EXP	No	Yes	Yes
0110036	FPL Port Everglades [c]													
	Units 1&2 at 2.5%s fuel oil	PTEVU12	564,300	2,857,400	104.5	4.27	415.9	26.72	1593.90	1593.90	NO	Yes	No	No
	Units 3&4 at 2.5%s fuel oil	PTEVU34	564,300	2,857,400	104.5	5.52	414.8	23.88	2772.00	2772.00	NO	Yes	No	No
	GT 1-12 (0.5% fuel oil)	PTEVGTS	564,300	2,857,400	13.4	4.75	733.2	28.43	530.70	530.70	NO	Yes	No	No
0250020	Tarmac [c]													
	Kiln 1 PSD Baseline	TARMC1	422,100	2,952,900	61.0	2.44	465.0	12.84	-5.71	-5.71	EXP	No	Yes	Yes
	Kiln 2 PSD Baseline	TARMC2B	422,100	2,952,900	61.0	2.44	465.0	12.84	-5.71	-5.71	EXP	No	Yes	Yes
	Kiln 3 PSD Baseline	TARMC3B	422,100	2,952,900	61.0	4.57	472.0	10.78	-2.76	-2.76	EXP	No	Yes	Yes
	Kiln 2 PSD	TABMC2P	422,100	2,952,900	61.0	2.44	422.0	9.10	24.57	24.57	CON	Yes	Yes	Yes
	Kiln 3 PSD	TARMC3P	422,100	2,952,900	61.0	4.57	450.0	11.04	51.43	51.43	CON	Yes	Yes	Yes

Table H-1. Summary of SO_2 Sources Included in the Air Modeling Analysis, New Hope Power Partnership

AIRS Number	Facility	Units	Modeling ID Name	Relative Location X (m)	Relative Location Y (m)	Stack and Operating Parameters Height (m)	Diameter (m)	Temper. (K)	Velocity (m/s)	Emission Rate(g/s) 3-Hour	24-Hour	PSD Source? (EXP/CON)	Modeled in AAQS	Class II	Class I
		Off-crop season future													
		Unit 1	USSBRL1F	545,600	2,991,500	65.0	2.44	347.0	14.05	51.64	24.29	CON	Yes	Yes	Yes
		Unit 2	USSBLR2F	545,600	2,991,500	65.0	2.44	338.0	12.68	51.27	24.02	CON	Yes	Yes	Yes
		Unit 3	USSBLR3F	545,600	2,991,500	65.0	2.44	333.2	6.20	30.74	30.20	CON	Yes	Yes	Yes
		Unit 4	USSBLR4F	545,600	2,991,500	45.7	2.51	344.3	0.00	0.00	0.00	CON	Yes	Yes	Yes
		Unit 7	USSBLR7F	545,600	2,991,500	68.6	2.59	405.4	23.60	17.39	15.81	CON	Yes	Yes	Yes
0990016	Atlantic Sugar [a]														
		Unit 1	ATLSUG1	552,900	2,945,200	27.4	1.83	346.0	17.97	16.28	16.28	CON	Yes	Yes	Yes
		Unit 2	ATLSUG2	552,900	2,945,200	27.4	1.83	350.0	23.36	16.28	16.28	CON	Yes	Yes	Yes
		Unit 3	ATLSUG3	552,900	2,945,200	27.4	1.83	350.0	21.56	16.02	16.02	CON	Yes	Yes	Yes
		Unit 4	ATLSUG4	552,900	2,945,200	27.4	1.83	344.0	25.16	16.21	16.21	CON	Yes	Yes	Yes
		Unit 5 PSD [b]	ATLSUG5	552,900	2,945,200	27.4	1.68	339.0	19.24	8.41	8.04	CON	Yes	Yes	Yes
		Unit 1 PSD Baseline	ATLSUG1B	552,900	2,945,200	18.9	1.92	506.0	12.71	-17.24	-17.24	EXP	No	Yes	Yes
		Unit 2 PSD Baseline	ATLSUG2B	552,900	2,945,200	18.9	1.92	511.0	10.89	-22.52	-22.52	EXP	No	Yes	Yes
		Unit 3 PSD Baseline	ATLSUG3B	552,900	2,945,200	21.9	1.83	522.0	17.52	-16.88	-16.88	EXP	No	Yes	Yes
		Unit 4 PSD Baseline	ATLSUG4B	552,900	2,945,200	18.3	1.83	344.0	15.03	-16.88	-16.88	EXP	No	Yes	Yes
0990061	US Sugar-Bryant [a]														
		Unit 5 PSD	USSBRY5	523,400	2,955,200	45.7	2.90	334.3	14.80	62.40	62.40	CON	No	Yes	Yes
		Unit 5 AAQS	USSBRY5	523,400	2,955,200	45.7	2.90	334.3	14.80	77.25	77.25	No	Yes	No	No
		Unit 1,2&3 PSD	USBRY123	523,400	2,955,200	19.8	1.64	344.3	34.60	160.68	160.68	CON	No	Yes	Yes
		Unit 1,2&3 AAQS	USBRY123	523,400	2,955,200	19.8	1.64	344.3	34.60	199.71	199.71	No	Yes	No	No
		Unit 1 PSD Baseline	USSBRY1B	523,400	2,955,200	19.8	1.68	494.0	44.30	-36.50	-36.50	EXP	No	Yes	Yes
		Unit 2&3 PSD Baseline	USBRY23B	523,400	2,955,200	19.8	1.68	344.0	37.90	-73.00	-73.00	EXP	No	Yes	Yes
0990019	Osceola Farms PSD Baseline [a]														
		Unit 2	OSBLR2	544,200	2,968,000	27.4	1.52	341.0	15.82	12.58	11.43	CON	Yes	Yes	Yes
		Unit 3	OSBLR3	544,200	2,968,000	27.4	1.91	342.0	16.86	9.82	2.00	CON	Yes	Yes	Yes
		Unit 4	OSBLR4	544,200	2,968,000	27.4	1.83	340.0	16.67	9.73	1.92	CON	Yes	Yes	Yes
		Unit 5	OSBLR5	544,200	2,968,000	27.4	1.52	341.0	15.50	12.96	11.79	CON	Yes	Yes	Yes
		Unit 6	OSBLR6	544,200	2,968,000	27.4	1.88	341.0	18.19	2.87	2.59	CON	Yes	Yes	Yes
		Unit 1 PSD Baseline	OSBLR1B	544,200	2,968,000	22.0	1.52	342.0	8.98	-5.07	-5.07	EXP	No	Yes	Yes
		Unit 2 PSD Baseline	OSBLR2B	544,200	2,968,000	22.0	1.52	342.0	14.22	-16.32	-16.32	EXP	No	Yes	Yes
		Unit 3 PSD Baseline	OSBLR3B	544,200	2,968,000	22.0	1.93	342.0	11.23	-7.26	-7.26	EXP	No	Yes	Yes
		Unit 4 PSD Baseline	OSBLR4B	544,200	2,968,000	22.0	1.83	342.0	13.35	-13.61	-13.61	EXP	No	Yes	Yes
0850102	Bechtel Indiantown PSD		BECHTIND	506,100	2,956,900	150.9	4.88	333.2	30.50	75.64	75.64	CON	Yes	Yes	Yes

Table H-1. Summary of SO_2 Sources Included in the Air Modeling Analysis, New Hope Power Partnership

AIRS Number	Facility	Units	Modeling ID Name	Relative Location X (m)	Relative Location Y (m)	Stack and Operating Parameters Height (m)	Diameter (m)	Temper. (K)	Velocity (m/s)	Emission Rate(g/s) 3-Hour	24-Hour	PSD Source? (EXP/CON)	Modeled in AAQS	Class II	Class I
0990005	Okeelanta Corp.[a]														
		Boiler 4 PSD Baseline	OKBLR4B	-201	58	22.9	2.29	333.0	7.36	-10.95	-10.95	EXP	No	Yes	Yes
		Boiler 5 PSD Baseline	OKBLR5B	-201	37	22.9	2.29	333.0	12.07	-15.64	-15.64	EXP	No	Yes	Yes
		Boiler 6 PSD Baseline	OKBLR6B	-201	23	22.9	2.29	334.0	8.74	-15.64	-15.64	EXP	No	Yes	Yes
		Boiler 10 PSD Baseline	OKBLR10B	-201	9	22.9	2.29	334.0	10.35	-17.15	-17.15	EXP	No	Yes	Yes
		Boiler 11 PSD Baseline	OKBLR11B	-201	67	22.9	2.29	342.0	9.89	-16.79	-16.79	EXP	No	Yes	Yes
		Boiler 16 PSD	OKBLR16	-223	18	22.9	1.52	483.0	22.86	1.47	1.47	CON	Yes	Yes	Yes
0990086	Glades Correctional Institute		GLADCORR	525,000	2,937,400	9.8	0.40	389.0	11.28	2.82	2.82	NO	Yes	No	No
0990026	Sugar Cane Growers[a]														
		Unit 1&2	SUGCN12	533,500	2,954,100	45.7	1.87	339.0	21.75	41.20	41.20	CON	Yes	Yes	Yes
		Unit 3	SUGCN3	533,500	2,954,100	27.4	1.52	339.0	22.25	16.20	16.20	CON	Yes	Yes	Yes
		Unit 4 PSD	SUGCN4	533,500	2,954,100	54.9	2.44	339.0	21.73	38.20	38.20	CON	Yes	Yes	Yes
		Unit 5	SUGCN5	533,500	2,954,100	45.7	2.30	339.0	15.94	27.90	27.90	CON	Yes	Yes	Yes
		Unit 8 PSD	SUGCN8	533,500	2,954,100	47.2	2.90	339.0	13.62	23.50	23.50	CON	Yes	Yes	Yes
		Unit 1&2 PSD Baseline	SUGCN12B	533,500	2,954,100	24.4	1.40	344.0	11.40	-24.20	-24.20	EXP	No	Yes	Yes
		Unit 3 PSD Baseline	SUGCN3B	533,500	2,954,100	24.4	1.60	344.0	15.60	-4.40	-4.40	EXP	No	Yes	Yes
		Unit 4 PSD Baseline	SUGCN4B	533,500	2,954,100	25.9	1.63	344.0	11.20	-24.20	-24.20	EXP	No	Yes	Yes
		Unit 5 PSD Baseline	SUGCN5B	533,500	2,954,100	24.4	1.40	344.0	15.20	-16.20	-16.20	EXP	No	Yes	Yes
		Unit 6&7 PSD Baseline	SUGCN67B	533,500	2,954,100	12.2	1.52	606.0	11.20	-51.00	-51.00	EXP	No	Yes	Yes
0510001	Everglades Sugar[b]	Main Boiler	EVERGLAD	562,000	2,960,000	21.9	1.10	477.0	10.10	34.90	34.90	NO	Yes	No	No
0510003	US Sugar - Clewiston[d]														
		PSD Baseline (On-crop season only)													
		Unit 1 PSD Baseline	USSBRL1B	545,600	2,991,500	23.1	1.86	344.0	30.20	-79.86	-58.21	EXP	No	Yes	Yes
		Unit 2 PSD Baseline	USSBLR2B	545,600	2,991,500	23.1	1.86	343.0	35.70	-79.86	-58.21	EXP	No	Yes	Yes
		Unit 3 PSD Baseline	USSBLR3B	545,600	2,991,500	27.4	2.29	342.0	14.70	-48.30	-33.20	EXP	No	Yes	Yes
		East Pellet Plant PSD Baseline	EPELLET	545,600	2,991,500	12.2	1.52	347.0	8.54	-10.30	-10.30	EXP	No	Yes	Yes
		West Pellet Plant PSD Baseline	WPELLET	545,600	2,991,500	15.7	1.52	347.0	8.54	-10.30	-10.30	EXP	No	Yes	Yes
		On-crop season future													
		Unit 1	USSBRL1N	545,600	2,991,500	65.0	2.44	347.0	15.36	78.79	73.73	CON	Yes	Yes	Yes
		Unit 2	USSBLR2N	545,600	2,991,500	65.0	2.44	338.0	13.86	78.49	73.44	CON	Yes	Yes	Yes
		Unit 3	USSBLR3N	545,600	2,991,500	65.0	2.44	333.2	6.78	47.08	47.08	CON	Yes	Yes	Yes
		Unit 4	USSBLR4N	545,600	2,991,500	45.7	2.51	344.3	20.28	21.53	3.68	CON	Yes	Yes	Yes
		Unit 7	USSBLR7N	545,600	2,991,500	68.6	2.59	405.4	20.77	13.91	12.65	CON	Yes	Yes	Yes

Table A-1. Current Actual Emissions (January 2000 through December 2001), New Hope Power Partnership

Boiler	Operating Hours	Heat Input (MMBtu/yr)	Actual Annual Emissions (tons)[c] PM	PM_{10}	SO_2	NO_x	CO	VOC	Pb	Hg	F	SAM
Calendar Year 2000[a]												
Boiler A	6,602	3,785,865	289.77	52.34	73.62	276.36	376.69	20.92	0.0134	0.0007	0.5751	5.655
Boiler B	6,312	3,640,829	77.88	21.91	72.81	265.77	500.61	12.15	0.0129	0.0006	0.5471	5.438
Boiler C	6,788	3,957,456	272.63	51.17	72.60	288.88	417.50	18.23	0.0250	0.0011	0.6851	5.907
Total--*2000*	19,702	11,384,150	172.50 [c]	125.42	219.03	831.01	1,294.80	51.30	0.0513	0.0024	1.8072	17.000
Calendar Year 2001[b]												
Boiler A	5,455	3,056,969	28.62	30.07	55.02	217.04	360.71	7.43	0.0590	0.0016	0.9810	4.570
Boiler B	5,982	3,394,860	29.48	31.89	44.12	241.02	541.45	18.33	0.0440	0.0018	0.8310	5.078
Boiler C	6,321	3,202,078	25.31	28.65	65.63	224.14	473.89	10.79	0.0420	0.0013	0.7060	4.780
Total--*2001*	17,758	9,653,907	83.4	90.61	164.77	682.20	1,376.05	36.55	0.1450	0.0046	2.5181	14.427
Average												
Boiler A	6,029	3,421,417	159.19	41.20	64.32	246.70	368.70	14.17	0.0362	0.0011	0.7781	5.112
Boiler B	6,147	3,517,845	53.68	26.90	58.47	253.40	521.03	15.24	0.0285	0.0012	0.6891	5.258
Boiler C	6,555	3,579,767	148.97	39.91	69.12	256.51	445.70	14.51	0.0335	0.0012	0.6956	5.344
Average (Tons Per Year)	18,730	10,519,029	127.96	108.02	191.90	756.60	1,335.43	43.93	0.0982	0.0035	2.1627	15.714

[a] Obtained from 2000 Annual Operating Report.

[b] Obtained from 2001 Annual Operating Report.

[c] Annual emissions exceeded permit limit, therefore, permit limit was used.

Table 6-6. Summary of SO_2 Facilities Considered for Inclusion in the AAQS and PSD Class II Air Modeling Analyses, New Hope Power Partnership

			UTM Coordinates		Relative to Palm Beach Power [a]				Maximum	Q,	
AIRS Number	Facility	County	East (km)	North (km)	X (km)	Y (km)	Distance (km)	Direction (deg)	SO_2 Emissions (TPY)	Emission Threshold [b] (Dist - SIA) x 20	Include in Modeling Analysis ?
0990005	Okeelanta Corp.	Palm Beach	525.0	2937.4	0.1	-2.7	2.7	178	39	SIA	YES
0990086	Glades Correctional Institute	Palm Beach	523.4	2955.2	-1.5	15.1	15.2	354	98	83.5	YES
0990594	El Paso Belle Glade Generating Station	Palm Beach	533.5	2954.1	8.6	14.0	16.4	32	69	108.6	NO
0990026	Sugar Cane Growers	Palm Beach	534.9	2953.3	10.0	13.2	16.6	37	2,555	111.2	YES
0510001	Everglades Sugar	Hendry	509.6	2954.2	-15.3	14.1	20.8	313	1,216	196.1	YES
0510003	U.S. Sugar Clewiston	Hendry	506.1	2956.9	-18.8	16.8	25.2	312	7,806	284.3	YES
0990016	Atlantic Sugar	Palm Beach	552.9	2945.2	28.0	5.1	28.5	80	954	349.2	YES
0990349	South Florida WMD--Pump Stn. G-310/S-6	Palm Beach	554.2	2940.5	29.3	0.4	29.3	89	5	366.1	NO
0990061	U.S. Sugar -Bryant	Palm Beach	537.8	2969.2	12.9	29.1	31.8	24	2,698	415.9	YES
	Palm Beach Power Corp. (Osceola Power)	Palm Beach	544.4	2967.4	19.5	27.3	33.5	0	451	451.0	NO
0990019	Osceola Farms	Palm Beach	544.2	2968.0	19.3	27.9	33.9	0	1,467	458.5	YES
0510015	Southern Gardens Citrus	Hendry	487.6	2957.6	-37.3	17.5	41.2	295	409	604.0	NO
0990021	Pratt & Whitney (United Technologies)	Palm Beach	562.0	2960.0	37.1	19.9	42.1	62	504	622.0	NO
0850102	Bechtel Indiantown	Martin	545.6	2991.5	20.7	51.4	55.4	22	2,629	888.2	YES
0850001	FPL - Martin	Martin	543.1	2992.9	18.2	52.8	55.8	19	22,982	897.0	YES
0990234	Palm Beach Resource Recovery [c]	Palm Beach	585.8	2960.2	60.9	20.1	64.1	72	1,533	1062.6	YES
0990350	South Florida WMD--Pump Stn. S-9	Broward	555.9	2882.2	31.0	-57.9	65.7	152	2	1093.2	NO
0112534	Enron/Deerfield Beach Energy Center	Broward	583.1	2907.9	58.2	-32.2	66.5	119	166	1110.3	NO
0112545	El Paso Broward Energy Center	Broward	583.3	2908.0	58.4	-32.1	66.6	119	87	1112.8	NO
0110120	North Broward Resource Recovery	Broward	583.6	2907.6	58.7	-32.5	67.1	119	896	1121.9	NO
0990045	Lake Worth Utilities [c]	Palm Beach	592.8	2943.7	67.9	3.6	68.0	87	7,415	1139.9	YES
0990568	Lake Worth Generating	Palm Beach	592.8	2943.7	67.9	3.6	68.0	87	54	1139.9	NO
0112515	Enron/Pompano Energy Center	Broward	583.7	2905.5	58.8	-34.6	68.2	120	166	1144.5	NO
0990042	FPL -Riviera Beach [c]	Palm Beach	594.2	2960.6	69.3	20.5	72.3	74	73,475	1225.4	YES
0112119	South Broward Resource Recovery [c]	Broward	579.6	2883.3	54.7	-56.8	78.9	136	1,318	1357.1	YES
0110037	FPL -Lauderdale [c]	Broward	580.1	2883.3	55.2	-56.8	79.2	136	47,858	1364.1	YES
1110103	CPV Cana, LTD.	St. Lucie	550.9	3018.1	26.0	78.0	82.2	18	76	1424.4	NO
0110036	FPL -Port Everglades [c]	Broward	587.4	2885.3	62.5	-54.8	83.1	131	170,215	1442.4	YES
0850021	Stuart Contracting	Martin	575.2	3006.8	50.3	66.7	83.5	37	100	1450.8	NO
0250020	Tarmac [c]	Dade	562.9	2861.7	38.0	-78.4	87.1	154	2,792	1522.5	YES
0250348	Dade Co. Resource Recovery	Dade	564.3	2857.4	39.4	-82.7	91.6	155	857	1612.1	NO
0710019	Lee County Resource Recovery	Lee	424.2	2945.7	-100.7	5.6	100.9	273	163	1797.1	NO
0710000	FPL - Fort Myers [c]	Lee	422.1	2952.9	-102.8	12.8	103.6	277	22,702	1851.9	YES
1110003	Fort Pierce Utilities [c]	St. Lucie	566.8	3036.3	41.9	96.2	104.9	24	1,497	1878.6	YES
0550018	TECO-Phillips [c]	Highlands	464.3	3035.4	-60.6	95.3	112.9	328	4,053	2038.7	YES
0550004	TECO-Sebring/Dinner Lake [c]	Highlands	456.8	3042.5	-68.1	102.4	123.0	326	1,313	2239.5	YES
0610029	Vero Beach Power [c]	St. Lucie	567.1	3056.5	42.2	116.4	123.8	20	10,274	2256.3	YES

Note: deg = degrees
km = kilometers
SIA = significant impact area
TPY = tons per year

[a] New Hope Power Partnership's East and North Coordinates (km) are: 524.9 and 2940.1, respectively.

[b] Based on North Carolina Screening Technique for annual average basis. "Dist" is the distance the facility is located from the project.
"SIA" is the significant impact area. The project's 24-hour, 3-hour, and annual SO_2 concentrations are predicted to be significant out to 11 km from the project.

[c] Large source with annual emissions greater than 1,000 TPY located beyond the screening area (61 km) that were included in the inventory.

Table 2-4. New Hope Power Partnership Facility Maximum Annual Fugitive Dust Emissions

SOURCE	TYPE OF OPERATION	M MOISTURE CONTENT (%)	U WIND SPEED (MPH)	UNCONTROLLED PM EMISSION FACTOR (LB/TON) [a]	UNCONTROLLED PM_{10} EMISSION FACTOR (LB/TON) [a]	CONTROL	CONTROL EFFICIENCY (%)	CONTROLLED PM EMISSION FACTOR (LB/TON)	CONTROLLED PM_{10} EMISSION FACTOR (LB/TON)	ACTIVITY FACTOR	MAXIMUM ANNUAL PM(TSP) EMISSIONS (TONS/YR)	MAXIMUM ANNUAL PM_{10} EMISSIONS (TONS/YR)
BIOMASS HANDLING												
TRUCK DUMPS (2)	BATCH DROP	37	9.4	0.00009	0.00004	NONE	0	0.00009	0.00004	3,761,731 TPY [g]	0.170	0.0805
CHAIN CONVEYORS-TO-UNLOADING CONVEYOR (2)	CONTINUOUS DROP	37	9.4	0.00009	0.00004	ENCLOSURE	0	0.00009	0.00004	3,761,731 TPY [g]	0.170	0.0805
UNLOADING CONVEYOR-TO-SCREEN	CONTINUOUS DROP	37	9.4	0.00009	0.00004	ENCLOSURE	0	0.00009	0.00004	3,761,731 TPY [g]	0.170	0.0805
SCREEN	CONTINUOUS DROP	37	9.4	0.00009	0.00004	NONE	0	0.00009	0.00004	3,761,731 TPY [g]	0.170	0.0805
SCREEN-TO-HOGGER	CONTINUOUS DROP	37	9.4	0.00009	0.00004	ENCLOSURE	0	0.00009	0.00004	3,761,731 TPY [g]	0.170	0.0805
HOGGER	CRUSHING	--	--	0.02	0.01	ENCLOSED	95	0.00100	0.00047	3,761,731 TPY [g]	1.881	0.8896
HOGGER-TO-STORAGE CONVEYOR	BATCH DROP	37	9.4	0.00009	0.00004	ENCLOSURE	0	0.00009	0.00004	3,761,731 TPY [g]	0.170	0.0805
SCREEN-TO-STORAGE CONVEYOR	CONTINUOUS DROP	37	9.4	0.00009	0.00004	ENCLOSURE	0	0.00009	0.00004	0 TPY	0.000	0.0000
SCREEN-TO-BOILER FEED CONVEYOR	CONTINUOUS DROP	37	9.4	0.00009	0.00004	ENCLOSURE	0	0.00009	0.00004	0 TPY	0.000	0.0000
STORAGE CONVEYOR-TO-RADIAL STACKER	CONTINUOUS DROP	37	9.4	0.00009	0.00004	ENCLOSURE	0	0.00009	0.00004	3,761,731 TPY [g]	0.170	0.0805
RADIAL STACKER-TO-BIOMASS STORAGE PILE	CONTINUOUS DROP	37	9.4	0.00009	0.00004	NONE	0	0.00009	0.00004	3,761,731 TPY [g]	0.170	0.0805
UNDERPILE RECLAIMERS (2)	CONTINUOUS DROP	37	9.4	0.00009	0.00004	ENCLOSED	90	0.00001	0.00000	3,761,731 TPY [g]	0.017	0.0081
RECLAIMERS-TO-BOILER FEED CONVEYOR (2)	CONTINUOUS DROP	37	9.4	0.00009	0.00004	ENCLOSURE	0	0.00009	0.00004	3,761,731 TPY [g]	0.170	0.0805
BOILER FEED CONVEYOR-TO-CHAIN DIST. CONVEYOR (2)	CONTINUOUS DROP	37	9.4	0.00009	0.00004	ENCLOSURE	0	0.00009	0.00004	3,761,731 TPY [g]	0.170	0.0805
CHAIN DIST. CONVEYOR -TO-BOILER METER BINS (4)	BATCH DROP	37	9.4	0.00009	0.00004	ENCLOSURE	0	0.00009	0.00004	3,761,731 TPY [g]	0.170	0.0805
BAGASSE CONVEYOR-TO-CHAIN DIST CONVEYOR (2)	CONTINUOUS DROP	37	9.4	0.00009	0.00004	ENCLOSURE	0	0.00009	0.00004	0 TPY	0.000	0.0000
BAGASSE CONVEYOR-TO-RECYCLE CONVEYOR	CONTINUOUS DROP	37	9.4	0.00009	0.00004	ENCLOSURE	0	0.00009	0.00004	0 TPY	0.000	0.0000
CHAIN DIST. CONVEYORS-TO-RECYLE CONVEYOR (2)	CONTINUOUS DROP	37	9.4	0.00009	0.00004	ENCLOSURE	0	0.00009	0.00004	376,173 TPY [f]	0.017	0.0081
RECYCLE CONVEYOR-TO-RECYCLE STACKER	CONTINUOUS DROP	37	9.4	0.00009	0.00004	ENCLOSURE	0	0.00009	0.00004	0 TPY	0.000	0.0000
RECYCLE CONVEYOR-TO-STORAGE CONVEYOR	CONTINUOUS DROP	37	9.4	0.00009	0.00004	ENCLOSURE	0	0.00009	0.00004	376,173 TPY [f]	0.017	0.0081
RECYCLE STACKER-TO-BIOMASS STORAGE PILE	CONTINUOUS DROP	37	9.4	0.00009	0.00004	NONE	0	0.00009	0.00004	0 TPY	0.000	0.0000
BIOMASS STORAGE PILES (2)	WIND EROSION	--	--	--		NONE	0	--		--	0.175 [d]	0.0000 [d]
BIOMASS STORAGE PILE MAINTENANCE	VEHICULAR TRAFFIC	--	--	0.75	0.23 lb/VMT [b]	WATERING	50	0.38	0.11 lb/VMT [b]	21,900 VMT [c]	4.110 [d]	1.2330 [d]
FLY ASH HANDLING												
FLY ASH SILO FILTER	--	--	--	--	--	BAGHOUSE	99	0.01	0.0047 gr/acf	2,500 acfm	0.939	0.444
FLY ASH TRANSFER-TO-TRUCK	CONTINUOUS DROP	5.0	9.4	0.00149	0.00071	WETTING	50	0.00075	0.00035	110,131 TPY [e]	0.041	0.019
TOTAL											9.069	3.496

Notes/References:

[a] Batch Drop and Continuous Drop Emission Factors are computed from AP-42 (USEPA, 1995) Section 13.2.4:
E= k x 0.0032 x (U/5)^1.3 / (M/2)^1.4 lb/ton, where k = 0.74 for PM and 0.35 for PM_{10}.

[b] Pound per Vehicle Mile Travel (lb/VMT), see Appendix B, Table B-1 for derivation.

[c] Based on vehicle operating 12 hrs/day, 365 days/yr @ 5 mph.

[d] Refer to Appendix B for derivation.

[e] Based on 1,063,162 TPY woodwaste @ 9% ash and 1,444,659 TPY bagasse @ 1% ash. Assuming 100% is fly ash. See Appendix B, Table B-2 for derivation.

[f] Assuming 10% of biomass is overfeed and is returned to biomass storage pile.

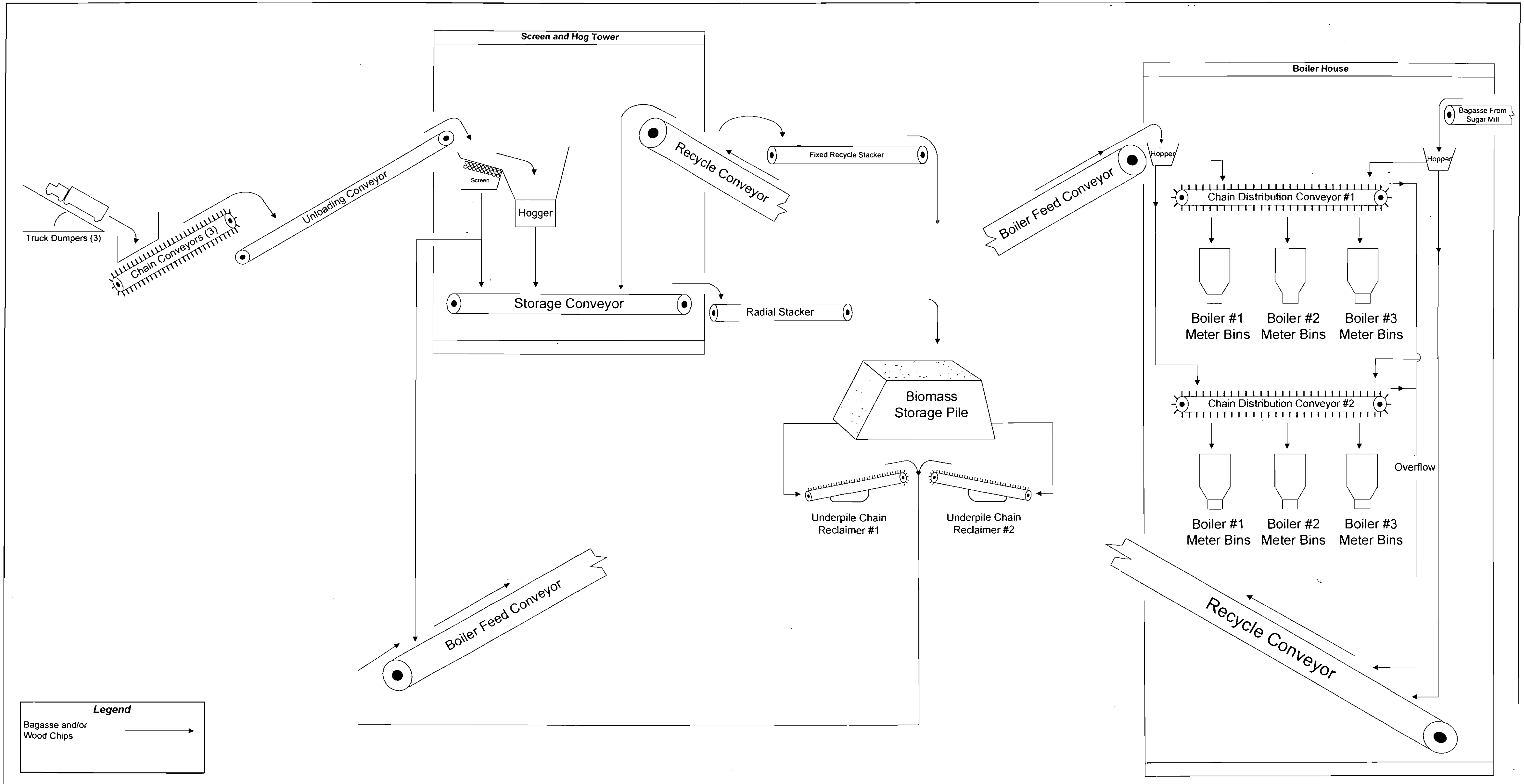
[g] Activity Factor based on 19.97×10^{12} Btu/yr; 47.9% is from wood (4,500 Btu/lb) and the remaining 52.1% is from bagasse (3,600 Btu/lb) = 2,507,821 TPY; an additional 50% was added to account for year-to-year variations. See Appendix B, Table B-2 for derivation.

Table 2-2. Maximum Short-Term Emissions for New Hope Power Partnership Cogeneration Facility (per boiler)

Regulated Pollutant	Biomass Emission Factor (lb/MMBtu)	Biomass Activity Factor (MMBtu/hr)	Biomass Maximum Emissions (lb/hr)	No. 2 Fuel Oil Emission Factor (lb/MMBtu)	No. 2 Fuel Oil Activity Factor (MMBtu/hr)	No. 2 Fuel Oil Maximum Emissions (lb/hr)	Natural Gas Emission Factor (lb/MMBtu)	Natural Gas Activity Factor (MMBtu/hr)	Natural Gas Maximum Emissions (lb/hr)	Maximum Emissions for any fuel (lb/hr)	Total All Three Boilers (lb/hr)
Particulate (PM)	0.03 (1)	760	22.8	0.03 (1)	490	14.70	0.0073 (2)	605	4.42	22.80	68.40
Particulate (PM_{10})	0.03 (1)	760	22.8	0.03 (1)	490	14.70	0.0073 (2)	605	4.42	22.80	68.40
Sulfur Dioxide--3-hr Average	0.30 (5)	760	228.0	--	--	--	--	--	--	228.0	684.0
--24-hr Average	0.20 (2)	760	152.0	0.05 (6)	490	24.50	0.0058 (2)	605	3.51	152.0	456.0
Carbon Monoxide--1-hr Average (cold-startup)	6.5 (5)	225 [a]	1,462.5	1.0 (2)	490	490.0	0.08 (2)	605	48.4	1,462.5	4,387.5
--1-hr Average (normal operation)	1.0 (5)	760	760.0	--	--	--	--	--	--	760.0	2,280.0
--8-hr Average (cold startup)	4.5 (5)	225 [a]	1,012.5	--	--	--	--	--	--	1,012.5	3,037.5
--8-hr Average (normal operation)	1.0 (5)	760	760.0	--	--	--	--	--	--	760.0	2,280.0
Nitrogen Oxides	0.20 (5)	760	152.00	0.20 (5)	490	98.00	0.20 (5)	605	121	152.00	456.0
VOC	0.06 (2)	760	45.6	0.03 (2)	490	14.70	0.0053 (2)	605	3.21	45.60	136.80
Lead	1.5E-04 (2)	760	0.11	8.9E-07 (2)	490	4.4E-04	4.8E-07 (2)	605	2.9E-04	0.11	0.34
Mercury	5.4E-06 (2)	760	4.10E-03	2.4E-06 (2)	490	1.2E-03	2.5E-07 (2)	605	1.5E-04	4.10E-03	0.0123
Fluorides	7.0E-04 (3)	760	0.53	6.27E-06 (2)	490	3.1E-03	--	--	--	0.53	1.60
Sulfuric Acid Mist	0.018 (4)	760	13.68	0.003 (4)	490	1.4700	3.48E-04 (4)	605	2.11E-01	13.68	41.04

[a] Under cold startup conditions, each boiler is limited to 150,000 lb/hr of steam. Heat input rate is based on this limited steam rate.

References:
1. NSPS, 40 CFR 60, Subpart Da.
2. Based on Permit No. 0990332-014-AC.
3. Based on maximum of 3 most recent stack tests (1999-2001).
4. Based on 6% of the SO_2 emissions (Permit No. 0990332-014-AC).
5. Based on CEM data.
6. Based on use of No. 2 fuel oil with a maximum sulfur content of 0.05% sulfur.



Attachment NH-EU1-J1. Materials Handling System

New Hope Power Partnership - South Bay, Florida

Golder Associates

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

7001 0320 0001 3692 7904

OFFICIAL USE

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

Postmark Here

Sent To Rodney Williams

Street, Apt. No.; or PO Box No. P.O. Box 9

City, State, ZIP+4 South Bay, FL 33493

PS Form 3800, January 2001 See Reverse for Instructions

SENDER: *COMPLETE THIS SECTION*

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

1. Article Addressed to:

Mr. Rodney Williams
Plant Manager
New Hope Power Partnership
P. O. Box 9
South Bay, FL 33493

2. Art 7001 0320 0001 3692 7904

COMPLETE THIS SECTION ON DELIVERY

A. Received by *(Please Print Clearly)* Brenda Spooner B. Date of Delivery 10/9/02

C. Signature X Brenda Spooner ☐ Agent ☐ Addressee

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

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

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

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

7001 0320 0001 3692 7539

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

OFFICIAL USE

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

Postmark Here

Sent To Rodney Williams
Street, Apt. No.; or PO Box No. PO Box 9
City, State, ZIP+4 South Bay, FL 33493

PS Form 3800, January 2001 See Reverse for Instructions

SENDER: *COMPLETE THIS SECTION*

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

1. Article Addressed to:

Mr. Rodney Williams
Plant Manager
New Hope Power Partnership
P. O. Box 9
South Bay, FL 33493

COMPLETE THIS SECTION ON DELIVERY

A. Received by (*Please Print Clearly*) Amanda Kinman B. Date of Delivery 11/25/02

C. Signature X Amanda Kinman ☐ Agent ☐ Addressee

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

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

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

2. 7001 0320 0001 3692 7539

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

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

7001 0320 0001 3692 6785

OFFICIAL USE

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

Postmark Here

Sent To Rodney Williams

Street, Apt. No.; or PO Box No. PO Box 9

City, State, ZIP+4 South Bay, FL 33493

PS Form 3800, January 2001 — See Reverse for Instructions

SENDER: ***COMPLETE THIS SECTION***

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

1. Article Addressed to:

Mr. Rodney Williams
Plant Manager
New Hope Power Partnership
P. O. Box 9
South Bay, FL 33493

COMPLETE THIS SECTION ON DELIVERY

A. Signature
X [signature]
☐ Agent
☐ Addressee

B. Received by *(Printed Name)* Michael Mauriño.

C. Date of Delivery 4/3/03

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

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

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

2. 7001 0320 0001 3692 6785

PS Form 3811, August 2001 — Domestic Return Receipt — 102595-02-M-1540

7001 0320 0001 3692 5498

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

OFFICIAL USE

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

Postmark Here

Sent To Rodney Williams
Street, Apt. No.; or PO Box No. Box 9
City, State, ZIP+4 South Bay, FL 33493

PS Form 3800, January 2001 — See Reverse for Instructions

SENDER: *COMPLETE THIS SECTION*

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

1. Article Addressed to:

Mr. Rodney Williams
Plant Manager
New Hope Power Partnership
P.O. Box 9
South Bay, FL 33493

COMPLETE THIS SECTION ON DELIVERY

A. Received by *(Please Print Clearly)* Raphael Martinez
B. Date of Delivery 8/5/3

C. Signature
X
☒ Agent
☐ Addressee

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

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

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

2. 7001 0320 0001 3692 5498

PS Form 3811, July 1999 Domestic Return Receipt 102595-99-M-1789

U.S. Postal Service
CERTIFIED MAIL RECEIPT
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PS Form 3800, January 2001 — See Reverse for Instructions

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1. Article Addressed to:

Mr. Rodney Williams
Plant Manager
New Hope Power Partnership
Okeelanta Cogeneration Plant
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South Bay, FL 33493

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PS Form 3811, July 1999 — Domestic Return Receipt — 102595-99-M-1789

PSD preconstruction review requires the Department to establish emissions standards that represent the Best Available Control Technology (BACT) for each PSD-significant pollutant. Based on reasonable assurances provided by the applicant and other available information, the Department establishes emissions standards in the draft permit based on the following BACT-level controls: CO and VOC – boiler design and good combustion practices; NOx – selective non-catalytic reduction (SNCR); SO2 and SAM – low sulfur fuels; PM/PM10 – mechanical dust collectors followed by an electrostatic precipitator (ESP); Fl and Pb – authorized fuels containing only trace amounts of fluorides and with and prospective removal in the mechanical dust collectors/ESP.

As part of the PSD required preconstruction review, the Department reviewed the applicant's air quality analysis conducted for each PSD-significant pollutant. The analysis provides the Department with reasonable assurance that the project will not significantly contribute to or cause a violation of any state or federal ambient air quality standards. A refined analysis was required to evaluate the 3-hour and 24-hour SO2 increments in the vicinity of the plant (Class II areas) and in the Everglades National Park (nearest PSD Class I area). The following table shows the maximum predicted for SO2 impacts and PSD increments consumed by all sources in the area, including the project.

PSD CLASS II INCREMENT ANALYSIS – VICINITY OF THE PLANT

Pollutant	Averaging Time	Maximum Predicted Impact (µg/m3)	Impact Greater than Allowable Increment?	Allowable Increment (µg/m3)	Percent of Increment
SO2	24-hr	62	No	91	68%
	3-hr	218	No	512	43%

PSD CLASS I INCREMENT ANALYSIS – EVERGLADES NATIONAL PARK

Pollutant	Averaging Time	Maximum Predicted Impact (µg/m3)	Impact Greater than Allowable Increment?	Allowable Increment (µg/m3)	Percent of Increment
SO2	24-hr	4.0	No	5	80%
	3-hr	12.2	No	25	49%

Based on the analyses, the Department has reasonable assurance that the proposed project will not significantly contribute to or cause a violation of any Class I or Class II PSD increments.

The Department will issue the Final Permit with the proposed conditions unless a response received in accordance with the following procedures results in a different decision or significant change of terms or conditions. The Department will accept written comments and requests for public meetings concerning the proposed permit issuance action for a period of thirty (30) days from the date of publication of this Public Notice of Intent to Issue Permit. Written comments and requests for public meetings should be provided to the Department's Bureau of Air Regulation at 2600 Blair Stone Road, Mail Station #5505, Tallahassee, FL 32399-2400. Any written comments filed shall be made available for public inspection. If written comments received result in a significant change in the proposed agency action, the Department shall revise the proposed permit and require, if applicable, another Public Notice.

The Department will issue the permit with the attached conditions unless a timely petition for an administrative hearing is filed pursuant to Sections 120.569 and 120.57, F.S., before the deadline for filing a petition. The procedures for petitioning for a hearing are set forth below. Mediation is not available in this proceeding.

A person whose substantial interests are affected by the proposed permitting decision may petition for an administrative proceeding (hearing) under Sections 120.569 and 120.57, F.S. The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department at 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida, 32399-3000. Petitions filed by the permit applicant must be filed within fourteen (14) days of receipt of the notice of intent. Petitions filed by any persons other than those entitled to written notice under Section 120.60(3), F.S. must be filed within fourteen (14) days of publication of this Public Notice or within fourteen (14) days of receipt of the notice of intent, whichever occurs first. Under Section 120.60(3), F.S., however, any person who asked the Department for notice of agency action may file a petition within fourteen (14) days of receipt of that notice, regardless of the date of publication. A petitioner shall mail a copy of the petition to the applicant at the address indicated above at the time of filing. The failure of any person to file a petition within the appropriate time period shall constitute a waiver of that person's right to request an administrative determination (hearing) under Sections 120.569 and 120.57, F.S., or to intervene in this proceeding and participate as a party to it. Any subsequent intervention will be only at the approval of the presiding officer upon the filing of a motion in compliance with Rule 28-106.205, F.A.C.

A petition that disputes the material facts on which the Department's action is based must contain the following information: (a) The name and address of each agency affected and each agency's file or identification number, if known; (b) The name, address, and telephone number of the petitioner, the name, address, and telephone number of the petitioner's representative, if any, which shall be the address for service purposes during the course of the proceeding; and an explanation of how the petitioner's substantial interests will be affected by the agency determination; (c) A statement of how and when petitioner received notice of the agency action or proposed action; (d) A statement of all disputed issues of material fact. If there are none, the petition must so indicate; (e) A concise statement of the ultimate facts alleged, including the specific facts the petitioner contends warrant reversal or modification of the agency's proposed action; (f) A statement of the specific rules or statutes the petitioner contends require reversal or modification of the agency's proposed action; and (g) A statement of the relief sought by the petitioner, stating precisely the action petitioner wishes the agency to take with respect to the agency's proposed action.

A petition that does not dispute the material facts upon which the Department's action is based shall state that no such facts are in dispute and otherwise shall contain the same information as set forth above, as required by Rule 28-106.301, F.A.C.

Because the administrative hearing process is designed to formulate final agency action, the filing of a petition means that the Department's final action may be different from the position taken by it in this notice. Persons whose substantial interests will be affected by any such final decision of the Department on the application have the right to petition to become a party to the proceeding, in accordance with the requirements set forth above.

A complete project file is available for public inspection during normal business hours, 8:00 a.m. to 5:00 p.m., Monday through Friday, except legal holidays, at:

Dept. of Environmental Protection
Bureau of Air Regulation
New Source Review Section
Suite 4,
111 S. Magnolia Drive
Tallahassee, Florida 32301
Telephone: 850/488-0114

Dept. of Environmental Protection
South District Office
Air Resources Section
2295 Victoria Avenue,
Suite 364
Fort Myers, Florida
33901-3381
Telephone: 941/332-6975

Palm Beach County Health Dept.
Environmental Health and Engineering
Air Pollution Control Section
901 Evernia Street
West Palm Beach, Florida
33401
Telephone: 561/355-3136

The complete project file includes the application, Technical Evaluation and Preliminary Determination, Draft Permit, and the information submitted by the responsible official, exclusive of confidential records under Section 403.111, F.S. Interested persons may contact the Department's project engineer for additional information at the address and phone numbers listed above.

PUB: The Palm Beach Post
September 24, 2003

7000 2870 0000 7028 3321

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PS Form 3800, May 2000 — See Reverse for Instructions

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PS Form 3800, May 2000 — See Reverse for Instructions

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1. Article Addressed to:

Mr. Rodney Williams
Plant Manager
New Hope Power Partnership
Post Office Box 9
South Bay, FL 33493

COMPLETE THIS SECTION ON DELIVERY

A. Received by (Please Print Clearly) Kathy Yarkes
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PS Form 3811, July 1999 — Domestic Return Receipt — 102595-99-M-1789

THE PALM BEACH POST

Published Daily and Sunday
West Palm Beach, Palm Beach County, Florida

PROOF OF PUBLICATION

STATE OF FLORIDA
COUNTY OF PALM BEACH

Before the undersigned authority personally appeared **Tracey Diglio**, who on oath says that she is **Telephone Sales Supervisor** of The Palm Beach Post, a daily and Sunday newspaper published at West Palm Beach in Palm Beach County, Florida; that the attached copy of advertising, being **Notice** in the matter of **DEP #PSD-FL-196(O)** was published in said newspaper in the issues of **September 24, 2003**. Affiant further says that the said The Post is a newspaper published at West Palm Beach, in said Palm Beach County, Florida, and that the said newspaper has heretofore been continuously published in said Palm Beach County, Florida, daily and Sunday and has been entered as second class mail matter at the post office in West Palm Beach, in said Palm Beach County, Florida, for a period of one year next preceding the first publication of the attached copy of advertisement; and affiant further says that she/her has neither paid nor promised any person, firm or corporation any discount rebate, commission or refund for the purpose of securing this advertisement for publication in the said newspaper.

Tracey Diglio

Sworn to and subscribed before this 24th day of September, A.D. 2003

KM McLinton

Personally known XX or Produced Identification________________________
Type of Identification Produced__________________________________

NOTARY PUBLIC STATE OF FLORIDA
KAREN M McLINTON
MY COMMISSION # CC 979669
EXPIRES: Nov 15, 2004
1-800-3-NOTARY FL Notary Service & Bonding, Inc.

NO. 7608915
PUBLIC NOTICE OF INTENT TO ISSUE PERMIT MODIFICATION OF PSD AIR CONSTRUCTION PERMIT
STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
Project No. 0990332-016-AC
Draft Permit No. PSD-FL-196(O)
New Hope Power Partnership – Okeelanta Cogeneration Plant

The Department of Environmental Protection (Department) gives notice of its intent to issue an air construction permit modification to the applicant, New Hope Power Partnership. The applicant operates an existing cogeneration plant that is located approximately six miles south of South Bay on U.S. Highway 27 in Palm Beach County, Florida. The Okeelanta Cogeneration Plant's authorized representative is Mr. Rodney Williams, Plant Manager, and the mailing address is 8001 U.S. Highway 27 South, South Bay, FL 33493.

The applicant, applied to the Department for a permit to authorize increases in the hourly and annual heat input rates for the existing boilers at the Okeelanta Cogeneration Plant. The maximum hourly heat input rate will increase from 715 to 760 MMBtu per hour by taking the last feedwater heater on each unit out of service to reduce the feedwater temperature. The increase in the hourly heat input rate is within the manufacturer's maximum continuous steam rating for these units. The cogeneration plant's maximum potential annual heat input will increase from 11,500,000 to 19,970,000 MMBtu per year, which will relax a permit limit originally taken to avoid new source preconstruction review for several pollutants. The applicant requests the flexibility to operate the cogeneration units without synthetic operational restrictions.

The applicant has notified the Department of possible future plans to add a new steam turbine-electrical generator, which would increase the electrical generating capacity of the plant from 74.9 MW to approximately 140 MW. Such a future request would require application and review in accordance the Florida Electrical Power Plant Siting Act in Sections 403.501-403.518 of the Florida Statutes. Approval of such a request would require a revision of the PSD air permit.

The existing cogeneration plant is located in Palm Beach County, which is an area that is currently in attainment with (or designated as unclassifiable for) all pollutants subject to federal and state Ambient Air Quality Standards. The plant is a major facility with respect to the Prevention of Significant Deterioration (PSD) of Air Quality as defined in Rule 62-212.400, F.A.C. Based on the application, the project will result in the following potential increases in emissions in terms of "tons per year" (TPY): 2160 TPY of carbon monoxide (CO); 5 TPY of fluorides (Fl); 1.4 TPY of lead (Pb); 98 pounds per year of mercury (Hg); 741 TPY of nitrogen oxides (NOx); 181 TPY of particulate matter (PM/PM10); 20 TPY of sulfuric acid mist (SAM); 407 TPY of sulfur dioxide (SO2); and 555 TPY of volatile organic compounds (VOC). Emissions of CO, Fl, Pb, NOx, PM/ PM10, SAM, SO2, and VOC exceed the PSD significant emission rates defined in Table 62-212.400-2, F.A.C. Therefore, the project is subject to PSD preconstruction review for these pollutants.

Golder Associates Inc.

6241 NW 23rd Street, Suite 500
Gainesville, FL 32653-1500
Telephone (352) 336-5600
Fax (352) 336-6603

Golder Associates

September 3, 2003

0337520

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SEP 04 2003

BUREAU OF AIR REGULATION

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

Attention: Mr. A. A. Linero, Administrator, New Source Review

RE: NEW HOPE POWER PARTNERSHIP, OKEELANTA COGENERATION PLANT
INCREASED HEAT INPUT RATES
PROJECT NO. 0990332-016-AC; PSD-FL-196(O)

Dear Mr. Linero:

Thank you and Jeff Koerner for meeting with representatives of New Hope Power Partnership (NHPP) on August 19 regarding the draft air construction permit ('Draft Permit") and Public Notice of Intent To Issue Air Permit for the above referenced project, dated July 31, 2003. Based on our discussions, and your requests, the following information is being provided concerning NHPP's plan to add electrical generating capacity at NHPP's Okeelanta cogeneration facility ("Facility").

In simple terms, the expansion in generating capacity will be accomplished by operating the existing boilers at a higher capacity factor and by adding a second steam turbine generator (STG) to the Facility. The net electrical generating capacity will increase from 74.9 MW to approximately 140 MW. In terms of equipment sourcing, the most likely scenario is that NHPP will transfer the STG located at Osceola to the Facility. However, pending the results of a detailed condition assessment and other considerations, NHPP may decide to procure a new STG of comparable design and rating. Along with the STG, NHPP will add a cooling tower, a step up transformer, and auxiliary equipment necessary to operate and protect the STG.

NHPP recognizes it must obtain Power Plant Siting Act (PPSA) approval before NHPP generates more than 74.9 MW net, and thus NHPP intends to file a Site Certification Application (SCA) under the PPSA within the next few months.

Based on our analysis of NHPP's proposed expansion plans, we believe that NHPP's application to increase the Facility's annual heat input would not need to be revised, except as described below. We also believe that the Draft Permit [PSD-FL-196(O)] DEP has recently issued for the annual heat input increase would not need to be revised, except to delete the limitation on the Facility's electrical generating capacity.

- The Facility's three boilers are expected to operate at a higher actual annual capacity factor with the addition of the second STG. The new expected annual capacity factor for the three boilers is approximately 70% to 75% (based on the new maximum heat input rate of 760 MMBtu/hr), whereas in the past the boilers have operated at an average annual capacity factor of approximately 60% (based on the former maximum heat input of 715 MMBtu/hr). The air permit application and projected emissions were based on a 100% capacity factor, except as described below in regards to the best available control technology (BACT) analysis.

- The additional fuel used to support the additional production will come from the same suppliers currently used by NHPP. Also recall that at one time both the Okeelanta and Osceola cogeneration plants were operating, and both had an adequate fuel supply.

- It is expected that the higher production will increase the fuel burning rate by approximately 15-20% from historical levels. It is further expected that all of the incremental fuel will be biomass, most likely wood, although the supply of bagasse may also increase. As in the past, fossil fuel will be burned only during startup, shutdown, to supplement biomass combustion, and as needed to promote good combustion.

- None of the short-term or annual emissions rates presented in the pending application for the Draft Permit would change. The maximum heat input capacity for each boiler would remain at 760 MMBtu/hr. Annual emissions were based on operation at this heat input rate for 8,760 hr/yr. Fugitive emissions from biomass and ash handling would not change, as these are dependent upon the heat input rates. In the pending application, the total tonnage of biomass processed through the biomass handling system was assumed to be 50% greater than the biomass consumed if the Facility operated at a 100% capacity factor. This conservative assumption was used to account for potential year-to-year variability in the amounts of biomass delivered and stockpiled at the Facility.

- Since the addition of a second STG will not cause any changes in the maximum emissions from the Facility, as presented in the pending permit application, the modeling analysis in the application also will be unaffected by the addition of the STG. It is noted that the new cooling tower will likely cause some additional particulate matter emissions in the form of cooling tower drift. Historically, such emissions have not been considered in non-utility PSD permitting. However, it is understood that these emissions will be addressed in the PPSA process.

- In the BACT analysis presented in the application, the cost effectiveness calculations were based on a projected future capacity factor for the boilers of 90%. As explained above, the projected capacity factor with the second STG is approximately 70% to 75%.

- The NHPP boilers are currently subject to the NSPS in 40 CFR 60, Subpart Da. The proposed change in the Facility's electrical generating capacity does not physically affect the boilers, and thus no "modification" or "reconstruction" will occur. Therefore, no new Subpart Da requirements will be triggered by the project. Although the facility will remain a cogeneration unit under FERC, Subpart Da does not define or otherwise address cogeneration units.

- NHPP's proposed project does not conflict with any of the conditions contained in the Draft Permit, except Condition 1 in Section III, which we have already commented on. To resolve this conflict, we suggest rewording this condition as follows:

    1. <u>Generating Capacity</u>: Construction of the proposed cogeneration plant shall reasonably conform to the plans described in the application. The owner or operator shall comply with all of the applicable requirements in the Florida Electrical Power Plant Siting Act, Sections 403.501-.518, F.S., and the rules contained in Chapter 62-17, F. A. C. The hourly average net electrical generation rate shall be recorded and retained for at least 5 years.

Thank you for consideration of this information. 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 these comments.

Sincerely,

GOLDER ASSOCIATES INC.

David A. Buff

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

DB/

cc: R. Blackburn, DEP
J. Meriwether, NHPP
W. Tarr, Florida Crystals
G. Cepero, Florida Crystals
D. Dee, Landers & Parsons
J. Kahner
C. Holladay,
B. Owen, DEP
G. Worley, EPA
J. Bunyak, NPS
J. Stormer, PBCo. HD

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Golder Associates Inc.
6241 NW 23rd Street, Suite 500
Gainesville, FL 32653-1500
Telephone (352) 336-5600
Fax (352) 336-6603

Golder Associates

August 19, 2003

0337520

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AUG 19 2003

BUREAU OF AIR REGULATION

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

Attention: Mr. A. A. Linero, Administrator, New Source Review

RE: NEW HOPE POWER PARTNERSHIP, OKEELANTA COGENERATION PLANT
INCREASED HEAT INPUT RATES
PROJECT NO. 0990332-016-AC (PSD-FL-196O)

Dear Mr. Linero:

New Hope Power Partnership (NHPP) has received the draft air construction permit and Public Notice of Intent To Issue Air Permit for the above referenced project, dated July 31, 2003. NHPP and its representatives have reviewed the draft permit, and have the following comments.

Draft Permit

Pg. 1 of 13, Project and Location: It is requested that the reference to megawatt electrical generation be deleted from the PSD permit. The megawatt generation has no relationship to air emissions. This permit will allow the boilers to operate continuously year-around at full load. Therefore, there is no reason to limit the amount of electrical generation by the facility. In fact, increased generation with the same permitted air emissions would only further benefit the environment. If NHPP decides to increase its power generation beyond 74.9 MW net, it will address this change through the power plant certification process.

Pg. 2 of 13, Facility Description: Reword the beginning sentence to read "For PSD purposes, the facility consists of two adjacent plants."

Pg. 2 of 13, Regulatory Classification: Under Title III, retain the wording from the previous PSD permit (PSD-FL-196M), and the current Title V permit (0990005-003-AV), i.e., "Based on the Title V operation permit, the facility may have emissions of hazardous air pollutants (HAPs) at levels greater than the major source thresholds."

Under NSPS, delete the reference to Subpart Db being applicable. Subpart Db is applicable to Okeelanta's Boiler No. 16, which is not a part of the NHPP facility.

Pg. 4 of 13, Administrative Requirements, Item #8.: It is requested that up to 180 days be allowed to submit a Title V application.

Pg. 5 of 13, Item #1, Generating Capacity: As requested above, please delete the last three sentences in this paragraph, which deal with megawatt power generation.

Pg. 5 of 13, Item #2, Boiler Design: Reword second sentence as "Natural gas and distillate oil are fired at startup **and shutdown, when necessary to ensure good combustion,** to supplement biomass fuel, and for periods when the biomass fuel supply is interrupted.

Pg. 5 of 13, Item #5, Control Equipment: In the first bullet item, second sentence, reword as "Four burners are installed with one in each corner **of** the boiler."

Pg. 7 of 13, Item #10, Permitted Capacity: The permit does not address the allowable operating hours of the boilers. Therefore, add a sentence to this condition as follows: "The operating hours of the cogeneration boilers are not restricted."

Pg. 8 of 13, Item #16, Emissions Standards:

Particulate Matter- The Department has set a lower PM limit of 0.026 lb/MMBtu based on the proposed MACT standards for industrial boilers. However, based on actual operation of the NHPP boilers, this limit is too stringent. Presented in Table 1 is a summary of PM/PM10 compliance test data for the boilers since the mechanical dust collectors were installed (note: these data were also presented in the permit application). These data show individual boilers have tested as high as 0.025 lb/MMBtu, with a total of six compliance tests with PM emissions of 0.021 lb/MMBtu or higher. Setting a new PM limit of 0.026 lb/MMBtu would provide little if any margin for compliance in the future. Given the variability in wood and bagasse fuel quality, variability in boiler operation, and variability in ESP operation and performance over time, NHPP strongly urges that Department retain the 0.030 lb/MMBtu limit for PM/PM10.

Volatile Organic Compounds- The Department has set a lower VOC limit of 0.05 lb/MMBtu based on the actual tested emission rates for the NHPP boilers. Based on actual operation of the NHPP boilers, this limit is too stringent. The Department was possibly not made aware of the most recent VOC compliance tests. Presented in Table 1 is a summary of VOC compliance test data for the boilers firing the normal combination of wood and bagasse, including the tests conducted in 2003. The 2003 data show that an individual boiler tested as high as 0.058 lb/MMBtu for VOC. Although this may not be typical of VOC emissions, it is reflective of the variability that can occur in wood and bagasse fuel quality and variability in boiler operation. Further investigation of operation during this test showed that CO emissions averaged approximately 0.45 lb/MMBtu. CO emissions for the entire day averaged 0.33 lb/MMBtu. These CO levels were in compliance with the 30-day rolling average limit of 0.5 lb/MMBtu. It is therefore requested that the 0.06 lb/MMBtu limit for VOC be retained. Setting a new VOC limit of 0.05 lb/MMBtu would provide no margin for compliance in the future.

Pg. 9 of 13, Item #16, Emissions Standards, Footnote "a": The Department has added a requirement to record and report the CO emissions from each boiler in terms of ppmvd corrected to 3% O_2. As the CEMS software is not setup to do this currently, a significant cost would result to upgrade the software. In addition, it is premature at this time to report additional CO data since the final form of the MACT standards may change significantly from the proposed form. It is therefore requested that this new requirement be deleted.

Pg. 9 of 13, Item #16, Emissions Standards, Footnote "f": Clarify that the VOC emissions should be "reported as carbon".

Pg. 13 of 13, Item #19, Stack Test Requirements, Item "e": For Method 25A, clarify that VOC should be reported as carbon.

Pg. 13 of 13, Item #21, Quarterly Reports: Delete the sentence "The fuel usage summary shall include the monthly heat input and the 12-month rolling total heat input for the cogeneration boilers." The annual heat input limitation on the facility has been deleted.

<u>**Technical Evaluation and Preliminary Determination**</u>

Pg. 2 of 24, Regulatory Categories: Retain the wording from the previous PSD permit (PSD-FL-196M), and the current Title V permit (0990005-003-AV), i.e., "Based on the Title V operation permit, the facility may have emissions of hazardous air pollutants (HAPs) at levels greater than the major source thresholds."

Pg. 10 of 24: First bullet item related to Osceola cogen: this facility is no longer being re-permitted.

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 these comments.

Sincerely,

GOLDER ASSOCIATES INC.

David A. Buff

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

DB/jej

cc: R. Blackburn, DEP
J. Meriwether, NHPP
W. Tarr, Florida Crystals
G. Cepero, Florida Crystals
D. Dee, Landers & Parsons
G. Kaerner

Y:\Projects\2003\0337520 NHPP\4\4.1\081803\L081803.doc

C. Holladay
G. Stormer, PBCo,
B. Worley, EPA
G. Bunyak, WPS

Table 1. Summary of PM and VOC Test Data, NHPP Cogeneration Facility

Test Date	Boiler	Fuel	Particulate (TSP) (lb/MMBtu)	Particulate (PM10) (lb/MMBtu)	VOC (lb/MMBtu)
Jan 3-23, 2001	A	100% wood	0.022	0.025	--
	B	100% wood	0.013	0.014	--
	C	100% wood	0.022	0.023	--
	A	100% bagasse	0.016	0.015	--
	B	100% bagasse	0.021	0.023	--
	C	100% bagasse	0.010	0.013	--
Feb 12-14, 2002	A	50% wood/50% bagasse	0.008	0.008	0.007
	B	50% wood/50% bagasse	0.010	0.01	0.036
	C	50% wood/50% bagasse	0.011	0.011	0.020
Jan. 21-23, 2003	A	50% wood/50% bagasse	0.0089	--	0.0027
	B	50% wood/50% bagasse	0.0079	--	0.0057
	C	50% wood/50% bagasse	0.0081	--	0.058

Florida Department of

Memorandum Environmental Protection

TO: Trina Vielhauer, Chief
Bureau of Air Regulation

THROUGH: Al Linero, Manager
New Source Review Section

FROM: Jeff Koerner, New Source Review Section

DATE: July 25, 2003

SUBJECT: Project No. 0990332-016-AC
Draft Air Permit No. PSD-FL-196(O)
New Hope Power Partnership, Okeelanta Cogeneration Plant
Increased Heat Input Rates

The applicant requests increases in the hourly and annual heat input rates for the three existing boilers at the Okeelanta Cogeneration Plant. The maximum hourly heat input rate will increase from 715 to 760 MMBtu per hour by taking the last feedwater heater on each unit out of service to reduce the feedwater temperature. The increase in the hourly heat input rate will not result in increased electrical generating capacity and is within the manufacturer's maximum continuous steam rating for these units. The maximum annual heat input will increase from 11.50 x 10^{+06} to 19.97 x 10^{+06} MMBtu per year, which will relax a permit limit originally taken to avoid new source preconstruction review for several pollutants. The cogeneration boilers have shown increasing reliability and have approached the annual heat input limit. The applicant requests the flexibility to operate the cogeneration units without a synthetic restriction (8760 hours per year). The project is subject to PSD preconstruction review and requires BACT determinations for CO, Fl, Pb, NOx, PM/PM_{10}, SAM, SO_2, and VOC emissions.

Attached for your review are the following items:

- Intent to Issue Permit and Public Notice Package;
- Technical Evaluation and Preliminary Determination;
- Draft Permit; and
- P.E. Certification

The P.E. certification briefly summarizes the proposed project. The Technical Evaluation and Preliminary Determination provide a detailed description of the project, rationale, and conclusion. Day #74 is August 2, 2003. I recommend your approval of the attached Draft Permit for this project.

Attachments

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

OFFICIAL USE

7001 0320 0001 3692 5498

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

Postmark Here

Sent To
Rodney Williams
Street, Apt. No.; or PO Box No. P.O. Box 9
City, State, ZIP+4 South Bay, FL 33493

PS Form 3800, January 2001 See Reverse for Instructions

SENDER: *COMPLETE THIS SECTION*

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

1. Article Addressed to:

Mr. Rodney Williams
Plant Manager
New Hope Power Partnership
P.O. Box 9
South Bay, FL 33493

COMPLETE THIS SECTION ON DELIVERY

A. Received by *(Please Print Clearly)* Raphael Hammer
B. Date of Delivery 8/5/3

C. Signature
X
☒ Agent
☐ Addressee

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

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

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

2. 7001 0320 0001 3692 5498

PS Form 3811, July 1999 Domestic Return Receipt 102595-99-M-1789

P.E. CERTIFICATION STATEMENT

PERMITTEE

New Hope Power Partnership
Okeelanta Cogeneration Plant
8001 U.S. Highway 27 South
South Bay, FL 33493

Project No. 0990332-016-AC
Draft Air Permit No. PSD-FL-196(O)
Okeelanta Cogeneration Plant
Increased Heat Input Rates

PROJECT DESCRIPTION

The applicant, applied to the Department for a permit to authorize increases in the hourly and annual heat input rates for the existing boilers at the Okeelanta Cogeneration Plant. The maximum hourly heat input rate will increase from 715 to 760 MMBtu per hour by taking the last feedwater heater on each unit out of service to reduce the feedwater temperature. The increase in the hourly heat input rate will not result in increased electrical generating capacity and is within the manufacturer's maximum continuous steam rating for these units. The maximum annual heat input will increase from $11.50 \times 10^{+06}$ to $19.97 \times 10^{+06}$ MMBtu per year, which will relax a permit limit originally taken to avoid new source preconstruction review for several pollutants. The cogeneration boilers have shown increasing reliability and have approached the annual heat input limit. The applicant requests the flexibility to operate the cogeneration units without a synthetic restriction (8760 hours per year).

The existing cogeneration plant is located in Palm Beach County, which is an area that is currently in attainment with (or designated as unclassifiable for) all pollutants subject to federal and state Ambient Air Quality Standards. The plant is a major facility with respect to the Prevention of Significant Deterioration (PSD) of Air Quality as defined in Rule 62-212.400, F.A.C. Based on the application, the project will result in the following potential increases in emissions in terms of "tons per year" (TPY): 2160 TPY of carbon monoxide (CO); 5 TPY of fluorides (Fl); 1.4 TPY of lead (Pb); 98 pounds per year of mercury (Hg); 741 TPY of nitrogen oxides (NOx); 181 TPY of particulate matter (PM/PM_{10}); 20 TPY of sulfuric acid mist (SAM); 407 TPY of sulfur dioxide (SO_2); and 555 TPY of volatile organic compounds (VOC). CO, Fl, Pb, NOx, PM/PM_{10}, SAM, SO_2, and VOC emissions exceed the PSD significant emission rates defined in Table 62-212.400-2, F.A.C. Therefore, the project is subject to PSD preconstruction review for these pollutants and the Department is required to establish corresponding emissions standards that represent the Best Available Control Technology (BACT). Based on reasonable assurances provided by the applicant and other available information, the emissions standards in the draft permit are based on the following BACT-level controls: CO and VOC – boiler design and good combustion practices; NOx – selective non-catalytic reduction (SNCR); SO_2 and SAM – low sulfur fuels; PM/PM_{10} – mechanical dust collectors followed by an electrostatic precipitator (ESP); Fl and Pb – authorized fuels containing only trace amounts of fluorides with prospective removal in the mechanical dust collectors/ESP.

In summary, the BACT determinations for CO, Fl, NOx, SAM, and SO_2 emissions in the current PSD permit were reaffirmed. The BACT determination for VOC was reduced from 0.06 to 0.05 lb/MMBtu based on previous stack test data and to maintain a VOC net increase less than the de minimis compared to the original baseline emissions. The emission standard for particulate matter was reduced from 0.03 to 0.026 lb/MMBtu due to the addition of the mechanical dust collectors and corresponding emissions test data. It also serves as a surrogate standard for lead emissions. The lead emissions standard was removed based on data from 21 stack tests showing very low emission rates and the firing of fuels that contain very low levels of lead. This standard is consistent with the proposed MACT standard for solid fuel-fired industrial boilers.

***I HEREBY CERTIFY** that the air pollution control engineering features described in the above referenced application and subject to the proposed permit conditions provide reasonable assurance of compliance with applicable provisions of Chapter 403, Florida Statutes, and Florida Administrative Code Chapters 62-4 and 62-204 through 62-297. However, I have not evaluated and I do not certify aspects of the proposal outside of my area of expertise (including, but not limited to, the electrical, mechanical, structural, hydrological, geological, and meteorological features).*

Jeffery F. Koerner 7-31-03

Jeffery F. Koerner, P.E. (Date)
Registration Number: 49441

FLORIDA DEPARTMENT OF ENVIRONMENTAL PROTECTION

Department of Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

July 31, 2003

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. Rodney Williams, Plant Manager
New Hope Power Partnership
Okeelanta Cogeneration Plant
8001 U.S. Highway 27 South
South Bay, FL 33493

Re: Project No. 0990332-016-AC
Draft Air Permit No. PSD-FL-196(O)
New Hope Power Partnership, Okeelanta Cogeneration Plant
Increased Heat Input Rates

Dear Mr. Williams:

One copy of the draft permit authorizing the requested increase in hourly and annual heat input rates for the boilers at the Okeelanta Cogeneration Plant is enclosed. The existing plant is located off U.S. Highway 27 approximately six miles south of South Bay in Palm Beach County, Florida. The Department's "Technical Evaluation and Preliminary Determination", "Intent to Issue Permit", and the "Public Notice of Intent to Issue Permit" are also included.

The "Public Notice of Intent to Issue Permit" must be published one time only, as soon as possible, in the legal advertisement section of a newspaper of general circulation in the area affected, pursuant to the requirements Chapter 50, Florida Statutes. Proof of publication, i.e., newspaper affidavit, must be provided to the Department's Bureau of Air Regulation office within seven days of publication. Failure to publish the notice and provide proof of publication may result in the denial of the permit.

Please submit any written comments you wish to have considered concerning the Department's proposed action to A. A. Linero, Administrator of the New Source Review Section, at the above letterhead address. If you have any other questions, please contact Jeff Koerner at 850/921-9536.

Sincerely,

Trina L Vielhauer

Trina Vielhauer, Chief
Bureau of Air Regulation

Enclosures

In the Matter of an
Application for Air Permit by:

New Hope Power Partnership
Okeelanta Cogeneration Plant
8001 U.S. Highway 27 South
South Bay, FL 33493

Authorized Representative:
Mr. Rodney Williams, Plant Manager

Project No. 0990332-016-AC
Draft Air Permit No. PSD-FL-196(O)
Okeelanta Cogeneration Plant
Increased Heat Input Rates
Palm Beach County, Florida

INTENT TO ISSUE AIR CONSTRUCTION PERMIT

The Department of Environmental Protection (Department) gives notice of its intent to issue an air construction permit (copy of Draft Permit attached) for the proposed project as detailed in the application and the enclosed Technical Evaluation and Preliminary Determination, for the reasons stated below. The applicant, New Hope Power Partnership, applied on September 6, 2002 to the Department for a permit authorizing increases in hourly and annual heat input rates for the existing boilers at the Okeelanta Cogeneration Plant. The existing plant is located off U.S. Highway 27 approximately six miles south of South Bay in Palm Beach County, Florida.

The Department has permitting jurisdiction under the provisions of Chapter 403 of the Florida Statutes (F.S.), and Chapters 62-4, 62-210, and 62-212 of the Florida Administrative Code (F.A.C.). The above actions are not exempt from permitting procedures. The Department has determined that an air construction permit modification is required to perform proposed work. The Department intends to issue this air construction permit modification based on the belief that the applicant has provided reasonable assurances to indicate that operation of these emission units will not adversely impact air quality, and the emission units will comply with all appropriate provisions of Chapters 62-4, 62-204, 62-210, 62-212, 62-296, and 62-297, F.A.C.

Pursuant to Section 403.815, F.S., and Rule 62-110.106(7)(a)1, F.A.C., you (the applicant) are required to publish at your own expense the enclosed Public Notice of intent to issue an air construction permit modification. The notice shall be published one time only in the legal advertisement section of a newspaper of general circulation in the area affected. Rule 62-110.106(7)(b), F.A.C., requires that the applicant cause the notice to be published as soon as possible after notification by the Department of its intended action. For the purpose of these rules, "publication in a newspaper of general circulation in the area affected" means publication in a newspaper meeting the requirements of Sections 50.011 and 50.031, F.S., in the county where the activity is to take place. If you are uncertain that a newspaper meets these requirements, please contact the Department at the address or telephone number listed below. The applicant shall provide proof of publication to the Department's Bureau of Air Regulation, at 2600 Blair Stone Road, Mail Station #5505, Tallahassee, Florida 32399-2400 (Telephone: 850/488-0114 / Fax 850/ 922-6979). You must provide proof of publication within seven days of publication, pursuant to Rule 62-110.106(5), F.A.C. No permitting action for which published notice is required shall be granted until proof of publication of notice is made by furnishing a uniform affidavit in substantially the form prescribed in Section 50.051, F.S. to the office of the Department issuing the permit. Failure to publish the notice and provide proof of publication may result in the denial of the permit pursuant to Rules 62-110.106(9) and (11), F.A.C.

The Department will issue the final permit with the attached conditions unless a response received in accordance with the following procedures results in a different decision or significant change of terms or conditions.

The Department will accept written comments and requests for public meetings concerning the proposed permit issuance action for a period of thirty (30) days from the date of publication of the Public Notice. Written comments and requests for public meetings should be provided to the Department's Bureau of Air Regulation at 2600 Blair Stone Road, Mail Station #5505, Tallahassee, FL 32399-2400. Any written comments filed shall be made available for public inspection. If written comments received result in a significant change in the proposed agency action, the Department shall revise the proposed permit and require, if applicable, another Public Notice.

The Department will issue the permit with the attached conditions unless a timely petition for an administrative hearing is filed pursuant to Sections 120.569 and 120.57 F.S., before the deadline for filing a petition. The procedures for petitioning for a hearing are set forth below.

A person whose substantial interests are affected by the proposed permitting decision may petition for an administrative proceeding (hearing) under Sections 120.569 and 120.57, F.S. The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department at 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida, 32399-3000. Petitions filed by the permit applicant or any of the parties listed below must be filed within fourteen (14) days of receipt of this notice of intent. Petitions filed by any persons other than those entitled to written notice under Section 120.60(3), F.S. must be filed within fourteen (14) days of publication of the Public

Notice or within fourteen (14) days of receipt of this notice of intent, whichever occurs first. Under Section 120.60(3), F.S. however, any person who asked the Department for notice of agency action may file a petition within fourteen (14) days of receipt of that notice, regardless of the date of publication. A petitioner shall mail a copy of the petition to the applicant at the address indicated above at the time of filing. The failure of any person to file a petition within the appropriate time period shall constitute a waiver of that person's right to request an administrative determination (hearing) under Sections 120.569 and 120.57, F.S., or to intervene in this proceeding and participate as a party to it. Any subsequent intervention will be only at the approval of the presiding officer upon the filing of a motion in compliance with Rule 28-106.205, F.A.C.

A petition that disputes the material facts on which the Department's action is based must contain the following information: (a) The name and address of each agency affected and each agency's file or identification number, if known; (b) The name, address, and telephone number of the petitioner, the name, address, and telephone number of the petitioner's representative, if any, which shall be the address for service purposes during the course of the proceeding; and an explanation of how the petitioner's substantial interests will be affected by the agency determination; (c) A statement of how and when petitioner received notice of the agency action or proposed action; (d) A statement of all disputed issues of material fact. If there are none, the petition must so indicate; (e) A concise statement of the ultimate facts alleged, including the specific facts the petitioner contends warrant reversal or modification of the agency's proposed action; (f) A statement of the specific rules or statutes the petitioner contends require reversal or modification of the agency's proposed action; and (g) A statement of the relief sought by the petitioner, stating precisely the action petitioner wishes the agency to take with respect to the agency's proposed action.

A petition that does not dispute the material facts upon which the Department's action is based shall state that no such facts are in dispute and otherwise shall contain the same information as set forth above, as required by Rule 28-106.301, F.A.C.

Because the administrative hearing process is designed to formulate final agency action, the filing of a petition means that the Department's final action may be different from the position taken by it in this notice. Persons whose substantial interests will be affected by any such final decision of the Department on the application have the right to petition to become a party to the proceeding, in accordance with the requirements set forth above.

In addition to the above, a person subject to regulation has a right to apply for a variance from or waiver of the requirements of particular rules, on certain conditions, under Section 120.542, F.S. The relief provided by this state statute applies only to state rules, not statutes, and not to any federal regulatory requirements. Mediation is not available in this proceeding. Applying for a variance or waiver does not substitute or extend the time for filing a petition for an administrative hearing or exercising any other right that a person may have in relation to the action proposed in this notice of intent.

The application for a variance or waiver is made by filing a petition with the Office of General Counsel of the Department, 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida 32399-3000. The petition must specify the following information: (a) The name, address, and telephone number of the petitioner; (b) The name, address, and telephone number of the attorney or qualified representative of the petitioner, if any; (c) Each rule or portion of a rule from which a variance or waiver is requested; (d) The citation to the statute underlying (implemented by) the rule identified in (c) above; (e) The type of action requested; (f) The specific facts that would justify a variance or waiver for the petitioner; (g) The reason why the variance or waiver would serve the purposes of the underlying statute (implemented by the rule); and (h) A statement whether the variance or waiver is permanent or temporary and, if temporary, a statement of the dates showing the duration of the variance or waiver requested.

The Department will grant a variance or waiver when the petition demonstrates both that the application of the rule would create a substantial hardship or violate principles of fairness, as each of those terms is defined in Section 120.542(2), F.S., and that the purpose of the underlying statute will be or has been achieved by other means by the petitioner.

Persons subject to regulation pursuant to any federally delegated or approved air program should be aware that Florida is specifically not authorized to issue variances or waivers from any requirements of any such federally delegated or approved program. The requirements of the program remain fully enforceable by the Administrator of the EPA and by any person under the Clean Air Act unless and until the Administrator separately approves any variance or waiver in accordance with the procedures of the federal program.

Executed in Tallahassee, Florida.

Trina L Vielhauer

Trina Vielhauer, Chief
Bureau of Air Regulation

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this Intent to Issue Permit package (including the Public Notice, Technical Evaluation and Preliminary Determination, and the Draft Permit) was sent by certified mail (*) and copies were mailed by U.S. Mail before the close of business on 7/31/03 to the persons listed:

Mr. Rodney Williams, Plant Manager*
Mr. James Meriwether, Okeelanta Cogeneration Plant
Mr. David Buff, Golder Associates Inc.
Mr. James Stormer, PBCHD
Mr. Ron Blackburn, SD
Mr. Gregg Worley, EPA Region 4
Mr. John Bunyak, NPS

Clerk Stamp

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

Victoria Gibson July 31, 2003
(Clerk) (Date)

PUBLIC NOTICE OF INTENT TO ISSUE PERMIT
MODIFICATION OF PSD AIR CONSTRUCTION PERMIT

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

Project No. 0990332-016-AC
Draft Permit No. PSD-FL-196(O)

New Hope Power Partnership – Okeelanta Cogeneration Plant

The Department of Environmental Protection (Department) gives notice of its intent to issue an air construction permit modification to the applicant, New Hope Power Partnership. The applicant operates an existing cogeneration plant that is located approximately six miles south of South Bay on U.S. Highway 27 in Palm Beach County, Florida. The Okeelanta Cogeneration Plant's authorized representative is Mr. Rodney Williams, Plant Manager, and the mailing address is 8001 U.S. Highway 27 South, South Bay, FL 33493.

The applicant, applied to the Department for a permit to authorize increases in the hourly and annual heat input rates for the existing boilers at the Okeelanta Cogeneration Plant. The maximum hourly heat input rate will increase from 715 to 760 MMBtu per hour by taking the last feedwater heater on each unit out of service to reduce the feedwater temperature. The increase in the hourly heat input rate will not result in increased electrical generating capacity and is within the manufacturer's maximum continuous steam rating for these units. The cogeneration plant's maximum annual heat input will increase from $11.50 \times 10^{+06}$ to $19.97 \times 10^{+06}$ MMBtu per year, which will relax a permit limit originally taken to avoid new source preconstruction review for several pollutants. The cogeneration boilers have shown increasing reliability and have approached the annual heat input limit. The applicant requests the flexibility to operate the cogeneration units without synthetic operational restrictions.

The existing cogeneration plant is located in Palm Beach County, which is an area that is currently in attainment with (or designated as unclassifiable for) all pollutants subject to federal and state Ambient Air Quality Standards. The plant is a major facility with respect to the Prevention of Significant Deterioration (PSD) of Air Quality as defined in Rule 62-212.400, F.A.C. Based on the application, the project will result in the following potential increases in emissions in terms of "tons per year" (TPY): 2160 TPY of carbon monoxide (CO); 5 TPY of fluorides (Fl); 1.4 TPY of lead (Pb); 98 pounds per year of mercury (Hg); 741 TPY of nitrogen oxides (NOx); 181 TPY of particulate matter (PM/PM_{10}); 20 TPY of sulfuric acid mist (SAM); 407 TPY of sulfur dioxide (SO_2); and 555 TPY of volatile organic compounds (VOC). Emissions of CO, Fl, Pb, NOx, PM/PM_{10}, SAM, SO_2, and VOC exceed the PSD significant emission rates defined in Table 62-212.400-2, F.A.C. Therefore, the project is subject to PSD preconstruction review for these pollutants.

PSD preconstruction review requires the Department to establish emissions standards that represent the Best Available Control Technology (BACT) for each PSD-significant pollutant. Based on reasonable assurances provided by the applicant and other available information, the Department establishes emissions standards in the draft permit based on the following BACT-level controls: CO and VOC – boiler design and good combustion practices; NOx – selective non-catalytic reduction (SNCR); SO_2 and SAM – low sulfur fuels; PM/PM_{10} – mechanical dust collectors followed by an electrostatic precipitator (ESP); Fl and Pb – authorized fuels containing only trace amounts of fluorides and with and prospective removal in the mechanical dust collectors/ESP.

As part of the PSD required preconstruction review, the Department reviewed the applicant's air quality analysis conducted for each PSD-significant pollutant. The analysis provides the Department with reasonable assurance that the project will not significantly contribute to or cause a violation of any state or federal ambient air quality standards. A refined analysis was required to evaluate the 3-hour and 24-hour SO_2 increments in the vicinity of the plant (Class II areas) and in the Everglades National Park (nearest PSD Class I area). The following table shows the maximum predicted for SO_2 impacts and PSD increments consumed by all sources in the area, including the project.

PSD CLASS II INCREMENT ANALYSIS – VICINITY OF THE PLANT					
Pollutant	**Averaging Time**	**Maximum Predicted Impact (μg/m³)**	**Impact Greater than Allowable Increment?**	**Allowable Increment (μg/m³)**	**Percent of Increment**
SO_2	24-hr	62	No	91	68%
	3-hr	218	No	512	43%

NOTICE TO BE PUBLISHED IN THE NEWSPAPER

PSD CLASS I INCREMENT ANALYSIS – EVERGLADES NATIONAL PARK					
Pollutant	Averaging Time	Maximum Predicted Impact ($\mu g/m^3$)	Impact Greater than Allowable Increment?	Allowable Increment ($\mu g/m^3$)	Percent of Increment
SO_2	24-hr	4.0	No	5	80%
	3-hr	12.2	No	25	49%

Based on the analyses, the Department has reasonable assurance that the proposed project will not significantly contribute to or cause a violation of any Class I or Class II PSD increments.

The Department will issue the Final Permit with the proposed conditions unless a response received in accordance with the following procedures results in a different decision or significant change of terms or conditions. The Department will accept written comments and requests for public meetings concerning the proposed permit issuance action for a period of thirty (30) days from the date of publication of this Public Notice of Intent to Issue Permit. Written comments and requests for public meetings should be provided to the Department's Bureau of Air Regulation at 2600 Blair Stone Road, Mail Station #5505, Tallahassee, FL 32399-2400. Any written comments filed shall be made available for public inspection. If written comments received result in a significant change in the proposed agency action, the Department shall revise the proposed permit and require, if applicable, another Public Notice.

The Department will issue the permit with the attached conditions unless a timely petition for an administrative hearing is filed pursuant to Sections 120.569 and 120.57, F.S., before the deadline for filing a petition. The procedures for petitioning for a hearing are set forth below. Mediation is not available in this proceeding.

A person whose substantial interests are affected by the proposed permitting decision may petition for an administrative proceeding (hearing) under Sections 120.569 and 120.57, F.S. The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department at 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida, 32399-3000. Petitions filed by the permit applicant must be filed within fourteen (14) days of receipt of the notice of intent. Petitions filed by any persons other than those entitled to written notice under Section 120.60(3), F.S. must be filed within fourteen (14) days of publication of this Public Notice or within fourteen (14) days of receipt of the notice of intent, whichever occurs first. Under Section 120.60(3), F.S., however, any person who asked the Department for notice of agency action may file a petition within fourteen (14) days of receipt of that notice, regardless of the date of publication. A petitioner shall mail a copy of the petition to the applicant at the address indicated above at the time of filing. The failure of any person to file a petition within the appropriate time period shall constitute a waiver of that person's right to request an administrative determination (hearing) under Sections 120.569 and 120.57, F.S., or to intervene in this proceeding and participate as a party to it. Any subsequent intervention will be only at the approval of the presiding officer upon the filing of a motion in compliance with Rule 28-106.205, F.A.C.

A petition that disputes the material facts on which the Department's action is based must contain the following information: (a) The name and address of each agency affected and each agency's file or identification number, if known; (b) The name, address, and telephone number of the petitioner, the name, address, and telephone number of the petitioner's representative, if any, which shall be the address for service purposes during the course of the proceeding; and an explanation of how the petitioner's substantial interests will be affected by the agency determination; (c) A statement of how and when petitioner received notice of the agency action or proposed action; (d) A statement of all disputed issues of material fact. If there are none, the petition must so indicate; (e) A concise statement of the ultimate facts alleged, including the specific facts the petitioner contends warrant reversal or modification of the agency's proposed action; (f) A statement of the specific rules or statutes the petitioner contends require reversal or modification of the agency's proposed action; and (g) A statement of the relief sought by the petitioner, stating precisely the action petitioner wishes the agency to take with respect to the agency's proposed action.

A petition that does not dispute the material facts upon which the Department's action is based shall state that no such facts are in dispute and otherwise shall contain the same information as set forth above, as required by Rule 28-106.301, F.A.C.

Because the administrative hearing process is designed to formulate final agency action, the filing of a petition means that the Department's final action may be different from the position taken by it in this notice. Persons whose substantial interests will be affected by any such final decision of the Department on the application have the right to petition to become a party to the proceeding, in accordance with the requirements set forth above.

A complete project file is available for public inspection during normal business hours, 8:00 a.m. to 5:00 p.m., Monday through Friday, except legal holidays, at:

Dept. of Environmental Protection
Bureau of Air Regulation
New Source Review Section
Suite 4, 111 S. Magnolia Drive
Tallahassee, Florida 32301
Telephone: 850/488-0114

Dept. of Environmental Protection
South District Office
Air Resources Section
2295 Victoria Avenue, Suite 364
Fort Myers, Florida 33901-3381
Telephone: 941/332-6975

Palm Beach County Health Dept.
Environmental Health and Engineering
Air Pollution Control Section
901 Evernia Street
West Palm Beach, Florida 33401
Telephone: 561/355-3136

The complete project file includes the application, Technical Evaluation and Preliminary Determination, Draft Permit, and the information submitted by the responsible official, exclusive of confidential records under Section 403.111, F.S. Interested persons may contact the Department's project engineer for additional information at the address and phone numbers listed above.

NOTICE TO BE PUBLISHED IN THE NEWSPAPER

TECHNICAL EVALUATION
&
PRELIMINARY DETERMINATIONS

PROJECT

Project No. 0990332-016-AC
Draft Permit No. PSD-FL-196(O)

New Hope Power Partnership - Okeelanta Cogeneration Plant
Request to Increase Heat Input Rates of Cogeneration Boilers

ARMS Facility ID Nos. 0990332
Emissions Unit Nos. 001 - 003

COUNTY

Palm Beach County

APPLICANT

New Hope Power Partnership
8001 U.S. Highway 27 South
South Bay, FL 33493

Authorized Representative: Mr. Rodney Williams, Plant Manager

PERMITTING AUTHORITY

Florida Department of Environmental Protection
Division of Air Resources Management
Bureau of Air Regulation
New Source Review Section

July 24, 2003

{Filename: PSD-FL-196(O) TEPD}

1. APPLICATION INFORMATION

Processing Schedule

01/31/02 Department last modified Permit No. PSD-FL-196.

09/06/02 Department received initial application.

10/04/02 Department requested additional information.

11/21/02 Department mailed reminder of request for additional information.

12/17/02 Department received applicant's request for extension of time to submit additional information.

03/04/03 Department received additional information.

03/26/03 Department requested additional information.

05/21/03 Department received additional information.

Facility Description and Location

New Hope Power Partnership operates the Okeelanta Cogeneration Plant (OkCP) located near Highway 27, approximately 6 miles south of South Bay in Palm Beach County, Florida. The plant consists of three cogeneration boilers fired with biomass and fossil fuels. The plant provides process steam to the adjacent sugar mill and refinery (Okeelanta Corporation) and also produces up to 74.9 MW delivered to the electrical power grid. For the purposes of the Department's Prevention of Significant Deterioration (PSD) preconstruction review program and Title V operating permit program, the cogeneration plant, sugar mill, and refinery are considered to be a single facility. The following table identifies the Standard Industrial Classification (SIC) code for each plant.

Owner/Operator	Plant	Standard Industrial Classification
New Hope Power Partnership	Okeelanta Cogeneration Plant	4911 - Electric Services
Okeelanta Corporation	Sugar Mill	2061 - Cane Sugar, Except Refining
	Sugar Refinery	2062 - Cane Sugar Refining

Regulatory Categories

Title III: Existing facility is a major source of hazardous air pollutants (HAPs).

Title IV: Existing facility is not subject to the federal acid rain provisions.

Title V: Existing facility is a Title V major source of air pollution in accordance with Chapter 62-213, F.A.C.

PSD: Existing facility is a PSD major source of air pollution in accordance with Rule 62-212.400, F.A.C.

NSPS: Existing facility operates units subject to the New Source Performance Standards in 40 CFR 60.

Summary of Existing Cogeneration Boilers

The cogeneration boilers are identified as Boiler A (EU-001), Boiler B (EU-002), and Boiler C (EU-003). Each unit is a spreader-stoker boiler designed to fire a combination of wood and bagasse, which will be referred to as "biomass". Wood chips are delivered by independent suppliers from around the state and consist of clean construction and demolition wood debris, dry wood, yard trash, land clearing debris, and other clean cellulose and vegetative matter. Bagasse is received from the adjacent sugar mill and consists of the fibrous, vegetative residue remaining from sugarcane after the milling process. These solid fuels enter through the fuel chute and are pneumatically spread across the furnace grate. Small particles of biomass fuel burn in suspension above the grate. Larger materials burn in a thin, even bed as they move along the grate. Combustion occurs in three stages within a single chamber: moisture evaporation, distillation and burning of volatile matter, and burning of fixed carbon. Natural gas and distillate oil may be fired for startup or as supplemental fuels. Each existing boiler is equipped with the following air pollution control equipment:

- Nitrogen Oxide Controls: A selective non-catalytic reduction (SNCR) system designed to reduce emissions of nitrogen oxides by about 40% with the injection of urea.

- Particulate Matter Controls: Multi-tube cyclone dust collectors followed by an electrostatic precipitator designed to remove more than 99% of the particulate matter.
- Mercury Controls: A system that injects activated carbon into the exhaust flue gas to adsorb mercury for removal by the particulate matter controls. (Originally included for coal firing operation, which is no longer permitted.)

Each boiler is equipped with continuous monitoring systems to monitor and record emissions of carbon monoxide, nitrogen oxides, sulfur dioxide, and stack plume opacity. The following parameters are also monitored and recorded for each unit: fuel feed rate, steam production, steam pressure, steam temperature, flue gas oxygen content and electrical energy production. Other miscellaneous equipment includes: the biomass fuel feed system; the ash handling and storage system; exhaust fans; ductwork and exhaust stacks; steam turbine-electrical generator sets; steam condensers; cooling towers; distillate oil storage tanks; and a diesel fire pump.

Project Description

Construction of the cogeneration boilers was authorized under the original PSD air permit issued in 1993. Due to a netting analysis that included the shutdown of several sugar mill boilers, the original project was only subject to PSD review for emissions of beryllium, fluorides, sulfuric acid mist, and sulfur dioxide (primarily due to the proposed use of coal as an "emergency backup fuel"). Several modifications have been made to the original PSD permit. The most recent occurred in 2002, which included removing coal as an authorized fuel, revising the averaging period for CO emissions, and revising the SO_2 standards for biomass fuels. This modification resulted in revised BACT determinations for carbon monoxide, fluorides, sulfuric acid mist, and sulfur dioxide. The current PSD permit specifies the maximum heat input rate to each cogeneration boiler as 715 MMBtu per hour. The total heat input to all three boilers combined is limited to 11.5 x 10^{+06} MMBtu per year, which effectively limits the annual capacity to approximately 60%. The cogeneration plant was completed in 1997 and has maintained consistent commercial operation since the 1998/1999 sugarcane crop season.

The applicant proposes the following changes:

- Increase the maximum heat input rate for each boiler from 715 to 760 MMBtu per hour by taking the last feedwater heater on each unit out of service to reduce the feedwater temperature; and
- Remove the restriction on the total annual heat input to all three boilers combined.

The increase in the hourly heat input rate would not result in increased electrical generating capacity and is within the manufacturer's maximum continuous steam rating for these units. Due to increased reliability, the cogeneration plant has been able to approach the maximum annual heat input limit reaching 11.4 x 10^{+06} MMBtu during 2000. The applicant requests the flexibility to operate the cogeneration units without restriction (8760 hours per year). The combined requests would result in a combined annual heat input rate of 19.97 x 10^{+06} MMBtu per year.

2. APPLICABLE REGULATIONS

General State Regulations

This project is subject to the applicable environmental laws of Section 403 of the Florida Statutes (F.S.). The Florida Statutes authorize the Department of Environmental Protection to establish rules and regulations regarding air quality as part of the Florida Administrative Code (F.A.C.). This project is subject to the applicable rules and regulations of the following chapters.

Chapter	Description
62-4	Permitting Requirements
62-204	Ambient Air Quality Requirements, PSD Increments, and Federal Regulations Adopted by Reference
62-210	Required Permits, Public Notice, Reports, Stack Height Policy, Circumvention, Excess Emissions, and Forms

62-212 Preconstruction Review, PSD Requirements, and BACT Determinations
62-212.300 - General Preconstruction Review Requirements
62-212.400 – Prevention of Significant Deterioration of Air Quality

62-213 Operation Permits for Major Sources of Air Pollution (Title V)

62-296 State Emission Limiting Standards
62-296.405 - New Fossil Fuel Steam Generators with More Than 250 Million Btu Per Hour Heat Input.
62-296.410 - Carbonaceous Fuel Burning Equipment
62-296.500 - Reasonably Available Control Technology Requirements for VOC and NOx
62-296.570 - Reasonably Available Control Technology Requirements for Major VOC and NOx Sources

62-297 Test Methods and Procedures, Continuous Monitoring Specifications, and Alternate Sampling Procedures

General Federal Regulations

This project is also subject to the following applicable federal provisions regarding air quality established in the Code of Federal Regulations (CFR) and adopted by reference in Chapter 62-204, F.A.C.

Title 40, CFR	Description
Part 60	Subpart A - General Provisions for NSPS Sources Subpart Da - NSPS for Electric Utility Steam Generating Units, Constructed After September 18, 1978 Subpart Ea - NSPS for Municipal Waste Combustors, Applicability and Exemption Requirements Subpart Kb - NSPS for Distillate Oil Storage Tank, Record Keeping Requirements Applicable Appendices

Project PSD Applicability

Operation at the requested maximum heat input rates would result in increased emissions. In the following table, the applicant summarizes the net increase in annual emissions from the proposed project.

Table 2A. Applicant's PSD Applicability Analysis

Pollutant	Past Actual Emissions, TPY	Potential Emissions, TPY	Net Change TPY	PSD SER TPY	PSD/BACT?
CO	1335.40	3495.20	2160	100	Yes
NOx	756.60	1498.00	741	40	Yes
PM	127.96	299.59	181	25	Yes
PM_{10}	108.02	299.59	195	15	Yes
SO_2	191.90	599.18	407	40	Yes
VOC	43.93	599.18	555	40	Yes
Lead	0.098	1.50	1.4	0.6	Yes
Mercury	0.0035	0.054	0.049	0.100	No
Fluorides	2.16	6.99	5	3	Yes
Sulfuric Acid Mist	15.71	35.95	20	7	Yes

a. Past actual emissions of the three boilers are based on the 2-year average emissions for 2000 and 2001.

b. The project would also result in 9.07 TPY of fugitive PM emissions and 3.5 TPY of fugitive PM_{10} emissions.

The cogeneration plant is located in Palm Beach County, an area that is currently in attainment (or designated as unclassifiable) for all air pollutants subject to a National Ambient Air Quality Standard (NAAQS). The facility includes three electric utility steam generating units that belong to one of the 28 major facility categories listed in Table 212.400-1, F.A.C. As such, the threshold for a major PSD facility is 100 tons per year. The cogeneration plant is a major PSD facility because at least one regulated pollutant exceeds 100 tons per year. Therefore, new projects and modifications require a PSD applicability review. Emissions increases exceeding the PSD significant emission rates for the regulated pollutants specified in Table 212.400-2, F.A.C. are subject to PSD review and a determination of the Best Available Control Technology.

Therefore, the project is subject to PSD preconstruction review for emissions of carbon monoxide, fluorides, lead, nitrogen oxides, particulate matter, sulfuric acid mist, sulfur dioxide, and volatile organic compounds. For each of these pollutants, the applicant must review available control technologies and make a recommendation of the Best Available Control Technology (BACT). Based on information provided by the applicant as well as other available information sources, the Department determines BACT for each PSD-significant pollutant. The applicant is required to provide an Air Quality Analysis demonstrating that the proposed project will not adversely impact PSD Class I and II areas and will not contribute significantly to, or cause a violation of, any state or federal ambient air quality standards. The applicant must evaluate air quality impacts from the project upon soils, vegetation, wildlife, and visibility. Finally, the applicant must provide an assessment of the air quality impacts resulting from associated commercial, residential, and industrial growth related to the proposed project.

3. BEST AVAILABLE CONTROL TECHNOLOGY (BACT) REVIEW

The determination of the Best Available Control Technology (BACT) must be based on the maximum degree of emissions reduction that the Department determines is achievable through application of production processes and available methods, systems, and techniques for control of each PSD-significant pollutant. The Department's determination is made on a case-by-case basis for each proposed project, taking into account energy, environmental and economic impacts. The Department must also give consideration to:

- Any EPA determination of BACT pursuant to Section 169 of the Clean Air Act, and any emission limitation contained in 40 CFR Part 60 (NSPS) or 40 CFR Part 61 (NESHAP).
- All scientific, engineering, and technical material and other information available to the Department.
- The emission limiting standards or BACT determinations of any other state.
- The social and economic impacts of the application of such technology.

The EPA currently directs that BACT should be determined using the "top-down" approach. In this approach, available control technologies are ranked in order of control effectiveness for the emissions unit under review. The most stringent control option is evaluated first and selected as BACT unless it is technically infeasible for the proposed project or rejected due to adverse energy, environmental or economic impacts. If the control option is eliminated, the next most stringent alternative is considered. This top-down approach continues until BACT is determined.

BACT determinations must result in the selection of control technologies capable of achieving at least the applicable emission standards regulated by 40 CFR Part 60 (NSPS) or 40 CFR Part 61 (NESHAP). The Department will consider the control or reduction of "non-regulated" air pollutants when determining the BACT limit for regulated pollutants, and will weigh control of non-regulated air pollutants favorably when considering control technologies for regulated pollutants. The Department will also favorably consider control technologies that utilize pollution prevention strategies. These approaches are consistent with EPA's consideration of environmental impacts and stated goals regarding pollution prevention.

3.1 BACT Review for Carbon Monoxide (CO) and Volatile Organic Compounds (VOC)

Emissions of carbon monoxide and volatile organic compounds are emitted as the result of incomplete combustion of the fuels. The firing of distillate oil and natural gas through burners results in relatively low emissions of these pollutants. These fuels are consistent in nature and offer efficient and controlled combustion. However, the firing of wood and bagasse is much less efficient due to the inherent combustion process on the fuel grate as well as wide variability of fuel characteristics including heating value. In addition, these fuels are high in moisture (~ 50% by weight), which results in lower firing temperatures and less efficient combustion. For most large industrial and utility boilers, CO and VOC emissions are controlled by good combustion practices for the given boiler design. These pollutants will be reviewed together because the methods of control are similar.

Applicant Technology Review and Recommendation

Based on previous determinations, the applicant believes that boiler design and good combustion practices are the only technically feasible and economically viable option for controlling CO and VOC emissions from the biomass-fired cogeneration boilers. (See summary tables at the end of this report for a compilation of recent BACT determinations based primarily of EPA's RACT/BACT/LAER Clearinghouse database.) Therefore, the applicant recommends retaining the current CO and VOC emissions standards as BACT, which are:

CO	≤ 0.50 lb/MMBtu, 30-day rolling CEMS average
	≤ 0.35 lb/MMBtu, 12-month rolling CEMS average
VOC	≤ 0.06 lb/MMBtu, 3-run test average

The applicant notes that standards based on good combustion practices are primarily dependent on the original boiler design.

Department's Review and Draft BACT Determination

The following technologies are potentially available for reducing CO and VOC emissions.

- *Thermal Incinerator*: The flue gas temperatures can be raised to complete oxidization of CO and VOC emissions resulting in removal efficiencies of greater than 90%. This would require the combustion of additional auxiliary fuel and associated emissions. In the BACT review for VOC emissions, the applicant estimated that a thermal oxidizer would require an additional 146 million standard cubic feet of natural gas per year. However, such systems are more likely to be considered for gas streams having much lower exhaust flow rates and much higher pollutant concentrations. Based on a review of similar boilers, thermal incineration does not appear to be appropriate for this project.
- *Catalytic Incinerator*: Oxidation of CO emissions can be completed at lower temperatures by employing a catalyst resulting in removal efficiencies of approximately 90%. Such a system must be incorporated at a point that maintains the proper operational temperatures; otherwise cooling or heating of the flue gas may be necessary to achieve the required oxidation and protect the catalyst from damage. Typically, catalytic oxidation for combustion sources has been limited to relatively clean exhaust gas streams such as natural gas-fired boilers or combustion turbines. Catalysts can be blinded and/or fouled due to heavy particulate loading of the flue gas. They can also suffer premature deactivation due to poisoning by various compounds present in the flue gas from firing biomass and distillate oil. Once again, such systems are more likely to be considered for gas streams having much lower exhaust flow rates with much higher pollutant concentrations. Based on a review of similar boilers and concerns regarding catalyst blinding, fouling, and early deactivation, catalytic incineration does not appear to be appropriate for this project.
- *Boiler Design with Good Combustion Practices*: The boiler design generally provides a moderately high temperature with sufficient turbulence and residence time at that temperature to complete combustion of the fuel. Based on a given boiler design, operators use good combustion practices to maintain efficient combustion to minimize products of incomplete combustion.

The following additional control technologies are also identified for primarily reducing VOC emissions:

- *Carbon Adsorbers*: Fixed or fluidized carbon beds can be used to adsorb organic gases onto carbon particles. The adsorption process includes a cycle to regenerate the carbon and either condense the concentrated organic stream for recovery or destroy them. Flue gas temperatures are generally maintained at less than 130° F and humidity to less than 50%. Carbon adsorption is not considered technically feasible for this project due to the large flow rates (>300,000 acfm), high flue gas temperatures, and expected low VOC concentrations.

- *Refrigerated Condensers*: This equipment can be used to cool the gas stream to condense and collect the organic vapors. Such systems are generally installed on processes with high VOC concentrations (> 5000 ppmv) when the specific organic compounds can be recovered and used again. Refrigerated condensation is not considered technically feasible for this project due to the large flow rates (>300,000 acfm), high flue gas temperatures, and expected low VOC concentrations (~ 100 ppmv).

The Department was unable to find any previous BACT determinations that relied on add-on control technologies to remove CO and VOC emissions from biomass-fired boilers. All of the determinations in EPA's RACT/BACT/LAER Clearinghouse listed either "good combustions practices" or "no controls feasible". At this time, the Department agrees that the add-on CO/VOC control technologies are not considered appropriate for the project. The Department makes a preliminary determination to retain the following CO standards as BACT based on good combustion practices.

CO ≤ 0.50 lb/MMBtu, 30-day rolling CEMS average
≤ 0.35 lb/MMBtu, 12-month rolling CEMS average

Compliance will be determined by continuously monitoring CO emissions. The above standards were established in a 2002 PSD permit modification and reflect the actual performance of the boilers as constructed based on actual CEMS data. The standards consider the variability of the fuel heating values and moisture contents of the biomass fuels. As shown in the summary tables at the end of this report, these standards are well within the range of recent BACT determinations for biomass-fired boilers, which were all based upon good combustion practices for the given boiler design. The Department reaffirms these standards as the draft BACT determinations for this project, which will increase the hourly heat input by approximately 6%. In addition, the Department will require that CO emissions be reported in terms of "ppmvd @ 3% oxygen" for each hour of operation and averaged for each 24-hour period (day). These are the same units as the proposed MACT standard for large solid fuel-fired industrial boilers. This will provide preliminary data for informational purposes only with regard to the upcoming MACT, which is based on "good combustion practices".

For VOC emissions, the Department reviewed stack test information for the cogeneration boilers to determine actual VOC emission rates based on the boiler design and good combustion practices. Based on about 30 actual stack tests, there is some variation in the VOC emissions between boilers and fuel combinations. The highest tested emission rates are 0.014 lb/MMBtu for wood firing, 0.020 lb/MMBtu for bagasse firing, and 0.036 lb/MMBtu for a combination of these fuels. Based on good combustion practices for the boiler as constructed and the actual tested emission rates, the Department makes a preliminary BACT determination.

VOC ≤ 0.05 lb/MMBtu, 3-run test average conducted at permitted capacity

Compliance will be demonstrated by annual stack tests for each boiler.

3.2 BACT Review for Nitrogen Oxides (NOx)

Applicant Technology Review and Recommendation

The applicant identified selective catalytic reduction (SCR) and selective non-catalytic reduction (SNCR) as the top two NOx control technologies for boilers firing biomass. SCR is capable of control efficiencies in the range of 70% - 90% and SNCR is capable of control efficiencies in the range of approximately 35% - 70%. The initial application for this project identified a capital cost for SCR of $4,246,000 per boiler, annual operating costs of $3,810,000 per boiler, and total annualized costs of $4,211,000 per boiler. Based on a 70% reduction and 90% capacity factor, the applicant estimated the cost effectiveness for SCR to be approximately $7800 per ton of NOx removed. Initially, the applicant rejected SCR primarily due to costs, but also noted the following additional reasons:

- There is a lack of actual operating experience because SCR has not yet been applied to a boiler firing biomass in the United States.
- Due to concerns of catalyst poisoning, only one SCR vendor (Hamon Research Cottrell) would provide a quote for the project. The catalyst life was guaranteed for only 10,000 hours of operation.
- Due to blinding and poisoning concerns, the SCR would likely be located after the ESP. A reheat system supplying approximately 100 MMBtu per hour would be required to raise the flue gas temperature to the operational level (~700° F) for SCR.

In response to the Department's request for additional information, the applicant identified other available NOx control alternatives. Of these, the applicant rejected the following options as technically infeasible.

- *SCONOx™*: This technology is a proven, proprietary, and patented catalytic oxidation and absorption technology, which is recognized by the EPA as "demonstrated in practice" for the control of NOx emissions from combined cycle gas turbines. However, there are only two known applications of this technology, which are both for combined cycle gas turbine projects. This technology has never been designed for, or demonstrated on, a biomass-fired boiler.
- *Selective Catalytic Reduction (SCR)*: In the applicant's response for additional information, the applicant indicated Hamon Research Cottrell retracted their initial quote after further discussion and recommended the use of an SNCR system for NOx control. Hamon Research Cottrell believed that catalyst deactivation would occur at an unreasonably high rate due to the presence of potassium, sodium, and phosphorous in the exhaust flue gas. Other vendors (Engelhard Corporation, Babcock & Wilcox, and Wheelabrator A.P.C.) declined to provide an SCR system for a biomass-fired boiler. The applicant also summarized results from Swedish pilot plants that use SCR for wood-fired boilers. Data for the first several years shows that the catalyst deactivates 3-4 times faster than similar coal-fired units. The CHEC Research Center in Denmark reports that "... by co-combustion of coal with biomass or separate biomass combustion, SCR catalysts deactivate at an unacceptable rate." In addition, the Lund Institute of Technology in Sweden states that, "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." Therefore, the applicant does not believe that SCR is technically feasible for biomass-fired boilers.
- *Low-NOx Burners (Biomass Combustion)*: The boilers have low-NOx burners for natural gas and distillate oil. This technology is not applicable to the spreader stoker boiler design.
- *Non-Thermal Plasma Reactor*: This technique generates electron energies in the gas stream that produce gas-phased radicals, such as hydoxyl and atomic oxygen by the collision of electrons with water and oxygen molecules present in the flue gas. These radicals oxidize NOx in the flue gas to form nitric acid, which can be condensed out with a wet condensing precipitator. This technique has never been demonstrated on large-scale boilers or biomass-fired boilers.
- *Oxidant Injection*: Oxidants such as ozone, ionized oxygen, or hydrogen peroxide can be injected in a gas stream to make NOx soluble in water and then removed with a gas absorber. However, this reduction technique has never been demonstrated on large-scale boilers or biomass-fired boilers.

The following table summarizes the applicant's ranking of the remaining NOx control alternatives.

Table 3.2A. NOx Control Alternatives

Control	Efficiency	Rank	Used by Okeelanta
SNCR	35%-55%	1	Yes
Air staging of combustion	50% - 65%	2	Yes
Fuel staging of combustion	50% - 65%	2	No

Steam injection	50% - 65%	2	No
Flue gas recirculation	15% - 25%	3	No
Reburn w/natural gas	15% - 25%	3	No
Overfire air	15% - 25%	3	Yes
Less excess air	15% - 25%	3	No
Combustion optimization	15% - 25%	3	Yes
Reduce air preheat	15% - 25%	3	No
Low-NOx burners, Oil/gas	15% - 25%	3	Yes
Ultra-low nitrogen fuel	ND	4	Yes

The applicant believes that the next highest ranking NOx control technology is SNCR and notes that the existing Okeelanta cogeneration boilers currently employ SNCR, air staging, overfire air, low-NOx gas/oil burners, combustion optimization, and an ultra-low nitrogen fuels (biomass, natural gas, and distillate oil). The Department assumes that the higher ranking of SNCR is due to the existing combination of controls currently in use with the cogeneration boilers. The applicant believes that the existing SNCR system represents the best available control technology for biomass-fired boilers and recommends retaining the current emissions standard as BACT, which is:

NOx $\leq$ 0.15 lb/MMBtu, 30-day rolling CEMS average

The increased hourly heat input rate will result in increased hourly emissions, which triggers the latest revision to the NSPS Subpart Da NOx standard (§60.44a(d)(2)), which is 0.15 lb/MMBtu of heat input. The proposed BACT standard is as stringent as the applicable NSPS standard.

Department's Review and Draft BACT Determination

The Department does not completely accept the applicant's conclusion that SCR is not technically feasible. However, it is recognized that the known worldwide applications of SCR on boilers firing bagasse and wood is very limited, even more so than applications of SCR for refuse-fired plants, for which only non-U.S. applications currently exist. It is acknowledged that, even if SCR is technically feasible, substantial retrofit costs could be incurred to incorporate such a system into the existing configuration of equipment. The existing SNCR system has been successfully used to continuously comply with the current NOx standard (0.15 lb/MMBtu) since commercial operation began. Considering this current level of NOx control with SNCR, the retrofit of a new SCR system with an 85% reduction and 90% annual capacity factor would potentially result in removing an additional 366 tons of NOx per year. However, based on the estimated annualized cost of $4,211,000, the cost effectiveness for this additional level of control would be more than $10,000 per ton of NOx removed. Operating these units near a 90% annual capacity factor would be very difficult due to the down time needed to perform periodic inspection, maintenance and repair. For example, the cogeneration plant had one of its highest years of operation in 2000, during which the annual capacity factor approached only 57%.

A review of EPA's RACT/BACT/LAER Clearinghouse indicates 22 similar biomass-fired boilers with NOx BACT determinations. See the summary tables at the end of this report. Of these, only seven boilers were required to install add-on controls. In each case, SNCR was the chosen technology. The following three facilities list NOx BACT standards that are less than the proposed standard of 0.15 lb/MMBtu.

- Virginia's Multitrade facility consists of three spreader stoker boilers (374 MMBtu/hour), which are about half the size of the Okeelanta boilers. Each boiler fires 100% wood with a NOx limit of 0.10 lb/MMBtu based on a 30-day rolling average. Although permitted for full operation, the plant's actual operation appears more typical of a peaking plant.
- Florida's Ridge Generating Station operates a 630 MMBtu/hour steam generating unit that fires wood, tires, and landfill gas. The NOx standard is 90 lb/hour based on a 30-day rolling average, which is equivalent to

approximately 0.143 lb/MMBtu. It is noted that long-term "lb/hour" emission standards can be much easier to achieve than similar lb/MMBtu standards when factoring in low load operation.

- Florida's Osceola Power Cogeneration Plant is a sister facility to the Okeelanta Cogeneration Plant consisting of two similar spreader stoker boilers. Although the NOx BACT limit is 0.14 lb/MMBtu, the plant is not currently in operation and is in the process of being "re-permitted". The new draft BACT determination specifies a NOx standard of 1.6 lb/MW-hr, which is the new NSPS Subpart Da NOx standard and is approximately equivalent to 0.15 lb/MMBtu.

In considering a lower NOx standard for the cogeneration units, it is important to keep in mind that the existing SNCR system was originally designed to continuously meet a standard of 0.15 lb/MMBtu. Simply requiring a lower limit for the existing control system would likely result in increased urea usage and higher ammonia slip that could potentially cause corrosion problems. The sister facility, the Osceola Cogeneration Plant, initially requested a NOx standard of 0.12 lb/MMBtu to avoid PSD preconstruction review as part of a netting analysis. It did not appear that the SNCR design was any different than that of the Okeelanta Cogeneration Plant. However, about 40% more urea was injected to meet a standard that was only 20% lower. Combined with the high moisture conditions and extended periods of shutdown, the additional ammonia is believed to have caused premature failure of the superheater tubes.

The Department rejects SCR for the existing biomass-fired boilers due to technical concerns regarding catalyst poisoning and the corresponding high costs for retrofitting an SCR system. The Department believes that SNCR represents the appropriate control technology and makes a preliminary determination to retain the current emission standard as the draft BACT standard for NOx emissions as follows.

NOx $\leq$ 0.15 lb/MMBtu, 30-day rolling CEMS average

Compliance will be determined by continuously monitoring NOx emissions.

3.3 BACT Review for Particulate Matter (PM) and Lead (Pb)

Applicant Technology Review and Recommendation

The applicant identified cyclones, wet scrubbers, baghouses, and electrostatic precipitators (ESP) as technically feasible add-on control technologies for removing particulate matter from the flue gas exhaust. Control efficiencies of baghouses and ESPs can be more than 99%. The cogeneration boilers were originally designed with ESPs. In 2000, mechanical dust collectors were installed as pre-controls to prevent overloading the ESP. Actual tests with the mechanical dust collectors and ESP in place indicate particulate matter emission rates in the range of 0.01 to 0.02 lb/MMBtu.

A review of the EPA RACT/BACT/LAER Clearinghouse shows recent BACT determinations ranging from about 0.02 to 0.24 lb/MMBtu. The applicant believes that the combination of mechanical dust collectors / ESP reflects the top level of control, which is comparable to a baghouse. The applicant recommends retaining the current emissions standards as BACT, which are:

PM $\leq$ 0.03 lb/MMBtu, average of 3 test runs

Pb $\leq$ 1.5×10^{-04} lb/MMBtu, average of 3 test runs (if a standard is necessary)

The applicant notes that the standard for lead is proposed at the maximum expected rate due to the variability of lead in the biomass fuels and the inherently low levels of emissions. Based on test data, actual lead emissions are expected to average about 2.6×10^{-05} lb/MMBtu. At this rate, total lead emissions from the cogeneration boilers would be less than 600 pounds per year, which is less than the PSD significant emission rate for lead of 1200 pounds per year.

Department's Review and Draft BACT Determination

The Department also recognizes the combination of the mechanical dust collectors/ESP as capable of the top level of control for reducing particulate matter emissions from biomass-fired boilers. This is consistent with previous BACT determinations listed in EPA's RACT/BACT/LAER Clearinghouse. The Department notes that EPA recently performed an extensive review of existing particulate matter control technologies in support of the recently proposed Maximum Achievable Control Technology (MACT) standards for large industrial boilers. The proposed rule specifies a particulate matter standard of 0.026 lb/MMBtu as a surrogate for showing good control of particulate metal emissions (arsenic, beryllium, cadmium, chromium, lead, manganese, nickel, and selenium). Based on the available information, the Department proposes the following as the new draft BACT standard for lead and PM emissions.

PM $\leq$ 0.026 lb/MMBtu, average of 3 test runs

A permitting note will be added to reflect that the average emission rate for lead is 2.6 x 10^{-05} lb/MMBtu. The Department notes that three tests conducted on the existing mechanical dust collectors/ESP combination show actual particulate matter emissions of less than half the proposed new standard. Also, the Department will retain the current opacity standard, which is no more than 20% opacity, except for one 6-minute block per hour that shall not be greater than 27% opacity. Compliance with the PM standard will be demonstrated by annual stack tests for each boiler. Compliance with the opacity standard will be demonstrated by a continuous opacity monitor.

3.4 BACT REVIEW FOR SULFUR DIOXIDE (SO_2) AND SULFURIC ACID MIST (SAM)

Bagasse, wood, distillate oil, and even natural gas contain sulfur. During combustion, fuel sulfur is oxidized to sulfur dioxide, which can also lead to emissions of sulfuric acid mist. Generally, wood and bagasse contain low levels of sulfur compared to most fossil fuels. The distillate oil allowed by the current permit is restricted to no more than 0.05% sulfur by weight, which is equivalent to about 0.05 lb/MMBtu of heat input. Natural gas contains almost negligible amounts of sulfur and is typically added as an odorant to aid in leak detection.

Applicant Technology Review and Recommendation

The applicant identified wet, dry, and regenerable flue gas desulfurization (FGD) systems as technically feasible control alternatives. These technologies typically mix wet or dry lime with the flue gas to chemically react with the sulfur dioxide. The sulfur compounds are ultimately removed in the solid and/or liquid waste streams. In regenerable systems, the goal is to produce a concentrated stream of sulfur dioxide or sulfuric acid, which can then be sold. These systems generally achieve control efficiencies greater than 90% depending on the inlet concentration.

The least expensive flue gas desulfurization technique is a lime spray dryer absorber. The applicant submitted a cost analysis based on two bids for a project with similar boilers (Palm Beach Power's Osceola Cogeneration Plant). Capital costs ranged from \$4.4 to \$6 million and annual operating costs ranged from \$700,000 to \$800,000 per year. The total annualized costs ranged from \$1.6 to \$2.0 million per year. Based on a 90% annual capacity factor and 90% control efficiency, the applicant estimated 182 tons per year of SO_2 and fluoride emissions reductions. The cost effectiveness ranged from \$10,000 to \$12,000 per ton of pollutants removed. Based on this analysis, the applicant rejected the lime spray dryer absorber as not cost effective. The applicant also rejected other flue gas desulfurization techniques as not cost effective because they were expected to be even more costly than the lime spray dryer absorber.

The applicant notes that all of the fuels contain low levels of sulfur. Test data indicates that SO_2 emissions during biomass combustion are much lower than determined stoichiometrically by actual fuel sulfur. It is believed that much of the SO_2 generated during biomass combustion is adsorbed onto alkaline fly ash particles, which are removed by the combination of mechanical dust collectors/ESP. Therefore, the applicant recommends retaining the following standards as BACT based on the known low fuel sulfur fuels.

SO_2 $\leq$ 0.20 lb/MMBtu, 24-hour CEMS average
$\leq$ 0.10 lb/MMBtu, 30-day CEMS average
$\leq$ 0.06 lb/MMBtu, annual CEMS average

Fuel Specification: Distillate oil shall not contain more than 0.05% sulfur by weight.

Compliance will be determined by continuously monitoring SO_2 emissions.

Department's Review and Draft BACT Determination

The Department believes that the applicant's estimated cost effectiveness may be at the high end. However, based on CEMS data collected in 2000 for the New Hope Power cogeneration boilers firing a combination of wood and bagasse, the annual SO_2 emission rate is approximately 0.03 lb/MMBtu. Basing the annual emission reductions from a lime spray dryer absorber on this factor would increase the actual cost effectiveness well above $10,000 per ton. At this level, flue gas desulfurization is clearly not cost effective for the proposed project. Therefore, the Department also rejects add on flue gas desulfurization as not cost effective for this project.

As shown in the summary tables at the end of this report, the EPA RACT/BACT/LAER Clearinghouse lists 26 SO_2 BACT standards for similar biomass-fired boilers ranging from 0.002 to 0.46 lb/MMBtu. All but three of these projects identify the use of "low sulfur fuels" or "no controls feasible". It is important to realize that the actual fuel source is critical when establishing a permit standard based solely on "low sulfur fuels". Two facilities in Maine did require sodium carbonate scrubbers, but the corresponding BACT standard is much higher (0.27 lb/MMBtu) than that proposed by the applicant. The Department notes that these units are probably burning process sludge with a high sulfur content. The third facility, Florida's Ridge Generating Station, operates a lime spray dryer absorber to meet the BACT standard of 0.10 lb/MMBtu; however, this unit also burns tires and landfill gas, which contain much higher concentrations of sulfur. Higher uncontrolled SO_2 emissions from these sources made flue gas desulfurization cost effective. Even so, the proposed SO_2 standard for the cogeneration boilers that is based on a 30-day rolling average and "low sulfur fuels" is equivalent to the "controlled" emission standard for the Ridge Generating Station. Similarly, the proposed annual SO_2 standard for the cogeneration boilers is 40% lower than for the Ridge Generating Station.

Based on a review of the available information for the cogeneration boilers, the Department makes a preliminary determination to retain the existing SO_2 standards as BACT for this project based on low sulfur fuels.

SO_2 0.20 lb/MMBtu, 24-hour CEMS average
0.10 lb/MMBtu, 30-day CEMS average
0.06 lb/MMBtu, annual CEMS average

Fuel Specification: Distillate oil shall not contain more than 0.05% sulfur by weight.

The draft permit will also include requirements to periodically sample and analyze the bagasse and wood for the fuel sulfur content to monitor for significant changes in fuel characteristics. Due to the predicted low levels of sulfuric acid mist emissions, the SO_2 standard and distillate oil sulfur specification will serve as surrogate standards that effectively limit potential emissions of this pollutant.

3.5 BACT FOR FLUORIDES (FL)

Bagasse, wood, and distillate oil can contain trace amounts of fluorides, which convert primarily to hydrogen fluoride gas when combusted in a boiler. Similar to sulfur dioxide, some of the hydrogen fluoride will adsorb onto alkaline fly ash particles and be removed in the downstream mechanical dust collectors and electrostatic precipitators. Full operation of the cogeneration boilers as requested will result potential annual fluoride emissions of approximately 7 tons per year and a PSD significant net emissions increase. It is noted that the applicant's estimate of potential fluoride emissions is based on the highest tested emission rate for 18 individual stack tests (7.0×10^{-04} lb/MMBtu). Based on the average fluoride emission rate (3.0×10^{-04} lb/MMBtu), the maximum annual emissions would be about 3 tons per year, which is the PSD significant emission rate for fluorides.

Applicant Technology Review and Recommendation

Hydrogen fluoride is an acid gas and could be removed using the technologies discussed for controlling emissions of sulfur dioxide. However, the previous analysis for sulfur dioxide emissions (which included removal of hydrogen fluoride) showed that such equipment was not cost effective for this project. Other than Florida's Okeelanta and Osceola Cogeneration Plants, EPA's RACT/BACT/LAER Clearinghouse shows only one other BACT determination for fluoride emissions from a biomass-fired boiler, Virginia's Multitrade Limited Partnership. The BACT standard for the Multitrade boiler is 0.0017 lb/MMBtu, which is more than twice the highest tested emission rate for the cogeneration boilers. The applicant requests that the current fluoride BACT be retained, which is the use of low fluoride fuels and the existing mechanical dust collectors and electrostatic precipitator.

Department's Review and Draft BACT Determination

Based on existing test data for Okeelanta's cogeneration boilers, actual fluoride emissions are very low. As discussed for sulfur dioxide emissions, the cost to install add-on control equipment to further reduce fluoride emissions would be prohibitive. The Department intends to retain the existing fluoride BACT as follows.

Fluorides *BACT is the use of low-fluoride fuels and prospective removal with the fly ash in the mechanical dust collectors and electrostatic precipitator.*

The Department believes that sufficient data exists to show that fluoride emissions from the cogeneration boilers are relatively low. No further testing will be required.

4. AIR QUALITY MODELING

Introduction

The applicant predicts the proposed project will increase PM_{10}, SO_2, NOx, CO, sulfuric acid mist (SAM), fluorides, Pb and VOC emissions at levels in excess of PSD significant amounts. PM_{10}, SO_2 and NOx are criteria pollutants and have national and state ambient air quality standards (AAQS), PSD increments, significant impact levels, and significant monitoring concentrations (de minimis concentrations) defined for them. CO is a criteria pollutant and has only AAQS, significant impact levels and a de minimis concentration defined for it. Pb is a criteria pollutant and has only AAQS and a de minimis concentration defined for it. Fluorides are a non-criteria pollutant and have no AAQS or PSD increments defined for them; however fluorides do have a de minimis concentration. SAM is a non-criteria pollutant and has no applicable AAQS, PSD increments or PSD significance levels defined for it; therefore, no air quality impact analysis was required for SAM. VOC is a precursor for ozone, which is a criteria pollutant. There are no applicable AAQS, PSD increments, PSD significance levels for VOC. However, projects with net increases of more than 100 tons per year of VOC require an ambient impact analysis.

The air quality impact analyses required by the PSD regulations for this project include:

- An analysis of existing air quality for SO_2 and VOC;
- A significant impact analysis for PM_{10}, SO_2, NO_2, CO and VOC;
- A PSD increment analysis for SO_2;
- An Ambient Air Quality Standards (AAQS) analysis for SO_2 and Pb
- An analysis of impacts on soils, vegetation, and visibility and growth-related impacts to air quality.

The analysis of existing air quality generally relies on preconstruction monitoring data collected with EPA-approved methods. The significant impact, PSD increment, and AAQS analyses depend on air quality dispersion modeling carried out in accordance with EPA and Department guidelines. Good Engineering Practice (GEP) stack height means the greater of: (1) 65 m (213 ft) or (2) the maximum nearby building height plus 1.5 times the building height or width, whichever is less. The existing boiler stacks are approximately 200 feet tall and do not exceed the GEP stack height regulations. Therefore, the potential for building downwash to occur was considered in the modeling analysis for these stacks.

Based on the required analyses, the Department has reasonable assurance that the proposed project, as described in this report and subject to the conditions of approval proposed herein, will not cause or significantly contribute to a violation of any AAQS or PSD increment. However, the following EPA-directed stack height language is included: "In approving this permit, the Department has determined that the application complies with the applicable provisions of the stack height regulations as revised by EPA on July 8, 1985 (50 FR 27892). Portions of the regulations have been remanded by a panel of the U.S. Court of Appeals for the D.C. Circuit in NRDC v. Thomas, 838 F. 2d 1224 (D.C. Cir. 1988). Consequently, this permit may be subject to modification if and when EPA revises the regulation in response to the court decision. This may result in revised emission limitations or may affect other actions taken by the source owners or operators."

Analysis of Existing Air Quality

Preconstruction ambient air quality monitoring is required for all pollutants subject to PSD review unless otherwise exempted or satisfied. If available, previously existing representative monitoring data may be used to satisfy this monitoring requirement. An exemption to the monitoring requirement shall be granted by rule if either of the following conditions is met: the maximum predicted air quality impact resulting from the projected emissions increase, as determined by air quality modeling, is less than a pollutant-specific de minimis ambient concentration; or the existing ambient concentrations are less than a pollutant-specific de minimis ambient concentration. If preconstruction ambient monitoring is exempted, determination of background concentrations for PSD significant pollutants with established AAQS may still be necessary for use in any required AAQS analysis. These concentrations may be established from the required preconstruction ambient air quality monitoring analysis or from existing representative monitoring data. The background ambient air quality concentrations are added to pollutant impacts predicted by modeling and represent the air quality impacts of sources not included in the modeling. No de minimis ambient concentration is provided for ozone. Instead the net emissions increase of VOC is compared to a de minimis monitoring emission rate of 100 tons per year.

The table below shows maximum project air quality impacts for comparison to these de minimis levels.

MAXIMUM PROJECT AIR QUALITY IMPACTS FOR COMPARISON TO THE DE MINIMIS CONCENTRATIONS				
Pollutant	**Averaging Time**	**Maximum Predicted Impact ($\mu g/m^3$)**	**Impact Greater than De Minimis?**	**De Minimis Level ($\mu g/m^3$)**
PM_{10}	24-hr	1	NO	10
CO	8-hr	5	NO	575
NO_2	Annual	0.6	NO	14
VOC	Annual Emission Rate	555 TPY*	YES	100 TPY
SO_2	24-hr	9	NO	13
Lead	3-mo	0.0044	NO	0.1
Fluorides	24-hr	0.017	NO	0.25

* The original project included the permanent shutdown of several existing boilers with baseline VOC emissions of 402 tons per year. Revised potential VOC emissions for the boilers are 499, which would be a net increase of only 97 tons per year over the original 1991/1992 baseline years.

As shown in the table all pollutant emissions, with the exception of VOC are predicted to be less than the de minimis levels; therefore, preconstruction monitoring is not required for these pollutants. However, since VOC impacts from the project are predicted to be greater than the de minimis level; the applicant is not exempt from preconstruction monitoring for this pollutant. The applicant may instead satisfy the preconstruction monitoring requirement using previously existing representative data. These data do exist from ozone monitors located in the urbanized West Palm Beach area to the east of the project, and show no violation of any ozone standard. In addition SO_2 data has been collected in the Belle Glade area. These data are appropriate to establish background concentrations for use in the SO_2 AAQS analysis. The background concentrations for SO_2 are shown in the table below.

BACKGROUND CONCENTRATIONS FOR USE IN AAQS ANALYSES		
Pollutant	**Averaging Time**	**Background Concentration (μg/m³)**
SO_2	Annual	5
	24-hour	13
	3-hour	47

Models and Meteorological Data Used in Significant Impact, PSD Increment and AAQS Analyses

PSD Class II Area Model

The EPA-approved Industrial Source Complex Short-Term (ISCST3) dispersion model was used to evaluate the pollutant emissions from the proposed project and other existing major facilities. The model determines ground-level concentrations of inert gases or small particles emitted into the atmosphere by point, area, and volume sources. The model incorporates elements for plume rise, transport by the mean wind, Gaussian dispersion, and pollutant removal mechanisms such as deposition. The ISCST3 model allows for the separation of sources, building wake downwash, and various other input and output features. A series of specific model features, recommended by the EPA, are referred to as the regulatory options. The applicant used the EPA recommended regulatory options in each modeling scenario. Direction-specific downwash parameters were used for all sources for which downwash was considered. The stacks associated with this project will not exceed the good engineering practice (GEP) stack height criteria.

Meteorological data used in the ISCST3 model consisted of a concurrent 5-year period of hourly surface weather observations and twice-daily upper air soundings from the National Weather Service (NWS) station at West Palm Beach, Florida. The 5-year period of meteorological data was from 1987 through 1991. This NWS station was selected for use in the study because it is the closest primary weather station to the study area and is most representative of the project site. The surface observations included wind direction, wind speed, temperature, cloud cover, and cloud ceiling.

Because five years of data are used in ISCST3, the highest-second-high (HSH) short-term predicted concentrations were compared with the appropriate AAQS or PSD increments. For the annual averages, the highest predicted yearly average was compared with the standards. For determining the project's significant impact area in the vicinity of the facility, and for determining if there are significant impacts occurring from the project on any PSD Class I area, both the highest short-term predicted concentrations and the highest predicted yearly averages were compared to their respective significant impact levels.

PSD Class I Area Model

Since the PSD Class I Everglades National Park (ENP) is greater than 50 km from the proposed facility, long-range transport modeling was required for the Class I impact assessment. The California Puff (CALPUFF) dispersion model was used to evaluate the potential impact of the proposed pollutant emissions on the PSD Class I increments and on one Air Quality Related Value (AQRV): regional haze. CALPUFF is a non-steady state, Lagrangian, long-range transport model that incorporates Gaussian puff dispersion algorithms. This model determines ground-level concentrations of inert gases or small particles emitted into the atmosphere by point, line, area, and volume sources. The CALPUFF model has the capability to treat time-varying sources. It is also suitable for modeling domains from tens of meters to hundreds of kilometers, and has mechanisms to handle rough or complex terrain situations. Finally, the CALPUFF model is applicable for inert pollutants as well as pollutants that are subject to linear removal and chemical conversion mechanisms.

The meteorological data used in the CALPUFF model was processed by the California Meteorological (CALMET) model. The CALMET model utilizes data from multiple meteorological stations and produces a three-dimensional modeling grid domain of hourly temperature and wind fields. The wind field is enhanced by the use of terrain data, which is also input into the model. Two-dimensional fields such as mixing heights, dispersion properties, and surface characteristics are produced by the CALMET model as well. For this project, the CALMET model produced a modeling domain extending 470 km in the north-south direction by 450 km in the east-west direction. The modeling domain was produced by using 1990 meteorological data from 3 upper air, 8 surface, and 23 precipitation stations located throughout the state of Florida.

Significant Impact Analysis

Preliminary modeling is conducted using only the proposed project's worst-case emission scenario for each pollutant and applicable averaging time. Over 1000 receptors were placed along the facility's restricted property line and out to 35 km from the facility, which is located in a PSD Class II area. Modeling refinements were done, as needed, by using a polar receptor grid with a maximum spacing of 100 m along each radial and an angular spacing between radials of one or two degrees. 126 receptors were placed in the Everglades National Park (ENP) PSD Class I area, which is located 92 km to the south at its closest boundary. For each pollutant subject to PSD and also subject to PSD increment and/or AAQS analyses, this modeling compares maximum predicted impacts due to the project with PSD significant impact levels to determine whether significant impacts due to the project were predicted in a PSD Class II area in the vicinity of the facility or in any PSD Class I area. In the event that the maximum predicted impact of a proposed project is less than the appropriate significant impact level, a full impact analysis for that pollutant is not required. Full impact modeling is modeling that considers not only the impact of the project but also other major sources, including background concentrations, located within the vicinity of the project to determine whether all applicable AAQS or PSD increments are predicted to be met for that pollutant. Consequently, a preliminary modeling analysis, which shows an insignificant impact, is accepted as the required air quality analysis (AAQS and PSD increments) for that pollutant and no further modeling for comparison to the AAQS and PSD increments is required for that pollutant. The tables below show the results of this modeling. The radius of significant impact, if any, for each pollutant and applicable pollutant averaging time is also shown in the tables below.

MAXIMUM PROJECT AIR QUALITY IMPACTS FOR COMPARISON TO THE PSD CLASS II SIGNIFICANT IMPACT LEVELS IN THE VICINITY OF THE FACILITY					
Pollutant	**Averaging Time**	**Maximum Predicted Impact ($\mu g/m^3$)**	**Significant Impact Level ($\mu g/m^3$)**	**Significant Impact?**	**Radius of Significant Impact (km)**
PM_{10}	Annual	0.2	1	NO	----
	24-hr	1.2	5	NO	----
CO	8-hr	5	500	NO	----
	1-hr	22	2,000	NO	----
NO_2	Annual	0.5	1	NO	----
SO_2	Annual	0.3	1	NO	----
	24-hr	9	5	YES	11
	3-hr	32	25	YES	11
VOC	AER	555 TPY	100 TPY	YES	----

MAXIMUM PROJECT IMPACTS IN THE ENP FOR COMPARISON TO THE PSD CLASS I SIGNIFICANT IMPACT LEVELS				
Pollutant	**Averaging Time**	**Maximum Predicted Impact ($\mu g/m^3$)**	**Significant Impact Level ($\mu g/m^3$)**	**Significant Impact?**
PM_{10}	Annual	0.002	0.2	NO
	24-hr	0.06	0.3	NO
NO_2	Annual	0.005	0.1	NO
SO_2	Annual	0.004	0.1	NO
	24-hr	0.45	0.2	YES
	3-hr	1.1	1.0	YES

As shown in the tables, the maximum predicted 24-hr and 3-hr air quality impacts due to SO_2 emissions from the proposed project are greater than the PSD Class II significant impact levels in the vicinity of the facility and the PSD Class I significant impact levels in the Everglades National Park (ENP). Therefore, the applicant was required to do full impact SO_2 modeling in the vicinity of the facility, within the applicable significant impact area, to determine the impacts of the project along with all other sources in the vicinity of the facility. The significant impact area in the vicinity of the facility is based upon the predicted radius of significant impact. The applicant was required to do full impact SO_2 PSD increment modeling in the ENP.

As previously shown, potential VOC emissions increases are above the de minimis level of 100 tons per year, which requires an analysis of the impacts from the project on ambient ozone concentrations. Ozone is not directly emitted from stationary sources. Impacts of VOC emissions on ozone are usually not seen locally, but contribute to the regional formation of ozone. The regional ozone monitors in the county suffice for any background ozone pre-construction monitoring requirements. The main impact on ozone from stationary sources in the area is due to nitrogen oxides emissions (NOx) rather than VOC emissions. Furthermore, ozone formation occurs on a regional basis and includes the contributions of emissions from traffic, power plants throughout the region, miscellaneous VOC sources throughout the region, etc. The Palm Beach County Health Department is the approved local air pollution control program in the county. Each year, the Health Department compiles an annual air emissions inventory. Based on the March 2003 report presented to the county commissioners, almost half of the VOC emissions in the county originate from mobile sources of air pollution, such as automobiles and construction vehicles. The maximum potential VOC emissions from the cogeneration boilers operating 24 hours per day at full capacity would represent less than 1% of the total actual annual VOC emissions in the county.

It is further noted that actual VOC emissions from the cogeneration boilers have been very low (< 50 tons per year). Based on the preliminary BACT determination, the maximum potential VOC emissions are 499 tons per year compared to the original 1991/1992 actual baseline VOC emissions of 402 tons per year from the previous boilers, which were shut down as a result of the cogeneration project. Therefore, the revised BACT standard maintains net VOC emissions increases from the original project below the 100 ton per year de minimis level. In addition, the increases in the short term and long term maximum heat input rates are not likely to result in any meaningful changes in VOC emissions.

The applicant presented the potential VOC emissions increases to the Department and discussed available options to predict potential impacts associated with the emissions and formation of ozone. However, there are no approved stationary point source models available for use in predicting ozone impacts. Actual annual VOC emissions from the cogeneration boilers are expected to be less than 100 tons per year based on past performance test data and predicted operational levels. Ambient ozone monitoring data collected in Palm Beach County over the last several years show attainment with the current ozone standards and predict attainment with the proposed new ozone standards. Based on the available information, the Department determines that the use of a regional model incorporating the complex chemical mechanisms for predicting ozone formation is not suitable for this project, nor would it be sensitive enough to evaluate impacts associated with the changes from this project.

Receptor Grids for Performing PSD Increments and AAQS Analyses

For the PSD Class II increment and AAQS analyses, receptor grids normally are based on the size of the significant impact area for each pollutant. As shown in the previous section, the sizes of the significant impact areas for the required SO_2, analyses were 11 km.

PSD Increment Analysis

The PSD increment represents the amount that new sources in an area may increase ambient ground level concentrations of a pollutant from a baseline concentration which was established in 1977 for PM_{10} and SO_2 (the baseline year was 1975 for existing major sources of PM_{10} and SO_2), and 1988 for NO_2 (the baseline year was 1988 for existing major sources of NO_2). The emission values that are input into the model for predicting increment consumption are based on maximum potential emissions from increment-consuming project sources and all other increment-consuming sources in the vicinity of the facility. The maximum predicted PSD Class I and II area SO_2 increments consumed by this project and all other increment-consuming sources in the vicinity of the facility and in the ENP are shown below. The results show that all of the maximum predicted impacts are less than the allowable increments.

PSD CLASS II INCREMENT ANALYSIS				
Pollutant	**Averaging Time**	**Maximum Predicted Impact ($\mu g/m^3$)**	**Impact Greater than Allowable Increment?**	**Allowable Increment ($\mu g/m^3$)**
SO_2	24-hr	62	NO	91
	3-hr	218	NO	512

PSD CLASS I INCREMENT ANALYSIS – EVERGLADES NATIONAL PARK				
Pollutant	**Averaging Time**	**Maximum Predicted Impact ($\mu g/m^3$)**	**Impact Greater than Allowable Increment?**	**Allowable Increment ($\mu g/m^3$)**
SO_2	24-hr	4.0	NO	5
	3-hr	12.2	NO	25

AAQS Analysis

For pollutants subject to an AAQS review, the total impact on ambient air quality is obtained by adding a "background" concentration to the maximum-modeled concentration. This "background" concentration takes into account all sources of a particular pollutant that are not explicitly modeled. The results of the AAQS analysis are summarized in the table below. As shown in this table, emissions from the proposed facility are not expected to cause or significantly contribute to a violation of any AAQS.

AMBIENT AIR QUALITY IMPACTS						
Pollutant	**Averaging Time**	**Major Sources Impact ($\mu g/m^3$)**	**Background Concentration ($\mu g/m^3$)**	**Total Impact ($\mu g/m^3$)**	**Total Impact Greater than AAQS?**	**Florida AAQS ($\mu g/m^3$)**
SO_2	Annual	20	5	25	NO	60
	24-hr	132	13	145	NO	260
	3-hr	470	47	517	NO	1300
Pb	Quarterly	0.001	0	0.001	NO	1.5

Additional Impacts Analysis

Impacts on Soils, Vegetation, Wildlife, and Visibility

The maximum ground-level concentrations predicted to occur due to PM_{10}, NOx CO, Pb and SO_2 emissions as a result of the proposed project, including all other nearby sources, will be below the associated AAQS. The AAQS are designed to protect both the public health and welfare. As such, this project is not expected to have a harmful impact on soils and vegetation in the PSD Class II area. An air quality related values (AQRV) analysis was done by the applicant for the Class I area. No significant impacts on this area are expected. A regional haze analysis using the long-range transport model CALPUFF was done for the Everglades National Park Class I area. This analysis showed no significant impact on visibility in this area. Total nitrogen and sulfur deposition rates on the ENP Class I were also predicted using CALPUFF. The maximum predicted deposition rates are below the National Park Service recommended deposition threshold levels for nitrogen and sulfur.

Growth-Related Air Quality Impacts

The proposed modification will not significantly change employment, population, housing or commercial or industrial development in the area to the extent that a significant air quality impact will result.

5. PRELIMINARY DETERMINATION

The Department makes a preliminary determination that the proposed project will comply with all applicable state and federal air pollution regulations as conditioned by the draft permit. This determination is based on a technical review of the complete PSD application, reasonable assurances provided by the applicant, the draft determinations of Best Available Control Technology (BACT), review of the Air Quality Analysis, and the revised specific conditions of the draft permit. Cleve Holladay is the project meteorologist responsible for reviewing and validating the Air Quality Analysis for the project. Jeff Koerner is the project engineer responsible for reviewing the application, recommending the BACT determinations, and drafting the permit. Additional details of this analysis may be obtained by contacting the project engineer at the Department's Bureau of Air Regulation at Mail Station #5505, 2600 Blair Stone Road, Tallahassee, Florida 32399-2400.

Summary Tables – Previous BACT Determinations

Table 1. Recent CO BACT Determinations for Similar Biomass-Fired Boilers

RBLC ID	Initial Permit Date	Facility Name	Capacity MMBtu/hr	CO Limit lb/MMBtu	Controls, Fuels and Comments
AL-0047	1990	Alabama River Pulp, Co.	266	0.3	GCPs; wood
AL-0099	1997	Mead Container Board	622	0.4	GCPs; wood
AL-0079	1994	Weyerhaeuser Company	91	1.4	GCPs; wood
AL-0107	1998	Wellborn Cabinet Inc.	30	0.8	GCPs; wood
AL-0112	1997	Champion International	710	0.30	GCPs; wood
AL-0122	1998	Gulf States Paper Corp.	98	0.5	GCPs; wood
CT-0007	>1991	Bio-Gen Tarrington Partnership	208	0.29	GCPs; wood
FL-?	1985	US Sugar Clewiston Boiler 4	633	6.5	GCPs; bagasse
FL-0011	1981	Atlantic Sugar Boiler 5	255	6.5	GCPs; bagasse
FL-0220	1996	Sugar Cane Growers Coop.	504	5.5	GCPs; bagasse
FL-0094	1995	US Sugar Clewiston Boiler 7	738	6.5	GCPs; bagasse
FL-0069	1993	New Hope Power, 3 Boilers	715	0.35, 12-month	GCPs; wood/bagasse
FL-0198	1992	Ridge Generating Station	630	0.32	GCPs; wood
LA-0074	1991	Willamette Industries, Inc.	940	0.30	GCPs; wood
ME-0013	1991	Beaver-Livermore Falls	533	0.30	GCPs; wood
MI-0139	1989	Hillman Limited Partners	300	0.35	GCPs; wood
MI-0147	1991	Cogeneration Michigan, Inc.	293	0.35	GCPs; wood
MI-0151	1990	Grayling Generating Station	450/523	0.40	GCPs; wood
MI-0180	1992	Cogeneration Michigan, Assoc.	523	0.40	GCPs; wood
MS-0023	1995	Georgia Pacific, Gloster	244	0.69	GCPs, wood
MS-0026	1995	Weyerhaeuser Company	90	0.4	GCPs; wood
MT-0005	1995	Plum Creek, Columbia Falls	292	1.6	GCPs; wood
MT-0007	1997	Plum Creek, Evergreen	225	2.25	GCPs; wood
NH-0003	1990	Pinetree Power, Bethlehem	289	0.50	GCPs; wood
NH-0004	1990	Pinetree Power, Tamworth	404	0.50	GCPs; wood
NY-0055	1994	KES Chateauguay Project	275	0.35	GCPs; wood
SC-0045	1996	Willamette Ind., Marlboro	470	0.3	GCPs; wood
PA-0093	1992	Newman Paper Co.	129	0.3	GCPs; wood
VA-0174	1992	Mulitrade Ltd. Partnership	373	0.35	GCPs; wood
VA-0237	1996	Vaugan Furniture Co.	28	0.85	GCPs; wood
VT-0004	1990	Ryegate Wood Energy Co.	300	0.30	GCPs; wood
WA-0276	1993	Scott Paper Co.	718	0.50	GCPs; wood

Notes:

a. Recent BACT determinations primarily based on data from EPA's RACT/BACT/LAER Clearinghouse.

b. "GCPs" means good combustion practices for a given boiler design.

Table 2. Recent NOx BACT Determinations for Similar Biomass-Fired Boilers

RBLC ID	Initial Permit Date	Facility Name	Capacity MMBtu/hr	NOx Limit lb/MMBTU	Controls, Fuels and Comments
AL-0047	1990	Alabama River Pulp, Co.	266	0.25	GCPs; wood
AL-0099	1997	Mead Container Board	622	0.25	GCPs; wood
AL-0079	1994	Weyerhaeuser Company	91	0.23	GCPs; wood
AL-0107	1998	Wellborn Cabinet Inc.	30	0.46	GCPs; wood
AL-0112	1997	Champion International	710	0.25	GCPs; wood
AL-0116	1997	Gulf States Paper Corp.	775	0.3	GCPs; wood
AL-0122	1998	Gulf States Paper Corp.	98	0.3	GCPs; wood
CT-0147	2001	Killingly Energy	517	0.18	SNCR; wood
FL-?	1985	US Sugar Clewiston Boiler 4	633	0.20	GCPs; bagasse
FL-0011	1981	Atlantic Sugar Boiler 5	255	0.16	GCPs; bagasse
FL-0094	1995	US Sugar Clewiston Boiler 7	738	0.25	GCPs; bagasse
FL-0069	1993	New Hope Power, 3 Boilers	715	0.15	SNCR; wood/bagasse
FL-0198	1992	Ridge Generating Station	630	0.14	SNCR; wood
LA-0074	1991	Willamette Industries, Inc.	940	0.30	GCPs; wood
ME-0021	2001	SD Warren Co. - Skowhegan	1300	0.20	SNCR; wood
ME-0022	2001	SD Warren Co. – Somerset	900	0.20	SNCR; wood
ME-0024	1992	Beaver -Ashland Alternative Energy	534	0.15	SNCR; wood
ME-0026	1999	Wheelabrator Sherman Energy	315	0.25, 30-day	GCPs; wood
MI-0139	1989	Hillman Limited Partners	300	0.15	SNCR; wood
MI-0147	1991	Cogeneration Michigan, Inc.	293	0.21	SNCR; wood
MI-0151	1990	Grayling Generating Station L.P.	450/523	0.15	SNCR; wood
MI-0180	1992	Cogeneration Michigan, Assoc.	523	0.15	SNCR; wood
MN-0033	1998	Potlatch Corporation	140	0.3	GCPs; wood
MS-0023	1995	Georgia Pacific Corp. – Gloster	244	0.3	GCPs, wood
MS-0026	1995	Weyerhaeuser Company	90	0.23	GCPs; wood
MT-0007	1997	Plum Creek Mfg. – Evergreen	225	0.46	GCPs; wood
ND-0018	1998	Archer Daniels Mid. – Northern Sun	200	0.20	GCPs; hulls
NH-0003	1990	Pinetree Power, Inc. - Bethlehem	289	0.30	GCPs; wood
NH-0004	1990	Pinetree Power, Inc. Tamworth	404	0.265	GCPs; wood
NY-0055	1994	KES Chateauguay Project	275	0.23	GCPs; wood
SC-0045	1996	Willamette Industries - Marlboro	470	0.3	GCPs; wood
PA-0093	1992	Newman Paper Company	129	0.3	GCPs; wood
VA-0174	1992	Mulitrade Limited Partnership	373	0.1	SNCR; wood
VA-0237	1996	Vaugan Furniture Company	28	0.20	GCPs; wood
VT-0004	1990	Ryegate Wood Energy Co.	300	0.25	GCPs; wood
WA-0276	1993	Scott Paper Company	718	0.25, 30-day	GCPs; wood

Notes:

a. Recent BACT determinations primarily based on data from EPA's RACT/BACT/LAER Clearinghouse.

b. GCPs means good combustion practices for a given boiler design.

Table 3. Recent PM BACT Determinations for Similar Biomass-Fired Boilers

RBLC ID	Date	Facility Name	Capacity MMBtu/hr	PM Limit lb/MMBTU	Controls, Fuels and Comments
AL-0047	1990	Alabama River Pulp, Co.	266	0.10	ESP; wood
AL-0099	1997	Mead Container Board	622	0.03	ESP; wood
AL-0079	1994	Weyerhaeuser Company	91	0.15	Venturi Scrubber; wood
AL-0112	1997	Champion International	710	0.03	ESP; wood
AL-0122	1998	Gulf States Paper Corp.	98	0.10	ESP; wood
CT-0147	2001	Killingly Energy	517	~0.011	ESP; wood (5.69 lb/hr)
FL-?	1985	US Sugar Clewiston Boiler 4	633	0.03	WIP; bagasse
FL-0011	1981	Atlantic Sugar Boiler	255	0.15	WIP; bagasse
FL-0094	1995	US Sugar Clewiston Boiler 7	738	0.030	ESP; bagasse
FL-0069	1993	New Hope Power, 3 Boilers	715	0.03	ESP; wood/bagasse
FL-0198	1992	Ridge Generating Station	630	See comment	Baghouse; wood (0.008 gr/dscf)
ME-0021	2001	SD Warren Co., Skowhegan	1300	0.03	ESP; wood
ME-0022	2001	SD Warren Co., Somerset	900	0.03	ESP; wood
ME-0024	1992	Beaver, Ashland Alt. Energy	534	0.02	ESP; wood
ME-0026	1999	Wheelabrator Sherman Energy	315	0.036	ESP; wood
MI-0139	1989	Hillman Limited Partners	300	0.03	ESP; wood
MI-0147	1991	Cogeneration Michigan, Inc.	293	0.03	Baghouse; wood
MI-0151	1990	Grayling Generating Station	450/523	0.03	ESP; wood
MI-0180	1992	Cogeneration Michigan, Assoc.	523	0.03	ESP; wood
MS-0023	1995	Georgia Pacific Corp., Gloster	244	0.10	Unknown, wood
MS-0026	1995	Weyerhaeuser Company	90	0.10	Unknown; wood
ND-0018	1998	Archer Daniels Mid., N. Sun	200	0.24	ESP; hulls
NH-0003	1990	Pinetree Power, Bethlehem	289	0.03	ESP; wood
NH-0004	1990	Pinetree Power, Tamworth	404	0.025	ESP; wood
NY-0055	1994	KES Chateauguay Project	275	0.038	ESP; wood
OK-0038	1996	Valliant	900	0.10	Wet Scrubber; wood
SC-0045	1996	Willamette Industries, Marlboro	470	0.05	ESP; wood
PA-0093	1992	Newman Paper Co.	129	0.10	Baghouse; wood
VA-0174	1992	Mulitrade Limited Partnership	373	0.02	ESP; wood
VA-0237	1996	Vaugan Furniture Co.	28	See comment	Multiclones; wood; (36.8 TPY)
VT-0004	1990	Decker International	300	See comment	ESP; wood; (0.0007 gr/dscf)
WA-0276	1993	Scott Paper Co.	718	See comment	Baghouse; wood; (0.011 gr/dscf)

Notes:

a. Recent BACT determinations primarily based on data from EPA's RACT/BACT/LAER Clearinghouse.

b. "WIP" means wet impingement scrubber.

Table 4. Recent SO_2 BACT Determinations for Similar Biomass-Fired Boilers

RBLC ID	Date	Facility Name	Capacity MMBtu/hr	SO_2 Limit lb/MMBTU	Controls, Fuels and Comments
AL-0047	1990	Alabama River Pulp, Co.	266	0.30	LSF; wood
AL-0099	1997	Mead Container Board	622	0.02	LSF; wood, sludge
AL-0116	1997	Gulf States Paper Corp.	775	0.46	LSF; wood
CT-0007	>1991	Bio-Gen Tarrington Partnership	209	0.10	LSF; wood
CT-0147	2001	Killingly Energy	517	0.044	LSF; wood
FL-?	1985	US Sugar Clewiston Boiler 4	633	0.06	LSF; bagasse
FL-0011	1981	Atlantic Sugar Boiler 5	255	0.05	LSF; bagasse
FL-0094	1995	US Sugar Clewiston Boiler 7	738	0.17	LSF; bagasse
FL-0069	1993	New Hope Power, 3 Boilers	715	0.06, 12 month	LSF - wood, bagasse
FL-0070	1993	Osceola Power L.P.	760	0.05, 30-day	LSF - wood, bagasse
FL-0198	1992	Ridge Generating Station	630	0.10	LSDA; wood, tires, LF gas
LA-0074	1991	Willamette Industries, Inc.	940	0.008	LSF; wood
ME-0013	1991	Beaver-Livermore Falls	534	0.023	LSF; wood
ME-0021	2001	SD Warren Co. - Skowhegan	1300	0.27	Na SDS; wood
ME-0022	2001	SD Warren Co. - Somerset	900	0.27	Na SDS; wood
ME-0024	1992	Beaver -Ashland Alternative Energy	534	0.014	LSF; wood
ME-0026	1999	Wheelabrator Sherman Energy	315	0.12	LSF; wood
ME-0139	1989	Hillman Ltd. Partners	300	0.018	LSF; wood
MS-0023	1995	Georgia Pacific Corp. – Glostee	244	0.017	LSF, wood
ND-0018	1998	Archer Daniels Mid. - Northern Sun	200	0.002	LSF; hulls
ND-0018	1998	Archer Daniels Mid. - Northern Sun	280	0.002	LSF; hulls
NY-0055	1994	KES Chateauguay Project	275	0.030	LSF; wood
OK-0038	1996	Valliant	900	0.80	LSF; wood
SC-0045	1996	Willamette Industries - Marlboro	470	0.10	LSF; wood
VA-0174	1992	Mulitrade Limited Partnership	373	0.016	LSF; wood
WA-0276	1993	Scott Paper Company	718	0.010	LSF; wood

Notes:

a. Recent BACT determinations primarily based on data from EPA's RACT/BACT/LAER Clearinghouse.

b. "LSF" means low sulfur fuels. "LSDA" means lime spray dryer absorber. "Na SDA" means sodium spray dryer absorber. "LF gas" means landfill gas.

Table 5. Recent VOC BACT Determinations for Similar Biomass-Fired Boilers

RBLC ID	Date	Facility Name	Capacity MMBtu/hr	VOC Limit lb/MMBTU	Controls, Fuels and Comments
AL-0047	1990	Alabama River Pulp, Co.	266	0.03	GCPs; wood
AL-0116	1997	Gulf States Paper Corp.	775	0.03	GCPs; wood
CT-0147	2001	Killingly Energy	517	0.05	GCPs; wood
FL-?	2001	US Sugar Clewiston Boiler 4	633	0.06	GCPs; bagasse
FL-0011	2001	Atlantic Sugar Boiler 5	255	0.25	GCPs; bagasse
FL-0094	1995	US Sugar Clewiston Boiler 7	738	0.212	GCPs; bagasse
FL-0069	2002	New Hope Power, 3 Boilers	715	0.06	GCPs; wood/bagasse
FL-0198	1992	Ridge Generating Station	630	0.035	GCPs; wood
LA-0074	1991	Willamette Industries, Inc.	940	0.10	GCPs; wood
ME-0021	2001	SD Warren Co. – Skowhegan	1300	0.007	GCPs; wood
ME-0022	2001	SD Warren Co. – Somerset	900	0.10	GCPs; wood
ME-0024	1992	Beaver -Ashland Alternative Energy	534	0.016	GCPs; wood
ME-0026	1999	Wheelabrator Sherman Energy	315	0.03	GCPs; wood
MI-0151	1990	Grayling Generating Station	450/523	0.05	GCPs; wood
NH-0003	1990	Pinetree Power, Inc. - Bethlehem	289	0.096	GCPs; wood
NH-0004	1990	Pinetree Power, Inc. Tamworth	404	0.096	GCPs; wood
NY-0055	1994	KES Chateauguay Project	275	0.10	GCPs; wood
OK-0038	1996	Valliant	900	0.047	GCPs; wood
SC-0045	1996	Willamette Industries - Marlboro	470	0.10	GCPs; wood
VA-0174	1992	Mulitrade Limited Partnership	373	0.07	GCPs; wood
VT-0004	1990	Ryegate Wood Energy Co.	300	0.03	GCPs; wood
WA-0276	1993	Scott Paper Company	718	0.50	GCPs; wood

Notes:

a. Recent BACT determinations primarily based on data from EPA's RACT/BACT/LAER Clearinghouse.

b. "GCPs" means good combustion practices for a given boiler design.

DRAFT PERMIT

PERMITTEE

New Hope Power Partnership
Okeelanta Cogeneration Plant
8001 U.S. Highway 27 South
South Bay, FL 33493

Authorized Representative:
Mr. Rodney Williams, Plant Manager

Air Permit No. PSD-FL-196(O)
Project No. 0990332-016-AC
Okeelanta Cogeneration Plant
SIC No. 4911
Palm Beach County

PROJECT AND LOCATION

The original PSD permit authorized the construction of a biomass and fossil fuel-fired 74.9 MW cogeneration plant adjacent to Okeelanta Corporation's sugar mill and refinery. The original PSD permit expired on July 1, 1996. The permittee obtained several previous permit modifications that extended some construction-related activities as well as revised specific conditions of the permit. This permit modification authorizes an increase in the hourly heat input rate from 715 to 760 MMBtu per hour per boiler and removes the previous limit on the annual heat input rate (11.5 x 10^{+06} MMBtu per year) for the three boilers combined. As a result of the changes, BACT determinations were required for emissions of carbon monoxide, fluorides, lead, nitrogen oxides, particulate matter, sulfur dioxide, sulfuric acid mist, and volatile organic compounds. In addition, Condition No. 15 was revised to simply require permanent shutdown of the existing Okeelanta sugar mill boilers, which were part of the netting analysis for the original project.

The cogeneration plant is located off U.S. Highway 27 approximately six miles south of South Bay in Palm Beach County, Florida. The UTM coordinates are Zone 17, 524.90 km East, and 2940.10 km North. The map coordinates are latitude 26° 35' 00 " N and longitude 80° 45' 00" W.

STATEMENT OF BASIS

This PSD air pollution construction permit is issued under the provisions of Chapter 403 of the Florida Statutes (F.S.), and Chapters 62-4, 62-204, 62-210, 62-212, 62-296, and 62-297 of the Florida Administrative Code (F.A.C.) and Title 40, Part 52, Section 21 of the Code of Federal Regulations. Specifically, this permit is issued pursuant to the requirements for the Prevention of Significant Deterioration (PSD) of Air Quality, Rule 62-212.400, F.A.C. The permittee is authorized to perform the proposed work and operate the installed equipment in accordance with the conditions of this permit, the conditions of the Title V operation permit, and as described in the application, approved drawings, plans, and other documents on file with the Department.

CONTENTS

(DRAFT)

Michael G. Cooke, Director
Division of Air Resources Management

Effective Date

FACILITY DESCRIPTION

The facility consists of two adjacent plants. Okeelanta Corporation operates a sugar mill (SIC No. 2061) and sugar refinery (SIC No. 2062) including packaging and transshipment activities. New Hope Power Partnership operates a 74.9 net MW cogeneration plant that provides process steam for the sugar mill/refinery and generates electricity for sale to the power grid (SIC 4911). This permit addresses the cogeneration plant, which consists of the following emissions units.

ID	Emission Unit Description
001	Cogeneration Boiler A (760 MMBtu per hour)
002	Cogeneration Boiler B (760 MMBtu per hour)
003	Cogeneration Boiler C (760 MMBtu per hour)
004	Material handling and storage

REGULATORY CLASSIFICATION

Title III: The existing facility is a major source of hazardous air pollutants (HAPs).

Title IV: The existing facility does not operate any units subject to the acid rain provisions of the Clean Air Act.

Title V: The existing facility is a Title V major source of air pollution in accordance with Chapter 213, F.A.C.

PSD: The existing facility is a PSD major source of air pollution with respect to Rule 62-212.400, F.A.C.

PPSC: The existing facility is not subject to Chapter 62-17, F.A.C. for Power Plant Site Certification because it produces less than 75 MW of steam-generated electrical power.

NSPS: The existing facility operates units subject to the New Source Performance Standards in 40 CFR 60, including Subparts Da and Db (boilers) and Subpart Kb (fuel storage tanks).

PERMITTING AUTHORITY

All documents related to PSD applications for permits to construct or modify shall be submitted to the Bureau of Air Regulation of the Florida Department of Environmental Protection (DEP) at 2600 Blair Stone Road (MS #5505), Tallahassee, Florida 32399-2400. All documents related to applications for permits to operate the cogeneration plant shall be submitted to the Air Resource Section of the Department's South District Office at P.O. Box 2549, Fort Myers, Florida 33902-2549. Copies of all such documents shall be submitted to the Air Pollution Control Section of the Palm Beach County Health Department at P.O. Box 29, West Palm Beach, Florida 33402-0029.

COMPLIANCE AUTHORITY

All documents related to compliance activities such as reports, tests, and notifications shall be submitted to the Air Pollution Control Section of the Palm Beach County Health Department at P.O. Box 29, West Palm Beach, Florida 33402-0029. Copies of all such documents shall be submitted to the Air Resources Section at the South District Office of the Florida Department of Environmental Protection (DEP) at 2295 Victoria Avenue, Suite 364 in Fort Myers, Florida 33902-2549.

APPENDICES

The following Appendices are attached as part of this permit.

Appendix A. Citation Format

Appendix B. General Conditions

Appendix C. Standard Requirements

Appendix D. Final BACT Determinations

Appendix E. Continuous Monitor Requirements

RELEVANT DOCUMENTS

The documents listed below are not a part of this permit; however, they are specifically related to this permitting action and are on file with the Department.

- Air Permit No. PSD-FL-196 issued September 27, 1993 and all subsequent modifications.
- Permit application received on September 6, 2002 and all related correspondence to make complete.

CITATION FORMAT

Appendix A of this permit describes the format used to cite applicable rules and regulations as well as previous permitting actions.

1. General Conditions: The permittee is subject to, and shall operate under, the attached General Conditions listed in Appendix B of this permit. General Conditions are binding and enforceable pursuant to Chapter 403 of the Florida Statutes. [Rule 62-4.160, F.A.C.]

2. Applicable Regulations, Forms and Application Procedures: Unless otherwise indicated in this permit, the construction and operation of the subject emissions unit shall be in accordance with the capacities and specifications stated in the application. The facility is subject to all applicable provisions of: Chapter 403 of the Florida Statutes (F.S.); Chapters 62-4, 62-204, 62-210, 62-212, 62-213, 62-296, and 62-297 of the Florida Administrative Code (F.A.C.); and the Title 40, Parts 51, 52, and 60 of the Code of Federal Regulations (CFR), adopted by reference in Rule 62-204.800, F.A.C. The terms used in this permit have specific meanings as defined in the applicable chapters of the Florida Administrative Code. The permittee shall use the applicable forms listed in Rule 62-210.900, F.A.C. and follow the application procedures in Chapter 62-4, F.A.C. Issuance of this permit does not relieve the permittee from compliance with any applicable federal, state, or local permitting or regulations. [Rules 62-204.800, 62-210.300 and 62-210.900, F.A.C.]

3. Permit Expiration: The original expiration date for the construction of this plant was July 1, 1996. Construction of the cogeneration plant is complete and commercial operation has commenced. This revised permit does not authorize any additional construction. The expiration date of this revised permit is September 1, 2004 strictly for the purpose of processing a Title V air permit revision to incorporate these changes. All physical construction is complete. [Rule 62-4.210(2), F.A.C.]

4. Effective Date: The effective date of the modified PSD permit is specified on the placard page (page 1).

5. Relaxations of Restrictions on Pollutant Emitting Capacity: If a previously permitted facility or modification becomes a facility or modification which would be subject to the preconstruction review requirements of this rule if it were a proposed new facility or modification solely by virtue of a relaxation in any federally enforceable limitation on the capacity of the facility or modification to emit a pollutant (such as a restriction on hours of operation), which limitation was established after August 7, 1980, then at the time of such relaxation the preconstruction review requirements of this rule shall apply to the facility or modification as though construction had not yet commenced on it. [Rule 62-212.400(2)(g), F.A.C.]

6. New or Additional Conditions: For good cause shown and after notice and an administrative hearing, if requested, the Department may require the permittee to conform to new or additional conditions. The Department shall allow the permittee a reasonable time to conform to the new or additional conditions, and on application of the permittee, the Department may grant additional time. [Rule 62-4.080, F.A.C.]

7. Modifications: No emissions unit or facility subject to this permit shall be constructed or modified without obtaining an air construction permit from the Department. Such permit shall be obtained prior to beginning construction or modification. [Rules 62-210.300(1) and 62-212.300(1)(a), F.A.C.]

8. Title V Permit Revision: Within 90 days of the effective date of this modified PSD permit, the permittee shall submit an application for a revised Title V permit to incorporate the changes. To apply for a revised Title V operation permit, the applicant shall submit the appropriate application form, compliance test results, and such additional information as the Department may by law require. As necessary, the application shall include a Compliance Assurance Monitoring Plan. The application shall be submitted to the Department's South District Office with copies to the Compliance Authority. [Rules 62-4.030, 62-4.050, 62-4.220, and Chapter 62-213, F.A.C.]

This section of the permit addresses the following emissions units.

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Emissions Units 001, 002, and 003: Cogeneration Boilers A, B, and C

Description: Each unit is a biomass-fired spreader stoker steam boiler manufactured by Zurn and designed to produce approximately ~~455,400~~ 506,100 pounds per hour of steam at 1500 psig and 975° F.

Fuels and Capacity: The primary fuel is biomass (~~715~~ 760 MMBtu per hour), which includes bagasse from the adjacent sugar mill and clean wood material delivered to the plant by area subcontractors. Auxiliary fuels include natural gas (~~400~~ 605 MMBtu per hour) and very low sulfur distillate oil (490 MMBtu per hour).

Controls: Pollution control equipment includes low-NOx burners for gas firing, a selective non-catalytic reduction system to reduce nitrogen oxides emissions, mechanical dust collectors and an electrostatic precipitator to reduce particulate matter emissions, and an activated carbon injection system to reduce potential mercury emissions. Good operating practices and the efficient combustion of clean, low-sulfur fuels minimizes emissions of carbon monoxide, sulfuric acid mist, sulfur dioxide, and volatile organic compounds.

Stack Parameters: Exhaust gases exit a 10 feet diameter stack that is at least 199 feet tall and with a volumetric flow rate of approximately ~~246,000~~ 319,000 acfm at ~~295~~ 352° F.

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Emissions Unit 004: Material handling and storage including unloading operations, stockpiles, transfer operations, conveyors, screens, crushers, hoppers, silos, and storage tanks.

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CONSTRUCTION DETAILS

1. Generating Capacity: Construction of the proposed cogeneration plant shall reasonably conform to the plans described in the application. The plant shall be designed, constructed, and operated such that the generating capacity does not exceed 74.9 net megawatt (MW) based on a 1-hour average. The owner or operator shall not modify the cogeneration plant in any way that would cause the plant to exceed the limit on maximum net generating capacity. The hourly average net generation rate shall be recorded and retained for at least 5 years.

2. Boiler Design: The cogeneration boilers shall consist of spreader stoker units designed to fire biomass as the primary fuel with pipeline natural gas and distillate oil as auxiliary fuels. Natural gas and distillate oil are fired at startup, to supplement biomass fuel, and for periods when the biomass fuel supply is interrupted. No other fuels are authorized. *{Permitting Note: Each boiler was originally designed to fire low sulfur coal as an emergency backup fuel, but no transfer, crushing, or storage systems were ever installed. The permittee shall obtain a permit modification before firing any other fuel (including coal) not specifically authorized by this permit.}*

3. Stack: Each boiler shall have an individual stack that is at least 199 feet tall. The permanent stack sampling facilities for each stack must comply with Rule 62-297.345, F.A.C.

4. Process Monitors: Each boiler shall be equipped with instruments to measure the fuel feed rate, heat input, steam production, steam pressure, and steam temperature. Appendix E identifies minimum requirements for monitoring equipment.

5. Control Equipment: Each boiler shall be equipped with:
   - Low-NOx natural gas burners rated for no more than 0.15 pounds of NOx per MMBtu of heat input. Four burners are installed with one in each corner the boiler. The maximum heat input rate from all four burners is ~~400~~ 605 MMBtu per hour.
   - Mechanical dust collectors consisting of four, large diameter, multi-tube modules with airfoil vanes or equivalent equipment. The mechanical dust collectors shall be installed and maintained as pre-control devices prior to each electrostatic precipitator and designed for a removal efficiency of at least 85% of the particulate matter greater than 10 microns in size (assuming a specific gravity of 2.00).
   - An electrostatic precipitator (ESP) designed for at least 98 percent removal of particulate matter.

- A selective non-catalytic reduction (SNCR) system designed for at least 40 percent removal of NOx.
- A carbon injection system (or equivalent) for potential control of mercury emissions.

6. Continuous Monitors: For each cogeneration boiler, the permittee shall install, calibrate, maintain, and operate continuous emissions monitors (CEMS) and continuous opacity monitors (COMS) to measure and record emissions of carbon monoxide (CO), nitrogen oxides (NOx), opacity, oxygen (O_2), and sulfur dioxide (SO_2) in a manner sufficient to demonstrate compliance with the standards of this permit. The opacity monitor shall be placed in the ductwork between the electrostatic precipitator and the stack or in the stack. Appendix E identifies minimum requirements for monitoring systems.

7. Good Combustion Practices: An oxygen meter shall be installed for each unit to continuously monitor a representative sample of the flue gas. The oxygen monitor shall be used with automatic feedback or manual controls to continuously optimize air/fuel ratio parameters. Depending on the fuel quality and existing combustion conditions, the operator shall provide sufficient excess air to ensure good combustion within the boiler. The application to revise the Title V operation permit shall identify "good combustion practices" for the cogeneration boilers to minimize pollutant emissions during startup, operation, and shutdown. The document "Use of Flue Gas Oxygen Meter as BACT for Combustion Controls" shall be used as a guide. Good combustion controls shall also include the following:

   - Maintain improved combustion controls to provide efficient tuning of air/fuel control instrumentation.
   - Maintain rotary pocket-style wood feeders with efficient air seal to minimize intrusion of ambient air.
   - Maintain effective water level controls in bottom ash system to prevent intrusion of ambient air.
   - Mix biomass fuel to provide a consistent fuel blend.
   - Maintain the flue gas oxygen content to provide efficient combustion for the existing conditions.
   - When necessary to enhance poor combustion, reduce the biomass feed rate below the maximum rate.
   - When necessary to enhance poor combustion, co-fire natural gas or distillate oil.

8. O&M Plans: The application to revise the Title V operation permit shall include an operation and maintenance plan consisting of at least the following items.

   a. For the cogeneration boilers, electrostatic precipitators (ESP), selective non-catalytic reduction (SNCR) systems, activated carbon injection (ACI) mercury control systems, and silo fabric filters, identify: the capacities, design efficiencies, pollutant emission rates, general operational description of equipment, key design and operating parameters, expected operating range of each key parameter, monitoring of key parameters, frequency of monitoring (instantaneous, continual, or continuous), and actions taken to return key parameters to within the expected operating ranges. The plan shall also specify good operating practices to promote efficient boiler combustion, startup and shutdown procedures for the boilers and control systems to minimize emissions, and precautions to prevent fugitive particulate matter emissions. *{Permitting Note: Operation outside of the specified operating range for any monitored parameter would not be a violation by itself. However, continued operation outside of a specified operating range without corrective action may be considered circumvention of the air pollution control equipment or methods.}*

   b. For the selective non-catalytic reduction (SNCR) systems identify an alternate NOx emissions control plan based on previous monitoring data that shall be implemented in case the NOx monitoring system is down. The plan shall identify the minimum urea injection rate that has demonstrated continuous compliance with the NOx emissions standard at various load conditions.

9. Materials Handling Controls: For the fly ash handling and mercury control system reactant storage systems:

   a. The particulate matter filter control system for the storage silos shall be designed to achieve an outlet dust loading of no greater than 0.01 grains per actual cubic feet of exhaust.

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

OPERATIONAL RESTRICTIONS

10. Permitted Capacity: The cogeneration boilers shall be constructed and operated in accordance with the capabilities and specifications described in the application. The maximum heat input rate to each cogeneration boiler shall not exceed ~~715~~ 760 MMBtu/hr when burning 100 percent biomass, ~~400~~ 605 MMBtu/hr when burning 100 percent natural gas, and 490 MMBtu/hr when burning 100 percent very low sulfur distillate oil. ~~The maximum heat input to the entire plant (total for all three boilers combined) shall not exceed 11.5 x 10^+6 MMBtu during any consecutive 12 month period.~~ The steam production of each boiler shall not exceed an average of ~~455,418~~ 506,100 pounds per hour at 1,500 psig and 975°F.

11. Primary Fuel: The primary fuel for the plant shall be biomass, which shall consist of bagasse and authorized wood material. Bagasse is the fibrous vegetative residue remaining after the sugarcane milling process. Authorized wood material is clean construction and demolition wood debris, yard trash, land clearing debris, and other clean cellulose and vegetative matter. Each cogeneration boiler shall combust no more than 30% by weight yard waste (yard trash) on a calendar quarter basis that is defined as a municipal solid waste (MSW) in 40 CFR 60.51a. The biomass fuel used at the cogeneration plant shall not contain hazardous substances, hazardous wastes, biomedical wastes, or garbage. The fuel used at the cogeneration plant shall not contain special wastes, except wood, lumber, trees, tree remains, bagasse, cane tops and leaves, and other clean vegetative and cellulose matter. The permittee shall perform a daily visual inspection of any wood material or similar vegetative matter that has been delivered to the plant for use as fuel. Any shipment observed to contain prohibited materials shall not be used as fuel, unless such materials can be readily segregated and removed from the wood material and vegetative matter.

    The permittee shall design and implement a management and testing program for the wood material and other materials delivered to the plant for fuel. The program shall be designed to keep painted and chemically treated wood, household garbage, toxic or hazardous non-biomass and non-combustible waste material, from being burned at this plant. The program shall provide for the routine inspection and/or testing of the fuel at the originating wood yard sites as well as at the cogeneration site, to ensure that the quantities of painted or chemically treated wood in the fuel are minimized. Based on the analysis of a composite sample, wood material containing more than 70.7 ppm arsenic or 83.3 ppm chromium or 62.8 ppm copper shall not be burned. Fuel scheduled for burning shall be inspected daily. At a minimum, the fuel management program shall include the following sampling and analyses:

    a. At least twice each month, the permittee shall have separate analyses conducted on an as-fired wood sample and an as-fired bagasse sample for the following: heating value (modified ASTM D3286, Btu/lb, dry), carbon content (modified ASTM D5373, percent by weight, dry), sulfur content (modified ASTM D4239 Method C, percent by weight, dry), and moisture content (modified ASTM D3173, percent by weight). In addition the wood sample shall be analyzed for copper, chromium, and arsenic in accordance with Methods 3050/6010 (EPA Method SW-846) and reported in ppm by weight, dry. Samples shall be taken at least two weeks apart.

    b. At least once each month, the permittee shall have an analysis conducted on a composite sample of fly ash and bottom ash for arsenic, copper, and chromium in accordance with the procedures described in EPA Method SW-846, *Test Methods for Evaluating Solid Waste, Physical/Chemical Methods* (40 CFR 261, Appendix III). The analytical results from ash testing shall be used in conjunction with those from the as-fired wood samples to evaluate the effectiveness of the fuel management program in removing chemically treated wood from the biomass fuel. The permittee shall dispose of all ash generated on site in accordance with the applicable state and federal regulations.

    c. Analytical results of the as-fired biomass fuels and ash sampling shall be summarized and provided in the quarterly report to the Compliance Authority.

    The ash and fuel management program shall become part of the Title V operation permit.

12. Auxiliary Fuel: The cogeneration boilers shall fire only distillate oil and pipeline natural gas as auxiliary fuels. Distillate oil shall be new No. 2 oil with a maximum sulfur content of 0.05 percent sulfur by weight as determined by the appropriate test method listed in 40 CFR 60.17. "New" oil is oil that has been refined from crude oil and that has not been used in any manner that may contaminate it. Each boiler may startup solely on pipeline natural gas or distillate oil.

13. Fossil Fuel Limitation: The firing of fossil fuels (distillate oil and natural gas) shall be less than 25 percent of the total heat input to each cogeneration boiler during any calendar quarter.

14. Fuel Records: The permittee shall maintain a daily log of the amounts and types of fuels used. The amount, heating value, and sulfur content of each fuel oil delivery shall be kept in a log for at least five years. For each calendar month, the actual monthly SO_2 emissions and the 12-month rolling total SO_2 emissions shall be determined and kept in a log.

15. ~~Emergency Standby: The existing sugar mill boilers shall comply with the following requirements.~~Permanent Shutdown: Sugar mill boiler Nos. 4, 5, 6, 10, 11, 12, 14, and 15 shall remain permanently shutdown and rendered incapable of operation. {Permitting Note: Okeelanta Corporation's Boiler No. 16 may operate in accordance with modified Permit No. PSD-FL-169(A).} [Rule 62-212.400, F.A.C.]

~~a. Sugar mill boiler Nos. 4, 5, 6, 10, 11, 12, 14, and 15 may be retained for emergency standby operation until April 1, 2002. These boilers shall only operate in the event of electrical or mechanical failure of all three of the cogeneration boilers. Simultaneous operation of any of these sugar mill boilers with any of the cogeneration boilers is prohibited. Sugar mill boiler Nos. 4, 5, 6, 10, 11, 12, 14, and 15 shall be permanently shutdown and rendered incapable of operation no later than October 1, 2002.~~

~~b. Each sugar mill boiler shall comply with its most recent air construction and operation permit, including all emissions performance, testing, and monitoring requirements as well as any applicable Alternate Sampling Procedures approved by the Department. The sugar mill boilers shall only fire fuels approved in the most recent permits.~~

~~16. Auxiliary Boiler: Sugar mill boiler No. 16 shall be operated in accordance with revised Permit No. PSD-FL-169A and the subsequently revised Title V operation permit.~~

EMISSIONS LIMITING STANDARDS

~~17.~~16. Emissions Standards: Based on the maximum permitted heat input to each cogeneration boiler, stack emissions shall not exceed the standards specified in the following table:

Pollutant	Averaging Period	Emissions Standards per Boiler [~~h~~i]	
		lb/MMBtu	lb/hr
Carbon Monoxide (CO) [a]	30-day rolling CEMS avg.	0.50	~~357.5~~380.0
	12-month rolling CEMS avg.	0.35	
Nitrogen Oxides (NOx) [b]	30-day rolling CEMS avg.	0.15	~~107.3~~114.0
Sulfur Dioxide (SO_2) [c]	24-hour rolling CEMS avg.	0.20	~~143.0~~152.0
	30-day rolling CEMS avg.	0.10	
	12-month rolling CEMS avg.	0.06	
Stack Opacity [d]	6-minute block COMS avg. (Alternative: EPA Method 9)	≤ 20% opacity, except for one 6-minute block per hour that is ≤ 27% opacity	
Particulate Matter (PM/PM_{10}) [e]	3-run test avg.	~~0.03~~0.026	~~21.5~~19.8
Volatile Organic Compounds (VOC) [f]	3-run test avg.	0.05	~~42.9~~38.0
~~Lead [g]~~	~~3-run test avg.~~	~~1.5×10^{-04}~~	~~NA~~

Mercury [~~h~~g]	3-run test avg.	5.4×10^{-06}	NA
Lead and Fluorides [~~i~~h]	Fluoride emissions shall be minimized by firing biomass as the primary fuel with natural gas and very low sulfur distillate oil as auxiliary fuels. *The BACT determination for lead and fluoride emissions is the use of fuels containing low levels of these compounds (bagasse, wood, distillate oil, and natural gas) and prospective removal with the fly ash by the mechanical dust collectors and electrostatic precipitators.*		

a. Compliance shall be determined by data collected from the required CO CEMS in terms of "lb/MMBtu of heat input". The 30-day rolling average shall be determined by calculating the arithmetic average of all hourly emission rates for 30 successive boiler operating days and be consistent with the NOx monitoring requirements below. Compliance with the 12-month standard shall be based on the rolling average for each consecutive 12-month period. In addition, the CO CEMS shall record CO emissions in terms of "ppmvd corrected to 3% oxygen" for each 1-hour block average and each 24-hour block average (day). *{Permitting Note: CO emissions data recorded and reported in terms of "ppmvd corrected to 3% oxygen" are for informational purposes only.}*

b. Compliance shall be determined by data collected from the required NOx CEMS in terms of "lb/MMBtu of heat input". The 30-day rolling average shall be determined by calculating the arithmetic average of all hourly emission rates for 30 successive boiler operating days and the requirements of 40 CFR 60.13, 60.44a, 60.46a, 60.47a, 60.48a, and 60.49a. A boiler-operating day is any day in which any authorized fuel is fired.

c. Compliance with the SO_2 standards shall be determined by data collected from the required SO_2 CEMS in terms of "lb/MMBtu of heat input". The 24-hour average shall be determined by calculating the arithmetic average of all valid hourly emission rates for 24 successive boiler-operating hours. The 30-day rolling average shall be determined by calculating the arithmetic average of all hourly emission rates for 30 successive boiler-operating days and the requirements of 40 CFR 60.13, 60.43a, 60.46a, 60.47a, 60.48a, and 60.49a. Compliance with the 12-month standard shall be based on the rolling average for each consecutive 12-month period. Valid SO_2 hourly averages shall not be excluded from any compliance average. *{Permitting Note: Potential emissions of sulfuric acid mist are minimized by the effective control of SO_2 emissions with the firing of low sulfur fuels. For reporting purposes, sulfuric acid mist emissions shall be estimated as 6% of the total measured SO_2 emissions.}*

d. Continuous compliance with the opacity standard shall be determined by data collected from the required COMS in terms of "percent opacity" based on 6-minute block averages. Alternatively, compliance may also be determined by conducting EPA Method 9 observations.

e. Compliance with the particulate matter standards shall be determined by the average of three test runs conducted in accordance with EPA Method 5. For purposes of reporting PM_{10} emissions, it shall be assumed that all particulate matter emitted is PM_{10}.

f. Compliance with the VOC standards shall be determined by the average of three test runs conducted in accordance with EPA Method 25A based on propane. In addition, the permittee may choose to conduct EPA Method 18 concurrently with EPA Method 25A to deduct emissions of methane and ethane from the measured VOC emissions. Otherwise, all emissions measured by EPA Method 25A shall be considered "volatile organic compounds".

~~g. Compliance with the lead standards shall be determined by the average of three test runs conducted in accordance with EPA Method 12 or 29.~~

~~h.~~g. Compliance with the mercury standards shall be determined by the average of three test runs conducted in accordance with EPA Method 101A or 29. Emissions in excess of this standard shall be a violation of the permit. In addition, if two or more cogeneration boilers exceed the annual mercury emission limit, the permittee shall reactivate the carbon injection system for all three units within 30 days of the stack test report due date. The minimum carbon injection rate shall be at least 7 pounds per hour. Within 60 days of the stack test report due date, the permittee shall submit to the permitting and compliance authorities a mercury testing protocol designed to establish an effective carbon injection rate to control mercury emissions. Within 60 days of receiving approval for the mercury testing protocol by the permitting authority, the permittee shall begin the approved testing program. At a minimum, the permittee shall submit a full engineering report summarizing the uncontrolled emissions, controlled emissions, fuels, operating capacities, and recommending a minimum activated carbon injection rate to control mercury emissions.

~~i.~~h. *The particulate matter standard is also a surrogate standard for lead emissions. {Permitting Note: For reporting purposes, average lead emissions are expected to be 2.6 x 10^{-05} lb/MMBtu and average fluoride emissions are expected to be 1.9 x 10^{-04} lb/MMBtu when firing bagasse/wood.}*

~~j.~~i. Each boiler shall comply with the standards when firing any combination of authorized fuels. The "lb/hour" rates are based on the highest emission standard shown for that pollutant. Required compliance tests shall be performed in accordance with the requirements of Condition No. 19. The cogeneration boilers are also subject to the new source performance standards (NSPS Subpart Da) for new electric utility steam generating units. These requirements include the general provisions of Subpart A in 40 CFR 60, as well as the following source-specific applicable requirements: 60.40a (Applicability and Designation of Affected Facility); 60.41a (Definitions); 60.42a (Standards for Particulate Matter); 60.43a (Standard for Sulfur Dioxide); 60.44a (Standard for Nitrogen Oxides); 60.46a (Compliance Provisions); 60.47a (Emissions Monitoring); 60.48a (Compliance Determination Procedures and Methods); and 60.49a (Reporting Requirements). The cogeneration boilers are also subject to Rule 62-296.405(2), F.A.C. (Fossil Fuel Steam Generators with more than 250 MMBtu per Hour of Heat Input), Rule 62-296.410, F.A.C. (Carbonaceous Fuel Burning Equipment), and Rule 62-296.570, F.A.C. (Reasonably Available Control Technology Requirements for Major VOC and NOx Facilities).

{Permitting Note: Appendix D identifies the final BACT determinations for the cogeneration boilers.}

~~18.~~17. Material Handling: The following conditions apply to the biomass, ash, and activated carbon handling facilities.

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

b. Water sprays, chemical wetting agents, and/or stabilizers shall be applied to storage piles, handling equipment, unenclosed transfer points, etc. during dry periods and as necessary to prevent visible emissions. When adding, moving or removing material from the storage pile, visible emissions of no more than 20% opacity are allowed.

c. The mercury control system reactant storage silos shall be maintained at a negative pressure while operating with the exhaust vented to a filter control system. Visible emissions from any storage silo shall not exceed 5 percent opacity based on a 6-minute block average. A visible emissions test (EPA Method 9) shall be performed at least annually for each silo that is loaded with carbon during the federal fiscal year.

STARTUP, SHUTDOWN, AND MALFUNCTION

~~19.~~18. Startup, Shutdown, and Malfunction Requirements: The permittee shall comply with the following requirements regarding periods of startup, shutdown, and malfunction for each cogeneration boiler.

a. *Definitions*

1) Excess emissions are emissions of pollutants in excess of those allowed by any applicable air pollution rule of the Department, or by a permit issued pursuant to any such rule or Chapter 62-4,

F.A.C. The term applies only to conditions that occur during startup, shutdown, or malfunction. [Rule 62-210.200(106), F.A.C.]

2) Startup is the commencement of operation of a boiler which has shut down or ceased operation for a period of time sufficient to cause temperature, pressure, chemical or pollution control device imbalances, which may result in excess emissions. Periods of startup for each boiler shall end once steam generation reaches 150,000 pounds per hour. A cold startup is a startup after the boiler has been shutdown for 24 hours or more. A warm startup is a startup after the boiler has been shutdown for less than 24 hours.

3) Shutdown is the cessation of the operation of a boiler for any purpose after steam generation drops below 150,000 pounds per hour.

4) Malfunction is any unavoidable mechanical and/or electrical failure of air pollution control equipment or process equipment or of a process resulting in operation in an abnormal or unusual manner. [Rule 62-210.200(160), F.A.C.]

b. *Prohibition*: Excess emissions which are caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure which may reasonably be prevented during startup, shutdown, or malfunction shall be prohibited. Emissions data recorded during such preventable periods shall be included in the compliance averages. [Rule 62-210.700(4), F.A.C.]

c. *Monitoring Data Exclusion*: Each continuous monitoring system shall operate and record data during all periods of operation (including startup, shutdown, and malfunction) except for continuous monitoring system breakdowns, repairs, calibration checks, and zero and span adjustments. Provided the operators implement best operational practices to minimize the amount and duration of emissions, the following conditions apply. Pursuant to Rules 62-210.700(1) and (5), F.A.C., these conditions consider the variations in operation of the cogeneration boilers.

1) Natural gas or distillate oil shall be fired during startup prior to energizing the electrostatic precipitator (ESP). Once the operating temperature recommended by the ESP manufacturer is maintained (approximately 340° F to 350 ° F), it shall be placed on line and the boiler shall comply with the opacity standard specified in Condition No. 16. The ESP shall be on line and functioning properly before firing any biomass. The opacity limit does not apply when the ESP is off line due to warm startup, cold startup, or shutdown. No more than twenty 6-minute block averages of opacity monitoring data shall be excluded in a 24-hour period due to documented malfunctions.

2) Hourly CO and NOx emission rate values collected during startup, shutdown, or documented malfunction may be excluded from the 30-day and/or 12-month compliance averages. No more than six hourly emission rate values (CO or NOx) shall be excluded in a 24-hour period due to a cold startup. No more than three hourly emission rate values (CO or NOx) shall be excluded in a 24-hour period due to a warm startup. No more than two hourly emission rate values (CO or NOx) shall be excluded in a 24-hour period due to a malfunction. No more than two hourly emission rate values (CO or NOx) shall be excluded in a 24-hour period due to a shutdown. For each cogeneration boiler, no more than 183 hourly emission rate values shall be excluded during any calendar quarter.

3) All valid hourly SO_2 emission rate values shall be included in all of the compliance averages. [40 CFR 60.46a and 60.49a]

4) To "document" a malfunction, the operator shall notify the Compliance Authority within one working day of the malfunction by phone, facsimile, or electronic mail. The notification shall include the date and time of malfunction, a description of the malfunction and probable cause, steps to taken to minimize emissions, and actions taken to correct the problem. [Rules 62-210.700(6) and 62-4.130, F.A.C.]

d. *Reporting*: In conjunction with the annual operating report, the permittee shall identify the number of startups, the number of shutdowns, and the number of malfunctions that occurred during the year for each boiler. For each boiler's CO and NOx monitors, the report shall identify the annual hours of emission data excluded from the compliance determination due to each type of incident (startups; shutdowns; and documented malfunctions).

[Rule 62-210.700, F.A.C.; Rule 62-4.070(3), F.A.C.; 40 CFR 60.8; and 40 CFR 60.46a]

COMPLIANCE METHODS AND REPORTING

~~20.~~19. Stack Test Requirements

a. *Initial Tests*: ~~Within 90 days of the effective date of this permit, the permittee shall conduct compliance tests for emissions of lead,~~ Initial tests were initially required for emissions of mercury, particulate matter, and volatile organic compounds. ~~If conducted within the 12-month period prior to the effective date of this permit, previous emissions tests may be used to demonstrate compliance for these pollutants.~~ The Department may require these initial tests to be repeated if major physical or operational changes are made that affect main components such as the boiler, fuels, and/or pollution control equipment.

b. *Annual Tests*: At least once during each federal fiscal year, the permittee shall conduct compliance tests for emissions of mercury, particulate matter, and volatile organic compounds.

c. *Renewal Tests*: Within the 12-month period prior to submitting an application to renew the Title V air operation permit, the permittee shall conduct compliance tests for emissions of ~~lead~~, mercury, particulate matter, and volatile organic compounds. Tests shall be conducted at five-year intervals.

d. *Test Procedures*: The emission compliance tests shall be conducted in accordance with the provisions of Chapter 62-297, F.A.C., 40 CFR 60.46a (NSPS Subpart Da), and as summarized in Appendix C of this permit. The permittee shall notify the Compliance Authority in writing at least 30 days prior to any initial NSPS performance tests and at least 15 days prior to any other required tests. The biomass fuel feed for each test run shall consist of at least 45% wood materials by weight. Testing of emissions shall be conducted with each cogeneration boiler operating at permitted capacity, which is defined as a heat input rate between 684 and 760 MMBtu/hour and firing 100% biomass. If it is impracticable to test at permitted capacity, a cogeneration boiler may be tested at less than the maximum permitted capacity; in this case, subsequent operation is limited to 110 percent of the test rate until a new test is conducted. Within three days of completing a test below permitted capacity, the permittee shall provide written notification of the restricted operational capacity to the Compliance Authority. Once the unit is so limited, operation at higher capacities is allowed for no more than 15 consecutive days for the purpose of additional compliance testing to regain the authority to operate at the permitted capacity. [Rule 62-297.310(7)(a)9, F.A.C. and 40 CFR 60.7, 60.8]

e. *Test Methods*: Compliance with the emission limits specified in this permit shall be demonstrated using EPA Methods, as contained in 40 CFR Part 60 (Standards of Performance for New Stationary Sources), or 40 CFR Part 61 (National Emission Standards for Hazardous Air Pollutants).

EPA Method*	Description
1	Selection of sample site and velocity traverses
2	Stack gas flow rate when converting concentrations to or from mass emission limits
3A	Gas analysis when needed for calculation of molecular weight or percent O_2
4	Moisture content when converting stack velocity to dry volumetric flow rate for use in converting concentrations in dry gases to or from mass emission limits
5	Particulate matter emissions
6 or 6C	Sulfur dioxide emissions

7 or 7E	Nitrogen oxide emissions
9	Visible emissions determination of opacity *{Permitting Note: Although each unit is required to monitor opacity with a COMS, visible observations may also be used to demonstrate compliance.}*
10	Carbon monoxide emissions
12	Inorganic lead emissions
19	Calculation of sulfur dioxide and nitrogen oxide emission rates
25A	Volatile organic compounds emissions *{Permitting Note: EPA Method 18 may be conducted concurrently with EPA Method 25A to deduct emissions of methane and ethane from the measured VOC emissions. Otherwise, all emissions measured by EPA Method 25A shall be considered "volatile organic compounds".*
29	Multiple metals emissions
101A	Particulate and gaseous mercury emissions

No other methods may be used to demonstrate compliance unless prior written approval is received from the Department~~ in accordance with a permit modification or an alternate sampling procedure issued pursuant to 62-297.620, F.A.C~~. Other applicable testing requirements are included in Appendix C of the permit. The permittee shall use CEMS and COMS data to demonstrate compliance with the emissions standards for CO, NOx, opacity, and SO_2. [Rules 62-204.800 and 62-297.100, F.A.C.; 40 CFR 60, Appendix A]

~~21.~~20. Continuous Monitor Requirements: The permittee shall demonstrate compliance with the emissions standards for CO, NOx, opacity, and SO_2 based on data collected from the continuous emissions monitoring systems (CEMS) and continuous opacity monitoring systems (COMS) required for each cogeneration boiler. Appendix E specifies the minimum requirements for monitoring equipment.

~~22.~~21. Quarterly Reports: For each cogeneration boiler, the permittee shall submit a quarterly report for each required continuous emissions and opacity monitoring system in accordance with the requirements specified in Appendix E of this permit. The permittee shall also submit a quarterly summary of the fuel analyses, fuel usage, and equipment malfunctions. The fuel usage summary shall include the monthly heat input and the 12-month rolling total heat input for the cogeneration boilers. For each malfunction, the report shall identify the cause (if known), and corrective actions taken. The quarterly reports and summaries shall be submitted to the Compliance Authority no later than 30 days following each calendar quarter.

~~23.~~22. Annual Operating Report: The permittee shall submit an annual report that summarizes the actual operating rates and emissions from this facility. Annual operating reports shall be submitted to the Compliance Authority by March 1st of each year. Along with this report, the permittee shall also submit a summary of CO emissions from each cogeneration boiler in terms of "ppmvd corrected to 3% oxygen based on a 24-hour average (day)" for each operational day. [Rule 62-210.370(2), F.A.C.]

CONTENTS

CITATION FORMAT

The following examples illustrate the format used in the permit to identify applicable permitting actions and regulations.

REFERENCES TO PREVIOUS PERMITTING ACTIONS

Old Permit Numbers

Example: Permit No. AC50-123456 or Air Permit No. AO50-123456

Where: "AC" identifies the permit as an Air Construction Permit
"AO" identifies the permit as an Air Operation Permit
"123456" identifies the specific permit project number

New Permit Numbers

Example: Permit Nos. 099-2222-001-AC, 099-2222-001-AF, 099-2222-001-AO, or 099-2222-001-AV

Where: "099" represents the specific county ID number in which the project is located
"2222" represents the specific facility ID number
"001"identifies the specific permit project
"AC" identifies the permit as an air construction permit
"AF" identifies the permit as a minor federally enforceable state operation permit
"AO" identifies the permit as a minor source air operation permit
"AV" identifies the permit as a Title V Major Source Air Operation Permit

PSD Permit Numbers

Example: Permit No. PSD-FL-317

Where: "PSD" means issued pursuant to the Prevention of Significant Deterioration of Air Quality
"FL" means that the permit was issued by the State of Florida
"317" identifies the specific permit project

RULE CITATION FORMATS

Florida Administrative Code (F.A.C.)

Example: [Rule 62-213.205, F.A.C.]

Means: Title 62, Chapter 213, Rule 205 of the Florida Administrative Code

Code of Federal Regulations (CFR)

Example: [40 CFR 60.7]

Means: Title 40, Part 60, Section 7

GENERAL CONDITIONS

The permittee shall comply with the following general conditions from Rule 62-4.160, F.A.C.

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

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

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

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

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

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

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

   a. Have access to and copy and records that must be kept under the conditions of the permit;
   b. Inspect the facility, equipment, practices, or operations regulated or required under this permit, and,
   c. Sample or monitor any substances or parameters at any location reasonably necessary to assure compliance with this permit or Department rules.

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

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

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

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

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

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

10. The permittee agrees to comply with changes in Department rules and Florida Statutes after a reasonable time for compliance, provided, however, the permittee does not waive any other rights granted by Florida Statutes or Department rules.

11. This permit is transferable only upon Department approval in accordance with Florida Administrative Code Rules 62-4.120 and 62-730.300, F.A.C., as applicable. The permittee shall be liable for any non-compliance of the permitted activity until the transfer is approved by the Department.

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

13. This permit also constitutes:

    a. Determination of Best Available Control Technology (X);
    b. Determination of Prevention of Significant Deterioration (X); and
    c. Compliance with New Source Performance Standards (X).

14. The permittee shall comply with the following:

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

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

    c. Records of monitoring information shall include:

        1) The date, exact place, and time of sampling or measurements;
        2) The person responsible for performing the sampling or measurements;
        3) The dates analyses were performed;
        4) The person responsible for performing the analyses;
        5) The analytical techniques or methods used; and
        6) The results of such analyses.

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

STANDARD REQUIREMENTS

{Permitting Note: Unless otherwise specified by permit, the following conditions are generally applicable to all emissions units.}

EMISSIONS AND CONTROLS

1. Plant Operation - Problems: If temporarily unable to comply with any of the conditions of the permit due to breakdown of equipment or destruction by fire, wind or other cause, the permittee shall notify each Compliance Authority as soon as possible, but at least within one working day, excluding weekends and holidays. The notification shall include: pertinent information as to the cause of the problem; steps being taken to correct the problem and prevent future recurrence; and, where applicable, the owner's intent toward reconstruction of destroyed facilities. Such notification does not release the permittee from any liability for failure to comply with the conditions of this permit or the regulations. [Rule 62-4.130, F.A.C.]

2. Circumvention: The permittee shall not circumvent the air pollution control equipment or allow the emission of air pollutants without this equipment operating properly. [Rule 62-210.650, F.A.C.]

3. Excess Emissions Prohibited: Excess emissions caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure that may reasonably be prevented during startup, shutdown or malfunction shall be prohibited. [Rule 62-210.700(4), F,A.C.]

4. Excess Emissions - Notification: In case of excess emissions resulting from malfunctions, the permittee shall notify the Department or the appropriate Local Program in accordance with Rule 62-4.130, F.A.C. A full written report on the malfunctions shall be submitted in a quarterly report, if requested by the Department. [Rule 62-210.700(6), F.A.C.]

5. VOC or OS Emissions: No person shall store, pump, handle, process, load, unload or use in any process or installation, volatile organic compounds or organic solvents without applying known and existing vapor emission control devices or systems deemed necessary and ordered by the Department. [Rule 62-296.320(1), F.A.C.]

6. Objectionable Odor Prohibited: No person shall cause, suffer, allow or permit the discharge of air pollutants, which cause or contribute to an objectionable odor. [Rule 62-296.320(2), F.A.C.]

7. General Visible Emissions: No person shall cause, let, permit, suffer or allow to be discharged into the atmosphere the emissions of air pollutants from any activity equal to or greater than 20 percent opacity. [Rule 62-296.320(4)(b)1, F.A.C.]

8. Unconfined Particulate Emissions: During the construction period, unconfined particulate matter emissions shall be minimized by dust suppressing techniques such as covering and/or application of water or chemicals to the affected areas, as necessary. [Rule 62-296.320(4)(c), F.A.C.]

TESTING REQUIREMENTS

9. Operating Rate During Testing: Testing of emissions shall be conducted with the emissions unit operating at permitted capacity. Permitted capacity is defined as 90 to 100 percent of the maximum operation rate allowed by the permit. If it is impractical to test at permitted capacity, an emissions unit may be tested at less than the maximum permitted capacity; in this case, subsequent emissions unit operation is limited to 110 percent of the test rate until a new test is conducted. Once the unit is so limited, operation at higher capacities is allowed for no more than 15 consecutive days for the purpose of additional compliance testing to regain the authority to operate at the permitted capacity. [Rule 62-297.310(2), F.A.C.]

10. Calculation of Emission Rate: For each emissions performance test, the indicated emission rate or concentration shall be the arithmetic average of the emission rate or concentration determined by each of the three separate test runs unless otherwise specified in a particular test method or applicable rule. [Rule 62-297.310(3), F.A.C.]

11. Test Procedures: Tests shall be conducted in accordance with all applicable requirements of Chapter 62-297, F.A.C.

    a. *Required Sampling Time.* Unless otherwise specified in the applicable rule, the required sampling time for each test run shall be no less than one hour and no greater than four hours, and the sampling time at each sampling point shall be of equal intervals of at least two minutes. The minimum observation period for a visible emissions compliance test shall be thirty (30) minutes. The observation period shall include the period during which the highest opacity can reasonably be expected to occur.

b. *Minimum Sample Volume.* Unless otherwise specified in the applicable rule or test method, the minimum sample volume per run shall be 25 dry standard cubic feet.

c. *Calibration of Sampling Equipment.* Calibration of the sampling train equipment shall be conducted in accordance with the schedule shown in Table 297.310-1, F.A.C.

[Rule 62-297.310(4), F.A.C.]

12. Determination of Process Variables

a. *Required Equipment.* The owner or operator of an emissions unit for which compliance tests are required shall install, operate, and maintain equipment or instruments necessary to determine process variables, such as process weight input or heat input, when such data are needed in conjunction with emissions data to determine the compliance of the emissions unit with applicable emission limiting standards.

b. *Accuracy of Equipment.* Equipment or instruments used to directly or indirectly determine process variables, including devices such as belt scales, weight hoppers, flow meters, and tank scales, shall be calibrated and adjusted to indicate the true value of the parameter being measured with sufficient accuracy to allow the applicable process variable to be determined within 10% of its true value.

[Rule 62-297.310(5), F.A.C.]

13. Sampling Facilities: The permittee shall provide stack testing facilities and sampling locations in accordance with Rule 62-297.310(6), F.A.C.

14. Test Notification: The permittee shall notify the Compliance Authority in writing at least 30 days prior to any initial NSPS performance tests and at least 15 days prior to any other required tests. [Rule 62-297.310(7)(a)9, F.A.C. and 40 CFR 60.7, 60.8]

15. Special Compliance Tests: When the Department, after investigation, has good reason (such as complaints, increased visible emissions or questionable maintenance of control equipment) to believe that any applicable emission standard contained in a Department rule or in a permit issued pursuant to those rules is being violated, it shall require the owner or operator of the emissions unit to conduct compliance tests which identify the nature and quantity of pollutant emissions from the emissions unit and to provide a report on the results of said tests to the Department. [Rule 62-297.310(7)(b), F.A.C.]

RECORDS AND REPORTS

16. Records Retention: All measurements, records, and other data required by this permit shall be documented in a permanent, legible format and retained for at least five (5) years following the date on which such measurements, records, or data are recorded. Records shall be made available to the Department upon request. [Rules 62-4.160(14) and 62-213.440(1)(b)2, F.A.C.]

17. Annual Operating Report: The permittee shall submit an annual report that summarizes the actual operating rates and emissions from this facility. Annual operating reports shall be submitted to the Compliance Authority by March 1st of each year. [Rule 62-210.370(2), F.A.C.]

18. Emissions Performance Test Reports: A report indicating the results of any required emissions performance test shall be submitted to each Compliance Authority no later than 45 days after completion of the last test run. The test report shall provide sufficient detail on the tested emission unit and the procedures used to allow the Department to determine if the test was properly conducted and if the test results were properly computed. At a minimum, the test report shall provide the applicable information listed in Rule 62-297.310(8)(c), F.A.C. [Rule 62-297.310(8), F.A.C.]

PSD Applicability

The existing facility is located in Palm Beach County, an area that is in attainment with (or designated as unclassifiable for) all air pollutants subject to a National Ambient Air Quality Standard (NAAQS). The cogeneration plant is classified as a fossil fuel-fired steam electric plant, which is one of the 28 PSD Major Facility Categories identified in Table 62-212.400-1, F.A.C. Potential emissions from the plant are greater than 100 tons per year for at least one regulated pollutant. As such, the facility is "major" with respect to the Prevention of Significant Deterioration (PSD) of Air Quality. The proposed project will result in net emissions increases that are greater than the PSD significant emission rates identified in Table 62-212.400-2, F.A.C. for the following pollutants: carbon monoxide, nitrogen oxides, particulate matter, sulfur dioxide, volatile organic compounds, lead, fluorides, and sulfuric acid mist. Therefore, the project is subject to PSD review and the Department makes the following determinations of Best Available Control Technology (BACT) for these pollutants.

Final BACT Determinations

In accordance with Rule 62-212.400, F.A.C., the Department determines that the following standards represent the Best Available Control Technology (BACT) for the existing biomass-fired cogeneration boilers.

Pollutant	BACT Standards for Each Cogeneration Boiler		
	Averaging Period	**lb/MMBtu**	**lb/hr**
Carbon Monoxide (CO) *Based on "good combustion practices".*	30-day rolling CEMS avg.	0.50	380.0
	12-month rolling CEMS avg.	0.35	
Nitrogen Oxides (NOx) *Based on the application of SNCR.*	30-day rolling CEMS avg.	0.15	114.0
Sulfur Dioxide (SO_2) *Based on "low sulfur fuels". The SO_2 standards are also surrogate standards for sulfuric acid mist (SAM) emissions.*	24-hour rolling CEMS avg.	0.20	152.0
	30-day rolling CEMS avg.	0.10	
	12-month rolling CEMS avg.	0.06	
Opacity *Based on application of mechanical dust collectors and electrostatic precipitator.*	6-minute block COMS avg. (Alternative: EPA Method 9)	≤ 20% opacity, except for one 6-minute block per hour that is ≤ 27% opacity	
Particulate Matter (PM) *Based on application of mechanical dust collectors and electrostatic precipitator.*	3-run test avg.	0.026	19.8
Volatile Organic Compounds (VOC) *Based on "good combustion practices".*	3-run test avg.	0.05	38.0
Lead (Pb) and Fluorides (Fl) *Based on "low lead/fluoride fuels".*	BACT is the use of fuels containing low levels of these compounds (bagasse, wood, distillate oil, and natural gas) and prospective removal with the fly ash by the mechanical dust collectors and electrostatic precipitators. The particulate matter standard shall also serve as a surrogate standard for lead.		

The Department's technical review and rationale for the BACT determinations are presented in Technical Evaluation and Preliminary Determination issued concurrently with the draft permit for this project.

Determination By:

(DRAFT)

Jeff Koerner, P.E., Project Engineer (Date)
New Source Review Section

Recommended By:

(DRAFT)

Trina Vielhauer, Chief (Date)
Bureau of Air Regulation

Approved By:

(DRAFT)

Michael G. Cooke, Director (Date)
Division of Air Resources Management

CONTINUOUS MONITOR REQUIREMENTS

{Permitting Note: The following summarizes the basic monitoring requirements for the cogeneration boilers.}

1. Process and Control Parameters: The permittee shall install, calibrate, maintain, and operate continuous monitoring systems to measure and record the following process and control equipment parameters:

   a. *Power Output.* The net power generation (MW) delivered for sale to the electrical power grid shall be continuously monitored and recorded in 1-hour block averages.

   b. *Fuel Feed Rate.* Fuel flow meters equipped with totalizers are required to monitor and record the fuel feed rates for distillate oil (gallons) and natural gas (million cubic feet). Biomass feed rates (tons of bagasse and tons of wood) shall be calculated and recorded based on actual fuel flows. The permittee shall continuously monitor the fuel throughput rates based on the fuel flow monitors and calculate the actual heat input rates (24 hour average) for each fuel during each day of operation.

   c. *Steam Parameters.* Each cogeneration boiler shall be equipped with monitors to measure and record the steam temperature (° F), steam pressure (psig), and steam production (pounds).

   d. *Urea Injection Rate (SNCR System).* The urea injection rate shall be continuously monitored and recorded for each cogeneration boiler. The urea injection rate shall be compared to actual NOx emissions data recorded by the CEMS. The permittee shall identify minimum urea injection rates for various load conditions that ensure compliance with the NOx standards. Should the NOx CEMS be unavailable, the urea injection rate shall be maintained at an appropriate minimum level.

   e. *Activated Carbon Injection Rate (Mercury Control System).* If the mercury injection system is reactivated, the carbon injection rate shall be continuously monitored and recorded. Based on the testing required in this permit, the permittee shall identify and maintain minimum carbon injection rates to ensure effective control of mercury emissions.

   The permittee shall maintain written procedures for inspecting, calibrating, and maintaining the process and control monitoring equipment. [Rules 62-4.070 and 62-212.400(BACT), F.A.C.]

2. CEMS and COMS: For each cogeneration boiler, the permittee shall install, calibrate, maintain, and operate continuous emissions monitors (CEMS) and continuous opacity monitors (COMS) to measure and record emissions of carbon monoxide (CO), nitrogen oxides (NOx), oxygen (O_2), sulfur dioxide (SO_2), and opacity in a manner sufficient to demonstrate compliance with the standards of this permit.

   a. *Performance Specifications.* Each monitor shall be located in the ductwork between the electrostatic precipitator and the stack (or in the stack) to obtain emissions measurements representative of actual stack emissions. Each CEMS and COMS shall comply with the corresponding performance specifications that identify location, installation, design, performance, and reporting requirements.

      (1) Opacity shall comply with Performance Specification 1 in Appendix B of 40 CFR 60.

      (2) NOx and SO_2 CEMS shall comply with Performance Specification 2 in Appendix B of 40 CFR 60. The SO_2 reference method for the annual RATA shall be EPA Method 6 (or 6C) in Appendix A of 40 CFR 60. The NOx reference method for the annual RATA shall be EPA Method 7 (or 7E) in Appendix A of 40 CFR 60.

      (3) O_2 CEMS shall comply with Performance Specification 3 in Appendix B of 40 CFR 60. The O_2 reference method for the annual RATA shall be EPA Method 3A Appendix A of 40 CFR 60.

      (4) CO CEMS shall meet Performance Specification 4 or 4A in Appendix B of 40 CFR 60. The CO reference method for the annual RATA shall be EPA Method 10 in Appendix A of 40 CFR 60.

   b. *Data Collection.* Each CEMS and COMS shall record emissions data at all times including episodes of startup, shutdown, and malfunction. Emissions data recorded during periods of startup, shutdown, or malfunction may only be excluded from the compliance averages in accordance with the requirements specified in Section III of this permit. To the extent practicable, the permittee shall minimize the duration of data excluded for startup, shutdown and malfunctions.

   Each CEMS shall be designed and operated to sample, analyze, and record emissions data evenly spaced over a 1-hour period. Each 1-hour average shall be computed using at least one data point in each fifteen minute quadrant of the 1-hour block during which the unit combusted fuel. Notwithstanding this requirement, each 1-hour average shall be computed from at least two data points separated by a minimum of 15 minutes. All valid measurements or data points collected during a 1-hour block shall be used to calculate the 1-hour emission averages. CO, NOx, and SO_2 CEMS shall express the 1-hour emission averages in terms of "lb/MMBtu of heat input". O_2 CEMS shall express the 1-hour emission average in terms of "percent by volume". A 30-day rolling emission average shall be the average of all valid 1-hour emission averages collected during the 30-day period. A 12-month rolling emission average shall be the average of all valid 1-hour emission averages collected during the 12-month period. NOx and SO_2 CEMS shall comply with NSPS Subpart Da in 40 CFR 60.

Each COMS shall be designed and operated to complete a minimum of one cycle of sampling and analyzing for each successive 10-second period and one cycle of data recording for each successive 6-minute period. Opacity shall be recorded in 6-minute block averages.

c. *Quality Assurance Procedures*. Each CEMS shall comply with the applicable quality assurance procedures specified in Appendix F of 40 CFR 60. These procedures include methods such as calibration, calibration drift, data recording, accuracy assessment, calculations, audit procedures, preventive maintenance, corrective actions, and reporting.

d. *Monitor Availability*. Monitor availability shall not be less than 95% in any calendar quarter. In the event 95% availability is not achieved, the permittee shall provide the Department with a report identifying the problems in achieving 95% availability and a plan of corrective actions that will be taken to achieve 95% availability. The permittee shall implement the reported corrective actions within the next calendar quarter. Failure to take corrective actions or continued failure to achieve the minimum monitor availability shall be violations of this permit.

e. *Other Applicable Requirements*: Each CEMS shall comply with the following applicable requirements Rules 62-204.800 and 62-297.520, F.A.C. (Continuous Monitor Performance Specifications); 40 CFR 60.13 (Subpart A - Monitoring Requirements); 40 CFR 60.47a (Subpart Da - Emissions Monitoring); 40 CFR 60.48a (Subpart Da - Compliance Determination Procedures and Methods); 60.49a (Subpart Da - Reporting Requirements).

f. *Quarterly Reports*: For each cogeneration boiler, the permittee shall submit the report on the following page to summarize each required continuous emissions and opacity monitoring system. The authorized representative shall certify that the information provided in each quarterly report is true, accurate, and complete to the best of his/her knowledge. Each quarterly report is due no later than 30 days following the calendar quarter.

CONTINUOUS MONITOR REQUIREMENTS

Facility Name Okeelanta Cogeneration Plant	**ARMS ID No.** 0990332	**Title V Air Permit No.**
Facility Address/Location Located off U.S. Highway 27 South, approximately six miles south of South Bay in Palm Beach County, Florida		

Emissions Unit Description	**Unit Operation in Calendar Quarter**
Spreader stoker boiler with maximum heat input of 760 MMBtu/hour ARMS EU ID No. ______ Cogeneration Boiler: ___ A ___ B ___ C	_________ hours

Control Equipment

Mercury - activated carbon injection; Nitrogen Oxides – low NOx burners and selective non-catalytic reduction (NOx) system; Particulate Matter – mechanical dust collectors and electrostatic precipitators

Primary Fuel	**Auxiliary Fuels**
Biomass, which includes bagasse from adjacent sugar mill and wood material from area suppliers (clean construction and demolition wood debris, yard trash, land clearing debris, and other clean cellulose and vegetative matter)	Pipeline natural gas Distillate oil (≤ 0.05% sulfur by weight)

Pollutant Monitored ***(Check one.)***	**Calendar Quarter of Operation Covered** ***(Check one.)***
_____ CO _____ NOx _____ SO_2 _____ Opacity	___ 1 ___ 2 ___ 3 ___ 4 for year ________
Continuous Monitor Information	**Emission Standards**
Manufacturer: ________________________________ Model No. ________________________________ Date of last certification or audit: __________________	_______ lb/MMBtu of heat input, 24-hour rolling average _______ lb/MMBtu of heat input, 30-day rolling average _______ lb/MMBtu of heat input, 12-month rolling average ≤ 20% opacity, except for one 6-minute block per hour that is ≤ 27% opacity
Emission Data Summary	**CMS Performance Summary**
1. Duration of excess emissions in reporting period due to: a. Startup/shutdown .... _____ b. Control equipment problems .... _____ c. Process problems.. _____ d. Other known causes .... _____ e. Unknown causes.. _____ 2. Total duration of excess emissions .... _____ 3. [Total duration of excess emissions] x (100%)........ _____ [Total source operating time]	1. CMS downtime in reporting period due to: a. Monitor Equipment Malfunctions...................... _____ b. Non-Monitor Equipment Malfunctions .... _____ c. Quality Assurance Calibration.......................... _____ d. Other Known Causes .... _____ e. Unknown Causes .... _____ 2. Total CMS Downtime .... _____ 3. [Total CMS Downtime] x (100%).................. _____ [Total source operating time]
Note: Report "excess emissions" as emission averages that are in excess of a permitted emissions standard. For gases, report excess emissions in terms of hours. For opacity, report excess emissions in terms of minutes.	*If monitor availability is not at least 95%, provide a report identifying the problems in achieving 95% availability and a plan of corrective actions that will be taken to achieve 95% availability*

Emissions Data Exclusion

1. Report the number of 1-hour emissions averages excluded the reporting period due to:
   a. Startup... _____
   b. Shutdown .... _____
   c. Malfunction .... _____
   d. Total .... _____
2. On a separate page, summarize each malfunction event, the cause (if known), and corrective actions taken.
3. On a separate page, describe any changes to CMS, process or controls during last quarter.

Golder Associates Inc.

6241 NW 23rd Street, Suite 500
Gainesville, FL 32653-1500
Telephone (352) 336-5600
Fax (352) 336-6603

Golder Associates

May 20, 2003

RECEIVED

MAY 21 2003

BUREAU OF AIR REGULATION

0337520

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

Attention: Mr. Jeffery F. Koerner,

RE: New Hope Power Partnership, Project No. 0990332-016-AC (PSD-FL-196M)

Dear Mr. Koerner:

On March 26, 2003, the Department issued a second request for additional information (RAI) for New Hope Power Partnership's (NHPP) 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 provided below.

1. **Comment: Your additional information indicates that an SCR system is not technically feasible due to high concentrations of potassium, sodium, and phosphorous in the flue gas. Please provide supporting documentation of the flue gas concentrations for these pollutants. Compare these levels with those of boilers that do employ SCR, such as coal-fired units.**

   Response: In order to investigate this, NHPP obtained samples of ESP ash and mechanical dust collector ash from the cogeneration boilers at two different times on April 11, 2003. The ash samples were sent to the lab and analyzed for sodium, potassium, and phosphorous. These elements are known SCR catalyst deactivators. The results of the analysis are shown in Table 1 attached. The lab analysis sheets are also attached. As shown, one set of ash samples exhibited potassium levels of greater than 8 percent. This level of potassium is much greater than the level found in coal ash, which is seen to range from 0.3 to 2.8 percent.

   Further testing of the NHPP ash would be expected to yield frequent levels of potassium of 8 percent and greater, as well as other undesirable constituents in regards to SCR application. Recent analysis of bagasse ash from U.S. Sugar's Clewiston mill revealed potassium levels of 15 percent and chlorine levels of 7.6 percent in the ash.

   Recent correspondence from a leading SCR catalyst manufacturer, Topsoe, stated that potassium levels in ash approaching 10 percent, coupled with chlorine, would produce a large amount of KCl aerosols in the flue gas, which would in turn result in a very rapid deactivation of the catalyst. The catalyst would have to be placed after the ESP to be manageable.

   We believe this information provides further basis for rejecting high-dust SCR based on technical infeasibility.

2. **<u>Comment:</u> Currently, NO_x emissions are reduced using SNCR to achieve a standard of 0.15 lb/MMBtu of heat input based on a 30-day rolling average. Have any of the boilers failed to comply with this limit since the beginning of commercial operation?**

   Response: Over the last 3 or 4 years, there has been only one exceedance of the 0.15 lb/MMBtu 30-day rolling NO_x standard. That exceedance was due to a malfunction.

3. **<u>Comment:</u> The Department understands the issue of flexibility regarding unrestricted annual operation. However, the cogeneration units currently operate with an annual capacity factor of less than 60%. Some of the cost effectiveness calculations estimate an upper range of 90%. Please estimate the maximum expected annual capacity factor (in terms of heat input rate) for the cogeneration plant. Consider the following:**
   - **What factors typically prevent operation at rated capacity?**
   - **Do these units normally operate at capacity during the cane-milling season? During the off-season?**
   - **Do the units ramp down at nighttime?**
   - **Does the available fuel supply limit operation at capacity?**
   - **How many days are planned for scheduled down times to perform maintenance and inspections?**
   - **How many days have periods of unscheduled maintenance accounted for in the past?**

   Response: At the requested maximum heat input rate of 19,972,800 MMBtu/yr, the cogeneration plant expects to average between 70- and 80-percent annual capacity factor (i.e., between 13,980,960 MMBtu and 15,978,240 MMBtu), depending upon process requirements.

   Heat input is typically lower during the summer or off-season. Scheduled and unscheduled outages also contribute to operation at less than capacity.

   The units normally operate at capacity during the crop season. During the off-season, the units operate at approximately less than 80 percent of maximum capacity.

   The units do not ramp down at nighttime.

   The available fuel supply does not limit operation of the facility or its capacity.

   Approximately 2 weeks per year are planned for scheduled down times to perform maintenance and inspections.

   During the past 3 years, the cogeneration facility has transitioned through a series of design issues that has contributed to downtime that is not representative of normal operating conditions. Therefore, it is difficult to accurately separate downtime from unscheduled maintenance versus downtime due to design issues.

4. **<u>Comment:</u> The application refers to a project in Virginia for the Multitrade facility identified as RBLC #0183. (The Department believes the correct RBLC is #0174.) Under the application review for NO_x emissions, this facility is identified as a "peaking plant", which should allow for consideration of higher urea injection rates to achieve lower NO_x emissions. However, the Department's review indicates that this is a spreader stoker boiler fired by wood. The current Title V permit for this facility does not describe the boiler as a "peaking unit". Please provide information that supports this boiler as a "peaking unit".**

Response: Information regarding the Multitrade facility was obtained from the Virginia Department of Environmental Quality in June 2002. In addition, Mr. Oven Barnes of the facility was contacted (434-324-8223). The facility has three identical boilers; spreader stokers fired by wood. While it is true that Multitrade's permit allows 8,760 hr/yr operation at maximum heat input rate for all three boilers, Mr. Barnes stated that it was a peaking plant when originally permitted, and indeed, is still operated as a peaking plant. This was confirmed from the first quarter 2002 Excess Emissions Report obtained from Virginia DEQ. This report contains a capacity factor report (attached) that shows over the previous 12 months, the facility had operated at monthly capacity factors ranging from 7 percent to 68 percent. The 12-month rolling capacity factor was 33 percent. Peak operation was in August while the lowest operation was in October.

5. **Comment: The Weyerhaeuser facility in Mississippi (RBLC #MS-0026) is identified as an electric utility boiler. This boiler is rated at 90 MMBtu per hour. The Department believes that the facility is not an electric utility, but rather a lumber mill and plywood plant. Please review and comment.**

Response: We obtained the PSD permit for this facility from the Mississippi DEQ, and spoke with the DEQ. The DEQ stated that the Weyerhaeuser Company Bruce Facility produces dimensional lumber. The principle raw material is southern yellow pine. The boilers are used to produce steam for the dry kilns. The BACT determination was for two boilers, a 60-MMBtu/hr woodwaste boiler and a 90-MMBtu/hr woodwaste boiler.

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/nav

Enclosures

cc: R. Blackburn, DEP
J. Meriwether, NHPP
W. Tarr, Florida Crystals
G. Cepero, Florida Crystals
D. Dee, Landers & Parsons
D. Larocca, Golder
J. Stormer, PBCo.
J. Bettle, EPA
J. Bunyak, NPS

L052003

Table 1. NHPP Ash Analysis Compared to Coal Ash

Constituent	NHPP Ash: ESP Ash #1	NHPP Ash: ESP Ash #2	NHPP Ash: Dust Collector Ash #1	NHPP Ash: Dust Collector Ash #2	Coal Fly Ash[a]: Class "F"	Coal Fly Ash[a]: Class "C"	Coal Fly Ash[a]: hvBb Utah	Coal Fly Ash[a]: hvAb Penn.	Coal Fly Ash[a]: hvC
Elemental analysis of ash (%)									
Silica (SiO_2)	NA	NA	NA	NA	58.0	35.9	52.5	51.1	52.0
Aluminum Oxide (Al_2O_3)	NA	NA	NA	NA	29.1	18.9	18.9	30.7	17.5
Iron Oxide (Fe_2O_3)	NA	NA	NA	NA	3.6	6.1	1.1	10.0	15.5
Titanium Oxide (TiO_2)	NA	NA	NA	NA	1.6	1.4	1.2	2.0	1.3
Calcium Oxide (CaO)	NA	NA	NA	NA	0.8	24.6	13.2	1.6	4.5
Magnesium Oxide (MgO)	NA	NA	NA	NA	0.8	5.4	1.3	0.9	1.1
Sodium Oxide (Na_2O)	1.1	0.27	1.2	0.22	0.1	1.9	3.8	0.4	0.6
Potassium Oxide (K_2O)	8.2	1.7	8.5	1.4	2.5	0.3	0.9	1.7	2.8
Sulfur Trioxide (SO_3)	NA	NA	NA	NA	0.2	2.3	6.2	1.4	4.2
Phosphorus Pentoxide (P_2O_5)	0.15	0.13	0.03	NA	0.1	1.1	--	--	0.1
Barium Oxide (BaO)	NA	NA	NA	NA	0.1	0.7	--	--	--
Manganese Oxide (Mn_2O_3)	NA	NA	NA	NA	0.1	<0.1	--	--	--
Strontium Oxide (SrO)	NA	NA	NA	NA	0.1	0.4	--	--	--

NA = Not analyzed

[a] From "Fossil Fuel Combustion", ABB.

Best Available Copy

CHAIN OF CUSTODY RECORD

USBiosystems — Working COC

Log # 75375 / TN4   Quote: ______

LAB USE ONLY	YES	NO	N/A
Samples INTACT upon arrival?	✓		
Received ON WET ICE? Temp____			✓
PROPER PRESERVATIVES indicated?			
Received WITHIN HOLDING TIME?			
CUSTODY SEALS INTACT?			
VOLATILES rec'd W/OUT HEADSPACE?			✓
PROPER CONTAINERS used?			

Company Name: New Hope Power   PO#:
Address:
City: SA   State: Zip:
Attn: James Meriwether   Fax#:
Project Name: Ash Samples   Proj#:
Sampler Name/Signature: Phone#:

Matrix: SOLID

#	Sample ID	Date	Time	Matrix Code	Containers No.	Size	LNA	Phosphorous	Remarks
1	ESP's	41103	1400	SD	1	1 gal	X	X	Fly Ash
2	ESP's	↓	1120	↓	↓	↓	X	X	↓
3	Dust Collectors	↓	1040	↓	↓	↓	X	X	Ash
4	Dust Collectors.	↓	1355	↓	↓	↓	X		↓
5									
6									
7									
8									
9									
0									

Matrix Codes*

SD	Solid Waste	OL	Oil
GW	Ground Water	SL	Sludge
EFF	Effluent	SO	Soil Sediment
AFW	Analyte Free H_2O	AQ	Aqueous
WW	Waste Water	NA	Nonaqueous
DW	Drinking Water	PE	Petroleum
SU	Surface Water	O	Other ____ (Please Specify)

Pres/Codes

A. None	G. $Na_2S_2O_3$
B. HNO_3	H. $NaHSO_4$
C. H_2SO_4	I. Ice
D. NaOH	J. MCAA
E. HCL	O. Other
F. MeOH	

Y/N   Date required   Y____ N____   None____ 1____ 2____ 3____ Other____   Y / N   0

Relinquished by	Date	Time	Received by	Date	Time
				41403	927

#____

3231 N.W. 7th Avenue
Boca Raton, FL 33431
888-862-LABS
561-447-7373
888-456-4846 Fax
561-447-6136 Fax

C.O.C. # 55600

ORIGINAL

USBiosystems

Client #: WPB-94-100506
Address: New Hope Power
P.O. Box 9
South Bay, FL 33493
James Meriwether

Page: Page 1 of 1
Date: 04/22/2003
Log #: L75375-1

Sample Description:

Ash Sample

Analytical Report: ESP's
Date Sampled: 04/11/2003
Time Sampled: 14:00
Date Received: 04/14/2003
Collected By: Client

Parameter	Results	Units	Method	Reportable Limit	Extr. Date	Anly. Date	Analyst
Percent Solids							
Percent Solid	100	%	SM2540B	0.10	04/14	04/14	KB
Metals							
Potassium	82000	mg/kg (dw)	3050/6010	50	04/16	04/21	ZL
Sodium	11000	mg/kg (dw)	3050/6010	50	04/16	04/21	ZL
General Chemistry							
Total Phosphorus as P	1500	mg/kg (dw)	365.1	100	04/17	04/17	MA

All analyses were performed using EPA, ASTM, NIOSH, USGS, or Standard Methods and certified to meet NELAC requirements.
Flags: BDL or U-below reporting limit; DL-diluted out; IL-meets internal lab limits; MI-matrix interference; NA-not appl.
Flags: CFR-Pb/Cu rule; ND-non detect(RL estimated); NFL-no free liquids; dw-dry wt; ww-wet wt; C(#)-see attached USB code
FLDEP Flags: J(#)-estimated 1:surr. fail 2:no known QC req. 3:QC fail %R or %RPD; 4:matrix int. 5:improper fld. protocol
FLDEP Flags: L-exceeds calibration; Q-holding time exceeded; T-value < MDL; V-present in blank
FLDEP Flags: Y-improper preservation; B-colonies exceed range; I-result between MDL and PQL

QAP# 980126
SUB DOH# 86122,86109,E86048
SC CERT# 96031001
USACE
VA CERT# 00395

DOH# E86240
ADEM ID# 40850
TN CERT# 02985
GA CERT# 917
USDA Soil Permit# S-35240

NC CERT# 444
IL CERT# 200020

Respectfully submitted,
LJones
LouAnn Jones
Project Manager

Client #: WPB-94-100506
Address: New Hope Power
P.O. Box 9
South Bay, FL 33493
James Meriwether

Page: Page 1 of 1
Date: 04/22/2003
Log #: L75375-2

Sample Description:

Ash Sample

Analytical Report: ESP's
Date Sampled: 04/11/2003
Time Sampled: 11:20
Date Received: 04/14/2003
Collected By: Client

Parameter	Results	Units	Method	Reportable Limit	Extr. Date	Anly. Date	Analyst
Percent Solids							
Percent Solid	100	%	SM2540B	0.10	04/14	04/14	KB
Metals							
Potassium	17000	mg/kg (dw)	3050/6010	50	04/16	04/21	ZL
Sodium	2700	mg/kg (dw)	3050/6010	50	04/16	04/21	ZL
General Chemistry							
Total Phosphorus as P	1300	mg/kg (dw)	365.1	50	04/17	04/17	MA

All analyses were performed using EPA, ASTM, NIOSH, USGS, or Standard Methods and certified to meet NELAC requirements.
Flags: BDL or U-below reporting limit; DL-diluted out; IL-meets internal lab limits; MI-matrix interference; NA-not appl.
Flags: CFR-Pb/Cu rule; ND-non detect(RL estimated); NFL-no free liquids; dw-dry wt; ww-wet wt; C(#)-see attached USB code
FLDEP Flags: J(#)-estimated 1:surr. fail 2:no known QC req. 3:QC fail %R or %RPD; 4:matrix int. 5:improper fld. protocol
FLDEP Flags: L-exceeds calibration; Q-holding time exceeded; T-value < MDL; V-present in blank
FLDEP Flags: Y-improper preservation; B-colonies exceed range; I-result between MDL and PQL

QAP# 980126
SUB DOH# 86122,86109,E86048
SC CERT# 96031001
USACE
VA CERT# 00395

DOH# E86240
ADEM ID# 40850
TN CERT# 02985
GA CERT# 917
USDA Soil Permit# S-35240

NC CERT# 444
IL CERT# 200020

Respectfully submitted,
LJones
LouAnn Jones
Project Manager

Client #: WPB-94-100506
Address: New Hope Power
P.O. Box 9
South Bay, FL 33493
James Meriwether

Date: 04/22/2003
Log #: L75375-3

Sample Description:

Ash Sample

Analytical Report: Dust Collectors
Date Sampled: 04/11/2003
Time Sampled: 10:40
Date Received: 04/14/2003
Collected By: Client

Parameter	Results	Units	Method	Reportable Limit	Extr. Date	Anly. Date	Analyst
Percent Solids							
Percent Solid	100	%	SM2540B	0.10	04/14	04/14	KB
Metals							
Potassium	85000	mg/kg (dw)	3050/6010	50	04/16	04/21	ZL
Sodium	12000	mg/kg (dw)	3050/6010	50	04/16	04/21	ZL
General Chemistry							
Total Phosphorus as P	300	mg/kg (dw)	365.1	10	04/17	04/17	MA

All analyses were performed using EPA, ASTM, NIOSH, USGS, or Standard Methods and certified to meet NELAC requirements.
Flags: BDL or U-below reporting limit; DL-diluted out; IL-meets internal lab limits; MI-matrix interference; NA-not appl.
Flags: CFR-Pb/Cu rule; ND-non detect(RL estimated); NFL-no free liquids; dw-dry wt; ww-wet wt; C(#)-see attached USB code
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Respectfully submitted,

LouAnn Jones
Project Manager

Client #: WPB-94-100506
Address: New Hope Power
P.O. Box 9
South Bay, FL 33493
James Meriwether

Page: Page 1 of 1
Date: 04/22/2003
Log #: L75375-4

Sample Description:

Ash Sample

Analytical Report: Dust Collectors
Date Sampled: 04/11/2003
Time Sampled: 13:55
Date Received: 04/14/2003
Collected By: Client

Parameter	Results	Units	Method	Reportable Limit	Extr. Date	Anly. Date	Analyst
Percent Solids							
Percent Solid	100	%	SM2540B	0.10	04/14	04/14	KB
Metals							
Potassium	14000	mg/kg (dw)	3050/6010	50	04/16	04/21	ZL
Sodium	2200	mg/kg (dw)	3050/6010	50	04/16	04/21	ZL

All analyses were performed using EPA, ASTM, NIOSH, USGS, or Standard Methods and certified to meet NELAC requirements.
Flags: BDL or U-below reporting limit; DL-diluted out; IL-meets internal lab limits; MI-matrix interference; NA-not appl.
Flags: CFR-Pb/Cu rule; ND-non detect(RL estimated); NFL-no free liquids; dw-dry wt; ww-wet wt; C(#)-see attached USB code
FLDEP Flags: J(#)-estimated 1:surr. fail 2:no known QC req. 3:QC fail %R or %RPD; 4:matrix int. 5:improper fld. protocol
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NC CERT# 444
IL CERT# 200020

Respectfully submitted,

LouAnn Jones
Project Manager

March 26, 2003

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Rodney Williams, Plant Manager
New Hope Power Partnership
8001 U.S. Highway 27, South
South Bay, FL 33493

Re: **Request for Additional Information**
Project No. 0990332-016-AC (PSD-FL-196N)
New Hope Power Partnership - Heat Input Rate Increase

Dear Mr. Williams:

Thank you for providing the requested additional information, which was received on March 4, 2003. The Department has a few additional questions and the application remains incomplete. In order to continue processing your application, the Department will need the additional information requested below. Should your response to any of the below items require new calculations, please submit the new calculations, assumptions, reference material and appropriate revised pages of the application form.

1. Your additional information indicates that an SCR system is not technically feasible due to high concentrations of potassium, sodium, and phosphorous in the flue gas. Please provide supporting documentation of the flue gas concentrations for these pollutants. Compare these levels with those of boilers that do employ SCR, such as coal-fired units.
2. Currently, NOx emissions are reduced using SNCR to achieve a standard of 0.15 lb/MMBtu of heat input based on a 30-day rolling average. Have any of the boilers failed to comply with this limit since the beginning of commercial operation?
3. The Department understands the issue of flexibility regarding unrestricted annual operation. However, the cogeneration units currently operate with an annual capacity factor of less than 60%. Some of the cost effectiveness calculations estimate an upper range of 90%. Please estimate the maximum expected annual capacity factor (in terms of heat input rate) for the cogeneration plant. Consider the following:
   - What factors typically prevent operation at rated capacity?
   - Do these units normally operate at capacity during the cane-milling season? During the off-season?
   - Do the units ramp down at nighttime?
   - Does the available fuel supply limit operation at capacity?
   - How many days are planned for scheduled down times to perform maintenance and inspections?
   - How many days have periods of unscheduled maintenance accounted for in the past?
4. The application refers to a project in Virginia for the Multitrade facility identified as RBLC #0183. (The Department believes the correct RBLC is #0174.) Under the application review for NOx emissions, this facility is identified as a "peaking plant", which should allow for consideration of higher urea injection

rates to achieve lower NOx emissions. However, the Department's review indicates that this is a spreader stoker boiler fired by wood. The current Title V permit for this facility does not describe the boiler as a "peaking unit". Please provide information that supports this boiler as a "peaking unit".

5. The Weyerhaeuser facility in Mississippi (RBLC #MS-0026) is identified as an electric utility boiler. This boiler is rated at 90 MMBtu per hour. The Department believes that the facility is not an electric utility, but rather a lumber mill and plywood plant. Please review and comment.

The Department will resume processing your application after receipt of the requested information. Rule 62-4.050(3), F.A.C. requires that all applications for a Department permit must be certified by a professional engineer registered in the State of Florida. This requirement also applies to responses to Department requests for additional information of an engineering nature. For any material changes to the application, please include a new certification statement by the authorized representative or responsible official. You are reminded that Rule 62-4.055(1), F.A.C. now requires applicants to respond to requests for information within 90 days or provide a written request for an additional period of time to submit the information.

If you have any questions regarding this matter, please call me at 850/921-9536.

Sincerely,

Jeffery F. Koerner

Jeffery F. Koerner
New Source Review Section

cc: Mr. James Meriwether, New Hope Power Partnership
Mr. David Buff, Golder Associates Inc.
Mr. Ron Blackburn, SD
Mr. James Stormer, PBCHD
Ms. Jeanneane Gettle, EPA Region 4
Mr. John Bunyak, NPS

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

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Sent To Rodney Williams

Street, Apt. No.; or PO Box No. PO Box 9

City, State, ZIP+4 South Bay, FL 33493

PS Form 3800, January 2001 See Reverse for Instructions

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1. Article Addressed to:

Mr. Rodney Williams
Plant Manager
New Hope Power Partnership
P. O. Box 9
South Bay, FL 33493

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PS Form 3811, August 2001 Domestic Return Receipt 102595-02-M-1540

Golder Associates Inc.

6241 NW 23rd Street, Suite 500
Gainesville, FL 32653-1500
Telephone (352) 336-5600
Fax (352) 336-6603

Golder Associates

RECEIVED

MAR 04 2003

BUREAU OF AIR REGULATION

March 3, 2003 0337520

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 Temp. (°F)	Feedwater Enthalpy (Btu/lb)	Steam Temp. (°F)	Steam Pressure (psig)	Steam Enthalpy (Btu/lb)	Steam Rate [a] (lb/hr)
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.

Comment 4: Please provide the missing Attachment NH-FI-C3 (Process Flow Diagram).

Response: See Attachment A.

Comment 5: 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.

Response: 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.**

<u>Response:</u> 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.**

<u>Response:</u> 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).

<u>**Response:**</u> 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.**

<u>**Response:**</u> 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.**

<u>**Response:**</u> 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.**

<u>**Response:**</u> 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.**

<u>**Response:**</u> 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

PROFESSIONAL ENGINEER

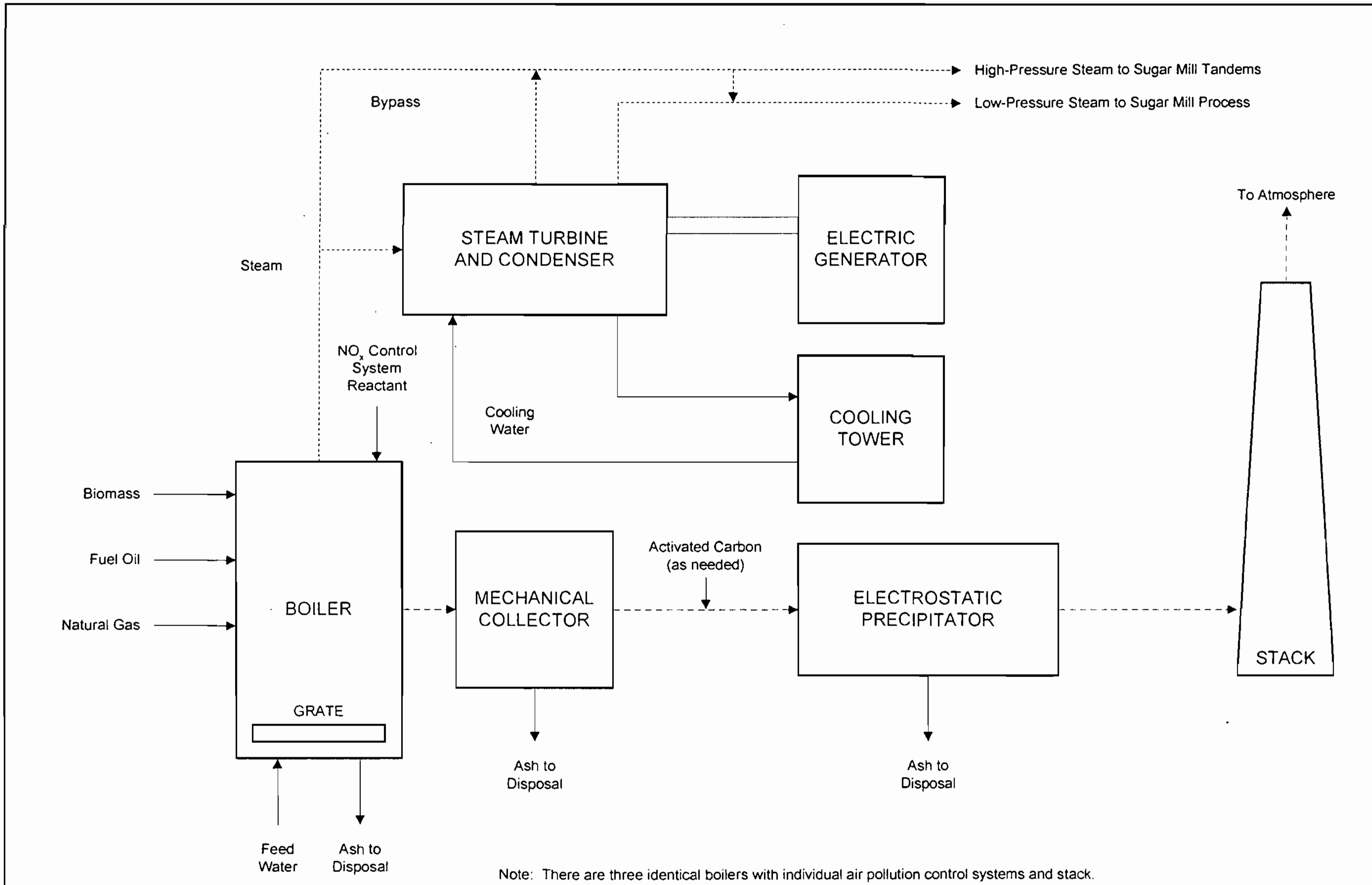
DB/DTL/jkw/nav

Enclosures

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

ATTACHMENT A

PROCESS FLOW DIAGRAM



Note: There are three identical boilers with individual air pollution control systems and stack.

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

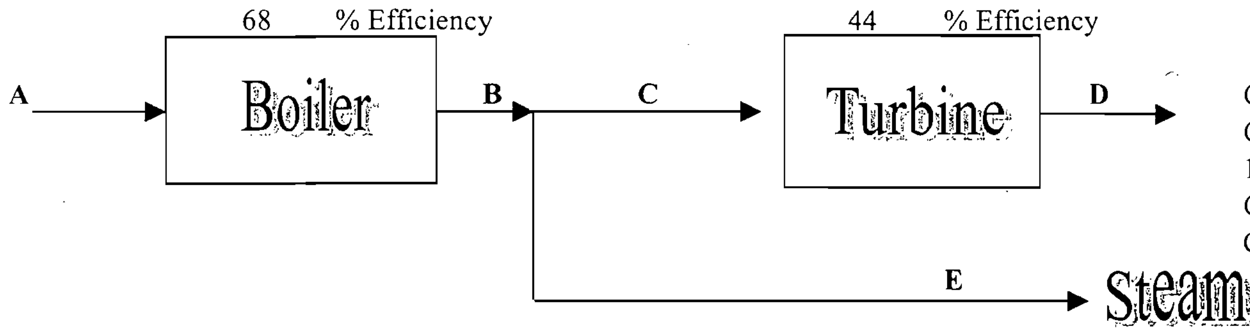
Process Flow Legend
Solid/Liquid ⟶
Steam ┈┈▸

Golder Associates

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-%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-%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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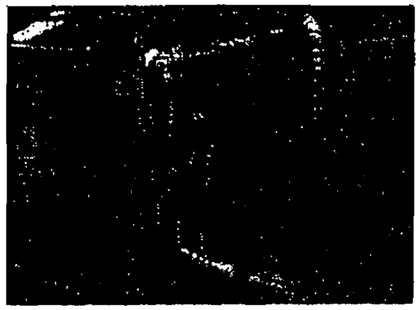
SCR (Selective Catalytic Reduction) pilot plant

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



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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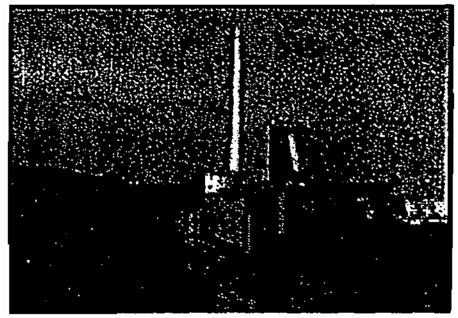
SCR-catalysts in Biofuelled Power-stations



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.

Info: Lena.Nilsson@chemeng.lth.se
Homepage: www.chemeng.lth.se/pk
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]

EPA-452-02-001

EPA AIR POLLUTION CONTROL COST MANUAL

Sixth Edition

EPA-452-02-001
January 2002

United States Environmental Protection Agency
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

Best Available Copy

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

C

A

T ECHNOLOGY

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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: **FAX:**	(352) 336-5600 (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 J 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 I-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

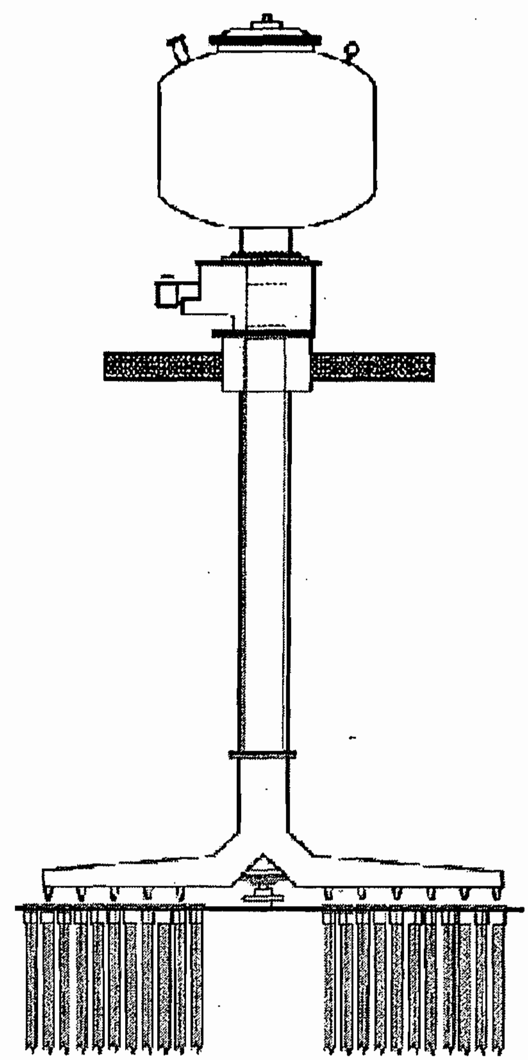


Figure 1

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, only six (6) diaphragm valves are required, that is, one per compartment. In contrast, a conventional pulse jet design could require at least 27 valves per compartment assuming a maximum of 20 bags per valve, equating to 162 valves. 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.

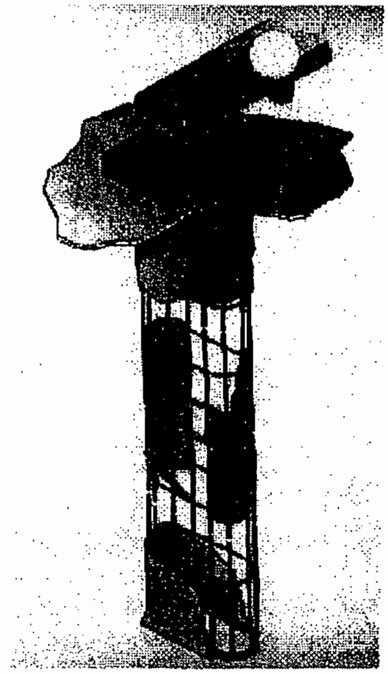
The volume of each cleaning air pulse is derived from theoretical gas laws as well as the number and length of bags being cleaned. The frequency of cleaning, and therefore the required flow rate of cleaning air, is determined from formulae derived from empirical data that has been gathered from an extensive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

Bag Inspection and Replacement

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

ATTACHMENT B – DETAIL OF SUPPLY

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.

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

TERMS AND CONDITIONS OF EQUIPMENT AND ERECTION SALES

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

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 11.5×10^{12} Btu per year for three cogeneration boilers to 19.97×10^{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 10.5×10^{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

Department of Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

November 21, 2002

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Rodney Williams, Plant Manager
New Hope Power Partnership
8001 U.S. Highway 27, South
South Bay, FL 33493

Re: **Request for Additional Information**
Project No. 0990332-016-AC (PSD-FL-196N)
New Hope Power Partnership - Plant Capacity Increase

Dear Mr. Williams:

On September 6, 2002, the Department received your application and sufficient fee for an air construction permit to increase the capacity of the Okeelanta Cogeneration Plant. The application was incomplete. On October 4, 2002, the Department requested additional information that would allow continued processing of your application. To date, we have not received the requested additional information. Rule 62-4.055(1) of the Florida Administrative Code requires the following:

> *"The applicant shall have ninety days after the Department mails a timely request for additional information to submit that information to the Department. If an applicant requires more than ninety days in which to respond to a request for additional information, the applicant may notify the Department in writing of the circumstances, at which time the application shall be held in active status for one additional period of up to ninety days. Additional extensions shall be granted for good cause shown by the applicant. A showing that the applicant is making a diligent effort to obtain the requested additional information shall constitute good cause. Failure of an applicant to provide the timely requested information by the applicable deadline shall result in denial of the application."*

It has been more than 45 days since our last request for additional information (copy attached). You are reminded that the permit processing time clock has stopped for this project and that we will not continue our review until we receive the additional information. If you require a period of time in addition to the 90 days allowed by rule, please submit a written request indicating the amount of time necessary. If you fail to provide the additional information or request additional time to submit the additional information, the Department will deny your application.

If you have any questions regarding this matter, please call me at 850/921-9536.

Sincerely,

Jeffery F. Koerner
Jeffery F. Koerner
New Source Review Section

cc: Mr. James Meriwether, New Hope Power Partnership
Mr. David Buff, Golder Associates Inc.
Mr. Ron Blackburn, SD
Mr. James Stormer, PBCHD
Ms. Jeanneane Gettle, EPA Region 4
Mr. John Bunyak, NPS

AAL/jfk

U.S. Postal Service
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Sent To Rodney Williams

Street, Apt. No.; or PO Box No. PO Box 9

City, State, ZIP+4 South Bay, FL 33493

PS Form 3800, January 2001 — See Reverse for Instructions

SENDER: ***COMPLETE THIS SECTION***

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

1. Article Addressed to:

Mr. Rodney Williams
Plant Manager
New Hope Power Partnership
P. O. Box 9
South Bay, FL 33493

COMPLETE THIS SECTION ON DELIVERY

A. Received by *(Please Print Clearly)* Amanda Kinman
B. Date of Delivery 11/25/02

C. Signature
X Amanda Kinman
☐ Agent
☐ Addressee

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

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

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

2. 7001 0320 0001 3692 7539

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

Department of Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

October 4, 2002

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Rodney Williams, Plant Manager
New Hope Power Partnership
8001 U.S. Highway 27, South
South Bay, FL 33493

Re: **Request for Additional Information**
Project No. 0990332-016-AC (PSD-FL-196N)
New Hope Power Partnership - Plant Capacity Increase

Dear Mr. Williams:

On September 6, 2002, the Department received your application and sufficient fee for an air construction permit to increase the capacity of the Okeelanta Cogeneration Plant. The application is incomplete. In order to continue processing your application, the Department will need the additional information requested below. Should your response to any of the below items require new calculations, please submit the new calculations, assumptions, reference material and appropriate revised pages of the application form.

1. 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?

2. NHPP requests that the total heat input restriction of $11.5 \times 10^{+06}$ 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.

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 NOx 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.

4. Please provide the missing Attachment NH-FI-C3 (Process Flow Diagram).

5. The floor for a NOx 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 NOx 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 NOx controls for the cogeneration boilers are capable of achieving this level of emissions.

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.

7. <u>NOx BACT Review</u>

   a. Please provide a top-down BACT review for all NOx 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.)

   b. Table 2-3 lists the potential annual NOx 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 NOx emissions from SNCR (the original design control efficiency), the uncontrolled NOx emission factor would be 0.25 lb/MMBtu. Table 5-3 uses an uncontrolled NOx emission factor of 0.26 lb/MMBtu and shows an estimated NOx 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 NOx 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 (8760 hours per year) as requested by NHPP.

   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.

   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.

   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 1000° 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).

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

   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.

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

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 NOx control.

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.

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.

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.

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.

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.

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

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

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?

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.

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.

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.

12. 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.

The Department will resume processing your application after receipt of the requested information. Rule 62-4.050(3), F.A.C. requires that all applications for a Department permit must be certified by a professional engineer registered in the State of Florida. This requirement also applies to responses to Department requests for additional information of an engineering nature. For any material changes to the application, please include a new certification statement by the authorized representative or responsible official. You are reminded that Rule 62-4.055(1), F.A.C. now requires applicants to respond to requests for information within 90 days or provide a written request for an additional period of time to submit the information.

If you have any questions regarding this matter, please call me at 850/921-9523 or Jeff Koerner at 850/921-9536.

Sincerely,

A. A. Linero, P.E. Administrator
New Source Review Section

AAL/jfk

cc: Mr. James Meriwether, New Hope Power Partnership
Mr. David Buff, Golder Associates Inc.
Mr. Ron Blackburn, SD
Mr. James Stormer, PBCHD
Ms. Jeanneane Gettle, EPA Region 4
Mr. John Bunyak, NPS

7001 0320 0001 3692 7904

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

OFFICIAL USE

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

Sent To Rodney Williams
Street, Apt. No.; or PO Box No. P.O. Box 9
City, State, ZIP+4 South Bay FL 33493

PS Form 3800, January 2001 See Reverse for Instructions

SENDER: *COMPLETE THIS SECTION*

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

1. Article Addressed to:

Mr. Rodney Williams
Plant Manager
New Hope Power Partnership
P. O. Box 9
South Bay, FL 33493

COMPLETE THIS SECTION ON DELIVERY

A. Received by *(Please Print Clearly)* Brenda Spooner B. Date of Delivery 10/9/02

C. Signature X Brenda Spooner ☐ Agent ☐ Addressee

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

3. Service Type
☒ Certified Mail ☐ Express Mail
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PS Form 3811, July 1999 Domestic Return Receipt 102595-00-M-0952

Department of
Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

September 18, 2002

Mr. Gregg Worley, Chief
Air, Radiation Technology Branch
Preconstruction/HAP Section
U.S. EPA, Region 4
61 Forsyth Street
Atlanta, Georgia 30303

RE: New Hope Power Partnership
(formerly Okeelanta Power L.P.)
DEP File No. 0990332-016-AC, PSD-FL-196N

Dear Mr. Worley:

Enclosed for your review and comment is an application submitted by New Hope Power Partnership to increase the heat input rate for the cogeneration boilers at their facility in Palm Beach County, Florida.

Your comments may be forwarded to my attention at the letterhead address or faxed to the Bureau of Air Regulation at 850/922-6979. If you have any questions, please contact Jeff Koerner, review engineer, at 850/921-9536.

Sincerely,

Patty Adams

for Al Linero, P.E.
Administrator
New Source Review Section

AAL/pa

Enclosure

Cc: Jeff Koerner

Department of Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

September 18, 2002

Mr. John Bunyak, Chief
Policy, Planning & Permit Review Branch
NPS – Air Quality Division
Post Office Box 25287
Denver, Colorado 80225

RE: New Hope Power Partnership
(formerly Okeelanta Power L.P.)
DEP File No. 0990332-016-AC, PSD-FL-196N

Dear Mr. Bunyak:

Enclosed for your review and comment is an application submitted by New Hope Power Partnership to increase the heat input rate for the cogeneration boilers at their facility in Palm Beach County, Florida.

Your comments may be forwarded to my attention at the letterhead address or faxed to the Bureau of Air Regulation at 850/922-6979. If you have any questions, please contact Jeff Koerner, review engineer, at 850/921-9536.

Sincerely,

Patty Adams
for Al Linero, P.E.
Administrator
New Source Review Section

AAL/pa

Enclosure

Cc: Jeff Koerner

Golder Associates Inc.

6241 NW 23rd Street, Suite 500
Gainesville, FL 32653-1500
Telephone (352) 336-5600
Fax (352) 336-6603

Golder Associates

TRANSMITTAL LETTER

To: Patty Adams
FDEP, Tallahasseee

Date: September 13, 2002
Project No.: 0137520-0100

Sent by: ARZ

☐ Mail
☐ Air Freight
☐ Hand Carried
☐ UPS
☒ Federal Express

Per: D.Buff

Quantity	Item	Description
3	Final Report	New Hope Power Partnership - Application to Increase the Heat Input Rate for the Cogeneration Boilers

G:\Projects\2001\0137520 NHPP\4\4.1\T091302.doc

NEW HOPE POWER PARTNERSHIP
OKEELANTA COGENERATION PLANT
P.O. BOX 9
8001 HWY 27 S.
SOUTH BAY, FLORIDA 33493
OFFICE (561) 993-1000 FAX (561) 992-7744

September 4, 2002

Department of Environmental Protection
Division of Air Resources Management
New Source Review Section
Twin Towers Office Building
2600 Blair Stone Road
MS #5505
Tallahassee, FL 32399-2400

RECEIVED
SEP 06 2002
BUREAU OF AIR REGULATION

Attn: A.A. Linero, P.E.
Administrator

Re: New Hope Power Partnership
Okeelanta Cogeneration Plant
Facility ID # 0990332

Dear Mr. Linero,

New Hope Power Partnership (formerly Okeelanta Power Limited Partnership) is hereby submitting four (4) signed and sealed copies of an "Application To Increase The Maximum Allowable Heat Input Rate For The Three Cogeneration Boilers". Check # 92681 in the amount of $7,500 is also enclosed to pay the application fee. If you have any questions please contact me at the letterhead above or by telephone at (561) 993-1003 or you may alternately contact David Buff of Golder Associates at (352) 336-5600.

Sincerely,

James M. Meriwether
Environmental and Safety Manager

cc: Rodney Williams
Gus Cepero
David Buff
Bill Tarr
David Dee

NEW HOPE POWER PARTNERSHIP
OKEELANTA COGENERATION PLANT
P.O. BOX 9
8001 HWY 27 S.
SOUTH BAY, FLORIDA 33493
OFFICE (561) 993-1000 FAX (561) 992-7744

July 25, 2002

023-7568

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

Attention: Mr. Jeff Koerner

RE: New Hope Power Partnership, Permit No. 0990332-014-AC/PSD-FL-196M

Dear Mr. Koerner:

An administrative requirement of Permit No. 0990332-014-AC for New Hope Power Partnership is the requirement to submit a Title V revision within 180 days of January 31, 2002. David A. Buff, P.E., the engineer of record for this project, has recently had a heart attack and will be out of the office for 4 to 6 weeks. Therefore, Mr. Buff will not be able to prepare the application by the deadline of July 31, 2002. New Hope Power Partnership is, therefore, requesting a 60-day extension until September 31, 2002, to submit the required Title V revision application.

Please feel free to call James Meriwether, New Hope Power Partnership, at (561) 993-1003 or Fawn Howard, Golder Associates Inc., at (352) 336-5600 if you have any questions or comments.

Sincerely,

NEW HOPE POWER PARTNERSHIP

Rodney Williams

Rodney Williams
Plant Manager

FH

Enclosures

cc: R. Blackburn, DEP
M. Capone, Okeelanta Corp.
F. Howard, Golder
J. Meriwether, NHPP

RECEIVED
SEP 06 2002
BUREAU OF AIR REGULATION

APPLICATION TO INCREASE THE HEAT INPUT RATE FOR THE COGENERATION BOILERS

NEW HOPE POWER PARTNERSHIP
SOUTH BAY, FLORIDA

Prepared For:

New Hope Power Partnership
8001 U.S. Highway 27 South
South Bay, Florida 33493

Prepared By:

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

August 2002
0137520

DISTRIBUTION:
4 Copies - FDEP
5 Copies - NHPP
2 Copies - Golder Associates Inc.

Department of Environmental Protection

Division of Air Resources Management

RECEIVED
SEP 06 2002
BUREAU OF AIR REGULATION

APPLICATION FOR AIR PERMIT - TITLE V SOURCE

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

I. APPLICATION INFORMATION

Identification of Facility

1. Facility Owner/Company Name: **New Hope Power Partnership**	
2. Site Name: **New Hope Power Partnership**	
3. Facility Identification Number: **0990332** [ ] Unknown	
4. Facility Location: **6 Miles South of South Bay on US 27** Street Address or Other Locator: **8001 U.S. Highway 27 South** City: **South Bay** County: **Palm Beach** Zip Code: **33493**	
5. Relocatable Facility? [ ] Yes [X] No	6. Existing Permitted Facility? [X] Yes [ ] No

Application Contact

1. Name and Title of Application Contact: **James Meriwether, Environmental and Safety Manager**
2. Application Contact Mailing Address: Organization/Firm: **New Hope Power Partnership** Street Address: **8001 U.S. Highway 27 South** City: **South Bay** State: **FL** Zip Code: **33493**
3. Application Contact Telephone Numbers: Telephone: **(561) 993 - 1003** Fax: **(561) 996-6596**

Application Processing Information (DEP Use)

1. Date of Receipt of Application:	9-6-02
2. Permit Number:	0990332-016-AC
3. PSD Number (if applicable):	PSD-FL-196 N
4. Siting Number (if applicable):	

Purpose of Application

Air Operation Permit Application

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

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

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

Current construction permit number: ______________________

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

Current construction permit number: ______________________

Operation permit number to be revised: ______________________

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

Operation permit number to be revised/corrected: ______________________

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

Operation permit number to be revised: ______________________

Reason for revision: ______________________

Air Construction Permit Application

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

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

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

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

Owner/Authorized Representative or Responsible Official

1. Name and Title of Owner/Authorized Representative or Responsible Official: **Rodney Williams - Plant Manager**	
2. Owner/Authorized Representative or Responsible Official Mailing Address: Organization/Firm: **New Hope Power Partnership** Street Address: **8001 U.S. Highway 27 South** City: **South Bay** State: **FL** Zip Code: **33493**	
3. Application Contact Telephone Numbers: Telephone: **(561) 993-1000**	Fax: **(561) 992-7744**

4. Owner/Authorized Representative or Responsible Official Statement:

I, the undersigned, am the owner or authorized representative(check here [ ], if so) or the responsible official (check here [ ], if so) of the Title V source addressed in this application, whichever is applicable. I hereby certify, based on information and belief formed after reasonable inquiry, that the statements made in this application are true, accurate and complete and that, to the best of my knowledge, any estimates of emissions reported in this application are based upon reasonable techniques for calculating emissions. The air pollutant emissions units and air pollution control equipment described in this application will be operated and maintained so as to comply with all applicable standards for control of air pollutant emissions found in the statutes of the State of Florida and rules of the Department of Environmental Protection and revisions thereof. I understand that a permit, if granted by the Department, cannot be transferred without authorization from the Department, and I will promptly notify the Department upon sale or legal transfer of any permitted emissions unit.*

Rodney C. Willi

Signature

9/4/02

Date

* Attach letter of authorization if not currently on file.

Professional Engineer Certification

1. Professional Engineer Name: **David A. Buff** Registration Number: **19011**	
2. Professional Engineer Mailing Address: Organization/Firm: **Golder Associates Inc.*** Street Address: **6241 NW 23rd Street, Suite 500** City: **Gainesville** State: **FL** Zip Code: **32653-1500**	
3. Professional Engineer Telephone Numbers: Telephone: **(352) 336 - 5600**	Fax: **(352) 336 - 6603**

*** Board of Professional Engineers Certificate 03000018**

4. Professional Engineer Statement:

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

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

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

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

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

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

David A. Buff — 8/30/2002

Signature — Date

(seal)

* Attach any exception to certification statement.

Scope of Application

Emissions Unit ID	Description of Emissions Unit	Permit Type	Processing Fee
029	Materials Handling and Storage Operations	AC1A	
030	Cogen Boiler A	AC1A	
031	Cogen Boiler B	AC1A	
032	Cogen Boiler C	AC1A	

Application Processing Fee

Check one: [X] Attached - Amount: $: 7,500 [ ] Not Applicable

Construction/Modification Information

1. Description of Proposed Project or Alterations: **Increase in maximum allowable heat input rates for the three (3) cogeneration boilers.**	
2. Projected or Actual Date of Commencement of Construction	**01 DEC 2002**
3. Projected Date of Completion of Construction:	**01 DEC 2003**

Application Comment

II. FACILITY INFORMATION

A. GENERAL FACILITY INFORMATION

Facility Location and Type

1. Facility UTM Coordinates: Zone: **17** East (km): **524.90** North (km): **2940.10**			
2. Facility Latitude/Longitude: Latitude (DD/MM/SS): / / Longitude (DD/MM/SS): / /			
3. Governmental Facility Code: **0**	4. Facility Status Code: **A**	5. Facility Major Group SIC Code: **49**	6. Facility SIC(s): **4911**
7. Facility Comment (limit to 500 characters): **The New Hope Power Partnership (formerly Okeelanta Power L.P.) cogeneration facility consists of three boilers and all operations necessary to generate steam for the Okeelanta Corporation sugar mill, as well as generate electricity for sale to the grid.**			

Facility Contact

1. Name and Title of Facility Contact: **James Meriwether, Environmental and Safety Manager**
2. Facility Contact Mailing Address: Organization/Firm: **New Hope Power Partnership** Street Address: **8001 U.S. Highway 27 South** City: **South Bay** State: **FL** Zip Code: **33493**
3. Facility Contact Telephone Numbers: Telephone: **(561) 993 - 1003** Fax: **(561) 996 - 6596**

Facility Regulatory Classifications

Check all that apply:

1. [ ] Small Business Stationary Source?	[ ] Unknown
2. [X] Major Source of Pollutants Other than Hazardous Air Pollutants (HAPs)?	
3. [ ] Synthetic Minor Source of Pollutants Other than HAPs?	
4. [X] Major Source of Hazardous Air Pollutants (HAPs)?	
5. [ ] Synthetic Minor Source of HAPs?	
6. [X] One or More Emissions Units Subject to NSPS?	
7. [ ] One or More Emission Units Subject to NESHAP?	
8. [ ] Title V Source by EPA Designation?	
9. Facility Regulatory Classifications Comment (limit to 200 characters): **See Attachment NH-FI-A9.**	

List of Applicable Regulations

Only those rules, regulations, and ordinances specifically identified herein apply to this facility.	
See attached Title V Core List, effective 3/1/02.	

Title V Core List

Effective: 03/01/02

[**Note:** The Title V Core List is meant to simplify the completion of the "List of Applicable Regulations" for DEP Form No. 62-210.900(1), Application for Air Permit - Long Form. The Title V Core List is a list of rules to which all Title V Sources are presumptively subject. The Title V Core List may be referenced in its entirety, or with specific exceptions. The Department may periodically update the Title V Core List.]

Federal: ***(description)***

~~40 CFR 61: National Emission Standards for Hazardous Air Pollutants (NESHAP)~~
~~40 CFR 61, Subpart M: NESHAP for Asbestos.~~
40 CFR 64, Compliance Assurance Monitoring
~~40 CFR 82: Protection of Stratospheric Ozone.~~
~~40 CFR 82, Subpart B: Servicing of Motor Vehicle Air Conditioners (MVAC).~~
~~40 CFR 82, Subpart F: Recycling and Emissions Reduction.~~

State: ***(description)***

CHAPTER 62-4, F.A.C.: PERMITS, effective 06-01-01

62-4.030, F.A.C.: General Prohibition.
62-4.040, F.A.C.: Exemptions.
62-4.050, F.A.C.: Procedure to Obtain Permits; Application.
62-4.060, F.A.C.: Consultation.
62-4.070, F.A.C.: Standards for Issuing or Denying Permits; Issuance; Denial.
62-4.080, F.A.C.: Modification of Permit Conditions.
62-4.090, F.A.C.: Renewals.
62-4.100, F.A.C.: Suspension and Revocation.
62-4.110, F.A.C.: Financial Responsibility.
62-4.120, F.A.C.: Transfer of Permits.
62-4.130, F.A.C.: Plant Operation - Problems.
62-4.150, F.A.C.: Review.
62-4.160, F.A.C.: Permit Conditions.
62-4.210, F.A.C.: Construction Permits.
62-4.220, F.A.C.: Operation Permit for New Sources.

CHAPTER 62-210, F.A.C.: STATIONARY SOURCES - GENERAL REQUIREMENTS, effective 06-21-01

62-210.300, F.A.C.: Permits Required.
62-210.300(1), F.A.C.: Air Construction Permits.
62-210.300(2), F.A.C.: Air Operation Permits.
62-210.300(3), F.A.C.: Exemptions.
62-210.300(5), F.A.C.: Notification of Startup.
62-210.300(6), F.A.C.: Emissions Unit Reclassification.
62-210.300(7), F.A.C.: Transfer of Air Permits.

62-210.350, F.A.C.: Public Notice and Comment.
62-210.350(1), F.A.C.: Public Notice of Proposed Agency Action.
62-210.350(2), F.A.C.: Additional Public Notice Requirements for Emissions Units Subject to Prevention of Significant Deterioration or Nonattainment-Area Preconstruction Review.
62-210.350(3), F.A.C.: Additional Public Notice Requirements for Sources Subject to Operation Permits for Title V Sources.

62-210.360, F.A.C.: Administrative Permit Corrections.
62-210.370(3), F.A.C.: Annual Operating Report for Air Pollutant Emitting Facility.
62-210.400, F.A.C.: Emission Estimates.
62-210.650, F.A.C.: Circumvention.
62-210.700, F.A.C.: Excess Emissions.

62-210.900, F.A.C.: Forms and Instructions.
62-210.900(1), F.A.C.: Application for Air Permit – Title V Source, Form and Instructions.
62-210.900(5), F.A.C.: Annual Operating Report for Air Pollutant Emitting Facility, Form and Instructions.
62-210.900(7), F.A.C.: Application for Transfer of Air Permit – Title V and Non-Title V Source.

CHAPTER 62-212, F.A.C.: STATIONARY SOURCES - PRECONSTRUCTION REVIEW, effective 08-17-00

CHAPTER 62-213, F.A.C.: OPERATION PERMITS FOR MAJOR SOURCES OF AIR POLLUTION, effective 04-16-01

62-213.205, F.A.C.: Annual Emissions Fee.
62-213.400, F.A.C.: Permits and Permit Revisions Required.
62-213.410, F.A.C.: Changes Without Permit Revision.
62-213.412, F.A.C.: Immediate Implementation Pending Revision Process.
62-213.415, F.A.C.: Trading of Emissions Within a Source.
62-213.420, F.A.C.: Permit Applications.
62-213.430, F.A.C.: Permit Issuance, Renewal, and Revision.
62-213.440, F.A.C.: Permit Content.
62-213.450, F.A.C.: Permit Review by EPA and Affected States
62-213.460, F.A.C.: Permit Shield.

62-213.900, F.A.C.: Forms and Instructions.
62-213.900(1), F.A.C.: Major Air Pollution Source Annual Emissions Fee Form.
62-213.900(7), F.A.C.: Statement of Compliance Form.

~~**CHAPTER 62-256, F.A.C.: OPEN BURNING AND FROST PROTECTION FIRES,** effective 11-30-94~~

~~**CHAPTER 62-257, F.A.C.: ASBESTOS NOTIFICATION AND FEE,** effective 03-24-96~~

~~**CHAPTER 62-281, F.A.C.: MOTOR VEHICLE AIR CONDITIONING REFRIGERANT RECOVERY AND RECYCLING,** effective 03-07-96~~

CHAPTER 62-296, F.A.C.: STATIONARY SOURCES - EMISSION STANDARDS, effective 03-02-99

62-296.320(4)(c), F.A.C.: Unconfined Emissions of Particulate Matter.

62-296.320(2), F.A.C.: Objectionable Odor Prohibited.

CHAPTER 62-297, F.A.C.: STATIONARY SOURCES - EMISSIONS MONITORING, effective 03-02-99

62-297.310, F.A.C.: General Test Requirements.
62-297.330, F.A.C.: Applicable Test Procedures.
62-297.340, F.A.C.: Frequency of Compliance Tests.
62-297.345, F.A.C.: Stack Sampling Facilities Provided by the Owner of an Emissions Unit.
62-297.350, F.A.C.: Determination of Process Variables.
62-297.570, F.A.C.: Test Report.
62-297.620, F.A.C.: Exceptions and Approval of Alternate Procedures and Requirements.

Miscellaneous:

CHAPTER 28-106, F.A.C.: Decisions Determining Substantial Interests
CHAPTER 62-110, F.A.C.: Exception to the Uniform Rules of Procedure, effective 07-01-98
~~**CHAPTER 62-256, F.A.C.**: Open Burning and Frost Protection Fires, effective 11-30-94~~
~~**CHAPTER 62-257, F.A.C.**: Asbestos Notification and Fee, effective 02-09-99~~
~~**CHAPTER 62-281, F.A.C.**: Motor Vehicle Air Conditioning Refrigerant Recovery and Recycling, effective 09-10-96~~

B. FACILITY POLLUTANTS

List of Pollutants Emitted

1. Pollutant Emitted	2. Pollutant Classif.	3. Requested Emissions Cap lb/hour	tons/year	4. Basis for Emissions Cap	5. Pollutant Comment
PM	**A**				**Particulate Matter – Total**
PM_{10}	**A**				**Particulate Matter – PM_{10}**
SO_2	**A**				**Sulfur Dioxide**
NO_X	**A**				**Nitrogen Oxides**
CO	**A**				**Carbon Monoxide**
VOC	**A**				**Volatile Organic Compounds**
PB	**B**				**Lead**
H114	**B**				**Mercury**
SAM	**B**				**Sulfuric Acid Mist**
HAPs	**A**				**Hazardous Air Pollutants** **See Att. NH-FI-A9**

C. FACILITY SUPPLEMENTAL INFORMATION

Supplemental Requirements

1. Area Map Showing Facility Location: [X] Attached, Document ID: NH-FI-C1 [ ] Not Applicable [ ] Waiver Requested	
2. Facility Plot Plan: [X] Attached, Document ID: NH-FI-C2 [ ] Not Applicable [ ] Waiver Requested	
3. Process Flow Diagram(s): [X] Attached, Document ID: NH-FI-C3 [ ] Not Applicable [ ] Waiver Requested	
4. Precautions to Prevent Emissions of Unconfined Particulate Matter: [ ] Attached, Document ID: ________ [X] Not Applicable [ ] Waiver Requested	
5. Fugitive Emissions Identification: [ ] Attached, Document ID: ________ [X] Not Applicable [ ] Waiver Requested	
6. Supplemental Information for Construction Permit Application: [X] Attached, Document ID: PSD Report [ ] Not Applicable	
7. Supplemental Requirements Comment:	

Additional Supplemental Requirements for Title V Air Operation Permit Applications

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

ATTACHMENT NH-FI-A9

FACILITY REGULATORY CLASSIFICATION COMMENT

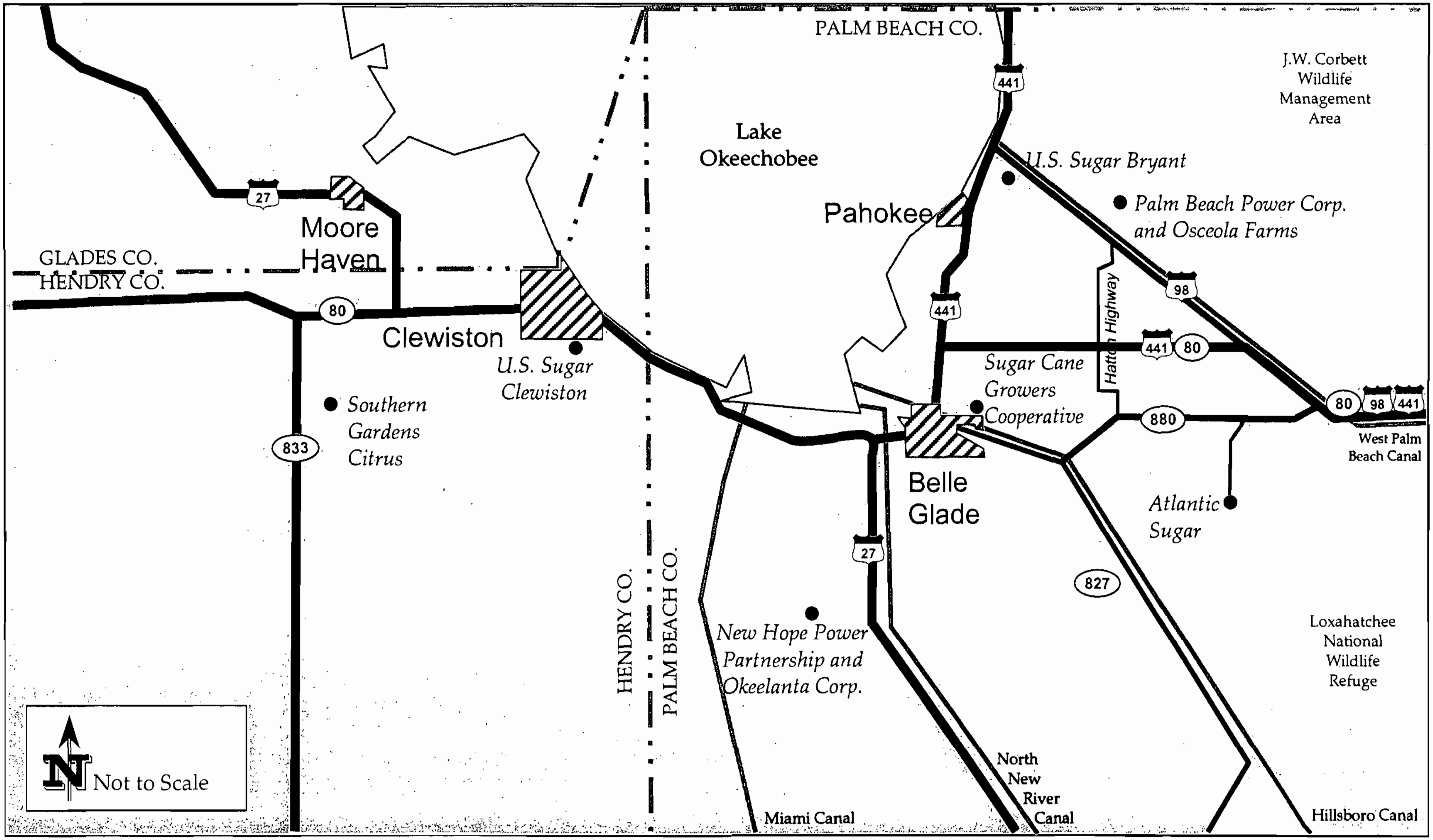
ATTACHMENT NH-FI-A9

FACILITY REGULATORY CLASSIFICATION COMMENT

At this time, it is unclear whether New Hope Power Partnership should be classified as major for HAPs. New Hope Power Partnership has no emissions test data indicating significant HAP emissions from its boilers. Emissions test data from the Pulp and Paper Industry indicates that there are HAPs emissions from wood-fired boilers. However, these emissions data may not be representative of New Hope Power Partnership HAP emissions. In addition, recent sugar industry test data indicates that there are HAPs emissions from sugar industry bagasse fired boilers. However, New Hope Power Partnership believes the HAPs emissions from its boilers are much lower than the emissions from the older boilers in the sugar industry. Further, Okeelanta Corporation is currently not operating its sugar mill boilers, as steam is being supplied by New Hope Power Partnership.

ATTACHMENT NH-FI-C1

AREA MAP SHOWING FACILITY LOCATION



Attachment NH-FI-C1
Location of New Hope Power Partnership

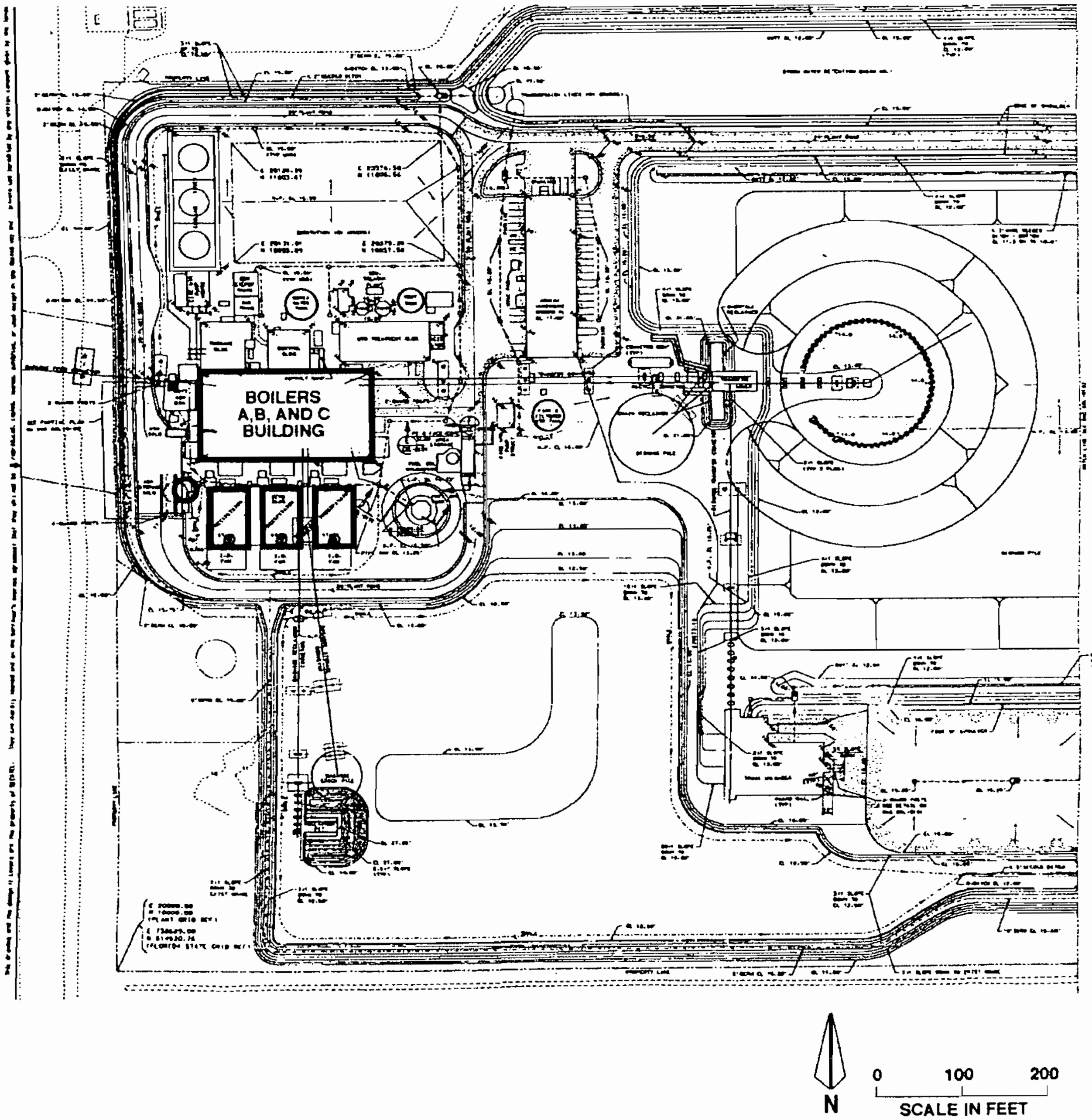
Source: Golder Associates Inc., 2002.

Golder Associates

ATTACHMENT NH-FI-C2

FACILITY PLOT PLAN

Best Available Copy



Attachment NH-FI-C2
Plot Plan of New Hope Power Partnership Facility

Source: Bechtel, 1996; Golder, 2000.

Golder Associates

ATTACHMENT NH-FI-C3

PROCESS FLOW DIAGRAM

III. EMISSIONS UNIT INFORMATION

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

A. GENERAL EMISSIONS UNIT INFORMATION
(All Emissions Units)

Emissions Unit Description and Status

1. Type of Emissions Unit Addressed in This Section: (Check one) [ ] This Emissions Unit Information Section addresses, as a single emissions unit, a single process or production unit, or activity, which produces one or more air pollutants and which has at least one definable emission point (stack or vent). [X] This Emissions Unit Information Section addresses, as a single emissions unit, a group of process or production units and activities which has at least one definable emission point (stack or vent) but may also produce fugitive emissions. [ ] This Emissions Unit Information Section addresses, as a single emissions unit, one or more process or production units and activities which produce fugitive emissions only.			
2. Regulated or Unregulated Emissions Unit? (Check one) [X] The emissions unit addressed in this Emissions Unit Information Section is a regulated emissions unit. [ ] The emissions unit addressed in this Emissions Unit Information Section is an unregulated emissions unit.			
3. Description of Emissions Unit Addressed in This Section (limit to 60 characters): **Biomass/ash handling system at New Hope Power Partnership**			
4. Emissions Unit Identification Number: ID: **029**			[ ] No ID [ ] ID Unknown
5. Emissions Unit Status Code: **A**	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code: **49**	8. Acid Rain Unit? [ ]
9. Emissions Unit Comment: (Limit to 500 Characters)			

Emissions Unit Control Equipment

1. Control Equipment/Method Description (Limit to 200 characters per device or method): **Baghouse** **Enclosures**	
2. Control Device or Method Code(s):	**18, 54**

Emissions Unit Details

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

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

Emissions Unit Operating Capacity and Schedule

1. Maximum Heat Input Rate:				mmBtu/hr
2. Maximum Incineration Rate:		lb/hr		tons/day
3. Maximum Process or Throughput Rate:			3,761,731 TPY	
4. Maximum Production Rate:				
5. Requested Maximum Operating Schedule:				
	24	hours/day	**7**	days/week
	52	weeks/year	**8,760**	hours/year
6. Operating Capacity/Schedule Comment (limit to 200 characters):				

1,063,162 TPY woodwaste; 1,444,659 TPY bagasse; plus 50% additional for yearly variability.

C. EMISSIONS UNIT REGULATIONS
(Regulated Emissions Units Only)

List of Applicable Regulations

62-296.320(4)(b)	
62-296.320(4)(c)	

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

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram? **Material Handling System**		2. Emission Point Type Code: **4**
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking (limit to 100 characters per point): **Fly Ash Silo** **Conveyor Transfer Points** **Hogger** **Biomass Storage Pile**		
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:		
5. Discharge Type Code: **F**	6. Stack Height: feet	7. Exit Diameter: feet
8. Exit Temperature: **77** °F	9. Actual Volumetric Flow Rate: acfm	10. Water Vapor: %
11. Maximum Dry Standard Flow Rate: dscfm		12. Nonstack Emission Point Height: **10** feet
13. Emission Point UTM Coordinates: Zone: East (km): North (km):		
14. Emission Point Comment (limit to 200 characters): **Fugitive emissions**		

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

Segment Description and Rate: Segment 1 of 1

1. Segment Description (Process/Fuel Type) (limit to 500 characters): **Bulk materials open stockpiles: Biomass**		
2. Source Classification Code (SCC): **3-02-103-99**	3. SCC Units: **Tons used**	
4. Maximum Hourly Rate:	5. Maximum Annual Rate: **3,761,731**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit:
10. Segment Comment (limit to 200 characters): **Segment represents biomass handling and storage operations.**		

Segment Description and Rate: Segment _____ of _____

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

F. EMISSIONS UNIT POLLUTANTS
(All Emissions Units)

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

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

Potential/Fugitive Emissions

1. Pollutant Emitted: **PM**	2. Total Percent Efficiency of Control:
3. Potential Emissions: lb/hour **9.07** tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference:	7. Emissions Method Code:
8. Calculation of Emissions (limit to 600 characters): **Refer to Table 2-4 in the PSD Report.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):	

Allowable Emissions Allowable Emissions ______ of ______

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance (limit to 60 characters):	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):	

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

Potential/Fugitive Emissions

1. Pollutant Emitted: **PM_{10}**	2. Total Percent Efficiency of Control:
3. Potential Emissions: lb/hour **3.50** tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference:	7. Emissions Method Code:
8. Calculation of Emissions (limit to 600 characters): **Refer to Table 2-4 in the PSD Report.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):	

Allowable Emissions Allowable Emissions ______ of ______

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance (limit to 60 characters):	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):	

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

Visible Emissions Limitation: Visible Emissions Limitation 1 of 1

1. Visible Emissions Subtype: VE20	2. Basis for Allowable Opacity: [X] Rule [ ] Other
3. Requested Allowable Opacity: Normal Conditions: 20 % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance: VE test using EPA Method 9	
5. Visible Emissions Comment (limit to 200 characters): Rule 62-296.320(4)(b), F.A.C.	

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

Continuous Monitoring System: Continuous Monitor ______ of ______

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

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

Supplemental Requirements

1. Process Flow Diagram [X] Attached, Document ID: NH-EU1-J1 [ ] Not Applicable [ ] Waiver Requested
2. Fuel Analysis or Specification [ ] Attached, Document ID:________ [ ] Not Applicable [X] Waiver Requested
3. Detailed Description of Control Equipment [ ] Attached, Document ID: ________ [ ] Not Applicable [X] Waiver Requested
4. Description of Stack Sampling Facilities [ ] Attached, Document ID:________ [ ] Not Applicable [X] Waiver Requested
5. Compliance Test Report [ ] Attached, Document ID:________ [ ] Previously submitted, Date:________ [X] Not Applicable
6. Procedures for Startup and Shutdown [ ] Attached, Document ID:________ [X] Not Applicable [ ] Waiver Requested
7. Operation and Maintenance Plan [ ] Attached, Document ID:________ [X] Not Applicable [ ] Waiver Requested
8. Supplemental Information for Construction Permit Application [X] Attached, Document ID: PSD Report [ ] Not Applicable
9. Other Information Required by Rule or Statute [ ] Attached, Document ID:________ [X] Not Applicable
10. Supplemental Requirements Comment:

Additional Supplemental Requirements for Title V Air Operation Permit Applications

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

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

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

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

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

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

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

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

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

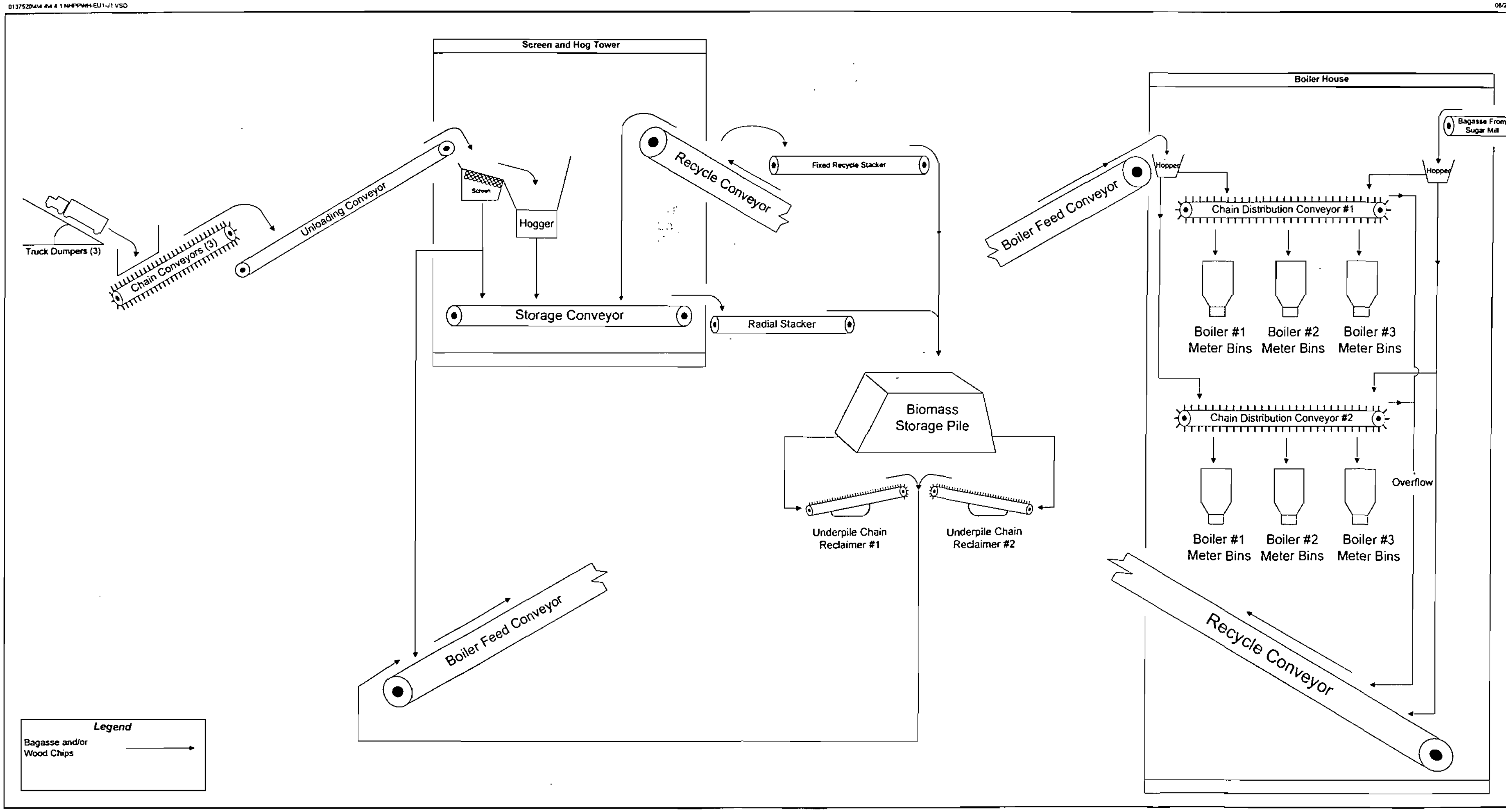
    [ ] Phase II NOx Compliance Plan (Form No. 62-210.900(1)(a)4.)
    Attached, Document ID:________

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

    [X] Not Applicable

ATTACHMENT NH-EU1-J1

PROCESS FLOW DIAGRAM



Attachment NH-EU1-J1. Materials Handling System

New Hope Power Partnership - South Bay, Florida

Golder Associates

III. EMISSIONS UNIT INFORMATION

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

A. GENERAL EMISSIONS UNIT INFORMATION
(All Emissions Units)

Emissions Unit Description and Status

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

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

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

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

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

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

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

3. Description of Emissions Unit Addressed in This Section (limit to 60 characters):
Cogen Boiler A fired by Biomass/No. 2 Fuel Oil/Natural Gas

4. Emissions Unit Identification Number: [ ] No ID
ID: **030** [ ] ID Unknown

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

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

74.9 MW net generating capacity for entire facility.

Emissions Unit Control Equipment

1. Control Equipment/Method Description (Limit to 200 characters per device or method): **ESP - Electrostatic Precipitator - High Efficiency** **Selective Non-catalytic Reduction for NO_x** **Multiple Cyclone w/o Fly Ash Reinjection** **Activated Carbon Injection System**	
2. Control Device or Method Code(s):	**010, 107, 076, 048**

Emissions Unit Details

1. Package Unit: Manufacturer:		Model Number:
2. Generator Nameplate Rating:	**75**	MW
3. Incinerator Information:		
Dwell Temperature:		°F
Dwell Time:		seconds
Incinerator Afterburner Temperature:		°F

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

Emissions Unit Operating Capacity and Schedule

1. Maximum Heat Input Rate:			760	mmBtu/hr
2. Maximum Incineration Rate:		lb/hr		tons/day
3. Maximum Process or Throughput Rate:				tons/hr
4. Maximum Production Rate:				
5. Requested Maximum Operating Schedule:				
	24	hours/day	7	days/week
	52	weeks/year	8,760	hours/year
6. Operating Capacity/Schedule Comment (limit to 200 characters): **Maximum heat input rates:** **Biomass - 760 MMBtu/hr;** **No. 2 Fuel Oil - 490 MMBtu/hr;** **Natural Gas - 605 MMBtu/hr**				

C. EMISSIONS UNIT REGULATIONS
(Regulated Emissions Units Only)

List of Applicable Regulations

See Attachment NH-EU2-C.	

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

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram? **BLR A**		2. Emission Point Type Code: **1**
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking (limit to 100 characters per point):		
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:		
5. Discharge Type Code: **V**	6. Stack Height: **199** feet	7. Exit Diameter: **10.0** feet
8. Exit Temperature: **352** °F	9. Actual Volumetric Flow Rate: **319,000** acfm	10. Water Vapor: %
11. Maximum Dry Standard Flow Rate: dscfm		12. Nonstack Emission Point Height: feet
13. Emission Point UTM Coordinates: Zone: East (km): North (km):		
14. Emission Point Comment (limit to 200 characters): **Stack parameters based on biomass firing. See Table 2-5 in PSD Report for all boiler stack data.**		

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

Segment Description and Rate: Segment 1 of 4

1. Segment Description (Process/Fuel Type) (limit to 500 characters): **Electric Utility Boiler - Bagasse**		
2. Source Classification Code (SCC): **1-01-011-01**	3. SCC Units: **Tons Burned (all solid fuels)**	
4. Maximum Hourly Rate: **105.56**	5. Maximum Annual Rate: **924,667**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **0.05**	8. Maximum % Ash: **1.0**	9. Million Btu per SCC Unit: **7.2**
10. Segment Comment (limit to 200 characters):		

Segment Description and Rate: Segment 2 of 4

1. Segment Description (Process/Fuel Type) (limit to 500 characters): **Electric Utility Boiler - Wood Fired Boiler**		
2. Source Classification Code (SCC): **1-01-009-03**	3. SCC Units: **Tons Burned (all solid fuels)**	
4. Maximum Hourly Rate: **84.44**	5. Maximum Annual Rate: **739,733**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **0.3**	8. Maximum % Ash: **9.0**	9. Million Btu per SCC Unit: **9.0**
10. Segment Comment (limit to 200 characters):		

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

Segment Description and Rate: Segment 3 of 4

1. Segment Description (Process/Fuel Type) (limit to 500 characters): **Electric Utility Boiler - Distillate Oil - Grades 1 and 2 Oil**		
2. Source Classification Code (SCC): **1-01-005-01**	3. SCC Units: **Thousand Gallons Burned (all liquid fuels)**	
4. Maximum Hourly Rate: **3.551**	5. Maximum Annual Rate: **11,309**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **0.05**	8. Maximum % Ash:	9. Million Btu per SCC Unit: **138**
10. Segment Comment (limit to 200 characters):		

Segment Description and Rate: Segment 4 of 4

1. Segment Description (Process/Fuel Type) (limit to 500 characters): **Electric Utility Boiler - Natural Gas**		
2. Source Classification Code (SCC): **1-01-006-01**	3. SCC Units: **MMscf Burned**	
4. Maximum Hourly Rate: **0.605**	5. Maximum Annual Rate: **1,561**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit: **1,000**
10. Segment Comment (limit to 200 characters):		

F. EMISSIONS UNIT POLLUTANTS
(All Emissions Units)

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
PM	076	010	EL
PM_{10}	076	010	EL
SO_2			EL
NO_X	107		EL
CO			EL
VOC			EL
PB	076	010	EL
SAM			NS
FL			NS
H114	048		EL

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

Potential/Fugitive Emissions

1. Pollutant Emitted: **PM**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **22.8** lb/hour **99.86** tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **0.03 lb/MMBtu** Reference: **40 CFR 60 Subpart Da**	7. Emissions Method Code: **0**
8. Calculation of Emissions (limit to 600 characters): **0.03 lb/MMBtu x 760 MMBtu/hr = 22.8 lb/hr**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Based on biomass firing.**	

Allowable Emissions Allowable Emissions 1 of 3

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **0.03 lb/MMBtu**	4. Equivalent Allowable Emissions: **22.8** lb/hour **99.86** tons/year
5. Method of Compliance (limit to 60 characters): **Annual Stack testing using EPA Method 5.**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Basis for Allowable Emissions Code: NSPS. Based on biomass firing.**	

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

Potential/Fugitive Emissions

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

Allowable Emissions Allowable Emissions 2 of 3

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **0.03 lb/MMBtu**	4. Equivalent Allowable Emissions: **14.70** lb/hour **23.42** tons/year
5. Method of Compliance (limit to 60 characters): **Fuel Analysis.**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Basis for Allowable Emissions Code: NSPS. Based on No. 2 fuel oil firing.**	

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

Potential/Fugitive Emissions

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

Allowable Emissions Allowable Emissions 3 of 3

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **0.03 lb/MMBtu**	4. Equivalent Allowable Emissions: **18.15** lb/hour **23.42** tons/year
5. Method of Compliance (limit to 60 characters): **Good combustion practices and limit natural gas burning to 24.9 percent.**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Basis for Allowable Emissions Code: NSPS. Based on natural gas firing. Hourly: 0.03 lb/MMBtu x 605 MMBtu/hr = 18.15 lb/hr; Annual: 0.03 lb/MMBtu x 1.561 x10^{12} Btu/yr ÷ 2000 lb/ton = 23.42 TPY**	

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

Potential/Fugitive Emissions

1. Pollutant Emitted: **PM_{10}**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **22.8** lb/hour **99.86** tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **0.03 lb/MMBtu** Reference: **40 CFR 60 Subpart Da**	7. Emissions Method Code: **0**
8. Calculation of Emissions (limit to 600 characters): **0.03 lb/MMBtu x 760 MMBtu/hr = 22.8 lb/hr**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Based on biomass firing.**	

Allowable Emissions Allowable Emissions 1 of 3

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **0.03 lb/MMBtu**	4. Equivalent Allowable Emissions: **22.8** lb/hour **99.86** tons/year
5. Method of Compliance (limit to 60 characters): **Annual Stack testing using EPA Method 5.**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Based on biomass firing.**	

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

Potential/Fugitive Emissions

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

Allowable Emissions Allowable Emissions 2 of 3

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **0.03 lb/MMBtu**	4. Equivalent Allowable Emissions: **14.70** lb/hour **23.42** tons/year
5. Method of Compliance (limit to 60 characters): **Fuel Analysis.**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Basis for Allowable Emissions Code: NSPS. Based on No. 2 fuel oil firing.**	

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

Potential/Fugitive Emissions

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

Allowable Emissions Allowable Emissions 3 of 3

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **0.03 lb/MMBtu**	4. Equivalent Allowable Emissions: **18.15** lb/hour **23.42** tons/year
5. Method of Compliance (limit to 60 characters): **Good combustion practices and limit natural gas burning to 24.9 percent.**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Basis for Allowable Emissions Code: NSPS. Based on natural gas firing. Hourly: 0.03 lb/MMBtu x 605 MMBtu/hr = 18.15 lb/hr; Annual: 0.03 lb/MMBtu x 1.561 x 10^{12} Btu/yr ÷ 2000 lb/ton = 23.42 TPY**	

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

Potential/Fugitive Emissions

1. Pollutant Emitted: SO_2	2. Total Percent Efficiency of Control:
3. Potential Emissions: **228.0** lb/hour **199.7** tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **0.30 lb/MMBtu** Reference: **CEM data**	7. Emissions Method Code: **0**

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

3-Hour average = 0.30 lb/MMBtu x 760 MMBtu/hr = 228.0 lb/hr
24-Hour average = 0.20 lb/MMBtu x 760 MMBtu/hr = 152 lb/hr
Annual average = 0.06 lb/MMBtu x 760 MMBtu/hr x 8,760 hr/yr ÷ 2,000 lb/ton = 199.73 TPY

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

Based on biomass firing.

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **0.20 lb/MMBtu**	4. Equivalent Allowable Emissions: **152.0** lb/hour **199.7** tons/year

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

Continuous SO_2 monitor.

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

Requested Allowable Emissions: 0.20 lb/MMBtu 24-hr average; 0.06 lb/MMBtu annual average. Based on biomass firing.

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

Potential/Fugitive Emissions

1. Pollutant Emitted: **SO_2**	2. Total Percent Efficiency of Control:
3. Potential Emissions: lb/hour tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference:	7. Emissions Method Code:
8. Calculation of Emissions (limit to 600 characters):	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **RULE**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **0.05 lb/MMBtu**	4. Equivalent Allowable Emissions: **24.5** lb/hour **39.0** tons/year
5. Method of Compliance (limit to 60 characters): **Fuel analysis and limit fuel oil burning to 24.9 percent.**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Based on No. 2 Fuel Oil firing and BACT.**	

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

Potential/Fugitive Emissions

1. Pollutant Emitted: NO_x	2. Total Percent Efficiency of Control:
3. Potential Emissions: 152.0 lb/hour 499.3 tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: 0.15 lb/MMBtu Reference: Permit Limit	7. Emissions Method Code: 0

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

Short-term: 0.20 lb/MMBtu x 760 MMBtu/hr = 152.0 lb/hr
Annual: 0.15 lb/MMBtu x 760 MMBtu/hr x 8,760 hr/yr ÷ 2000 lb/ton = 499.3 TPY

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

Based on biomass firing.

Allowable Emissions Allowable Emissions 1 of 3

1. Basis for Allowable Emissions Code: ESCPSD	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: 0.15 lb/MMBtu, 30-day rolling average	4. Equivalent Allowable Emissions: lb/hour 499.3 tons/year

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

Continuous NO_x monitor.

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

Based on biomass firing, as a 30-day rolling average.

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

Potential/Fugitive Emissions

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

Allowable Emissions Allowable Emissions 2 of 3

1. Basis for Allowable Emissions Code: **ESCPSD**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **0.15 lb/MMBtu, 30-day rolling average**	4. Equivalent Allowable Emissions: lb/hour **117.1** tons/year
5. Method of Compliance (limit to 60 characters): **Continuous NO_x monitor and limit fuel oil burning to 24.9 percent.**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Based on No. 2 fuel oil firing, as a 30-day rolling average.**	

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

Potential/Fugitive Emissions

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

Allowable Emissions Allowable Emissions 3 of 3

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **0.15 lb/MMBtu, 30-day rolling average**	4. Equivalent Allowable Emissions: lb/hour **117.1** tons/year
5. Method of Compliance (limit to 60 characters): **Continuous NO_x monitor and limit natural gas burning to 24.9 percent.**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Based on natural gas firing, as a 30-day rolling average.**	

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

Potential/Fugitive Emissions

1. Pollutant Emitted: **CO**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **1,462.5** lb/hour **1,165.1** tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **6.5 lb/MMBtu** Reference: **CEM Data**	7. Emissions Method Code:

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

6.5 lb/MMBtu x 225 MMBtu/hr = 1,462.5 lb/hr
0.35 lb/MMBtu x 760 MMBtu/hr x 8,760 hr/yr ÷ 2,000 lb/ton = 1,165.08 TPY

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

Maximum emissions occur under cold startup conditions. 0.35 lb/MMBtu is a 12-month rolling average. Based on biomass firing.

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **0.35 lb/MMBtu**	4. Equivalent Allowable Emissions: lb/hour **1,165.1** tons/year

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

Continuous CO monitor.

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

lb/MMBtu limit based on 12-month rolling average. Based on biomass firing.

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

Potential/Fugitive Emissions

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

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **0.35 lb/MMBtu**	4. Equivalent Allowable Emissions: lb/hour **273.2** tons/year
5. Method of Compliance (limit to 60 characters): **Continuous CO monitor.**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **lb/MMBtu limit based on 12-month rolling average. Based on No. 2 fuel oil firing.**	

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

Potential/Fugitive Emissions

1. Pollutant Emitted: **VOC**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **45.6** lb/hour **199.7** tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **0.06 lb/MMBtu** Reference: **Permit limit**	7. Emissions Method Code: **0**
8. Calculation of Emissions (limit to 600 characters): **0.06 lb/MMBtu x 760 MMBtu/hr = 45.6 lb/hr**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Based on biomass firing.**	

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **ESCNAA**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **0.06 lb/MMBtu**	4. Equivalent Allowable Emissions: **45.6** lb/hour **199.7** tons/year
5. Method of Compliance (limit to 60 characters): **Annual stack test using EPA Method 25A/18.**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Based on biomass firing.**	

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

Potential/Fugitive Emissions

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

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **ESCNAA**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **0.03 lb/MMBtu**	4. Equivalent Allowable Emissions: **14.7** lb/hour **23.4** tons/year
5. Method of Compliance (limit to 60 characters): **Limit No. 2 fuel oil burning to 24.9 percent for any single boiler.**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Based on No. 2 fuel oil firing.**	

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

Potential/Fugitive Emissions

1. Pollutant Emitted: **Pb - Lead**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **0.11** lb/hour **0.50** tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **1.5 x 10^{-4} lb/MMBtu** Reference: **Permit limit**	7. Emissions Method Code: **0**
8. Calculation of Emissions (limit to 600 characters): **1.5 x 10^{-4} lb/MMBtu x 760 MMBtu/hr = 0.11 lb/hr**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Based on biomass firing.**	

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **1.5 x 10^{-4} lb/MMBtu**	4. Equivalent Allowable Emissions: **0.11** lb/hour **0.50** tons/year
5. Method of Compliance (limit to 60 characters): **Stack test using EPA Method 12, once every 5 years.**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Based on biomass firing.**	

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

Potential/Fugitive Emissions

1. Pollutant Emitted: **SAM**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **13.7** lb/hour **12.0** tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **0.018 lb/MMBtu** Reference: **AP-42**	7. Emissions Method Code:

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

0.018 lb/MMBtu x 760 MMBtu/hr = 13.68 lb/hr
Annual average = 0.0036 lb/MMBtu x 760 MMBtu/hr x 8,760 hr/yr ÷ 2,000 lb/ton = 11.98 TPY

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

Based on biomass firing.

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

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **0.018 lb/MMBtu**	4. Equivalent Allowable Emissions: **13.7** lb/hour **12.0** tons/year

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

EPA Method 8, once every 5 years.

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

Based on biomass firing.

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

Potential/Fugitive Emissions

1. Pollutant Emitted: **Fl - Fluorides**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **0.53** lb/hour **2.33** tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **7×10^{-4} lb/MMBtu** Reference: **Stack Test Data**	7. Emissions Method Code: **0**
8. Calculation of Emissions (limit to 600 characters): **7×10^{-4} lb/MMBtu x 760 MMBtu/hr = 0.53 lb/hr**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Based on biomass firing.**	

Allowable Emissions Allowable Emissions ______ of ______

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance (limit to 60 characters):	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):	

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

Potential/Fugitive Emissions

1. Pollutant Emitted: **H114 - Mercury**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **0.0041** lb/hour **0.018** tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **5.4 x 10^{-6} lb/MMBtu** Reference: **Permit limit**	7. Emissions Method Code: **0**
8. Calculation of Emissions (limit to 600 characters): **5.4 x 10^{-6} lb/MMBtu x 760 MMBtu/hr = 0.0041 lb/hr**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Based on biomass firing.**	

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **5.4 x 10^{-6} lb/MMBtu**	4. Equivalent Allowable Emissions: **0.0041** lb/hour **0.018** tons/year
5. Method of Compliance (limit to 60 characters): **Stack test using EPA Method 29, once every 5 years.**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Based on biomass firing.**	

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

Visible Emissions Limitation: Visible Emissions Limitation 1 of 1

1. Visible Emissions Subtype: **VE20**	2. Basis for Allowable Opacity: [X] Rule [ ] Other
3. Requested Allowable Opacity: Normal Conditions: **20** % Exceptional Conditions: **27** % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance: **EPA Method 9**	
5. Visible Emissions Comment (limit to 200 characters): **40 CFR 60, Subpart Da.**	

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

Continuous Monitoring System: Continuous Monitor 1 of 5

1. Parameter Code: **VE**	2. Pollutant(s):
3. CMS Requirement:	[X] Rule [ ] Other
4. Monitor Information: Manufacturer: **Durag** Model Number: **D-R281-31-AV**	Serial Number: **31019**
5. Installation Date: **01 OCT 1995**	6. Performance Specification Test Date:
7. Continuous Monitor Comment (limit to 200 characters): **40 CFR 60, Subpart Da.**	

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

Visible Emissions Limitation: Visible Emissions Limitation ______ of ______

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

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

Continuous Monitoring System: Continuous Monitor 2 of 5

1. Parameter Code: **EM**	2. Pollutant(s): **NO_x**
3. CMS Requirement:	[X] Rule [ ] Other
4. Monitor Information: Manufacturer: **Thermo Environmental Instruments** Model Number: **42D**	Serial Number: **42D-52618-292**
5. Installation Date: **01 OCT 1995**	6. Performance Specification Test Date:
7. Continuous Monitor Comment (limit to 200 characters): **40 CFR 60, Subpart Da.**	

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

Visible Emissions Limitation: Visible Emissions Limitation ______ of ______

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

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

Continuous Monitoring System: Continuous Monitor 3 of 5

1. Parameter Code: **EM**	2. Pollutant(s): SO_2
3. CMS Requirement:	[ ] Rule [X] Other
4. Monitor Information: Manufacturer: **Thermo Environmental Instruments** Model Number: **43B**	Serial Number: **43B-51400-292**
5. Installation Date: **01 OCT 1995**	6. Performance Specification Test Date:
7. Continuous Monitor Comment (limit to 200 characters): **40 CFR 60, Subpart Da.**	

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

Visible Emissions Limitation: Visible Emissions Limitation ______ of ______

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

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

Continuous Monitoring System: Continuous Monitor 4 of 5

1. Parameter Code: **EM**	2. Pollutant(s): **CO**
3. CMS Requirement:	[ ] Rule [X] Other
4. Monitor Information: Manufacturer: **Thermo Environmental Instruments** Model Number: **48**	Serial Number: **48-45334-273**
5. Installation Date: **01 OCT 1995**	6. Performance Specification Test Date:
7. Continuous Monitor Comment (limit to 200 characters):	

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

Visible Emissions Limitation: Visible Emissions Limitation ____ of ____

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

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

Continuous Monitoring System: Continuous Monitor 5 of 5

1. Parameter Code:	2. Pollutant(s): O_2
3. CMS Requirement:	[X] Rule [ ] Other
4. Monitor Information: Manufacturer: **Yokogowa** Model Number: **ZA8C**	Serial Number: **JJ113MA345**
5. Installation Date: **01 OCT 1995**	6. Performance Specification Test Date:
7. Continuous Monitor Comment (limit to 200 characters): **40 CFR 60, Subpart Da.**	

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

Supplemental Requirements

1. Process Flow Diagram [X] Attached, Document ID: NH-FI-C3 [ ] Not Applicable [ ] Waiver Requested	
2. Fuel Analysis or Specification [X] Attached, Document ID: NH-EU2-J2 [ ] Not Applicable [ ] Waiver Requested	
3. Detailed Description of Control Equipment [X] Attached, Document ID: NH-EU2-J3 [ ] Not Applicable [ ] Waiver Requested	
4. Description of Stack Sampling Facilities [ ] Attached, Document ID:_______ [X] Not Applicable [ ] Waiver Requested	
5. Compliance Test Report [ ] Attached, Document ID:________ [ ] Previously submitted, Date:________________ [X] Not Applicable	
6. Procedures for Startup and Shutdown [ ] Attached, Document ID:________ [X] Not Applicable [ ] Waiver Requested	
7. Operation and Maintenance Plan [ ] Attached, Document ID:________ [X] Not Applicable [ ] Waiver Requested	
8. Supplemental Information for Construction Permit Application [X] Attached, Document ID: PSD Report [ ] Not Applicable	
9. Other Information Required by Rule or Statute [ ] Attached, Document ID:__________ [X] Not Applicable	
10. Supplemental Requirements Comment:	

Additional Supplemental Requirements for Title V Air Operation Permit Applications

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

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

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

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

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

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

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

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

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

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

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

 [X] Not Applicable

ATTACHMENT NH-EU2-C

LIST OF APPLICABLE REGULATIONS

EU ID 030 : Cogen Boiler A Rule Applicability for New Hope Power Partnership

APPLIC STAT	RULE DESCRIP	RULE NUMBER	RULE TITLE	RATIONALE FOR NON-APPLICABILITY
APPLICABLE	60 Subpart A	40CFR60.1	Subpart A -- General Provisions	
APPLICABLE	60 Subpart A	40CFR60.7	Notification and Record Keeping	
APPLICABLE	60Subpart A	40CFR60.8	Performance Testing	
APPLICABLE	60 Subpart A	40CFR60.11	Compliance with standards and maintenance requirements.	
APPLICABLE	60 Subpart A	40CFR60.12	Circumvention.	
APPLICABLE	60 Subpart A	40CFR60.13	Monitoring requirements.	
APPLICABLE	60 Subpart A	40CFR60.19	General notification and reporting requirements	
APPLICABLE	60 Subpart Da	40CFR60.40a	Subpart Da - NSPS for Electric Utility Units for which construction commenced after Sept. 18, 1978.	
APPLICABLE	60 Subpart Da	40CFR60.42a	Standard for particulate matter	
APPLICABLE	60 Subpart Da	40CFR60.43a	Standard for sulfur dioxide.	
APPLICABLE	60 Subpart Da	40CFR60.43a(a)	Standard for sulfur dioxide.	
APPLICABLE	60 Subpart Da	40CFR60.43a(b)	Standard for sulfur dioxide.	
APPLICABLE	60 Subpart Da	40CFR60.43a(d)(2)	Standard for sulfur dioxide.	
APPLICABLE	60 Subpart Da	40CFR60.43a(g)	Standard for sulfur dioxide.	
APPLICABLE	60 Subpart Da	40CFR60.43a(h)	Standard for sulfur dioxide.	
APPLICABLE	60 Subpart Da	40CFR60.44a	Standard for nitrogen oxides	
APPLICABLE	60 Subpart Da	40CFR60.44a(a)	Standard for nitrogen oxides	
APPLICABLE	60 Subpart Da	40CFR60.44a(c)	Standard for nitrogen oxides	
APPLICABLE	60 Subpart Da	40CFR60.46a	Compliance provisions.	
APPLICABLE	60 Subpart Da	40CFR60.46a(a)	Compliance provisions.	
APPLICABLE	60 Subpart Da	40CFR60.46a(b)	Compliance provisions.	
APPLICABLE	60 Subpart Da	40CFR60.46a(c)	Compliance provisions.	
NON-APPLICABLE	60 Subpart Da	40CFR60.46a(d)	Compliance provisions.	Cogen Boiler A does not have a flue gas desulfurization system.
APPLICABLE	60 Subpart Da	40CFR60.46a(e)	Compliance provisions.	
APPLICABLE	60 Subpart Da	40CFR60.46a(f)	Compliance provisions.	
APPLICABLE	60 Subpart Da	40CFR60.46a(g)	Compliance provisions.	
APPLICABLE	60 Subpart Da	40CFR60.46a(h)	Compliance provisions.	
NON-APPLICABLE	60 Subpart Da	40CFR60.46a(i)	Compliance provisions.	Cogen Boiler A has not been modified after July 7, 1997.
APPLICABLE	60 Subpart Da	40CFR60.47a	Emission monitoring	
APPLICABLE	60 Subpart Da	40CFR60.47a(a)	Emission monitoring	
APPLICABLE	60 Subpart Da	40CFR60.47a(b)(2)	Emission monitoring	
APPLICABLE	60 Subpart Da	40CFR60.47a(b)(3)	Emission monitoring	
APPLICABLE	60 Subpart Da	40CFR60.47a(c)(1)	Emission monitoring	
APPLICABLE	60 Subpart Da	40CFR60.47a(d)	Emission monitoring	
APPLICABLE	60 Subpart Da	40CFR60.47a(e)	Emission monitoring	
APPLICABLE	60 Subpart Da	40CFR60.47a(f)	Emission monitoring	
APPLICABLE	60 Subpart Da	40CFR60.47a(g)	Emission monitoring	
APPLICABLE	60 Subpart Da	40CFR60.47a(h)	Emission monitoring	
APPLICABLE	60 Subpart Da	40CFR60.47a(i)	Emission monitoring	
APPLICABLE	60 Subpart Da	40CFR60.47a(j)	Emission monitoring	
APPLICABLE	60 Subpart Da	40CFR60.48a	Compliance determination procedures and methods.	
APPLICABLE	60 Subpart Da	40CFR60.48a(a)	Compliance determination procedures and methods.	
APPLICABLE	60 Subpart Da	40CFR60.48a(b)	Compliance determination procedures and methods.	
APPLICABLE	60 Subpart Da	40CFR60.48a(c)	Compliance determination procedures and methods.	
APPLICABLE	60 Subpart Da	40CFR60.48a(d)	Compliance determination procedures and methods.	
APPLICABLE	60 Subpart Da	40CFR60.48a(e)	Compliance determination procedures and methods.	
APPLICABLE	60 Subpart Da	40CFR60.49a	Reporting requirements	
APPLICABLE	60 Subpart Da	40CFR60.49a(a)	Reporting requirements	
APPLICABLE	60 Subpart Da	40CFR60.49a(b)	Reporting requirements	
APPLICABLE	60 Subpart Da	40CFR60.49a(c)	Reporting requirements	
APPLICABLE	60 Subpart Da	40CFR60.49a(d)	Reporting requirements	
APPLICABLE	60 Subpart Da	40CFR60.49a(f)	Reporting requirements	
APPLICABLE	60 Subpart Da	40CFR60.49a(g)	Reporting requirements	

EU ID 030 : Cogen Boiler A Rule Applicability for New Hope Power Partnership

APPLIC STAT	RULE DESCRIP	RULE NUMBER	RULE TITLE	RATIONALE FOR NON-APPLICABILITY
APPLICABLE	60 Subpart Da	40CFR60.49a(h)	Reporting requirements	
APPLICABLE	60 Subpart Da	40CFR60.49a(i)	Reporting requirements	
APPLICABLE	60 Subpart Da	40CFR60.49a(j)	Reporting requirements	
APPLICABLE	60 Subpart Ea	40CFR60.50a(d)	Standards of performance for municipal waste combustors	
APPLICABLE	60 Subpart Ea	40CFR60.50b(j)	Standards of performance for municipal waste combustors	
APPLICABLE	62-204	62-204.800(7)2.	NSPS Subpart Da adopted by reference.	
APPLICABLE	62-296 <	62-296	STATIONARY SOURCES - EMISSION STANDARDS	
APPLICABLE	62-296 <	62-296.405(2)	Fossil Fuel Steam Generators with more than 250 million Btu per Hour Heat Input.	
NON-APPLICABLE	62-296 <	62-296.406	Fossil Fuel Steam Generators with less than 250 Million Btu per Hour Heat Input, New and Existing Em	Cogen Boiler A has a heat input of >250 MMBtu/hr.
NON-APPLICABLE	62-296 <	62-296.410	Carbonaceous Fuel Burning Equipment.	Not more stringent or different than NSPS.
APPLICABLE	62-296 >	62-296.500	Reasonably Available Control Technology (RACT) - Volatile Organic Compounds (VOC) and Nitrogen Oxide	
APPLICABLE	62-296 >	62-296.500(2)(a)	Reasonably Available Control Technology (RACT) - Volatile Organic Compounds (VOC) and Nitrogen Oxide	
APPLICABLE	62-296 >	62-296.500(2)(c)	Reasonably Available Control Technology (RACT) - Volatile Organic Compounds (VOC) and Nitrogen Oxide	
APPLICABLE	62-296 >	62-296.570	Reasonably Available Control Technology (RACT) - Requirements for Major VOC- and NOx-Emitting Facility	
APPLICABLE	62-296 >	62-296.570(1)	Applicability.	
APPLICABLE	62-296 >	62-296.570(1)(a)	Applicability.	
APPLICABLE	62-296 >	62-296.570(2)	Compliance Requirements.	
APPLICABLE	62-296 >	62-296.570(3)	Operation Permit Requirements.	
APPLICABLE	62-296 >	62-296.570(4)	Operation Permit Requirements.	
APPLICABLE	62-296 >	62-296.570(4)(a)	Operation Permit Requirements.	
APPLICABLE	62-296 >	62-296.570(4)(b)6.	Operation Permit Requirements.	
APPLICABLE	62-296 >	62-296.570(4)(c)	Operation Permit Requirements.	
APPLICABLE	62-296 >	62-296.620		
NON-APPLICABLE	62-296 >	62-296.700	Reasonably Available Control Technology (RACT) Particulate Matter.	New Hope Power Partnership is located in Palm Beach County, which is not a nonattainment or maintenance area for particulate matter.
NON-APPLICABLE	62-296 >	62-296.702	Fossil Fuel Steam Generators.	New Hope Power Partnership is located in Palm Beach County, which is not a nonattainment or maintenance area for particulate matter.
NON-APPLICABLE	62-296 >	62-296.703	Carbonaceous Fuel Burners.	New Hope Power Partnership is located in Palm Beach County, which is not a nonattainment or maintenance area for particulate matter.
APPLICABLE	62-297	62-297	STATIONARY SOURCES - EMISSIONS MONITORING	
APPLICABLE	62-297	62-297.310	General Compliance Test Requirements.	
APPLICABLE	62-297	62-297.401	Compliance Test Methods.	
APPLICABLE	62-297	62-297.401(1)(a)	EPA Method 1 - Sample and Velocity Traverses for Stationary sources - 40 CFR 60 Appendix A.	
APPLICABLE	62-297	62-297.401(10)	EPA Method 10 - Determination of Carbon Monoxide Emissions from Stationary Sources 40 CFR 60 Appendix	
APPLICABLE	62-297	62-297.401(12)	EPA Method 12 - Determination of Inorganic Lead Emissions from Stationary Sources - 40 CFR 60 Append	
APPLICABLE	62-297	62-297.401(13)	EPA Methods 13A and 13B.	
APPLICABLE	62-297	62-297.401(18)	EPA Method 18 - Measurement of Gaseous Organic Compound Emissions by Gas Chromatography - 40 CFR 60	
APPLICABLE	62-297	62-297.401(19)	EPA Method 19 - Determination of Sulfur Dioxide Removal Efficiency and Particulate, Sulfur Dioxide a	
APPLICABLE	62-297	62-297.401(2)	EPA Method 2 - Determination of Stack Gas Velocity and Volumetric Flow Rate - 40 CFR 60 Appendix A.	

EU ID 030 : Cogen Boiler A Rule Applicability for New Hope Power Partnership

APPLIC STAT	RULE DESCRIP	RULE NUMBER	RULE TITLE	RATIONALE FOR NON-APPLICABILITY
APPLICABLE	62-297	62-297.401(25)	EPA Method 25 - Determination of Total Gaseous Nonmethane Organic Emissions as Carbon - 40 CFR 60 Appendix	
APPLICABLE	62-297	62-297.401(3)	EPA Method 3 - Gas Analysis for Carbon Dioxide, Oxygen, Excess Air, and Dry Molecular Weight - 40 CF	
APPLICABLE	62-297	62-297.401(32)	EPA Method 101 - Determination of Particulate and Gaseous Mercury Emissions from Chlor-Alkali Plants	
APPLICABLE	62-297	62-297.401(4)	EPA Method 4 - Determination of Moisture Content in Stack Gases - 40 CFR 60 Appendix A.	
APPLICABLE	62-297	62-297.401(41)	EPA Method 201 - Determination of PM10 Emissions (Exhaust Gas Recycle Procedure) - 40 CFR 51 Appendix	
APPLICABLE	62-297	62-297.401(5)	EPA Method 5 - Determination of Particulate Emissions from Stationary Sources - 40 CFR 60 Appendix A	
APPLICABLE	62-297	62-297.401(6)	EPA Method 6 - Determination of Sulfur Dioxide Emissions from Stationary Sources - 40 CFR 60 Appendix	
APPLICABLE	62-297	62-297.401(6)(c)	EPA Method 6C - Determination of Sulfur Dioxide Emissions from Stationary Sources - 40 CFR 60 Appendix	
APPLICABLE	62-297	62-297.401(7)	EPA Method 7 - Determination of Nitrogen Oxide Emissions from Stationary Sources - 40 CFR 60 Appendix	
APPLICABLE	62-297	62-297.401(7)(e)	EPA Method 7E - Determination of Nitrogen Oxide Emissions from Stationary Sources - 40 CFR 60 Appendix	
APPLICABLE	62-297	62-297.401(9)	EPA Test Method 9	

ATTACHMENT NH-EU2-J2

FUEL ANALYSIS OR SPECIFICATION

ATTACHMENT NH-EU2-J2
DESIGN FUEL SPECIFICATIONS[a] FOR THE
NEW HOPE POWER PARTNERSHIP COGENERATION FACILITY

Parameter		Biomass			
		Bagasse	Wood Waste	No. 2 Fuel Oil	Natural Gas
Specific Gravity		–	–	0.865	–
Heating Value	(Btu/lb)	3,600	4,500	19,175	–
Heating Value	(Btu/gal)	–	–	138,000	–
Heating Value	(Btu/scf)				1,000
Ultimate Analysis (dry basis percentage):					
Carbon		48.93	49.58	87.01	82.96
Hydrogen		6.14	5.87	12.47	5.41
Nitrogen		0.25	0.40	0.02	1.58
Oxygen		43.84	40.90	0.00	5.72
Sulfur		0.03	0.07	0.05	0.67
Ash/Inorganic		1.0	9.0	0.00	3.66
Moisture		52	37	–	4.5

[a] Represents average fuel characteristics.

Sources: New Hope Power Partnership, 2000.
Combustion Engineering, 1981.

ATTACHMENT NH-EU2-J3

DETAILED DESCRIPTION OF CONTROL EQUIPMENT

ATTACHMENT NH-EU2-J3
DETAILED DESCRIPTION OF CONTROL EQUIPMENT

The cogeneration facility utilizes several emission control techniques to reduce emissions. A selective non-catalytic reduction (SNCR) system is used to reduce NO_X emissions. Further, the cogeneration boilers minimize CO and VOC through proper furnace design and good combustion practices, including: control of combustion air and combustion temperature; distribution of fuel on the combustion grate; and controls over the furnace loads and transient conditions. Particulate emissions are controlled by an ESP. Multiple cyclones were installed during the 2000 calendar year to improve control of particulate emissions.

Electrostatic Precipitator

The EPS's for the New Hope Power Partnership facility are manufactured by Flakt, Inc. Design specifications for the ESP (one per boiler) are provided below:

Chambers = 1
Collecting Plate = 12.30 ft L x 39.37 ft H
Fields/Chamber = 3
Specific Collection Area = 200 ft^2/1,000 acfm (minimum)
Gas Velocity = <4 ft/s
Pressure Drop = less than 2.8 inches H_2O
Operating Temperature = 350°F
Ash Handling = Trough hopper with screw conveyor
Particulate removal efficiency: >99.2%

NO_X Control System

The NO_X control system design employs a urea injection system manufactured by Nalco-Fueltech for NO_X control. The technology is a selective non-catalytic reduction process, which reduces NO_X emissions through chemical reaction with urea. In the process, urea is injected into the flue gas stream and reacts with nitrogen oxides to form nitrogen and water vapor.

The NO_X control system includes the following major components:

- Carrier air compressors,
- Urea tank,
- Urea/air flow controls,
- Control panel,

- Injection manifolds and injectors, and
- Valves and instrumentation.

A single urea storage tank system is installed to supply urea to all three boilers. Urea for injection into the boilers is drawn from the tank. Two injection zones are used to provide injection at full and part load conditions. Each zone has six injectors. Zone switching valves will direct the urea/carrier mixture to the appropriate injection zone.

Specifications for the urea injection system to meet the NO_X emission rate of 0.15 lb/MMBtu when firing biomass or No. 2 fuel oil are provided below (on a per boiler basis):

Urea injection rate - 65 gal/hr (max)

Ammonia Slip - Biomass, No. 2 fuel oil - 25 ppm (max)

<u>Dust Control System</u>

The cyclone dust collectors are supplied by Barron Industries, Model 460 Tube Base III 9K15-2023 AU. These are mechanical cyclone dust collectors which remove larger size particulate matter prior to the ESP. There are 460 Cyclone tubes in all.

III. EMISSIONS UNIT INFORMATION

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

A. GENERAL EMISSIONS UNIT INFORMATION
(All Emissions Units)

Emissions Unit Description and Status

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

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

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

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

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

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

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

3. Description of Emissions Unit Addressed in This Section (limit to 60 characters):
Cogen Boiler B fired by Biomass/No. 2 Fuel Oil/Natural Gas

4. Emissions Unit Identification Number: [ ] No ID
ID: **031** [ ] ID Unknown

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

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

74.9 MW net generating capacity for entire facility.

Emissions Unit Control Equipment

1. Control Equipment/Method Description (Limit to 200 characters per device or method): **ESP - Electrostatic Precipitator - High Efficiency** **Selective Non-catalytic Reduction for NO_x** **Multiple Cyclone w/o Fly Ash Reinjection** **Activated Carbon Injection System**
2. Control Device or Method Code(s): **010, 107, 076, 048**

Emissions Unit Details

1. Package Unit: Manufacturer:		Model Number:
2. Generator Nameplate Rating:	**75**	MW
3. Incinerator Information: Dwell Temperature: Dwell Time: Incinerator Afterburner Temperature:		 °F seconds °F

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

Emissions Unit Operating Capacity and Schedule

1. Maximum Heat Input Rate:		760	mmBtu/hr
2. Maximum Incineration Rate:	lb/hr		tons/day
3. Maximum Process or Throughput Rate:			tons/hr
4. Maximum Production Rate:			
5. Requested Maximum Operating Schedule:			
	24 hours/day	7	days/week
	52 weeks/year	8,760	hours/year
6. Operating Capacity/Schedule Comment (limit to 200 characters):			

Maximum heat input rates:
Biomass - 760 MMBtu/hr;
No. 2 Fuel Oil - 490 MMBtu/hr;
Natural Gas - 605 MMBtu/hr

C. EMISSIONS UNIT REGULATIONS
(Regulated Emissions Units Only)

List of Applicable Regulations

See Attachment NH-EU3-C.	

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

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram? **BLR B**	2. Emission Point Type Code: **1**
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking (limit to 100 characters per point):	
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:	

5. Discharge Type Code: **V**	6. Stack Height: **199** feet	7. Exit Diameter: **10.0** feet
8. Exit Temperature: **352** °F	9. Actual Volumetric Flow Rate: **319,000** acfm	10. Water Vapor: %

11. Maximum Dry Standard Flow Rate: dscfm	12. Nonstack Emission Point Height: feet
13. Emission Point UTM Coordinates: Zone: East (km): North (km):	
14. Emission Point Comment (limit to 200 characters): **Stack parameters based on biomass firing. See Table 2-5 in PSD Report for all boiler stack data.**	

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

Segment Description and Rate: Segment 1 of 4

1. Segment Description (Process/Fuel Type) (limit to 500 characters): **Electric Utility Boiler - Bagasse**		
2. Source Classification Code (SCC): **1-01-011-01**	3. SCC Units: **Tons Burned (all solid fuels)**	
4. Maximum Hourly Rate: **105.56**	5. Maximum Annual Rate: **924,667**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **0.05**	8. Maximum % Ash: **1.0**	9. Million Btu per SCC Unit: **7.2**
10. Segment Comment (limit to 200 characters):		

Segment Description and Rate: Segment 2 of 4

1. Segment Description (Process/Fuel Type) (limit to 500 characters): **Electric Utility Boiler - Wood Fired Boiler**		
2. Source Classification Code (SCC): **1-01-009-03**	3. SCC Units: **Tons Burned (all solid fuels)**	
4. Maximum Hourly Rate: **84.44**	5. Maximum Annual Rate: **739,733**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **0.3**	8. Maximum % Ash: **9.0**	9. Million Btu per SCC Unit: **9.0**
10. Segment Comment (limit to 200 characters):		

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

Segment Description and Rate: Segment 3 of 4

1. Segment Description (Process/Fuel Type) (limit to 500 characters): **Electric Utility Boiler - Distillate Oil - Grades 1 and 2 Oil**		
2. Source Classification Code (SCC): **1-01-005-01**	3. SCC Units: **Thousand Gallons Burned (all liquid fuels)**	
4. Maximum Hourly Rate: **3.551**	5. Maximum Annual Rate: **11,309**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **0.05**	8. Maximum % Ash:	9. Million Btu per SCC Unit: **138**
10. Segment Comment (limit to 200 characters):		

Segment Description and Rate: Segment 4 of 4

1. Segment Description (Process/Fuel Type) (limit to 500 characters): **Electric Utility Boiler - Natural Gas**		
2. Source Classification Code (SCC): **1-01-006-01**	3. SCC Units: **MMscf Burned**	
4. Maximum Hourly Rate: **0.605**	5. Maximum Annual Rate: **1,561**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit: **1,000**
10. Segment Comment (limit to 200 characters):		

F. EMISSIONS UNIT POLLUTANTS
(All Emissions Units)

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
PM	076	010	EL
PM_{10}	076	010	EL
SO_2			EL
NO_X	107		EL
CO			EL
VOC			EL
PB	076	010	EL
SAM			NS
FL			NS
H114	048		EL

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

Potential/Fugitive Emissions

1. Pollutant Emitted: **PM**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **22.8** lb/hour **99.86** tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **0.03 lb/MMBtu** Reference: **40 CFR 60 Subpart Da**	7. Emissions Method Code: **0**
8. Calculation of Emissions (limit to 600 characters): **0.03 lb/MMBtu x 760 MMBtu/hr = 22.8 lb/hr**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Based on biomass firing.**	

Allowable Emissions Allowable Emissions 1 of 3

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **0.03 lb/MMBtu**	4. Equivalent Allowable Emissions: **22.8** lb/hour **99.86** tons/year
5. Method of Compliance (limit to 60 characters): **Annual Stack testing using EPA Method 5.**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Basis for Allowable Emissions Code: NSPS. Based on biomass firing.**	

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

Potential/Fugitive Emissions

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

Allowable Emissions Allowable Emissions 2 of 3

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **0.03 lb/MMBtu**	4. Equivalent Allowable Emissions: **14.70** lb/hour **23.42** tons/year
5. Method of Compliance (limit to 60 characters): **Fuel Analysis.**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Basis for Allowable Emissions Code: NSPS. Based on No. 2 fuel oil firing.**	

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

Potential/Fugitive Emissions

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

Allowable Emissions Allowable Emissions 3 of 3

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **0.03 lb/MMBtu**	4. Equivalent Allowable Emissions: **18.15** lb/hour **23.42** tons/year
5. Method of Compliance (limit to 60 characters): **Good combustion practices and limit natural gas burning to 24.9 percent.**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Basis for Allowable Emissions Code: NSPS. Based on natural gas firing. Hourly: 0.03 lb/MMBtu x 605 MMBtu/hr = 18.15 lb/hr; Annual: 0.03 lb/MMBtu x 1.561 x 10^{12} Btu/yr ÷ 2000 lb/ton = 23.42 TPY**	

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

Potential/Fugitive Emissions

1. Pollutant Emitted: **PM_{10}**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **22.8** lb/hour **99.86** tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 _______ to _______ tons/year	
6. Emission Factor: **0.03 lb/MMBtu** Reference: **40 CFR 60 Subpart Da**	7. Emissions Method Code: **0**
8. Calculation of Emissions (limit to 600 characters): **0.03 lb/MMBtu x 760 MMBtu/hr = 22.8 lb/hr**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Based on biomass firing.**	

Allowable Emissions Allowable Emissions 1 of 3

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **0.03 lb/MMBtu**	4. Equivalent Allowable Emissions: **22.8** lb/hour **99.86** tons/year
5. Method of Compliance (limit to 60 characters): **Annual Stack testing using EPA Method 5.**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Based on biomass firing.**	

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

Potential/Fugitive Emissions

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

Allowable Emissions Allowable Emissions 2 of 3

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **0.03 lb/MMBtu**	4. Equivalent Allowable Emissions: **14.70** lb/hour **23.42** tons/year
5. Method of Compliance (limit to 60 characters): **Fuel Analysis.**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Basis for Allowable Emissions Code: NSPS. Based on No. 2 fuel oil firing.**	

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

Potential/Fugitive Emissions

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

Allowable Emissions Allowable Emissions 3 of 3

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **0.03 lb/MMBtu**	4. Equivalent Allowable Emissions: **18.15** lb/hour **23.42** tons/year
5. Method of Compliance (limit to 60 characters): **Good combustion practices and limit natural gas burning to 24.9 percent.**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Basis for Allowable Emissions Code: NSPS. Based on natural gas firing. Hourly: 0.03 lb/MMBtu x 605 MMBtu/hr = 18.15 lb/hr; Annual: 0.03 lb/MMBtu x 1.561 x 10^{12} Btu/yr ÷ 2000 lb/ton = 23.42 TPY**	

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

Potential/Fugitive Emissions

1. Pollutant Emitted: SO_2	2. Total Percent Efficiency of Control:
3. Potential Emissions: **228.0** lb/hour **199.7** tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **0.30 lb/MMBtu** Reference: **CEM data**	7. Emissions Method Code: **0**

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

3-Hour average = 0.30 lb/MMBtu x 760 MMBtu/hr = 228.0 lb/hr
24-Hour average = 0.20 lb/MMBtu x 760 MMBtu/hr = 152 lb/hr
Annual average = 0.06 lb/MMBtu x 760 MMBtu/hr x 8,760 hr/yr ÷ 2,000 lb/ton = 199.73 TPY

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

Based on biomass firing.

Allowable Emissions
Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **0.20 lb/MMBtu**	4. Equivalent Allowable Emissions: **152.0** lb/hour **199.7** tons/year

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

Continuous SO_2 monitor.

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

Requested Allowable Emissions: 0.20 lb/MMBtu 24-hr average; 0.06 lb/MMBtu annual average. Based on biomass firing.

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

Potential/Fugitive Emissions

1. Pollutant Emitted: **SO_2**	2. Total Percent Efficiency of Control:
3. Potential Emissions: lb/hour tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference:	7. Emissions Method Code:
8. Calculation of Emissions (limit to 600 characters):	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **RULE**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **0.05 lb/MMBtu**	4. Equivalent Allowable Emissions: **24.5** lb/hour **39.0** tons/year
5. Method of Compliance (limit to 60 characters): **Fuel analysis and limit fuel oil burning to 24.9 percent.**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Based on No. 2 Fuel Oil firing and BACT.**	

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

Potential/Fugitive Emissions

1. Pollutant Emitted: **NO_x**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **152.0** lb/hour **499.3** tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **0.15 lb/MMBtu** Reference: **Permit Limit**	7. Emissions Method Code: **0**
8. Calculation of Emissions (limit to 600 characters): **Short-term: 0.20 lb/MMBtu x 760 MMBtu/hr = 152.0 lb/hr** **Annual: 0.15 lb/MMBtu x 760 MMBtu/hr x 8,760 hr/yr ÷ 2000 lb/ton = 499.3 TPY**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Based on biomass firing.**	

Allowable Emissions Allowable Emissions 1 of 3

1. Basis for Allowable Emissions Code: **ESCPSD**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **0.15 lb/MMBtu, 30-day rolling average**	4. Equivalent Allowable Emissions: lb/hour **499.3** tons/year
5. Method of Compliance (limit to 60 characters): **Continuous NO_x monitor.**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Based on biomass firing, as a 30-day rolling average.**	

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

Potential/Fugitive Emissions

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

Allowable Emissions Allowable Emissions 2 of 3

1. Basis for Allowable Emissions Code: **ESCPSD**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **0.15 lb/MMBtu, 30-day rolling average**	4. Equivalent Allowable Emissions: lb/hour **117.1** tons/year
5. Method of Compliance (limit to 60 characters): **Continuous NO_x monitor and limit fuel oil burning to 24.9 percent.**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Based on No. 2 fuel oil firing, as a 30-day rolling average.**	

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

Potential/Fugitive Emissions

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

Allowable Emissions Allowable Emissions 3 of 3

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **0.15 lb/MMBtu, 30-day rolling average**	4. Equivalent Allowable Emissions: lb/hour **117.1** tons/year
5. Method of Compliance (limit to 60 characters): **Continuous NO_x monitor and limit natural gas burning to 24.9 percent.**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Based on natural gas firing, as a 30-day rolling average.**	

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

Potential/Fugitive Emissions

1. Pollutant Emitted: **CO**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **1,462.5** lb/hour **1,165.1** tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **6.5 lb/MMBtu** Reference: **CEM Data**	7. Emissions Method Code:

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

6.5 lb/MMBtu x 225 MMBtu/hr = 1,462.5 lb/hr
0.35 lb/MMBtu x 760 MMBtu/hr x 8,760 hr/yr ÷ 2,000 lb/ton = 1,165.08 TPY

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

Maximum emissions occur under cold startup conditions. 0.35 lb/MMBtu is a 12-month rolling average. Based on biomass firing.

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **0.35 lb/MMBtu**	4. Equivalent Allowable Emissions: lb/hour **1,165.1** tons/year

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

Continuous CO monitor.

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

lb/MMBtu limit based on 12-month rolling average. Based on biomass firing.

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

Potential/Fugitive Emissions

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

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **0.35 lb/MMBtu**	4. Equivalent Allowable Emissions: lb/hour **273.2** tons/year
5. Method of Compliance (limit to 60 characters): **Continuous CO monitor.**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **lb/MMBtu limit based on 12-month rolling average. Based on No. 2 fuel oil firing.**	

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

Potential/Fugitive Emissions

1. Pollutant Emitted: **VOC**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **45.6** lb/hour **199.7** tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **0.06 lb/MMBtu** Reference: **Permit limit**	7. Emissions Method Code: **0**
8. Calculation of Emissions (limit to 600 characters): **0.06 lb/MMBtu x 760 MMBtu/hr = 45.6 lb/hr**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Based on biomass firing.**	

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **ESCNAA**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **0.06 lb/MMBtu**	4. Equivalent Allowable Emissions: **45.6** lb/hour **199.7** tons/year
5. Method of Compliance (limit to 60 characters): **Annual stack test using EPA Method 25A/18.**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Based on biomass firing.**	

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

Potential/Fugitive Emissions

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

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **ESCNAA**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **0.03 lb/MMBtu**	4. Equivalent Allowable Emissions: **14.7** lb/hour **23.4** tons/year
5. Method of Compliance (limit to 60 characters): **Limit No. 2 fuel oil burning to 24.9 percent for any single boiler.**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Based on No. 2 fuel oil firing.**	

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

Potential/Fugitive Emissions

1. Pollutant Emitted: **Pb - Lead**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **0.11** lb/hour **0.50** tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **1.5×10^{-4} lb/MMBtu** Reference: **Permit limit**	7. Emissions Method Code: **0**
8. Calculation of Emissions (limit to 600 characters): **1.5×10^{-4} lb/MMBtu x 760 MMBtu/hr = 0.11 lb/hr**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Based on biomass firing.**	

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **1.5×10^{-4} lb/MMBtu**	4. Equivalent Allowable Emissions: **0.11** lb/hour **0.50** tons/year
5. Method of Compliance (limit to 60 characters): **Stack test using EPA Method 12, once every 5 years.**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Based on biomass firing.**	

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

Potential/Fugitive Emissions

1. Pollutant Emitted: **SAM**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **13.7** lb/hour **12.0** tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **0.018 lb/MMBtu** Reference: **AP-42**	7. Emissions Method Code:
8. Calculation of Emissions (limit to 600 characters): **0.018 lb/MMBtu x 760 MMBtu/hr = 13.68 lb/hr** **Annual average = 0.0036 lb/MMBtu x 760 MMBtu/hr x 8,760 hr/yr ÷ 2,000 lb/ton = 11.98 TPY**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Based on biomass firing.**	

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **0.018 lb/MMBtu**	4. Equivalent Allowable Emissions: **13.7** lb/hour **12.0** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Method 8, once every 5 years.**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Based on biomass firing.**	

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

Potential/Fugitive Emissions

1. Pollutant Emitted: **Fl - Fluorides**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **0.53** lb/hour **2.33** tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **7×10^{-4} lb/MMBtu** Reference: **Stack Test Data**	7. Emissions Method Code: **0**
8. Calculation of Emissions (limit to 600 characters): **7×10^{-4} lb/MMBtu x 760 MMBtu/hr = 0.53 lb/hr**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Based on biomass firing.**	

Allowable Emissions Allowable Emissions ______ of ______

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance (limit to 60 characters):	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):	

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

Potential/Fugitive Emissions

1. Pollutant Emitted: **H114 - Mercury**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **0.0041** lb/hour **0.018** tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **5.4 x 10^{-6} lb/MMBtu** Reference: **Permit limit**	7. Emissions Method Code: **0**
8. Calculation of Emissions (limit to 600 characters): **5.4 x 10^{-6} lb/MMBtu x 760 MMBtu/hr = 0.0041 lb/hr**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Based on biomass firing.**	

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **5.4 x 10^{-6} lb/MMBtu**	4. Equivalent Allowable Emissions: **0.0041** lb/hour **0.018** tons/year
5. Method of Compliance (limit to 60 characters): **Stack test using EPA Method 29, once every 5 years.**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Based on biomass firing.**	

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

Visible Emissions Limitation: Visible Emissions Limitation 1 of 1

1. Visible Emissions Subtype: **VE20**	2. Basis for Allowable Opacity: [X] Rule [ ] Other
3. Requested Allowable Opacity: Normal Conditions: **20** % Exceptional Conditions: **27** % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance: **EPA Method 9**	
5. Visible Emissions Comment (limit to 200 characters): **40 CFR 60, Subpart Da.**	

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

Continuous Monitoring System: Continuous Monitor 1 of 5

1. Parameter Code: **VE**	2. Pollutant(s):
3. CMS Requirement:	[X] Rule [ ] Other
4. Monitor Information: Manufacturer: **Durag** Model Number: **D-R281-31-AV** Serial Number: **31019**	
5. Installation Date: **01 OCT 1995**	6. Performance Specification Test Date:
7. Continuous Monitor Comment (limit to 200 characters): **40 CFR 60, Subpart Da.**	

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

Visible Emissions Limitation: Visible Emissions Limitation ______ of ______

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

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

Continuous Monitoring System: Continuous Monitor 2 of 5

1. Parameter Code: **EM**	2. Pollutant(s): **NO_x**
3. CMS Requirement:	[X] Rule [ ] Other
4. Monitor Information: Manufacturer: **Thermo Environmental Instruments** Model Number: **42D**	Serial Number: **42D-52618-292**
5. Installation Date: **01 OCT 1995**	6. Performance Specification Test Date:
7. Continuous Monitor Comment (limit to 200 characters): **40 CFR 60, Subpart Da.**	

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

Visible Emissions Limitation: Visible Emissions Limitation ______ of ______

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

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

Continuous Monitoring System: Continuous Monitor 3 of 5

1. Parameter Code: **EM**	2. Pollutant(s): **SO_2**
3. CMS Requirement:	[ ] Rule [**X**] Other
4. Monitor Information: Manufacturer: **Thermo Environmental Instruments** Model Number: **43B**	Serial Number: **43B-51400-292**
5. Installation Date: **01 OCT 1995**	6. Performance Specification Test Date:
7. Continuous Monitor Comment (limit to 200 characters): **40 CFR 60, Subpart Da.**	

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

Visible Emissions Limitation: Visible Emissions Limitation ______ of ______

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

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

Continuous Monitoring System: Continuous Monitor 4 of 5

1. Parameter Code: **EM**	2. Pollutant(s): **CO**
3. CMS Requirement:	[ ] Rule [**X**] Other
4. Monitor Information: Manufacturer: **Thermo Environmental Instruments** Model Number: **48**	Serial Number: **48-45334-273**
5. Installation Date: **01 OCT 1995**	6. Performance Specification Test Date:
7. Continuous Monitor Comment (limit to 200 characters):	

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

Visible Emissions Limitation: Visible Emissions Limitation ______ of ______

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

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

Continuous Monitoring System: Continuous Monitor 5 of 5

1. Parameter Code:	2. Pollutant(s): O_2
3. CMS Requirement:	[X] Rule [ ] Other
4. Monitor Information: Manufacturer: **Yokogowa** Model Number: **ZA8C**	Serial Number: **JJ113MA345**
5. Installation Date: **01 OCT 1995**	6. Performance Specification Test Date:
7. Continuous Monitor Comment (limit to 200 characters): **40 CFR 60, Subpart Da.**	

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

Supplemental Requirements

1. Process Flow Diagram [X] Attached, Document ID: NH-FI-C3 [ ] Not Applicable [ ] Waiver Requested
2. Fuel Analysis or Specification [X] Attached, Document ID: NH-EU2-J2 [ ] Not Applicable [ ] Waiver Requested
3. Detailed Description of Control Equipment [X] Attached, Document ID: NH-EU2-J3 [ ] Not Applicable [ ] Waiver Requested
4. Description of Stack Sampling Facilities [ ] Attached, Document ID:_______ [X] Not Applicable [ ] Waiver Requested
5. Compliance Test Report [ ] Attached, Document ID:________ [ ] Previously submitted, Date:________________ [X] Not Applicable
6. Procedures for Startup and Shutdown [ ] Attached, Document ID:________ [X] Not Applicable [ ] Waiver Requested
7. Operation and Maintenance Plan [ ] Attached, Document ID:________ [X] Not Applicable [ ] Waiver Requested
8. Supplemental Information for Construction Permit Application [X] Attached, Document ID: PSD Report [ ] Not Applicable
9. Other Information Required by Rule or Statute [ ] Attached, Document ID:_________ [X] Not Applicable
10. Supplemental Requirements Comment:

Additional Supplemental Requirements for Title V Air Operation Permit Applications

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

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

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

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

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

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

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

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

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

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

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

[X] Not Applicable

ATTACHMENT NH-EU3-C

LIST OF APPLICABLE REGULATIONS

EU ID 031 : Cogen Boiler B Rule Applicability for New Hope Power Partnership

APPLIC STAT	RULE DESCRIP	RULE NUMBER	RULE TITLE	RATIONALE FOR NON-APPLICABILITY
APPLICABLE	60 Subpart A	40CFR60.1	Subpart A -- General Provisions	
APPLICABLE	60 Subpart A	40CFR60.7	Notification and Record Keeping	
APPLICABLE	60Subpart A	40CFR60.8	Performance Testing	
APPLICABLE	60 Subpart A	40CFR60.11	Compliance with standards and maintenance requirements.	
APPLICABLE	60 Subpart A	40CFR60.12	Circumvention.	
APPLICABLE	60 Subpart A	40CFR60.13	Monitoring requirements.	
APPLICABLE	60 Subpart A	40CFR60.19	General notification and reporting requirements	
APPLICABLE	60 Subpart Da	40CFR60.40a	Subpart Da - NSPS for Electric Utility Units for which construction commenced after Sept. 18, 1978.	
APPLICABLE	60 Subpart Da	40CFR60.42a	Standard for particulate matter	
APPLICABLE	60 Subpart Da	40CFR60.43a	Standard for sulfur dioxide.	
APPLICABLE	60 Subpart Da	40CFR60.43a(a)	Standard for sulfur dioxide.	
APPLICABLE	60 Subpart Da	40CFR60.43a(b)	Standard for sulfur dioxide.	
APPLICABLE	60 Subpart Da	40CFR60.43a(d)(2)	Standard for sulfur dioxide.	
APPLICABLE	60 Subpart Da	40CFR60.43a(g)	Standard for sulfur dioxide.	
APPLICABLE	60 Subpart Da	40CFR60.43a(h)	Standard for sulfur dioxide.	
APPLICABLE	60 Subpart Da	40CFR60.44a	Standard for nitrogen oxides	
APPLICABLE	60 Subpart Da	40CFR60.44a(a)	Standard for nitrogen oxides	
APPLICABLE	60 Subpart Da	40CFR60.44a(c)	Standard for nitrogen oxides	
APPLICABLE	60 Subpart Da	40CFR60.46a	Compliance provisions.	
APPLICABLE	60 Subpart Da	40CFR60.46a(a)	Compliance provisions.	
APPLICABLE	60 Subpart Da	40CFR60.46a(b)	Compliance provisions.	
APPLICABLE	60 Subpart Da	40CFR60.46a(c)	Compliance provisions.	
NON-APPLICABLE	60 Subpart Da	40CFR60.46a(d)	Compliance provisions.	Cogen Boiler B does not have a flue gas desulfurization system.
APPLICABLE	60 Subpart Da	40CFR60.46a(e)	Compliance provisions.	
APPLICABLE	60 Subpart Da	40CFR60.46a(f)	Compliance provisions.	
APPLICABLE	60 Subpart Da	40CFR60.46a(g)	Compliance provisions.	
APPLICABLE	60 Subpart Da	40CFR60.46a(h)	Compliance provisions.	
NON-APPLICABLE	60 Subpart Da	40CFR60.46a(i)	Compliance provisions.	Cogen Boiler B has not been modified after July 7, 1997.
APPLICABLE	60 Subpart Da	40CFR60.47a	Emission monitoring	
APPLICABLE	60 Subpart Da	40CFR60.47a(a)	Emission monitoring	
APPLICABLE	60 Subpart Da	40CFR60.47a(b)(2)	Emission monitoring	
APPLICABLE	60 Subpart Da	40CFR60.47a(b)(3)	Emission monitoring	
APPLICABLE	60 Subpart Da	40CFR60.47a(c)(1)	Emission monitoring	
APPLICABLE	60 Subpart Da	40CFR60.47a(d)	Emission monitoring	
APPLICABLE	60 Subpart Da	40CFR60.47a(e)	Emission monitoring	
APPLICABLE	60 Subpart Da	40CFR60.47a(f)	Emission monitoring	
APPLICABLE	60 Subpart Da	40CFR60.47a(g)	Emission monitoring	
APPLICABLE	60 Subpart Da	40CFR60.47a(h)	Emission monitoring	
APPLICABLE	60 Subpart Da	40CFR60.47a(i)	Emission monitoring	
APPLICABLE	60 Subpart Da	40CFR60.47a(j)	Emission monitoring	
APPLICABLE	60 Subpart Da	40CFR60.48a	Compliance determination procedures and methods.	
APPLICABLE	60 Subpart Da	40CFR60.48a(a)	Compliance determination procedures and methods.	
APPLICABLE	60 Subpart Da	40CFR60.48a(b)	Compliance determination procedures and methods.	
APPLICABLE	60 Subpart Da	40CFR60.48a(c)	Compliance determination procedures and methods.	
APPLICABLE	60 Subpart Da	40CFR60.48a(d)	Compliance determination procedures and methods.	
APPLICABLE	60 Subpart Da	40CFR60.48a(e)	Compliance determination procedures and methods.	
APPLICABLE	60 Subpart Da	40CFR60.49a	Reporting requirements	
APPLICABLE	60 Subpart Da	40CFR60.49a(a)	Reporting requirements	
APPLICABLE	60 Subpart Da	40CFR60.49a(b)	Reporting requirements	
APPLICABLE	60 Subpart Da	40CFR60.49a(c)	Reporting requirements	
APPLICABLE	60 Subpart Da	40CFR60.49a(d)	Reporting requirements	
APPLICABLE	60 Subpart Da	40CFR60.49a(f)	Reporting requirements	
APPLICABLE	60 Subpart Da	40CFR60.49a(g)	Reporting requirements	

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APPLIC STAT	RULE DESCRIP	RULE NUMBER	RULE TITLE	RATIONALE FOR NON-APPLICABILITY
APPLICABLE	60 Subpart Da	40CFR60.49a(h)	Reporting requirements	
APPLICABLE	60 Subpart Da	40CFR60.49a(i)	Reporting requirements	
APPLICABLE	60 Subpart Da	40CFR60.49a(j)	Reporting requirements	
APPLICABLE	60 Subpart Ea	40CFR60.50a(d)	Standards of performance for municipal waste combustors	
APPLICABLE	60 Subpart Ea	40CFR60.50b(j)	Standards of performance for municipal waste combustors	
APPLICABLE	62-204	62-204.800(7)2.	NSPS Subpart Da adopted by reference.	
APPLICABLE	62-296 <	62-296	STATIONARY SOURCES - EMISSION STANDARDS	
APPLICABLE	62-296 <	62-296.405(2)	Fossil Fuel Steam Generators with more than 250 million Btu per Hour Heat Input.	
NON-APPLICABLE	62-296 <	62-296.406	Fossil Fuel Steam Generators with less than 250 Million Btu per Hour Heat Input, New and Existing Em	Cogen Boiler B has a heat input of >250 MMBtu/hr.
NON-APPLICABLE	62-296 <	62-296.410	Carbonaceous Fuel Burning Equipment.	Not more stringent or different than NSPS.
APPLICABLE	62-296 >	62-296.500	Reasonably Available Control Technology (RACT) - Volatile Organic Compounds (VOC) and Nitrogen Oxide	
APPLICABLE	62-296 >	62-296.500(2)(a)	Reasonably Available Control Technology (RACT) - Volatile Organic Compounds (VOC) and Nitrogen Oxide	
APPLICABLE	62-296 >	62-296.500(2)(c)	Reasonably Available Control Technology (RACT) - Volatile Organic Compounds (VOC) and Nitrogen Oxide	
APPLICABLE	62-296 >	62-296.570	Reasonably Available Control Technology (RACT) - Requirements for Major VOC- and NOx-Emitting Facility	
APPLICABLE	62-296 >	62-296.570(1)	Applicability.	
APPLICABLE	62-296 >	62-296.570(1)(a)	Applicability.	
APPLICABLE	62-296 >	62-296.570(2)	Compliance Requirements.	
APPLICABLE	62-296 >	62-296.570(3)	Operation Permit Requirements.	
APPLICABLE	62-296 >	62-296.570(4)	Operation Permit Requirements.	
APPLICABLE	62-296 >	62-296.570(4)(a)	Operation Permit Requirements.	
APPLICABLE	62-296 >	62-296.570(4)(b)6.	Operation Permit Requirements.	
APPLICABLE	62-296 >	62-296.570(4)(c)	Operation Permit Requirements.	
APPLICABLE	62-296 >	62-296.620		
NON-APPLICABLE	62-296 >	62-296.700	Reasonably Available Control Technology (RACT) Particulate Matter.	New Hope Power Partnership is located in Palm Beach County, which is not a nonattainment or maintenance area for particulate matter.
NON-APPLICABLE	62-296 >	62-296.702	Fossil Fuel Steam Generators.	New Hope Power Partnership is located in Palm Beach County, which is not a nonattainment or maintenance area for particulate matter.
NON-APPLICABLE	62-296 >	62-296.703	Carbonaceous Fuel Burners.	New Hope Power Partnership is located in Palm Beach County, which is not a nonattainment or maintenance area for particulate matter.
APPLICABLE	62-297	62-297	STATIONARY SOURCES - EMISSIONS MONITORING	
APPLICABLE	62-297	62-297.310	General Compliance Test Requirements.	
APPLICABLE	62-297	62-297.401	Compliance Test Methods.	
APPLICABLE	62-297	62-297.401(1)(a)	EPA Method 1 - Sample and Velocity Traverses for Stationary sources - 40 CFR 60 Appendix A.	
APPLICABLE	62-297	62-297.401(10)	EPA Method 10 - Determination of Carbon Monoxide Emissions from Stationary Sources 40 CFR 60 Appendix	
APPLICABLE	62-297	62-297.401(12)	EPA Method 12 - Determination of Inorganic Lead Emissions from Stationary Sources - 40 CFR 60 Append	
APPLICABLE	62-297	62-297.401(13)	EPA Methods 13A and 13B.	
APPLICABLE	62-297	62-297.401(18)	EPA Method 18 - Measurement of Gaseous Organic Compound Emissions by Gas Chromatography - 40 CFR 60	
APPLICABLE	62-297	62-297.401(19)	EPA Method 19 - Determination of Sulfur Dioxide Removal Efficiency and Particulate, Sulfur Dioxide a	
APPLICABLE	62-297	62-297.401(2)	EPA Method 2 - Determination of Stack Gas Velocity and Volumetric Flow Rate - 40 CFR 60 Appendix A.	

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APPLIC STAT	RULE DESCRIP	RULE NUMBER	RULE TITLE	RATIONALE FOR NON-APPLICABILITY
APPLICABLE	62-297	62-297.401(25)	EPA Method 25 - Determination of Total Gaseous Nonmethane Organic Emissions as Carbon - 40 CFR 60 Appendix	
APPLICABLE	62-297	62-297.401(3)	EPA Method 3 - Gas Analysis for Carbon Dioxide, Oxygen, Excess Air, and Dry Molecular Weight - 40 CF	
APPLICABLE	62-297	62-297.401(32)	EPA Method 101 - Determination of Particulate and Gaseous Mercury Emissions from Chlor-Alkali Plants	
APPLICABLE	62-297	62-297.401(35)	EPA Method 104 - Determination of Beryllium Emissions from Stationary Sources - 40 CFR 61 Appendix B	
APPLICABLE	62-297	62-297.401(39)	EPA Method 108 - Determination of Particulate and Gaseous Arsenic Emissions - 40 CFR 61 Appendix B.	
APPLICABLE	62-297	62-297.401(4)	EPA Method 4 - Determination of Moisture Content in Stack Gases - 40 CFR 60 Appendix A.	
APPLICABLE	62-297	62-297.401(41)	EPA Method 201 - Determination of PM10 Emissions (Exhaust Gas Recycle Procedure) - 40 CFR 51 Appendix	
APPLICABLE	62-297	62-297.401(5)	EPA Method 5 - Determination of Particulate Emissions from Stationary Sources - 40 CFR 60 Appendix A	
APPLICABLE	62-297	62-297.401(6)	EPA Method 6 - Determination of Sulfur Dioxide Emissions from Stationary Sources - 40 CFR 60 Appendix	
APPLICABLE	62-297	62-297.401(6)(c)	EPA Method 6C - Determination of Sulfur Dioxide Emissions from Stationary Sources - 40 CFR 60 Appendix	
APPLICABLE	62-297	62-297.401(7)	EPA Method 7 - Determination of Nitrogen Oxide Emissions from Stationary Sources - 40 CFR 60 Appendix	
APPLICABLE	62-297	62-297.401(7)(e)	EPA Method 7E - Determination of Nitrogen Oxide Emissions from Stationary Sources - 40 CFR 60 Appendix	
APPLICABLE	62-297	62-297.401(8)	EPA Method 8 - Determination of Sulfuric Acid Mist and Sulfur Dioxide Emissions from Stationary Sour	
APPLICABLE	62-297	62-297.401(9)	EPA Test Method 9	

III. EMISSIONS UNIT INFORMATION

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

A. GENERAL EMISSIONS UNIT INFORMATION
(All Emissions Units)

Emissions Unit Description and Status

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

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

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

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

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

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

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

3. Description of Emissions Unit Addressed in This Section (limit to 60 characters):
Cogen Boiler C fired by Biomass/No. 2 Fuel Oil/Natural Gas

4. Emissions Unit Identification Number: [ ] No ID
ID: **032** [ ] ID Unknown

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

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

74.9 MW net generating capacity for entire facility.

Emissions Unit Control Equipment

1. Control Equipment/Method Description (Limit to 200 characters per device or method): **ESP - Electrostatic Precipitator - High Efficiency** **Selective Non-catalytic Reduction for NO_x** **Multiple Cyclone w/o Fly Ash Reinjection** **Activated Carbon Injection System**	
2. Control Device or Method Code(s): **010, 107, 076, 048**	

Emissions Unit Details

1. Package Unit: Manufacturer:	Model Number:	
2. Generator Nameplate Rating: **75**	MW	
3. Incinerator Information: Dwell Temperature: Dwell Time: Incinerator Afterburner Temperature:		°F seconds °F

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

Emissions Unit Operating Capacity and Schedule

1. Maximum Heat Input Rate:			760	mmBtu/hr
2. Maximum Incineration Rate:		lb/hr		tons/day
3. Maximum Process or Throughput Rate:				tons/hr
4. Maximum Production Rate:				
5. Requested Maximum Operating Schedule:				
	24	hours/day	7	days/week
	52	weeks/year	8,760	hours/year

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

Maximum heat input rates:
Biomass - 760 MMBtu/hr;
No. 2 Fuel Oil - 490 MMBtu/hr;
Natural Gas - 605 MMBtu/hr

C. EMISSIONS UNIT REGULATIONS
(Regulated Emissions Units Only)

List of Applicable Regulations

See Attachment NH-EU4-C.	

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

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram? **BLR C**	2. Emission Point Type Code: **1**
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking (limit to 100 characters per point):	
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:	

5. Discharge Type Code: **V**	6. Stack Height: **199** feet	7. Exit Diameter: **10.0** feet
8. Exit Temperature: **352** °F	9. Actual Volumetric Flow Rate: **319,000** acfm	10. Water Vapor: %

11. Maximum Dry Standard Flow Rate: dscfm	12. Nonstack Emission Point Height: feet
13. Emission Point UTM Coordinates: Zone: East (km): North (km):	
14. Emission Point Comment (limit to 200 characters): **Stack parameters based on biomass firing. See Table 2-5 in PSD Report for all boiler stack data.**	

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

Segment Description and Rate: Segment 1 of 4

1. Segment Description (Process/Fuel Type) (limit to 500 characters): **Electric Utility Boiler - Bagasse**		
2. Source Classification Code (SCC): **1-01-011-01**	3. SCC Units: **Tons Burned (all solid fuels)**	
4. Maximum Hourly Rate: **105.56**	5. Maximum Annual Rate: **924,667**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **0.05**	8. Maximum % Ash: **1.0**	9. Million Btu per SCC Unit: **7.2**
10. Segment Comment (limit to 200 characters):		

Segment Description and Rate: Segment 2 of 4

1. Segment Description (Process/Fuel Type) (limit to 500 characters): **Electric Utility Boiler - Wood Fired Boiler**		
2. Source Classification Code (SCC): **1-01-009-03**	3. SCC Units: **Tons Burned (all solid fuels)**	
4. Maximum Hourly Rate: **84.44**	5. Maximum Annual Rate: **739,733**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **0.3**	8. Maximum % Ash: **9.0**	9. Million Btu per SCC Unit: **9.0**
10. Segment Comment (limit to 200 characters):		

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

Segment Description and Rate: Segment 3 of 4

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

   Electric Utility Boiler - Distillate Oil - Grades 1 and 2 Oil

2. Source Classification Code (SCC): **1-01-005-01**		3. SCC Units: **Thousand Gallons Burned (all liquid fuels)**
4. Maximum Hourly Rate: **3.551**	5. Maximum Annual Rate: **11,309**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **0.05**	8. Maximum % Ash:	9. Million Btu per SCC Unit: **138**

10. Segment Comment (limit to 200 characters):

Segment Description and Rate: Segment 4 of 4

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

   Electric Utility Boiler - Natural Gas

2. Source Classification Code (SCC): **1-01-006-01**		3. SCC Units: **MMscf Burned**
4. Maximum Hourly Rate: **0.605**	5. Maximum Annual Rate: **1,561**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit: **1,000**

10. Segment Comment (limit to 200 characters):

F. EMISSIONS UNIT POLLUTANTS
(All Emissions Units)

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
PM	076	010	EL
PM_{10}	076	010	EL
SO_2			EL
NO_X	107		EL
CO			EL
VOC			EL
PB	076	010	EL
SAM			NS
FL			NS
H114	048		EL

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

Potential/Fugitive Emissions

1. Pollutant Emitted: **PM**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **22.8** lb/hour **99.86** tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **0.03 lb/MMBtu** Reference: **40 CFR 60 Subpart Da**	7. Emissions Method Code: **0**
8. Calculation of Emissions (limit to 600 characters): **0.03 lb/MMBtu x 760 MMBtu/hr = 22.8 lb/hr**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Based on biomass firing.**	

Allowable Emissions Allowable Emissions 1 of 3

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **0.03 lb/MMBtu**	4. Equivalent Allowable Emissions: **22.8** lb/hour **99.86** tons/year
5. Method of Compliance (limit to 60 characters): **Annual Stack testing using EPA Method 5.**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Basis for Allowable Emissions Code: NSPS. Based on biomass firing.**	

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

Potential/Fugitive Emissions

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

Allowable Emissions Allowable Emissions 2 of 3

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **0.03 lb/MMBtu**	4. Equivalent Allowable Emissions: **14.70** lb/hour **23.42** tons/year
5. Method of Compliance (limit to 60 characters): **Fuel Analysis.**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Basis for Allowable Emissions Code: NSPS. Based on No. 2 fuel oil firing.**	

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

Potential/Fugitive Emissions

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

Allowable Emissions Allowable Emissions 3 of 3

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **0.030 lb/MMBtu**	4. Equivalent Allowable Emissions: **18.15** lb/hour **23.42** tons/year
5. Method of Compliance (limit to 60 characters): **Good combustion practices and limit natural gas burning to 24.9 percent.**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Basis for Allowable Emissions Code: NSPS. Based on natural gas firing. Hourly: 0.03 lb/MMBtu x 605 MMBtu/hr = 18.15 lb/hr; Annual: 0.03 lb/MMBtu x 1.561 x 10^{12} Btu/yr ÷ 2000 lb/ton = 23.42 TPY**	

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

Potential/Fugitive Emissions

1. Pollutant Emitted: **PM_{10}**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **22.8** lb/hour **99.86** tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **0.03 lb/MMBtu** Reference: **40 CFR 60 Subpart Da**	7. Emissions Method Code: **0**
8. Calculation of Emissions (limit to 600 characters): **0.03 lb/MMBtu x 760 MMBtu/hr = 22.8 lb/hr**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Based on biomass firing.**	

Allowable Emissions Allowable Emissions 1 of 3

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **0.03 lb/MMBtu**	4. Equivalent Allowable Emissions: **22.8** lb/hour **99.86** tons/year
5. Method of Compliance (limit to 60 characters): **Annual Stack testing using EPA Method 5.**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Based on biomass firing.**	

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

Potential/Fugitive Emissions

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

Allowable Emissions Allowable Emissions 2 of 3

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **0.03 lb/MMBtu**	4. Equivalent Allowable Emissions: **14.70** lb/hour **23.42** tons/year
5. Method of Compliance (limit to 60 characters): **Fuel Analysis.**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Basis for Allowable Emissions Code: NSPS. Based on No. 2 fuel oil firing.**	

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

Potential/Fugitive Emissions

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

Allowable Emissions Allowable Emissions 3 of 3

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **0.03 lb/MMBtu**	4. Equivalent Allowable Emissions: **18.15** lb/hour **23.42** tons/year
5. Method of Compliance (limit to 60 characters): **Good combustion practices and limit natural gas burning to 24.9 percent.**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Basis for Allowable Emissions Code: NSPS. Based on natural gas firing. Hourly: 0.03 lb/MMBtu x 605 MMBtu/hr = 18.15 lb/hr; Annual: 0.03 lb/MMBtu x 1.561 x 10^{12} Btu/yr ÷ 2000 lb/ton = 23.42 TPY**	

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

Potential/Fugitive Emissions

1. Pollutant Emitted: SO_2
2. Total Percent Efficiency of Control:
3. Potential Emissions: **228.0** lb/hour **199.7** tons/year
4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year
6. Emission Factor: **0.30 lb/MMBtu**
   Reference: **CEM data**
7. Emissions Method Code: **0**
8. Calculation of Emissions (limit to 600 characters):

   3-Hour average = 0.30 lb/MMBtu x 760 MMBtu/hr = 228.0 lb/hr
   24-Hour average = 0.20 lb/MMBtu x 760 MMBtu/hr = 152 lb/hr
   Annual average = 0.06 lb/MMBtu x 760 MMBtu/hr x 8,760 hr/yr ÷ 2,000 lb/ton = 199.73 TPY

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

   Based on biomass firing.

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **OTHER**
2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **0.20 lb/MMBtu**
4. Equivalent Allowable Emissions: **152.0** lb/hour **199.7** tons/year
5. Method of Compliance (limit to 60 characters):

   Continuous SO_2 monitor.

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

   Requested Allowable Emissions: 0.20 lb/MMBtu 24-hr average; 0.06 lb/MMBtu annual average. Based on biomass firing.

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

Potential/Fugitive Emissions

1. Pollutant Emitted: **SO_2**	2. Total Percent Efficiency of Control:
3. Potential Emissions: lb/hour tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference:	7. Emissions Method Code:
8. Calculation of Emissions (limit to 600 characters):	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **RULE**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **0.05 lb/MMBtu**	4. Equivalent Allowable Emissions: **24.5** lb/hour **39.0** tons/year
5. Method of Compliance (limit to 60 characters): **Fuel analysis and limit fuel oil burning to 24.9 percent.**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Based on No. 2 Fuel Oil firing and BACT.**	

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

Potential/Fugitive Emissions

1. Pollutant Emitted: **NO_x**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **152.0** lb/hour **499.3** tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 _______ to _______ tons/year	
6. Emission Factor: **0.15 lb/MMBtu** Reference: **Permit Limit**	7. Emissions Method Code: **0**
8. Calculation of Emissions (limit to 600 characters): **Short-term: 0.20 lb/MMBtu x 760 MMBtu/hr = 152.0 lb/hr** **Annual: 0.15 lb/MMBtu x 760 MMBtu/hr x 8,760 hr/yr ÷ 2000 lb/ton = 499.3 TPY**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Based on biomass firing.**	

Allowable Emissions Allowable Emissions 1 of 3

1. Basis for Allowable Emissions Code: **ESCPSD**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **0.15 lb/MMBtu, 30-day rolling average**	4. Equivalent Allowable Emissions: lb/hour **499.3** tons/year
5. Method of Compliance (limit to 60 characters): **Continuous NO_x monitor.**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Based on biomass firing, as a 30-day rolling average.**	

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

Potential/Fugitive Emissions

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

Allowable Emissions Allowable Emissions 2 of 3

1. Basis for Allowable Emissions Code: **ESCPSD**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **0.15 lb/MMBtu, 30-day rolling average**	4. Equivalent Allowable Emissions: lb/hour **117.1** tons/year
5. Method of Compliance (limit to 60 characters): **Continuous NO_x monitor and limit fuel oil burning to 24.9 percent.**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Based on No. 2 fuel oil firing, as a 30-day rolling average.**	

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

Potential/Fugitive Emissions

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

Allowable Emissions Allowable Emissions 3 of 3

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **0.15 lb/MMBtu, 30-day rolling average**	4. Equivalent Allowable Emissions: lb/hour **117.1** tons/year
5. Method of Compliance (limit to 60 characters): **Continuous NO_x monitor and limit natural gas burning to 24.9 percent.**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Based on natural gas firing, as a 30-day rolling average.**	

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

Potential/Fugitive Emissions

1. Pollutant Emitted: **CO**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **1,462.5** lb/hour **1,165.1** tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **6.5 lb/MMBtu** Reference: **CEM Data**	7. Emissions Method Code:
8. Calculation of Emissions (limit to 600 characters): **6.5 lb/MMBtu x 225 MMBtu/hr = 1,462.5 lb/hr** **0.35 lb/MMBtu x 760 MMBtu/hr x 8,760 hr/yr ÷ 2,000 lb/ton = 1,165.08 TPY**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Maximum emissions occur under cold startup conditions. 0.35 lb/MMBtu is a 12-month rolling average. Based on biomass firing.**	

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **0.35 lb/MMBtu**	4. Equivalent Allowable Emissions: lb/hour **1,165.1** tons/year
5. Method of Compliance (limit to 60 characters): **Continuous CO monitor.**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **lb/MMBtu limit based on 12-month rolling average. Based on biomass firing.**	

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

Potential/Fugitive Emissions

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

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **0.35 lb/MMBtu**	4. Equivalent Allowable Emissions: lb/hour **273.2** tons/year
5. Method of Compliance (limit to 60 characters): **Continuous CO monitor.**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **lb/MMBtu limit based on 12-month rolling average. Based on No. 2 fuel oil firing.**	

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

Potential/Fugitive Emissions

1. Pollutant Emitted: **VOC**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **45.6** lb/hour **199.7** tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **0.06 lb/MMBtu** Reference: **Permit limit**	7. Emissions Method Code: **0**
8. Calculation of Emissions (limit to 600 characters): **0.06 lb/MMBtu x 760 MMBtu/hr = 45.6 lb/hr**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Based on biomass firing.**	

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **ESCNAA**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **0.06 lb/MMBtu**	4. Equivalent Allowable Emissions: **45.6** lb/hour **199.7** tons/year
5. Method of Compliance (limit to 60 characters): **Annual stack test using EPA Method 25A/18.**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Based on biomass firing.**	

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

Potential/Fugitive Emissions

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

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **ESCNAA**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **0.03 lb/MMBtu**	4. Equivalent Allowable Emissions: **14.7** lb/hour **23.4** tons/year
5. Method of Compliance (limit to 60 characters): **Limit No. 2 fuel oil burning to 24.9 percent for any single boiler.**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Based on No. 2 fuel oil firing.**	

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

Potential/Fugitive Emissions

1. Pollutant Emitted: **Pb - Lead**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **0.11** lb/hour **0.50** tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **1.5×10^{-4} lb/MMBtu** Reference: **Permit limit**	7. Emissions Method Code: **0**
8. Calculation of Emissions (limit to 600 characters): **1.5×10^{-4} lb/MMBtu x 760 MMBtu/hr = 0.11 lb/hr**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Based on biomass firing.**	

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **1.5×10^{-4} lb/MMBtu**	4. Equivalent Allowable Emissions: **0.11** lb/hour **0.50** tons/year
5. Method of Compliance (limit to 60 characters): **Stack test using EPA Method 12, once every 5 years.**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Based on biomass firing.**	

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

Potential/Fugitive Emissions

1. Pollutant Emitted: **SAM**

2. Total Percent Efficiency of Control:

3. Potential Emissions: **13.7** lb/hour **12.0** tons/year

4. Synthetically Limited? [ ]

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

6. Emission Factor: **0.018 lb/MMBtu**
   Reference: **AP-42**

7. Emissions Method Code:

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

   0.018 lb/MMBtu x 760 MMBtu/hr = 13.68 lb/hr
   Annual average = 0.0036 lb/MMBtu x 760 MMBtu/hr x 8,760 hr/yr ÷ 2,000 lb/ton = 11.98 TPY

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

   Based on biomass firing.

Allowable Emissions Allowable Emissions 1 of 1

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

2. Future Effective Date of Allowable Emissions:

3. Requested Allowable Emissions and Units: **0.018 lb/MMBtu**

4. Equivalent Allowable Emissions: **13.7** lb/hour **12.0** tons/year

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

   EPA Method 8, once every 5 years.

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

   Based on biomass firing.

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

Potential/Fugitive Emissions

1. Pollutant Emitted: **Fl - Fluorides**
2. Total Percent Efficiency of Control:
3. Potential Emissions: **0.53** lb/hour **2.33** tons/year
4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year
6. Emission Factor: **7×10^{-4} lb/MMBtu**
   Reference: **Stack Test Data**
7. Emissions Method Code: **0**
8. Calculation of Emissions (limit to 600 characters):

   7×10^{-4} lb/MMBtu x 760 MMBtu/hr = 0.53 lb/hr

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

   Based on biomass firing.

Allowable Emissions Allowable Emissions ______ of ______

1. Basis for Allowable Emissions Code:
2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units:
4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance (limit to 60 characters):
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):

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

Potential/Fugitive Emissions

1. Pollutant Emitted: **H114 - Mercury**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **0.0041** lb/hour **0.018** tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **5.4 x 10^{-6} lb/MMBtu** Reference: **Permit limit**	7. Emissions Method Code: **0**
8. Calculation of Emissions (limit to 600 characters): **5.4 x 10^{-6} lb/MMBtu x 760 MMBtu/hr = 0.0041 lb/hr**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Based on biomass firing.**	

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **5.4 x 10^{-6} lb/MMBtu**	4. Equivalent Allowable Emissions: **0.0041** lb/hour **0.018** tons/year
5. Method of Compliance (limit to 60 characters): **Stack test using EPA Method 29, once every 5 years.**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Based on biomass firing.**	

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

Visible Emissions Limitation: Visible Emissions Limitation 1 of 1

1. Visible Emissions Subtype: **VE20**	2. Basis for Allowable Opacity: [X] Rule [ ] Other
3. Requested Allowable Opacity: Normal Conditions: **20** % Exceptional Conditions: **27** % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance: **EPA Method 9**	
5. Visible Emissions Comment (limit to 200 characters): **40 CFR 60, Subpart Da.**	

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

Continuous Monitoring System: Continuous Monitor 1 of 5

1. Parameter Code: **VE**	2. Pollutant(s):
3. CMS Requirement:	[X] Rule [ ] Other
4. Monitor Information: Manufacturer: **Durag** Model Number: **D-R281-31-AV**	Serial Number: **31019**
5. Installation Date: **01 OCT 1995**	6. Performance Specification Test Date:
7. Continuous Monitor Comment (limit to 200 characters): **40 CFR 60, Subpart Da.**	

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

Visible Emissions Limitation: Visible Emissions Limitation ____ of ____

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

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

Continuous Monitoring System: Continuous Monitor 2 of 5

1. Parameter Code: **EM**	2. Pollutant(s): **NO_x**
3. CMS Requirement:	[X] Rule [ ] Other
4. Monitor Information: Manufacturer: **Thermo Environmental Instruments** Model Number: **42D**	Serial Number: **42D-52618-292**
5. Installation Date: **01 OCT 1995**	6. Performance Specification Test Date:
7. Continuous Monitor Comment (limit to 200 characters): **40 CFR 60, Subpart Da.**	

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

Visible Emissions Limitation: Visible Emissions Limitation ______ of ______

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

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

Continuous Monitoring System: Continuous Monitor 3 of 5

1. Parameter Code: **EM**	2. Pollutant(s): **SO_2**
3. CMS Requirement: [ ] Rule [X] Other	
4. Monitor Information: Manufacturer: **Thermo Environmental Instruments** Model Number: **43B** Serial Number: **43B-51400-292**	
5. Installation Date: **01 OCT 1995**	6. Performance Specification Test Date:
7. Continuous Monitor Comment (limit to 200 characters): **40 CFR 60, Subpart Da.**	

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

Visible Emissions Limitation: Visible Emissions Limitation ____ of ____

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

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

Continuous Monitoring System: Continuous Monitor 4 of 5

1. Parameter Code: **EM**	2. Pollutant(s): **CO**
3. CMS Requirement:	[ ] Rule [**X**] Other
4. Monitor Information: Manufacturer: **Thermo Environmental Instruments** Model Number: **48**	Serial Number: **48-45334-273**
5. Installation Date: **01 OCT 1995**	6. Performance Specification Test Date:
7. Continuous Monitor Comment (limit to 200 characters):	

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

Visible Emissions Limitation: Visible Emissions Limitation ____ of ____

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

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

Continuous Monitoring System: Continuous Monitor 5 of 5

1. Parameter Code:	2. Pollutant(s): O_2
3. CMS Requirement: [X] Rule [ ] Other	
4. Monitor Information: Manufacturer: **Yokogowa** Model Number: **ZA8C** Serial Number: **JJ113MA345**	
5. Installation Date: **01 OCT 1995**	6. Performance Specification Test Date:
7. Continuous Monitor Comment (limit to 200 characters): **40 CFR 60, Subpart Da.**	

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

Supplemental Requirements

1. Process Flow Diagram [X] Attached, Document ID: NH-FI-C3 [ ] Not Applicable [ ] Waiver Requested
2. Fuel Analysis or Specification [X] Attached, Document ID: NH-EU2-J2 [ ] Not Applicable [ ] Waiver Requested
3. Detailed Description of Control Equipment [X] Attached, Document ID: NH-EU2-J3 [ ] Not Applicable [ ] Waiver Requested
4. Description of Stack Sampling Facilities [ ] Attached, Document ID:_______ [X] Not Applicable [ ] Waiver Requested
5. Compliance Test Report [ ] Attached, Document ID:________ [ ] Previously submitted, Date:_______________ [X] Not Applicable
6. Procedures for Startup and Shutdown [ ] Attached, Document ID:________ [X] Not Applicable [ ] Waiver Requested
7. Operation and Maintenance Plan [ ] Attached, Document ID:________ [X] Not Applicable [ ] Waiver Requested
8. Supplemental Information for Construction Permit Application [X] Attached, Document ID: PSD Report [ ] Not Applicable
9. Other Information Required by Rule or Statute [ ] Attached, Document ID:_________ [X] Not Applicable
10. Supplemental Requirements Comment:

Additional Supplemental Requirements for Title V Air Operation Permit Applications

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

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

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

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

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

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

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

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

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

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

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

    [X] Not Applicable

ATTACHMENT NH-EU4-C

LIST OF APPLICABLE REGULATIONS

EU ID 032 : Cogen Boiler C Rule Applicability for New Hope Power Partnership

APPLIC STAT	RULE DESCRIP	RULE NUMBER	RULE TITLE	RATIONALE FOR NON-APPLICABILITY
APPLICABLE	60 Subpart A	40CFR60.1	Subpart A -- General Provisions	
APPLICABLE	60 Subpart A	40CFR60.7	Notification and Record Keeping	
APPLICABLE	60Subpart A	40CFR60.8	Performance Testing	
APPLICABLE	60 Subpart A	40CFR60.11	Compliance with standards and maintenance requirements.	
APPLICABLE	60 Subpart A	40CFR60.12	Circumvention.	
APPLICABLE	60 Subpart A	40CFR60.13	Monitoring requirements.	
APPLICABLE	60 Subpart A	40CFR60.19	General notification and reporting requirements	
APPLICABLE	60 Subpart Da	40CFR60.40a	Subpart Da - NSPS for Electric Utility Units for which construction commenced after Sept. 18, 1978.	
APPLICABLE	60 Subpart Da	40CFR60.42a	Standard for particulate matter	
APPLICABLE	60 Subpart Da	40CFR60.43a	Standard for sulfur dioxide.	
APPLICABLE	60 Subpart Da	40CFR60.43a(a)	Standard for sulfur dioxide.	
APPLICABLE	60 Subpart Da	40CFR60.43a(b)	Standard for sulfur dioxide.	
APPLICABLE	60 Subpart Da	40CFR60.43a(d)(2)	Standard for sulfur dioxide.	
APPLICABLE	60 Subpart Da	40CFR60.43a(g)	Standard for sulfur dioxide.	
APPLICABLE	60 Subpart Da	40CFR60.43a(h)	Standard for sulfur dioxide.	
APPLICABLE	60 Subpart Da	40CFR60.44a	Standard for nitrogen oxides	
APPLICABLE	60 Subpart Da	40CFR60.44a(a)	Standard for nitrogen oxides	
APPLICABLE	60 Subpart Da	40CFR60.44a(c)	Standard for nitrogen oxides	
APPLICABLE	60 Subpart Da	40CFR60.46a	Compliance provisions.	
APPLICABLE	60 Subpart Da	40CFR60.46a(a)	Compliance provisions.	
APPLICABLE	60 Subpart Da	40CFR60.46a(b)	Compliance provisions.	
APPLICABLE	60 Subpart Da	40CFR60.46a(c)	Compliance provisions.	
NON-APPLICABLE	60 Subpart Da	40CFR60.46a(d)	Compliance provisions.	Cogen Boiler C does not have a flue gas desulfurization system.
APPLICABLE	60 Subpart Da	40CFR60.46a(e)	Compliance provisions.	
APPLICABLE	60 Subpart Da	40CFR60.46a(f)	Compliance provisions.	
APPLICABLE	60 Subpart Da	40CFR60.46a(g)	Compliance provisions.	
APPLICABLE	60 Subpart Da	40CFR60.46a(h)	Compliance provisions.	
NON-APPLICABLE	60 Subpart Da	40CFR60.46a(i)	Compliance provisions.	Cogen Boiler C has not been modified after July 7, 1997.
APPLICABLE	60 Subpart Da	40CFR60.47a	Emission monitoring	
APPLICABLE	60 Subpart Da	40CFR60.47a(a)	Emission monitoring	
APPLICABLE	60 Subpart Da	40CFR60.47a(b)(2)	Emission monitoring	
APPLICABLE	60 Subpart Da	40CFR60.47a(b)(3)	Emission monitoring	
APPLICABLE	60 Subpart Da	40CFR60.47a(c)(1)	Emission monitoring	
APPLICABLE	60 Subpart Da	40CFR60.47a(d)	Emission monitoring	
APPLICABLE	60 Subpart Da	40CFR60.47a(e)	Emission monitoring	
APPLICABLE	60 Subpart Da	40CFR60.47a(f)	Emission monitoring	
APPLICABLE	60 Subpart Da	40CFR60.47a(g)	Emission monitoring	
APPLICABLE	60 Subpart Da	40CFR60.47a(h)	Emission monitoring	
APPLICABLE	60 Subpart Da	40CFR60.47a(i)	Emission monitoring	
APPLICABLE	60 Subpart Da	40CFR60.47a(j)	Emission monitoring	
APPLICABLE	60 Subpart Da	40CFR60.48a	Compliance determination procedures and methods.	
APPLICABLE	60 Subpart Da	40CFR60.48a(a)	Compliance determination procedures and methods.	
APPLICABLE	60 Subpart Da	40CFR60.48a(b)	Compliance determination procedures and methods.	
APPLICABLE	60 Subpart Da	40CFR60.48a(c)	Compliance determination procedures and methods.	
APPLICABLE	60 Subpart Da	40CFR60.48a(d)	Compliance determination procedures and methods.	
APPLICABLE	60 Subpart Da	40CFR60.48a(e)	Compliance determination procedures and methods.	
APPLICABLE	60 Subpart Da	40CFR60.49a	Reporting requirements	
APPLICABLE	60 Subpart Da	40CFR60.49a(a)	Reporting requirements	
APPLICABLE	60 Subpart Da	40CFR60.49a(b)	Reporting requirements	
APPLICABLE	60 Subpart Da	40CFR60.49a(c)	Reporting requirements	
APPLICABLE	60 Subpart Da	40CFR60.49a(d)	Reporting requirements	
APPLICABLE	60 Subpart Da	40CFR60.49a(f)	Reporting requirements	
APPLICABLE	60 Subpart Da	40CFR60.49a(g)	Reporting requirements	

EU ID 032 : Cogen Boiler C Rule Applicability for New Hope Power Partnership

APPLIC STAT	RULE DESCRIP	RULE NUMBER	RULE TITLE	RATIONALE FOR NON-APPLICABILITY
APPLICABLE	60 Subpart Da	40CFR60.49a(h)	Reporting requirements	
APPLICABLE	60 Subpart Da	40CFR60.49a(i)	Reporting requirements	
APPLICABLE	60 Subpart Da	40CFR60.49a(j)	Reporting requirements	
APPLICABLE	60 Subpart Ea	40CFR60.50a(d)	Standards of performance for municipal waste combustors	
APPLICABLE	60 Subpart Ea	40CFR60.50b(j)	Standards of performance for municipal waste combustors	
APPLICABLE	62-204	62-204.800(7)2.	NSPS Subpart Da adopted by reference.	
APPLICABLE	62-296 <	62-296	STATIONARY SOURCES - EMISSION STANDARDS	
APPLICABLE	62-296 <	62-296.405(2)	Fossil Fuel Steam Generators with more than 250 million Btu per Hour Heat Input.	
NON-APPLICABLE	62-296 <	62-296.406	Fossil Fuel Steam Generators with less than 250 Million Btu per Hour Heat Input, New and Existing Em	Cogen Boiler C has a heat input of >250 MMBtu/hr.
NON-APPLICABLE	62-296 <	62-296.410	Carbonaceous Fuel Burning Equipment.	Not more stringent or different than NSPS.
APPLICABLE	62-296 >	62-296.500	Reasonably Available Control Technology (RACT) - Volatile Organic Compounds (VOC) and Nitrogen Oxide	
APPLICABLE	62-296 >	62-296.500(2)(a)	Reasonably Available Control Technology (RACT) - Volatile Organic Compounds (VOC) and Nitrogen Oxide	
APPLICABLE	62-296 >	62-296.500(2)(c)	Reasonably Available Control Technology (RACT) - Volatile Organic Compounds (VOC) and Nitrogen Oxide	
APPLICABLE	62-296 >	62-296.570	Reasonably Available Control Technology (RACT) - Requirements for Major VOC- and NOx-Emitting Facility	
APPLICABLE	62-296 >	62-296.570(1)	Applicability.	
APPLICABLE	62-296 >	62-296.570(1)(a)	Applicability.	
APPLICABLE	62-296 >	62-296.570(2)	Compliance Requirements.	
APPLICABLE	62-296 >	62-296.570(3)	Operation Permit Requirements.	
APPLICABLE	62-296 >	62-296.570(4)	Operation Permit Requirements.	
APPLICABLE	62-296 >	62-296.570(4)(a)	Operation Permit Requirements.	
APPLICABLE	62-296 >	62-296.570(4)(b)6.	Operation Permit Requirements.	
APPLICABLE	62-296 >	62-296.570(4)(c)	Operation Permit Requirements.	
APPLICABLE	62-296 >	62-296.620		
NON-APPLICABLE	62-296 >	62-296.700	Reasonably Available Control Technology (RACT) Particulate Matter.	New Hope Power Partnership is located in Palm Beach County, which is not a nonattainment or maintenance area for particulate matter.
NON-APPLICABLE	62-296 >	62-296.702	Fossil Fuel Steam Generators.	New Hope Power Partnership is located in Palm Beach County, which is not a nonattainment or maintenance area for particulate matter.
NON-APPLICABLE	62-296 >	62-296.703	Carbonaceous Fuel Burners.	New Hope Power Partnership is located in Palm Beach County, which is not a nonattainment or maintenance area for particulate matter.
APPLICABLE	62-297	62-297	STATIONARY SOURCES - EMISSIONS MONITORING	
APPLICABLE	62-297	62-297.310	General Compliance Test Requirements.	
APPLICABLE	62-297	62-297.401	Compliance Test Methods.	
APPLICABLE	62-297	62-297.401(1)(a)	EPA Method 1 - Sample and Velocity Traverses for Stationary sources - 40 CFR 60 Appendix A.	
APPLICABLE	62-297	62-297.401(10)	EPA Method 10 - Determination of Carbon Monoxide Emissions from Stationary Sources 40 CFR 60 Appendix	
APPLICABLE	62-297	62-297.401(12)	EPA Method 12 - Determination of Inorganic Lead Emissions from Stationary Sources - 40 CFR 60 Append	
APPLICABLE	62-297	62-297.401(13)	EPA Methods 13A and 13B.	
APPLICABLE	62-297	62-297.401(18)	EPA Method 18 - Measurement of Gaseous Organic Compound Emissions by Gas Chromatography - 40 CFR 60	
APPLICABLE	62-297	62-297.401(19)	EPA Method 19 - Determination of Sulfur Dioxide Removal Efficiency and Particulate, Sulfur Dioxide a	
APPLICABLE	62-297	62-297.401(2)	EPA Method 2 - Determination of Stack Gas Velocity and Volumetric Flow Rate - 40 CFR 60 Appendix A.	

EU ID 032 : Cogen Boiler C Rule Applicability for New Hope Power Partnership

APPLIC STAT	RULE DESCRIP	RULE NUMBER	RULE TITLE	RATIONALE FOR NON-APPLICABILITY
APPLICABLE	62-297	62-297.401(25)	EPA Method 25 - Determination of Total Gaseous Nonmethane Organic Emissions as Carbon - 40 CFR 60 Appendix	
APPLICABLE	62-297	62-297.401(3)	EPA Method 3 - Gas Analysis for Carbon Dioxide, Oxygen, Excess Air, and Dry Molecular Weight - 40 CF	
APPLICABLE	62-297	62-297.401(32)	EPA Method 101 - Determination of Particulate and Gaseous Mercury Emissions from Chlor-Alkali Plants	
APPLICABLE	62-297	62-297.401(35)	EPA Method 104 - Determination of Beryllium Emissions from Stationary Sources - 40 CFR 61 Appendix B	
APPLICABLE	62-297	62-297.401(39)	EPA Method 108 - Determination of Particulate and Gaseous Arsenic Emissions - 40 CFR 61 Appendix B.	
APPLICABLE	62-297	62-297.401(4)	EPA Method 4 - Determination of Moisture Content in Stack Gases - 40 CFR 60 Appendix A.	
APPLICABLE	62-297	62-297.401(41)	EPA Method 201 - Determination of PM10 Emissions (Exhaust Gas Recycle Procedure) - 40 CFR 51 Appendix	
APPLICABLE	62-297	62-297.401(5)	EPA Method 5 - Determination of Particulate Emissions from Stationary Sources - 40 CFR 60 Appendix A	
APPLICABLE	62-297	62-297.401(6)	EPA Method 6 - Determination of Sulfur Dioxide Emissions from Stationary Sources - 40 CFR 60 Appendix	
APPLICABLE	62-297	62-297.401(6)(c)	EPA Method 6C - Determination of Sulfur Dioxide Emissions from Stationary Sources - 40 CFR 60 Appendix	
APPLICABLE	62-297	62-297.401(7)	EPA Method 7 - Determination of Nitrogen Oxide Emissions from Stationary Sources - 40 CFR 60 Appendix	
APPLICABLE	62-297	62-297.401(7)(e)	EPA Method 7E - Determination of Nitrogen Oxide Emissions from Stationary Sources - 40 CFR 60 Appendix	
APPLICABLE	62-297	62-297.401(8)	EPA Method 8 - Determination of Sulfuric Acid Mist and Sulfur Dioxide Emissions from Stationary Sour	
APPLICABLE	62-297	62-297.401(9)	EPA Test Method 9	

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1.0 INTRODUCTION

New Hope Power Partnership (NHPP) (formerly Okeelanta Power L.P.) operates a 74.9 net megawatt electric (MWe) cogeneration facility located adjacent to the Okeelanta Corporation sugar mill, approximately 6 miles south of South Bay in Palm Beach County, Florida. The facility combusts primarily biomass (bagasse and wood) in three identical steam boilers to generate steam and electricity. The cogeneration facility supplies the adjacent sugar mill with process steam during the sugar cane grinding season, approximately October through March. The facility also supplies the Okeelanta sugar refinery with process steam year around.

NHPP is proposing to remove the current facility cap on heat input of $11.5x10^{12}$ British thermal units per year (Btu/yr) for the three cogeneration boilers combined. Due to increased reliability, the NHPP facility operated at a heat input rate of $11.38x10^{12}$ Btu/yr during 2000, and the current heat input cap could unnecessarily limit the facility operations in the future. The removal of this heat input cap will allow each of the three boilers to simultaneously operate at maximum steam rate for up to 8,760 hours per year (hr/yr), and provide the facility with additional flexibility in operations. The new total annual heat input for the facility will be $19.97x10^{12}$ Btu/yr. NHPP is also requesting an increase in the short-term heat input rate from 715 million British thermal units (MMBtu/hr) to 760 MMBtu/hr. No physical modifications or other changes to the facility are needed to accomplish the requested change.

Based on the potential increase in emissions of particulate matter (PM), particulate matter with aerodynamic diameter less than or equal to 10 micrometers (PM_{10}), sulfur dioxide (SO_2), nitrogen oxides (NO_x), carbon monoxide (CO), volatile organic compounds (VOC), lead (Pb), fluorides, and sulfuric acid mist (SAM) due to the proposed heat input rate increase, the proposed project will constitute a major modification to a major source, and thus trigger new source review (NSR) under the provisions of the prevention of significant deterioration (PSD) regulations for these pollutants.

For each pollutant subject to PSD review, the following analyses are required:

1. Ambient monitoring analysis, unless the net increase in emissions due to the modification causes impacts that are below specified significant impact levels;
2. Application of best available control technology (BACT) for each new or modified emissions unit;

3. Air quality impact analysis, unless the net increase in emissions due to the modification causes impacts which are below specified significant impact levels; and
4. Additional impact analysis (impact on soils, vegetation, and visibility), including impacts on PSD Class I areas.

This PSD permit application addresses these requirements and is organized into six additional sections, followed by the appendices. A description of the project including air emission sources and pollution control equipment is presented in Section 2.0. The regulatory applicability analysis of the proposed project is presented in Section 3.0. The ambient air monitoring analysis is presented in Section 4.0, and the BACT analysis is presented in Section 5.0. The air quality impact analysis and additional impact analysis are presented in Sections 6.0 and 7.0, respectively. Supporting documentation is presented in the appendices.

2.0 PROJECT DESCRIPTION

2.1 GENERAL

NHPP operates a 74.9 net MWe cogeneration facility located adjacent to the Okeelanta Corporation sugar mill, approximately 6 miles south of South Bay in Palm Beach County, Florida. The facility is currently operating under Final Title V Permit No. 0990005-003-AV, issued January 19, 2001. The original construction permit for the facility was issued to Okeelanta Power L.P. on September 27, 1993 (Permit No. AC50-219413/PSD-FL-196). The original construction permit has been modified several times. The latest amendment was Permit No. 0990332-014-AC/PSD-FL-196M, issued February 1, 2002. This permit modified the CO and SO_2 emission limits for the cogeneration boilers.

Construction was completed on the NHPP facility in 1995, and initial operations began in late 1995. However, the facility was operated at less than design capacity during 1996-1998. Debugging continued during the 1998-1999 crop and the facility began operating as designed in early 1999. Calendar year 2000 operation was normal although the boilers experienced downtime due to installation of mechanical dust collectors. Calendar year 2001 operations were impacted by the loss of the turbogenerator, which required several months to repair.

A regional map showing the location of the site is presented in Attachment NH-FI-C1 of the application form. A plot plan of the NHPP cogeneration facility is presented in Attachment NH-FI-C2 of the application form.

2.2 FACILITY DESCRIPTION

The facility combusts biomass (bagasse and wood), No. 2 fuel oil, and natural gas in three steam boilers to generate steam and electricity. Each boiler is currently permitted to produce an average of 455,418 lb/hr of steam. The cogeneration facility supplies the adjacent Okeelanta sugar mill with process steam during the sugar cane grinding season, approximately October through March, and also supplies the associated Okeelanta sugar refinery with process steam year around. The fuel burned in the facility boilers to date has been primarily bagasse and wood. Only a relatively small amount of No. 2 fuel oil or natural gas has been combusted to date, since these fuels are used primarily as a backup fuels.

The Title V operating permit limits the maximum heat input to each of the three boilers to 715 MMBtu/hr when firing 100-percent biomass, and 490 MMBtu/hr when firing 100-percent fossil fuels (No. 2 fuel oil). Permit No. 0990332-013-AC limits the maximum heat input to each of the three boilers to 605 MMBtu/hr when firing natural gas.

NHPP is requesting to increase the maximum heat input rate to each of the three boilers to 760 MMBtu/hr when firing 100-percent biomass. In addition, the average steam rate will increase to 506,100 lb/hr of steam. No physical changes to the boilers will be required to implement these capacity increases. The maximum annual heat input to the entire facility is currently limited to 11.5×10^{12} Btu/yr. NHPP is requesting to remove this facility cap to allow the three cogeneration boilers to simultaneously operate up to the maximum steam rate for 8,760 hr/yr. This would increase the total facility annual heat input to 19.97×10^{12} Btu/yr. Due to increased reliability, the NHPP facility operated at a heat input rate of 11.38×10^{12} Btu/yr during 2000, and the current heat input cap may unnecessarily limit the facility's operations in the near future.

2.3 POLLUTION CONTROL EQUIPMENT AND AIR EMISSIONS

Air pollution control equipment serving each boiler consists of mechanical dust collectors and an electrostatic precipitator (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. There will be no changes to this equipment as part of this project, although FDEP recently approved a request to eliminate the requirement to operate the carbon injection system. Historic data has shown that the carbon injection system has no effect on the Hg emissions from the boilers. The carbon injection system will be retained in the event that elevated Hg emissions are experienced in the future.

NHPP is requesting an increase in the hourly and annual emission rates for SO_2, PM, PM_{10}, NO_x, CO, VOC, Hg, and Pb due to the proposed heat input increase. No change in the current lb/MMBtu emission limits is being requested.

The maximum fuel usage and heat input rates for each cogeneration boiler, including maximum short-term and annual averages for biomass, No. 2 fuel oil, and natural gas, are summarized in Table 2-1. No. 2 fuel oil and natural gas firing will be limited to less than 25 percent on a calendar quarter heat input basis.

The maximum short-term emissions for each cogeneration boiler for biomass, No. 2 fuel oil, and natural gas are presented in Table 2-2. The maximum short-term emissions for each fuel burned alone are shown.

The maximum annual emissions for each boiler for three fuel combinations, including 100 percent biomass, 75.1 percent biomass/24.9 percent No. 2 fuel oil, and 75.1 percent biomass/24.9 percent natural gas, are presented in Table 2-3. The maximum annual emissions for any fuel scenario are indicated by the footnote. As shown, the maximum annual emissions for each pollutant are due to biomass firing.

The emission factors used in Tables 2-2 and 2-3 are consistent with the permit limits and emission factors contained in Permit No. 0990332-014-AC/PSD-FL-196M.

Since the proposed project will result in increased potential annual biomass usage, the potential annual fugitive emissions from the biomass and ash handling systems will also increase. The maximum annual fugitive emissions based on the increased maximum biomass usage are shown in Table 2-4. The maximum amount of biomass burned in the boilers consists of 1,063,162 TPY of wood and 1,444,659 TPY bagasse. However, an additional 50 percent processed through the material handling system was added to account for year-to-year variability in biomass fuel deliveries.

2.4 STACK DATA

Stack geometry and operating data are presented in Table 2-5. The parameters reflect actual operating data based on compliance testing. Each of the three boilers are served by a separate stack. The top of each stack is 199 feet (ft) above ground. Each stack is 10.0 ft in diameter. The locations of the three stacks are shown in Attachment NH-FI-C2.

Table 2-1. Maximum Fuel Usage and Heat Input Rates per Boiler, New Hope Power Partnership

Fuel	Heat Input	Heat Transfer Efficiency (%)	Heat Output	Fuel Firing Rate	
	Maximum Short-Term (per boiler)				
	(MMBtu/hr)		(MMBtu/hr)		
Biomass - Bagasse	760	68	517	211,111	lb/hr [a]
- Wood	760	68	517	168,889	lb/hr [b]
No. 2 Fuel Oil	490	85	417	3,551	gal/hr
Natural Gas	605	85	514	605,000	scf/hr
	Annual Average (per boiler)				
	(Btu/yr)		(Btu/yr)		
NORMAL OPERATIONS (100% BIOMASS)					
Biomass	6.658E+12	68	4.527E+12	924,667	TPY [a]
No. 2 Fuel Oil	0	85	0	0	gal/yr
Natural Gas	0	85	0	0	MMscf/yr
TOTAL	6.658E+12		4.527E+12		
24.9% OIL FIRING					
Biomass	4.707E+12	68	3.201E+12	653,750	TPY [a]
No. 2 Fuel Oil	1.561E+12	85	1.327E+12	11,309,008	gal/yr
Natural Gas	0	85	0	0	MMscf/yr
TOTAL	6.268E+12		4.527E+12		
24.9% NATURAL GAS FIRING					
Biomass	4.707E+12	68	3.201E+12	653,750	TPY [a]
No. 2 Fuel Oil	0	85	0	0	gal/yr
Natural Gas	1.561E+12	85	1.327E+12	1,561	MMscf/yr
TOTAL	6.268E+12		4.527E+12		

[a] Based on bagasse firing.

[b] Based on wood firing.

Notes:

40 CFR 60, Subpart Da, limits fossil-fuel firing to less than 25% for each boiler (heat input basis).

Total heat output required = 4.527E+12 Btu/yr per boiler.

Fuels may be burned in combination, not to exceed total heat outputs.

Based on fuel heating values as follows:

- Bagasse - 3,600 Btu/lb
- Wood - 4,500 Btu/lb
- No. 2 Fuel Oil - 138,000 Btu/gal
- Natural gas - 1,000 Btu/scf

Table 2-2. Maximum Short-Term Emissions for New Hope Power Partnership Cogeneration Facility (per boiler)

Regulated Pollutant	Biomass			No. 2 Fuel Oil			Natural Gas			Maximum Emissions for any fuel (lb/hr)	Total All Three Boilers (lb/hr)
	Emission Factor (lb/MMBtu)	Activity Factor (MMBtu/hr)	Maximum Emissions (lb/hr)	Emission Factor (lb/MMBtu)	Activity Factor (MMBtu/hr)	Maximum Emissions (lb/hr)	Emission Factor (lb/MMBtu)	Activity Factor (MMBtu/hr)	Maximum Emissions (lb/hr)		
Particulate (PM)	0.03 (1)	760	22.8	0.03 (1)	490	14.70	0.0073 (2)	605	4.42	22.80	68.40
Particulate (PM_{10})	0.03 (1)	760	22.8	0.03 (1)	490	14.70	0.0073 (2)	605	4.42	22.80	68.40
Sulfur Dioxide--3-hr Average	0.30 (5)	760	228.0	--	--	--	--	--	--	228.0	684.0
--24-hr Average	0.20 (2)	760	152.0	0.05 (6)	490	24.50	0.0058 (2)	605	3.51	152.0	456.0
Carbon Monoxide--1-hr Average (cold-startup)	6.5 (5)	225 [a]	1,462.5	1.0 (2)	490	490.0	0.08 (2)	605	48.4	1,462.5	4,387.5
--1-hr Average (normal operation)	1.0 (5)	760	760.0	--	--	--	--	--	--	760.0	2,280.0
--8-hr Average (cold startup)	4.5 (5)	225 [a]	1,012.5	--	--	--	--	--	--	1,012.5	3,037.5
--8-hr Average (normal operation)	1.0 (5)	760	760.0	--	--	--	--	--	--	760.0	2,280.0
Nitrogen Oxides	0.20 (5)	760	152.00	0.20 (5)	490	98.00	0.20 (5)	605	121	152.00	456.0
VOC	0.06 (2)	760	45.6	0.03 (2)	490	14.70	0.0053 (2)	605	3.21	45.60	136.80
Lead	1.5E-04 (2)	760	0.11	8.9E-07 (2)	490	4.4E-04	4.8E-07 (2)	605	2.9E-04	0.11	0.34
Mercury	5.4E-06 (2)	760	4.10E-03	2.4E-06 (2)	490	1.2E-03	2.5E-07 (2)	605	1.5E-04	4.10E-03	0.0123
Fluorides	7.0E-04 (3)	760	0.53	6.27E-06 (2)	490	3.1E-03	--	--	--	0.53	1.60
Sulfuric Acid Mist	0.018 (4)	760	13.68	0.003 (4)	490	1.4700	3.48E-04 (4)	605	2.11E-01	13.68	41.04

[a] Under cold startup conditions, each boiler is limited to 150,000 lb/hr of steam. Heat input rate is based on this limited steam rate.

References:
1. NSPS, 40 CFR 60, Subpart Da.
2. Based on Permit No. 0990332-014-AC.
3. Based on maximum of 3 most recent stack tests (1999-2001).
4. Based on 6% of the SO_2 emissions (Permit No. 0990332-014-AC).
5. Based on CEM data.
6. Based on use of No. 2 fuel oil with a maximum sulfur content of 0.05% sulfur.

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8/28/02

Table 2-3. Maximum Annual Emissions Per Boiler, New Hope Power Partnership Cogeneration Facility

Regulated Pollutant	Biomass Emission Factor (lb/MMBtu)	Biomass Activity Factor (E12 Btu/yr)	Biomass Annual Emissions (TPY)	Alternate Fuel Emission Factor (lb/MMBtu)	Alternate Fuel Activity Factor (E12 Btu/yr)	Alternate Fuel Annual Emissions (TPY)	Total Annual Emissions Per Boiler (TPY)	Total Annual Emissions 3 Boilers (TPY)
			100% Biomass					
Particulate (PM)	0.03	6.658	99.86	--	--	--	99.86 [a]	299.59
Particulate (PM_{10})	0.03	6.658	99.86	--	--	--	99.86 [a]	299.59
Sulfur dioxide[b]	0.06	6.658	199.73	--	--	--	199.73 [a]	599.18
Nitrogen oxides[c]	0.15	6.658	499.32	--	--	--	499.32 [a]	1,498.0
Carbon monoxide[b]	0.35	6.658	1165.08	--	--	--	1,165.08 [a]	3,495.2
VOC	0.06	6.658	199.73	--	--	--	199.73 [a]	599.18
Lead	1.5E-04	6.658	0.499	--	--	--	0.50 [a]	1.50
Mercury	5.4E-06	6.658	0.0180	--	--	--	0.018 [a]	0.054
Fluorides	7.0E-04	6.658	2.3302	--	--	--	2.33 [a]	6.99
Sulfuric acid mist	0.0036	6.658	11.98	--	--	--	11.98 [a]	36.0
			75.1% Biomass / 24.9% Fuel Oil					
Particulate (PM)	0.03	4.707	70.61	0.03	1.561	23.42	94.02	282.06
Particulate (PM_{10})	0.03	4.707	70.61	0.03	1.561	23.42	94.02	282.06
Sulfur dioxide[b]	0.06	4.707	141.21	0.05	1.561	39.03	180.24	540.71
Nitrogen oxides[c]	0.15	4.707	353.03	0.15	1.561	117.08	470.10	1,410.3
Carbon monoxide[b]	0.35	4.707	823.73	0.35	1.561	273.18	1,096.90	3,290.7
VOC	0.06	4.707	141.21	0.03	1.561	23.42	164.63	493.88
Lead	1.5E-04	4.707	0.353	8.9E-07	1.561	6.95E-04	0.35	1.06
Mercury	5.4E-06	4.707	0.0127	2.4E-06	1.561	0.0019	0.015	0.044
Fluorides	7.0E-04	4.707	1.6475	6.27E-06	1.561	0.0049	1.65	4.96
Sulfuric acid mist	0.0036	4.707	8.47	0.003	1.561	2.34	10.81	32.4
			75.1% Biomass / 24.9% Natural Gas					
Particulate (PM)	0.03	4.707	70.61	0.0073	1.561	5.70	76.30	228.91
Particulate (PM_{10})	0.03	4.707	70.61	0.0073	1.561	5.70	76.30	228.91
Sulfur dioxide[b]	0.06	4.707	141.21	0.0300	1.561	23.42	164.63	493.88
Nitrogen oxides[c]	0.15	4.707	353.03	0.15	1.561	117.08	470.10	1,410.3
Carbon monoxide[b]	0.35	4.707	823.73	0.08	1.561	62.44	886.17	2,658.5
VOC	0.06	4.707	141.21	0.0053	1.561	4.14	145.35	436.04
Lead	1.5E-04	4.707	0.353	4.8E-07	1.561	3.75E-04	0.35	1.06
Mercury	5.4E-06	4.707	0.0127	2.5E-07	1.561	1.95E-04	0.013	0.039
Fluorides	7.0E-04	4.707	1.6475	--	--	--	1.65	4.94
Sulfuric acid mist	0.0036	4.707	8.47	3.48E-04	1.561	0.27	8.74	26.2

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

[b] Based on 12-month rolling average.

[c] Based on 30-day rolling average.

Note: No emissions of total reduced sulfur, asbestos, or vinyl chloride are expected.
Fuel type percentages are based on heat input.

Table 2-4. New Hope Power Partnership Facility Maximum Annual Fugitive Dust Emissions

SOURCE	TYPE OF OPERATION	M MOISTURE CONTENT (%)	U WIND SPEED (MPH)	UNCONTROLLED PM EMISSION FACTOR (LB/TON)[a]	UNCONTROLLED PM_{10} EMISSION FACTOR (LB/TON)[a]	CONTROL	CONTROL EFFICIENCY (%)	CONTROLLED PM EMISSION FACTOR (LB/TON)	CONTROLLED PM_{10} EMISSION FACTOR (LB/TON)	ACTIVITY FACTOR	MAXIMUM ANNUAL PM(TSP) EMISSIONS (TONS/YR)	MAXIMUM ANNUAL PM_{10} EMISSIONS (TONS/YR)
BIOMASS HANDLING												
TRUCK DUMPS (2)	BATCH DROP	37	9.4	0.00009	0.00004	NONE	0	0.00009	0.00004	3,761,731 TPY [g]	0.170	0.0805
CHAIN CONVEYORS-TO-UNLOADING CONVEYOR (2)	CONTINUOUS DROP	37	9.4	0.00009	0.00004	ENCLOSURE	0	0.00009	0.00004	3,761,731 TPY [g]	0.170	0.0805
UNLOADING CONVEYOR-TO-SCREEN	CONTINUOUS DROP	37	9.4	0.00009	0.00004	ENCLOSURE	0	0.00009	0.00004	3,761,731 TPY [g]	0.170	0.0805
SCREEN	CONTINUOUS DROP	37	9.4	0.00009	0.00004	NONE	0	0.00009	0.00004	3,761,731 TPY [g]	0.170	0.0805
SCREEN-TO-HOGGER	CONTINUOUS DROP	37	9.4	0.00009	0.00004	ENCLOSURE	0	0.00009	0.00004	3,761,731 TPY [g]	0.170	0.0805
HOGGER	CRUSHING	--	--	0.02	0.01	ENCLOSED	95	0.00100	0.00047	3,761,731 TPY [g]	1.881	0.8896
HOGGER-TO-STORAGE CONVEYOR	BATCH DROP	37	9.4	0.00009	0.00004	ENCLOSURE	0	0.00009	0.00004	3,761,731 TPY [g]	0.170	0.0805
SCREEN-TO-STORAGE CONVEYOR	CONTINUOUS DROP	37	9.4	0.00009	0.00004	ENCLOSURE	0	0.00009	0.00004	0 TPY	0.000	0.0000
SCREEN-TO-BOILER FEED CONVEYOR	CONTINUOUS DROP	37	9.4	0.00009	0.00004	ENCLOSURE	0	0.00009	0.00004	0 TPY	0.000	0.0000
STORAGE CONVEYOR-TO-RADIAL STACKER	CONTINUOUS DROP	37	9.4	0.00009	0.00004	ENCLOSURE	0	0.00009	0.00004	3,761,731 TPY [g]	0.170	0.0805
RADIAL STACKER-TO-BIOMASS STORAGE PILE	CONTINUOUS DROP	37	9.4	0.00009	0.00004	NONE	0	0.00009	0.00004	3,761,731 TPY [g]	0.170	0.0805
UNDERPILE RECLAIMERS (2)	CONTINUOUS DROP	37	9.4	0.00009	0.00004	ENCLOSED	90	0.00001	0.00000	3,761,731 TPY [g]	0.017	0.0081
RECLAIMERS-TO-BOILER FEED CONVEYOR (2)	CONTINUOUS DROP	37	9.4	0.00009	0.00004	ENCLOSURE	0	0.00009	0.00004	3,761,731 TPY [g]	0.170	0.0805
BOILER FEED CONVEYOR-TO-CHAIN DIST. CONVEYOR (2)	CONTINUOUS DROP	37	9.4	0.00009	0.00004	ENCLOSURE	0	0.00009	0.00004	3,761,731 TPY [g]	0.170	0.0805
CHAIN DIST. CONVEYOR -TO-BOILER METER BINS (4)	BATCH DROP	37	9.4	0.00009	0.00004	ENCLOSURE	0	0.00009	0.00004	3,761,731 TPY [g]	0.170	0.0805
BAGASSE CONVEYOR-TO-CHAIN DIST CONVEYOR (2)	CONTINUOUS DROP	37	9.4	0.00009	0.00004	ENCLOSURE	0	0.00009	0.00004	0 TPY	0.000	0.0000
BAGASSE CONVEYOR-TO-RECYCLE CONVEYOR	CONTINUOUS DROP	37	9.4	0.00009	0.00004	ENCLOSURE	0	0.00009	0.00004	0 TPY	0.000	0.0000
CHAIN DIST. CONVEYORS-TO-RECYLE CONVEYOR (2)	CONTINUOUS DROP	37	9.4	0.00009	0.00004	ENCLOSURE	0	0.00009	0.00004	376,173 TPY [f]	0.017	0.0081
RECYCLE CONVEYOR-TO-RECYCLE STACKER	CONTINUOUS DROP	37	9.4	0.00009	0.00004	ENCLOSURE	0	0.00009	0.00004	0 TPY	0.000	0.0000
RECYCLE CONVEYOR-TO-STORAGE CONVEYOR	CONTINUOUS DROP	37	9.4	0.00009	0.00004	ENCLOSURE	0	0.00009	0.00004	376,173 TPY [f]	0.017	0.0081
RECYCLE STACKER-TO-BIOMASS STORAGE PILE	CONTINUOUS DROP	37	9.4	0.00009	0.00004	NONE	0	0.00009	0.00004	0 TPY	0.000	0.0000
BIOMASS STORAGE PILES (2)	WIND EROSION	--	--	--		NONE	0	--		--	0.175 [d]	0.0000 [d]
BIOMASS STORAGE PILE MAINTENANCE	VEHICULAR TRAFFIC	--	--	0.75	0.23 lb/VMT [b]	WATERING	50	0.38	0.11 lb/VMT[b]	21,900 VMT [c]	4.110 [d]	1.2330 [d]
FLY ASH HANDLING												
FLY ASH SILO FILTER	--	--	--	--	--	BAGHOUSE	99	0.01	0.0047 gr/acf	2,500 acfm	0.939	0.444
FLY ASH TRANSFER-TO-TRUCK	CONTINUOUS DROP	5.0	9.4	0.00149	0.00071	WETTING	50	0.00075	0.00035	110,131 TPY [e]	0.041	0.019
TOTAL											9.069	3.496

Notes/References:

[a] Batch Drop and Continuous Drop Emission Factors are computed from AP-42 (USEPA, 1995) Section 13.2.4:
E= k x 0.0032 x (U/5)^1.3 / (M/2)^1.4 lb/ton, where k = 0.74 for PM and 0.35 for PM_{10}.

[b] Pound per Vehicle Mile Travel (lb/VMT), see Appendix B, Table B-1 for derivation.

[c] Based on vehicle operating 12 hrs/day, 365 days/yr @ 5 mph.

[d] Refer to Appendix B for derivation.

[e] Based on 1,063,162 TPY woodwaste @ 9% ash and 1,444,659 TPY bagasse @ 1% ash. Assuming 100% is fly ash. See Appendix B, Table B-2 for derivation.

[f] Assuming 10% of biomass is overfeed and is returned to biomass storage pile.

[g] Activity Factor based on 19.97×10^{12} Btu/yr; 47.9% is from wood (4,500 Btu/lb) and the remaining 52.1% is from bagasse (3,600 Btu/lb) = 2,507,821 TPY; an additional 50% was added to account for year-to-year variations. See Appendix B, Table B-2 for derivation.

Table 2-5. Stack Parameters for Each Boiler, New Hope Power Partnership

Source	Heat Input Rate (MMBtu/hr)	Stack Height		Stack Diameter		Actual Gas Flowrate (acfm)	Gas Velocity		Gas Temperature	
		ft	m	ft	m		ft/s	m/s	^{o}F	K
Boilers (each)										
Biomass	760	199	60.66	10	3.05	319,000 - 348,000	67.7 - 73.8	20.63 - 22.51	352-373	451-463
No. 2 Fuel Oil	490	199	60.66	10	3.05	140,000 - 150,000	29.7 - 31.8	9.06 - 9.70	295-350	419-450
Natural Gas	605	199	60.66	10	3.05	140,000 - 150,000	29.7 - 31.8	9.06 - 9.70	295-350	419-450

Note: acfm = actual cubic feet per minute
^{o}F = degrees Fahrenheit
ft = feet
ft/s = feet per second
K = degrees Kelvin
m = meters
m/s = meters per second
MMBtu/hr = Million British thermal units per hour

3.0 AIR QUALITY REVIEW REQUIREMENTS

Federal and state air regulatory requirements for a major new or modified source of air pollution are discussed in Sections 3.1 through 3.4. The applicability of these regulations to the proposed NHPP modification is presented in Section 3.5. These regulations must be satisfied before the proposed project can be approved.

3.1 NATIONAL AND STATE AMBIENT AIR QUALITY STANDARDS (AAQS)

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

Florida has adopted state AAQS in Rule 62-204.240, Florida Administrative Code (F.A.C.). These standards are the same as the national AAQS, except in the case of SO_2. For SO_2, Florida has adopted the former 24-hour secondary standard of 260 micrograms per cubic meter ($\mu g/m^3$) and former annual average secondary standard of 60 $\mu g/m^3$.

3.2 PSD REQUIREMENTS

3.2.1 GENERAL REQUIREMENTS

Under Federal and State of Florida PSD review requirements, all major new or modified sources of air pollutants regulated under the Clean Air Act (CAA) must be reviewed and a pre-construction permit issued. Florida's State Implementation Plan (SIP), which contains PSD regulations, has been approved by the EPA; therefore, PSD approval authority has been granted to the FDEP.

A "major facility" is defined as any one of 28 named source categories that have the potential to emit 100 TPY or more, or any other stationary facility that has the potential to emit 250 TPY or more, of any pollutant regulated under the CAA. "Potential to emit" means the capability, at maximum design capacity, to emit a pollutant after the application of control equipment. Once a new source is determined to be a "major facility" for a particular pollutant, any pollutant emitted in amounts greater than the PSD significant emission rates is subject to PSD review. For an existing source for which a modification is proposed, the modification is subject to PSD review if the net increase in emissions due to the modification is greater than the PSD significant emission rates. The PSD significant emission rates are shown in Table 3-2.

The EPA class designation and allowable PSD increments are presented in Table 3-1. The magnitude of the allowable increment depends on the classification of the area in which a new source (or modification) will be located or have an impact. Three classifications are designated based on criteria established in the Clean Air Act Amendments. Congress promulgated areas as Class I (international parks, national wilderness areas, and memorial parks larger than 5,000 acres and national parks larger than 6,000 acres) or as Class II (all areas not designated as Class I). No Class III areas, which would be allowed greater deterioration than Class II areas, were designated. The State of Florida has adopted the EPA class designations and allowable PSD increments for SO_2, PM_{10}, and NO_2.

PSD review is used to determine whether significant air quality deterioration will result from the new or modified facility. Federal PSD requirements are contained in Title 40 of the Code of Federal Regulations (CFR), Part 52.21, Prevention of Significant Deterioration of Air Quality. The State of Florida has adopted the federal PSD regulations by reference (Rule 62-212.400, F.A.C.). Major new facilities and major modifications are required to undergo the following analysis related to PSD for each pollutant emitted in significant amounts:

1. Control technology review,
2. Source impact analysis,
3. Air quality analysis (monitoring),
4. Source information, and
5. Additional impact analyses.

In addition to these analyses, a new facility must also be reviewed with respect to Good Engineering Practice (GEP) stack height regulations. Discussions concerning each of these requirements are presented in the following sections.

3.2.2 CONTROL TECHNOLOGY REVIEW

The control technology review requirements of the federal and state PSD regulations require that all applicable federal and state emission-limiting standards be met, and that BACT be applied to control emissions from the source. The BACT requirements are applicable to all regulated pollutants for which the increase in emissions from the facility exceeds the respective significant emission rate (see Table 3-2).

BACT is defined in 40 CFR 52.21 (b)(12), as:

> An emissions limitation (including a visible emission standard) based on the maximum degree of reduction of each pollutant subject to regulation under the Act which would be emitted by any proposed major stationary source of major modification which the Administrator, on a case-by-case basis, taking into account energy, environmental, and economic impacts, and other costs, determination is achievable through application of production processes and available methods, systems, and techniques (including fuel cleaning or treatment or innovative fuel combustion techniques) for control of such pollutant. In no event shall application of best available control technology result in emissions of any pollutant, which would exceed the emissions allowed by any applicable standard under 40 CFR Parts 60 and 61. If the Administrator determines that technological or economic limitations on the application of measurement methodology to a particular part of a source or facility would make the imposition of an emission standard infeasible, a design, equipment, work practice, operational standard or combination thereof, may be prescribed instead to satisfy the requirement for the application of BACT. Such standard shall, to the degree possible, set forth the emissions reductions achievable by implementation of such design, equipment, work practice, or operation and shall provide for compliance by means, which achieve equivalent results.

BACT was promulgated within the framework of the PSD requirements in the 1977 amendments of the CAA [Public Law 95-95; Part C, Section 165(a)(4)]. The primary purpose of BACT is to optimize consumption of PSD air quality increments and thereby enlarge the potential for future economic growth without significantly degrading air quality (EPA, 1978; 1980). Guidelines for the evaluation of BACT can be found in the EPA's *Guidelines for Determining Best Available Control Technology (BACT)* (EPA, 1978) and in the PSD *Workshop Manual* (EPA, 1980). These guidelines were promulgated by the EPA to provide a consistent approach to BACT and to ensure that the impacts of alternative emission control systems are measured by the same set of parameters. In addition, through implementation of these guidelines, BACT in one area may not be identical to BACT in another area. According to the EPA (1980), "BACT analyses for the same types of emissions unit and the same pollutants in different locations or situations may determine that different control strategies should be applied to the different sites, depending on site-specific factors. Therefore, BACT analyses must be conducted on a case-by-case basis."

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

3.2.3 SOURCE IMPACT ANALYSIS

A source impact analysis must be performed for a proposed major source or major modification subject to PSD review, and for each pollutant for which the increase in emissions exceeds the PSD significant emission rate (Table 3-2). The PSD regulations specifically provide for the use of atmospheric dispersion models in performing impact analyses, estimating baseline and future air quality levels, and determining compliance with AAQS and allowable PSD increments. Models designated by the EPA must normally be used in performing the impact analysis. Specific applications for other than the EPA-approved models require the EPA's consultation and prior approval. Guidance for the use and application of dispersion models is presented in the EPA publication *Guideline on Air Quality Models* (EPA, 1980).

To address compliance with AAQS and PSD Class II increments, a source impact analysis must be performed for the criteria pollutants. However, this analysis is not required for a specific pollutant if the net increase in impacts as a result of the new source or modification is below significant impact levels, as presented in Table 3-1. The significant impact levels are threshold levels that are used to determine the level of air impact analyses needed for the project. If the new or modified source's impacts are predicted to be less than significant, then the source's impacts will not have a significant adverse affect on air quality, and additional modeling with other sources is not required. However, if the source's impacts are predicted to be greater than the significant impact levels, additional modeling with other sources is required to demonstrate compliance with AAQS and PSD increments.

The EPA has proposed significant impact levels for Class I areas as follows:

SO_2	3-hour	1 µg/m^3
	24-hour	0.2 µg/m^3
	Annual	0.1 µg/m^3
PM_{10}	24-hour	0.3 µg/m^3
	Annual	0.2 µg/m^3
NO_2	Annual	0.1 µg/m^3

Although these levels have not been officially promulgated as part of the PSD review process and may not be binding for states in performing PSD reviews, the proposed levels serve as a guideline in assessing a source's impact in a Class I area. The EPA action to incorporate Class I significant impact levels in the PSD process is part of implementing the NSR provisions of the 1990 CAA Amendments. Because the process of developing the regulations will be lengthy, the EPA believes that the proposed rules concerning the significant impact levels are appropriate in order to assist states in implementing the PSD permitting process.

Various lengths of record for meteorological data can be used for impact analysis. A 5-year period is normally used with corresponding evaluation of highest, second-highest (HSH) short-term concentrations for comparison to AAQS or PSD increments. The meteorological data are selected based on an evaluation of measured weather data from a nearby weather station that represents weather conditions at the project site. The criteria used in this evaluation include determining the distance of the project site to the weather station; comparing topographical and land use features between the locations; and determining availability of necessary weather parameters.

The term "highest, second-highest" (HSH) refers to the highest of the second-highest concentrations at all receptors (i.e., the highest concentration at each receptor is discarded). The second-highest concentration is important because short-term AAQS specify that the standard cannot be exceeded at any location more than once a year. If fewer than 5 years of meteorological data are used in the modeling analysis, the highest concentration at each receptor normally must be used for comparison to air quality standards.

The term "baseline concentration" evolves from federal and state PSD regulations and refers to a concentration level corresponding to a specified baseline date and certain additional baseline sources.

By definition, in the PSD regulations as amended August 7, 1980, baseline concentration means the ambient concentration level that exists in the baseline area at the time of the applicable baseline date. A baseline concentration is determined for each pollutant for which a baseline date is established and includes:

1. The actual emissions representative of facilities in existence on the applicable baseline date; and
2. The allowable emissions of major stationary facilities that commenced construction before January 6, 1975, for SO_2 and PM_{10} concentrations, or February 8, 1988, for NO_2 concentrations, but that were not in operation by the applicable baseline date.

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

1. Actual emissions from any major stationary facility on which construction commenced after January 6, 1975, for SO_2 and PM_{10} concentrations, and after February 8, 1988, for NO_2 concentrations; and
2. Actual emission increases and decreases at any stationary facility occurring after the baseline date.

In reference to the baseline concentration, the term "baseline date" actually includes three different dates:

1. The major facility baseline date, which is January 6, 1975, in the cases of SO_2 and PM_{10}, and February 8, 1988, in the case of NO_2.
2. The minor facility baseline date, which is the earliest date after the trigger date on which a major stationary facility or major modification subject to PSD regulations submits a complete PSD application.
3. The trigger date, which is August 7, 1977, for SO_2 and PM_{10}, and February 8, 1988, for NO_2.

3.2.4 AIR QUALITY MONITORING REQUIREMENTS

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

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

The regulations include an exemption that excludes or limits the pollutants for which an air quality analysis must be conducted. This exemption states that the FDEP may exempt a proposed major stationary facility or major modification from the monitoring requirements, with respect to a particular pollutant, if the emissions increase of the pollutant from the facility or modification would cause, in any area, air quality impacts less than the *de minimis* levels presented in Table 3-2.

3.2.5 SOURCE INFORMATION/GEP STACK HEIGHT

Source information must be provided to adequately describe the proposed project. The general type of information required for this project is presented in Section 2.0.

The 1977 CAA Amendments require that the degree of emission limitation required for control of any pollutant not be affected by a stack height that exceeds GEP or any other dispersion technique. On July 8, 1985, the EPA promulgated final stack height regulations (EPA, 1985a). The FDEP has adopted identical regulations (Rule 62-210.550, F.A.C.). GEP stack height is defined as the highest of:

1. 65 meters (m); or
2. A height established by applying the formula:

   $Hg = H + 1.5L$

   where: Hg = GEP stack height,

   H = Height of the structure or nearby structure, and

   L = Lesser dimension (height or projected width) of nearby structure(s); or
3. A height demonstrated by a fluid model or field study.

"Nearby" is defined as a distance up to five times the lesser of the height or width dimensions of a structure or terrain feature, but not greater than 0.8 kilometer. Although GEP stack height regulations require that the stack height used in modeling for determining compliance with AAQS and PSD increments not exceed the GEP stack height, the actual stack height may be greater.

The stack height regulations also allow increased GEP stack height beyond that resulting from the above formula in cases where plume impaction occurs. Plume impaction is defined as concentrations measured or predicted to occur when the plume interacts with elevated terrain. Elevated terrain is defined as terrain that exceeds the height calculated by the GEP stack height formula.

3.2.6 ADDITIONAL IMPACT ANALYSIS

In addition to air quality impact analyses, federal and State of Florida regulations require analyses of the impairment to visibility and the impacts on soils and vegetation that would occur as a result of the proposed source [40 CFR 52.21(o) and Rule 62-212.400, F.A.C.]. These analyses are to be conducted primarily for PSD Class I areas. Impacts as a result of general commercial, residential, industrial, and other growth associated with the source also must be addressed. These analyses are required for each pollutant emitted in significant amounts (Table 3-2).

3.3 NONATTAINMENT RULES

Based on the current nonattainment provisions, all major new facilities and modifications to existing major facilities located in a nonattainment area must undergo nonattainment review. A new major facility is required to undergo this review if the proposed pieces of equipment have the potential to emit 100 TPY or more of the nonattainment pollutant.

3.4 EMISSION STANDARDS

3.4.1 NEW SOURCE PERFORMANCE STANDARDS

The NSPS are a set of national emission standards that apply to specific categories of new sources. As stated in the CAA Amendments of 1977, these standards "shall reflect the degree of emission limitation and the percentage reduction achievable through application of the best technological system of continuous emission reduction the Administrator determines has been adequately demonstrated."

Federal NSPS exist for electric utility steam generating units (40 CFR 60, Subpart Da). The NSPS applies to all units capable of combusting more than 73 megawatts (250 MMBtu/hr) heat input of fossil fuel (either alone or in combination with any other fuel) for which construction commenced after September 18, 1978.

3.4.2 FLORIDA RULES

Several Florida emission limiting standards exist for steam generating units. Fossil fuel steam generating units with greater than 250 MMBtu/hr heat input are subject to the emission limitations of Rule 62-296.405(2), F.A.C. pertaining to PM, SO_2, NO_x, and visible emissions. Emissions limitations and visible emissions requirements for carbonaceous fuel-burning equipment are contained in Rule 62-296.410, F.A.C.

3.5 SOURCE APPLICABILITY

3.5.1 AREA CLASSIFICATION

The project site is located in Palm Beach County, which has been designated by the EPA and the FDEP as an attainment or maintenance area for all criteria pollutants. Palm Beach County and surrounding counties are designated as PSD Class II areas for SO_2, PM_{10}, and NO_2. The nearest Class I area to the site is the Everglades National Park (ENP), located about 92 km (57 miles) south of the NHPP facility.

3.5.2 PSD REVIEW

3.5.2.1 Pollutant Applicability

The NHPP facility is considered to be an existing major stationary facility because potential emissions of certain regulated pollutants exceed 100 TPY (for example, potential SO_2 emissions currently exceed 100 TPY). Therefore, PSD review is required for any pollutant for which the increase in emissions due to the modification is greater than the PSD significant emission rates (see Table 3-2).

The current actual emissions from the three cogeneration boilers are presented in Table 3-3. The current emissions are based on the 2-year period spanning calendar years 2000 and 2001 (see Appendix A, Table A-1). Actual stack test data and operations data were used in developing the current actual emissions.

Also presented in Table 3-3 are the future potential annual emissions from the NHPP facility, based on each of the three boilers operating at maximum heat input for 8,760 hr/yr (refer to Table 2-3). The net increase in emissions due to the proposed modification at the facility is shown in Table 3-3. As shown, the net increase exceeds the PSD significant emission rates for PM, PM_{10}, SO_2, NO_x, CO, VOC, SAM, Pb, and fluorides. As a result, PSD review applies for these pollutants.

3.5.2.2 Source Impact Analysis

A source impact analysis was performed for PM_{10}, SO_2, NO_x, CO, Pb, VOC, SAM, and fluoride emissions resulting from the proposed modification. This analysis is presented in Section 6.0. The results of that analysis are included herein, and additional impacts upon the PSD Class I are also addressed.

The pollutant impacts of the proposed project to the EPA Class II significant impact levels are compared to the *de minimis* monitoring concentrations in Table 3-4. As shown, the increase in impacts of PM_{10}, NO_x, and CO due to the proposed modification are below the significant impact levels. The increase in SO_2 impacts exceed significant impact levels, and therefore a full modeling analysis is required for SO_2.

3.5.2.3 Ambient Monitoring

Based on the increase in emissions from the proposed modification (see Table 3-3), a pre-construction ambient monitoring analysis is required for PM_{10}, SO_2, NO_x, CO, VOC, SAM, Pb, and fluorides, and monitoring data is required to be submitted as part of the application. However, if the net increase in impacts of a pollutant is less than the applicable *de minimis* monitoring concentration, then an exemption from submittal of pre-construction ambient monitoring data may be obtained [40 CFR 52.21(i)(8)]. In addition, if the EPA has not established an acceptable ambient monitoring method for the pollutant, monitoring is not required.

Pre-construction monitoring data for PM_{10}, SO_2, NO_x, CO, Pb, and fluorides may be exempted for this project because, as shown in Table 3-4, the proposed modification's impacts are predicted to be below the applicable *de minimis* monitoring concentration for these pollutants. In addition, no acceptable air monitoring method has been established for SAM. Since the proposed project would result in an increase in potential VOC emissions of 100 TPY or more, a pre-construction ambient monitoring analysis is required for ozone. This analysis is presented in Section 4.0.

3.5.2.4 GEP Stack Height Impact Analysis

The NHPP cogeneration boiler stacks are 199 ft high and will not change as part of this project. This stack height does not exceed the *de minimis* good engineering practice (GEP) stack height of 65 meters (213 ft), and therefore the project is in compliance with the GEP stack height rules.

3.5.3 EMISSION STANDARDS

3.5.3.1 New Source Performance Standards

The NHPP cogeneration boilers are currently subject to the NSPS for electric utility steam generating units, as contained in 40 CFR 60 Subpart Da. The NSPS applies to all steam generating units capable of combusting more than 250 MMBtu/hr heat input of fossil fuel (either alone or in combination with any other fuel). Since the NHPP cogeneration boilers combust biomass alone or in combination with No. 2 fuel oil or natural gas, the NSPS applies to combustion of No. 2 fuel oil, natural gas, and biomass, alone or in combination.

The applicable NSPS for fossil fuel steam generating units is 0.03 lb/MMBtu for PM and 1.2 lb/MMBtu for SO_2. For NO_x, the applicable limits are 0.15 lb/MMBtu when burning natural gas, 0.30 lb/MMBtu when burning fuel oil, and 0.60 lb/MMBtu when burning biomass. The cogeneration boilers will comply with the applicable emission limits.

3.5.3.2 State of Florida Standards

The applicable state of Florida emission limits for new fossil fuel steam generators with more than 250 MMBtu/hr heat input are the same as the applicable NSPS. For the cogeneration boilers, the applicable NSPS is 40 CFR 60 Subpart Da, as described in Section 3.5.3.1. For carbonaceous fuel-burning units, the standards are no more stringent than the NSPS. Therefore, the cogeneration boilers will comply with the Florida emission standards contained in Rules 62-296.405(2) and 62-296.410(2)(b)1, F.A.C.

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

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

Note: NA = Not applicable, i.e., no standard exists.

PM_{10} = particulate matter with aerodynamic diameter less than or equal to 10 micrometers.

[a] On July 18, 1997, the EPA promulgated revised AAQS for particulate matter and ozone. For particulate matter, $PM_{2.5}$ standards were introduced with a 24-hour standard of 65 $\mu g/m^3$ (3-year average of 98th percentile) and an annual standard of 15 $\mu g/m^3$ (3-year average at community monitors). Implementation of these standards has not yet occurred. The ozone standard was modified to be 0.08 ppm for 8-hour average; achieved when 3-year average of 99th percentile is 0.08 ppm or less. The FDEP has not yet adopted these standards.

[b] Short-term maximum concentrations are not to be exceeded more than once per year except for the PM_{10} AAQS (these do not apply to significant impact levels). The PM_{10} 24-hour AAQS is attained when the expected number of days per year with a 24-hour concentration above 150 $\mu g/m^3$ is equal to or less than 1. For modeling purposes, compliance is based on the sixth highest 24-hour average value over a 5-year period.

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

[d] Maximum concentrations.

Sources: Federal Register, Vol. 43, No. 118, June 19, 1978. 40 CFR 50. 40 CFR 52.21. Rule 62-204, F.A.C.

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

Pollutant	Regulated Under	Significant Emission Rate (TPY)	*De Minimis* Monitoring Concentration[a] ($\mu g/m^3$)
Sulfur Dioxide	NAAQS, NSPS	40	13, 24-hour
Particulate Matter [PM(TSP)]	NSPS	25	NA
Particulate Matter (PM_{10})	NAAQS	15	10, 24-hour
Nitrogen Dioxide	NAAQS, NSPS	40	14, annual
Carbon Monoxide	NAAQS, NSPS	100	575, 8-hour
Volatile Organic Compounds (Ozone)	NAAQS, NSPS	40	100 TPY[b]
Lead	NAAQS	0.6	0.1, 3-month
Sulfuric Acid Mist	NSPS	7	NM
Total Fluorides	NSPS	3	0.25, 24-hour
Total Reduced Sulfur	NSPS	10	10, 1-hour
Reduced Sulfur Compounds	NSPS	10	10, 1-hour
Hydrogen Sulfide	NSPS	10	0.2, 1-hour
Mercury	NESHAP	0.1	0.25, 24-hour
Beryllium	NESHAP	0.0004	0.001, 24-hour
Asbestos	NESHAP	0.007	NM
Vinyl Chloride	NESHAP	1	15, 24-hour
MWC Organics	NSPS	3.5×10^{-6}	NM
MWC Metals	NSPS	15	NM
MWC Acid Gases	NSPS	40	NM
MSW Landfill Gases	NSPS	50	NM

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

NA = Not applicable.
NAAQS = National Ambient Air Quality Standards.
NM = No ambient measurement method established; therefore, no *de minimis* concentration has been established.
NSPS = New Source Performance Standards.
NESHAP = National Emission Standards for Hazardous Air Pollutants.
$\mu g/m^3$ = micrograms per cubic meter.
MWC = Municipal waste combustor.
MSW = Municipal solid waste.

[a] Short-term concentrations are not to be exceeded.
[b] No *de minimis* concentration; an increase in VOC emissions of 100 TPY or more will require monitoring analysis for ozone.

Sources: 40 CFR 52.21.
Rule 62-212.400.

Table 3-3. PSD Source Applicability Analysis, New Hope Power Partnership

Regulated Pollutant	Current Actual Emissions From Boilers A, B, C[a] (TPY)	Future Potential Emissions (TPY)		Net Change In Emissions Due to Proposed Project (TPY)	PSD Significant Emission Rate (TPY)	PSD Review Triggered?
		Boilers A, B, C	Fugitive Emissions[b]			
Particulate (PM)	127.96	299.59	9.07	180.71	25	Yes
Particulate (PM_{10})	108.02	299.59	3.50	195.07	15	Yes
Sulfur Dioxide	191.90	599.18	0	407.29	40	Yes
Nitrogen Oxides	756.60	1,498.0	0	741.36	40	Yes
Carbon Monoxide	1,335.4	3,495.2	0	2,159.8	100	Yes
VOC	43.93	599.18	0	555.26	40	Yes
Lead	0.098	1.50	0	1.40	0.6	Yes
Mercury	0.0035	0.054	0	0.050	0.1	No
Fluorides	2.16	6.99	0	4.83	3	Yes
Sulfuric Acid Mist	15.71	35.95	0	20.24	7	Yes

[a] Actual emissions based on the average emissions for 2000 and 2001.

[b] See Table 2-4 for fugitive emissions calculations.

Note: PM = Particulate Matter
PM_{10} = Particulate Matter with aerodynamic diameter less than or equal to 10 microns
VOC = Volatile Organic Compound

Table 3-4. Increase in Impacts Due to Proposed Modification Compared to Class II Significant Impact Levels and Ambient Monitoring *De Minimis* Levels, New Hope Power Partnership

Pollutant	Averaging Time	Maximum Concentration[a] (µg/m³)	EPA Class II Significant Impact Levels (µg/m³)	Above EPA Class II Significant Impact Level?	*De Minimis* Monitoring Concentration (µg/m³)	Ambient Monitoring Review Applies?
Particulate (PM_{10})	Annual	0.16	1	No	NA	NA
	24-hour	1.20	5	No	10	No
Sulfur Dioxide	Annual	0.31	1	No	NA	NA
	24-hour	9.29	5	Yes	13	No
	3-hour	31.84	25	Yes	NA	NA
Nitrogen Oxides	Annual	0.55	1	No	14	No
Carbon Monoxide	8-hour	5.0	500	No	575	No
	1-hour	21.5	2000	No	NA	NA
VOC	Annual	NA	NA	NA	100 TPY	Yes[b]
Lead	3-month	0.0044[c]	NA	NA	0.1	No
Fluorides	24-hour	0.017	NA	NA	0.25	No
Sulfuric Acid Mist	NA	NA	NA	NA	NA	NA

[a] Highest concentration from significant impact analysis (see Section 6.0).

[b] An increase in VOC emissions of 100 TPY or more requires monitoring analysis for ozone.

[c] Based on the annual average impact of 1.10E-03 µg/m³ times four.

Note: NA = Not Applicable

4.0 AMBIENT MONITORING ANALYSIS

4.1 MONITORING REQUIREMENTS

In accordance with requirements of 40 CFR 52.21(m) and Rule 62-212.400(5)(f), F.A.C., any application for a PSD permit must contain an analysis of continuous ambient air quality data in the area affected by the proposed major stationary facility or major modification. For a new major facility, the affected pollutants are those that the facility would potentially emit in significant amounts. For a major modification, the pollutants are those for which the net emissions increase exceeds the significant emission rate (see Table 3-2). As discussed in Section 3.0, only ozone requires an air quality analysis to meet PSD pre-construction monitoring requirements for the proposed NHPP annual heat input rate increase.

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

An exemption from the preconstruction ambient monitoring requirements is available if certain criteria are met. If the predicted increase in ambient concentrations due to the proposed modification is less than specified *de minimis* concentrations, then the modification can be exempted from the pre-construction air monitoring requirements for that pollutant.

There is no PSD *de minimis* monitoring concentration established for VOC. However, an increase in VOC emissions of 100 TPY or more requires a preconstruction ambient monitoring analysis for ozone. This analysis is presented in the following section. In addition, existing ambient air quality data for the ENP Class I area is presented to support the AQRV analysis presented in Section 7.0.

The PSD ambient monitoring guidelines allow the use of existing data to satisfy preconstruction review requirements and to develop background concentrations. Background concentrations are necessary to determine total ambient air quality impacts to demonstrate compliance with AAQS. "Background concentrations" are defined as concentrations due to sources other than those specifically included in the modeling analysis. For all pollutants, background would include other point sources not included in the modeling (i.e., faraway sources or small sources), fugitive emission sources, and natural background sources. Background concentrations for SO_2 are presented in this section to support the air impact analysis.

4.2 OZONE AMBIENT MONITORING ANALYSIS

Presented in Table 4-1 is a summary of existing continuous ambient ozone data for monitors located in the vicinity of NHPP. Data are presented for the last three years of record, 1999 to 2001. As shown, no ozone monitors were operational in the vicinity of NHPP during the period between 1999 and 2001. The nearest ozone monitoring station was located in Royal Palm Beach (just west of West Palm Beach).

The ozone monitors show that ambient ozone concentrations were below the ambient air quality standards of 0.12 ppm (235 $\mu g/m^3$), maximum 1-hour average allowed to be exceeded on average one day per year. The monitor in Royal Palm Beach is considered to be representative of the NHPP facility area since it is relatively close to NHPP.

4.3 SO_2 AMBIENT BACKGROUND CONCENTRATIONS

Presented in Table 4-2 is a summary of existing continuous ambient SO_2 data for monitors located in the vicinity of NHPP. Data are presented for the last 5 years of record, 1997 to 2001. As shown, only one SO_2 monitor was operational in the vicinity of NHPP during this period. This station, located in South Bay, operated in 1997 but was shutdown in 1998. One station in Riviera Beach operated during 1997 through 2001, but is located over 60 km from NHPP.

The monitor at South Bay shows that ambient SO_2 concentrations were well below the ambient air quality standards of: 1,300 $\mu g/m^3$, maximum 3-hour average; 260 $\mu g/m^3$, maximum 24-hour average; and 60 $\mu g/m^3$, annual average. The monitor in Riviera Beach is not considered to be representative of the NHPP mill site due to its distance from NHPP, and its urban location near a major power plant. The South Bay monitor is considered representative of the NHPP area, since it was located within 5 miles and in a similar rural setting.

For purposes of an ambient SO_2 background concentration for use in the modeling analysis, the annual average SO_2 concentration of 5 $\mu g/m^3$ recorded at the South Bay monitor during 1997 was selected. Similarly, the concentrations used for the 3- and 24-hour background SO_2 concentrations in the air quality impact analysis were 47 and 13 µg/m^3, respectively, which are the second-highest short-term concentrations measured at the site.

4.4 EVERGLADES NATIONAL PARK CLASS I AREA

Presented in Table 4-3 is a summary of existing ambient PM/PM_{10}, SO_2, and NO_2 monitoring data for monitors located in the vicinity of the ENP Class I area. One PM_{10} monitor and one SO_2 monitor was located directly in the ENP in 1997 and 1998. The nearest NO_2 data is from a site located in downtown Miami.

The monitoring data show that ambient PM_{10} concentrations were well below the ambient air quality standards of 150 µg/m^3, maximum 24-hour average, and 50 µg/m^3, annual average, and ambient SO_2 concentrations were extremely low and are representative of natural background concentrations.

Table 4-1. Summary of Continuous Ozone Ambient Monitoring Data Collected Near South Bay

County	Station ID	Monitor Location	Year	Number of Observations	Percent Data Recovery	Concentration (ppm) Maximum 1-hour	2nd High 1-hour	3rd High 1-hour	4th High 1-hour
Palm Beach	12-099-0007	West Palm Beach 10999 Okeechobee Blvd.	1999	174	71	0.057	0.056	0.055	0.055
Palm Beach	12-099-2004	Delray Beach 210 NW 1st Avenue	1999	242	99	0.108	0.104	0.101	0.091
			2000	238	97	0.096	0.093	0.087	0.083
			2001	243	99	0.102	0.098	0.081	0.08
Palm Beach	12-099-0009	Royal Palm Beach 980 Crestwood Blvd.	2000	231	94	0.083	0.078	0.077	0.075
			2001	190	78	0.107	0.090	0.084	0.077

Note: ppm = parts per million.

Table 4-2. Summary of Continuous Sulfur Dioxide Ambient Monitoring Data Collected Near South Bay

					Concentration (µg/m³)				
County	Station ID	Monitor Location	Year	Number of Observations	Maximum 3-hour	2nd High 3-hour	Maximum 24-hour	2nd High 24-hour	Annual Average
Palm Beach	4150-001-J02	South Bay-300 North US 27	1997	8,486	55	47	19	13	5
Palm Beach	12-099-3004	Riviera Beach-1050 15th Street	1997	8,274	165	154	50	37	4
			1998	8,299	177 (0.068 ppm)	31 (0.012 ppm)	24 (0.009 ppm)	10 (0.004 ppm)	3 (0.001 ppm)
			1999	8,221	45 (0.017 ppm)	37 (0.014 ppm)	34 (0.013 ppm)	34 (0.013 ppm)	5 (0.002 ppm)
			2000	8,404	34 (0.013 ppm)	31 (0.012 ppm)	26 (0.010 ppm)	21 (0.008 ppm)	5 (0.002 ppm)
			2001	6,361	13 (0.005 ppm)	10 (0.004 ppm)	8 (0.003 ppm)	8 (0.003 ppm)	3 (0.001 ppm)

Note: µg/m³ = micrograms per cubic meter
ppm = parts per million

Table 4-3. Summary of Sulfur Dioxide, PM_{10}, and NO_2 Monitoring Data, Everglades National Park

					Concentration ($\mu g/m^3$)				
County	Station ID	Monitor Location	Year	Number of Observations	Maximum 1-hour	2nd High 1-hour	Maximum 24-hour	2nd High 24-hour	Annual Average
SO_2 Monitoring Data									
Dade	National Park Service	Within Everglades National Park	1997	91	--	--	0.52	0.18	0.046
			1998	71	--	--	0.72	0.68	0.13
			1999	41	--	--	0.65	0.46	0.15
PM_{10} Monitoring Data									
Dade	National Park Service	Within Everglades National Park	1990	89	--	--	79	44	20
			1991	53	--	--	38	37	18
NO_2 Monitoring Data									
Dade	12-025-4002	Miami-864 NW 3rd Street	1999	7,916	202	164	--	--	32
			2000	6,805	379	315	--	--	30 (0.016 ppm)
			2001	8,488	143	139	--	--	30 (0.016 ppm)
Dade	12-025-0027	Miami-Rosentiel School	1999	8,340	134	121	--	--	11
			2000	6,861	123	121	--	--	11 (0.006 ppm)
			2001	7,807	103	98	--	--	11 (0.006 ppm)

Note: $\mu g/m^3$ = micrograms per cubic meter.
ppm = parts per million.

Source: Improve, NPS for SO_2 and PM_{10} data; Allsum, FDEP for NO_2 data.

5.0 BEST AVAILABLE CONTROL TECHNOLOGY ANALYSIS

5.1 REQUIREMENTS

The 1977 CAA Amendments established requirements for the approval of pre-construction permit applications under the PSD program. One of these requirements is that BACT be installed for applicable pollutants. BACT determinations must be made on a case-by-case basis considering technical, economic, energy, and environmental impacts for various BACT alternatives. To bring consistency to the BACT process, the EPA developed the "top-down" approach to BACT determinations.

The first step in a top-down BACT analysis is to determine, for each applicable pollutant, the most stringent control alternative available for a similar source or source category. If it can be shown that this level of control is not feasible on the basis of technical, economic, energy, or environmental impacts for the source in question, then the next most stringent level of control is identified and similarly evaluated. This process continues until the BACT level under consideration cannot be eliminated by any technical, economic, energy, or environmental consideration.

In the case of the proposed NHPP project, PM/PM_{10}, SO_2, NO_x, CO, VOC, SAM, Pb, and fluorides require a BACT analysis. The BACT analysis is presented in the following sections.

5.2 PARTICULATE MATTER (PM/PM_{10})

5.2.1 EXISTING AND PROPOSED CONTROL TECHNOLOGY

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. Based on ash generation, the dust collectors are removing about 80 percent of the particulate matter in the flue gases. The dust collectors remove larger size PM prior to the ESP. Each cogeneration boiler is vented though separate ESPs and stacks. The current PM/PM_{10} permit limit for the NHPP boilers is 0.03 lb/MMBtu, equivalent to NSPS Subpart Da standards.

The proposed BACT for PM/PM_{10} is based on the current control techniques: use of mechanical cyclone dust collectors followed by ESPs. The proposed PM/PM_{10} emission limit is based on the current limit of 0.03 lb/MMBtu.

NHPP PM/PM_{10} stack test results for wood firing, bagasse firing, and biomass firing, respectively performed in 1999, 2000, 2001, and 2002 (biomass), are presented in Appendix C. Since the dust collectors were installed in 2000, the two most recent stack tests reflect a decrease in PM emissions and compliance with the 0.03 lb/MMBtu limit. Only the most recent stack tests reflect the normal operating case of burning approximately a 50/50 combination of wood and bagasse. Since there is not enough stack test data for normal operation to support a lower limit, the proposed BACT is based on the current permit limit of 0.03 lb/MMBtu.

5.2.2 BACT ANALYSIS

The proposed maximum PM/PM_{10} emissions for the cogeneration boilers are 0.03 lb/MMBtu for firing of all fuels (biomass, fuel oil, and natural gas). These are the current limits for the boilers. 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 due to biomass firing.

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 are presented in Appendix D, Table D-1. Determinations issued during the last ten years are 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 0.02 lb/MMBtu to 0.15 lb/MMBtu of PM/PM_{10} emissions. The most recent determinations are in the range of 0.03 to 0.15 lb/MMBtu.

5.2.2.1 <u>Control Technology Feasibility</u>

The technically feasible PM/PM_{10} controls for the NHPP boilers consist of the following add-on PM/PM_{10} control systems:

- Cyclones;
- Baghouses;
- ESPs; and
- Wet scrubbers.

NHPP already utilizes mechanical cyclone dust collectors and ESPs to control PM/PM_{10} emissions. Baghouses and wet scrubbers are discussed in the following paragraphs.

Baghouses, or fabric filters, utilize porous fabric to clean an airstream. They includes 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.

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 90 to 98 percent, depending on the type of scrubbing system used.

5.2.2.2 Economic Analysis

Since NHPP currently utilizes mechanical cyclone dust collectors and ESPs to control PM/PM_{10}, any further add-on control equipment would not be appropriate. Additional PM/PM_{10} control equipment would result in capital costs of several million dollars per cogeneration boiler. The mechanical dust collectors and ESPs have demonstrated efficient PM/PM_{10} removal at NHPP. The NHPP stack test data demonstrate PM/PM_{10} emission levels in the range of 0.01 to 0.02 lb/MMBtu, based on testing since the mechanical dust collectors were installed. These levels are already in the range achievable by a fabric filter system, and are lower than previous BACT determinations.

5.2.3 SUMMARY

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

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 for each boiler. The dust collectors and ESPs are already in operation and are demonstrating efficient

PM/PM_{10} control. Therefore, the proposed PM/PM_{10} BACT limit of 0.03 lb/MMBtu is based on the existing mechanical cyclone dust collectors and ESPs.

5.3 SULFUR DIOXIDE

5.3.1 EXISTING AND PROPOSED CONTROL TECHNOLOGY

SO_2 emissions are currently controlled by burning biomass, low sulfur No. 2 distillate fuel oil (0.05 percent sulfur, maximum) and natural gas. All of these fuels are inherently very low in sulfur, and therefore produce low SO_2 emissions. The following table summarizes the expected biomass fuel sulfur content, based on historical fuel sampling at the NHPP cogeneration facility.

Wood (% by wt. Dry)	Bagasse (% by wt. Dry)
0.02%, low	0.02%, low
0.07%, avg.	0.03%, avg.
0.27%, high	0.05%, high

In addition, SO_2 removal is inherent to the process of combusting biomass. The fly ash produced during biomass firing is alkaline in nature and acts as a dry scrubbant, adsorbing SO_2 from the exhaust stream. The ash is then collected in the mechanical collectors and the ESP. Significant SO_2 removal has been demonstrated at NHPP. Based on fuel analysis and CEM data, daily SO_2 removal efficiencies at NHPP were estimated to range from 87 to 99 percent.

The proposed BACT for SO_2 is based on the existing control technique and the current permit limits: firing of low sulfur fuels. The proposed BACT emission limits for SO_2 for biomass firing are:

- 0.20 lb/MMBtu on a 24-hour average;
- 0.10 lb/MMBtu on a 30-day rolling average, and;
- 0.06 lb/MMBtu on a 12-month rolling average.

For fuel oil firing, the proposed BACT is burning low sulfur distillate oil with a maximum sulfur content of 0.05 percent. This is equivalent to SO_2 emissions of approximately 0.05 lb/MMBtu. No limit is proposed for natural gas firing; however, estimated SO_2 emissions are 0.0058 lb/MMBtu based on emission factors.

5.3.2 BACT ANALYSIS

5.3.2.1 Control Technology Feasibility

The technically feasible SO_2 control alternatives for the NHPP boilers consist of the following add-on SO_2 control systems;

- Wet flue gas desulfurization (FGD);
- Dry FGD; and
- Regenerable FGD.

Wet FGD includes technologies such as lime, limestone forced or inhibited oxidation, and magnesium-enhanced lime FGD. These systems create solid and liquid waste streams, which must be treated before disposal. SO_2 control efficiencies for wet limestone FGD range from 50 to 98 percent, depending on the type of device and design, with an average of 90 percent.

Dry FGD systems include lime spray drying, dry lime furnace injection, and dry lime duct injection. These systems must be followed by a highly efficient PM control device, which is typically a fabric filter, although an electrostatic precipitator could also be used. The dominant dry FGD technique is spray drying. Lime spray drying efficiency ranges from 70 to 96 percent, with an average of 90 percent.

Regenerable FGD systems can be either wet or dry and result in a concentrated stream of SO_2, which can then be sold. These systems include sodium sulfite, magnesium oxide, sodium carbonate, and amine.

5.3.2.2 Economic Analysis

Wet, dry, and regenerable FGD systems can all achieve the same level of SO_2 control efficiency. To evaluate the cost effectiveness of FGD applied to the proposed NHPP, cost estimates for a lime spray drying system were developed. Spray drying systems are generally less expensive than the wet limestone FGD process and are therefore more economical. To develop costs, vendor quotes obtained for Palm Beach Power Corp.'s (PBPC's) proposed cogeneration boilers were used. PBPC will use boilers identical to NHPP's boilers, and will burn the same type fuel. Therefore, control equipment costs should be very similar for the two facilities, except that NHPP would represent a retrofit installation. One quote was from Hamon Research-Cottrell, Inc., and the other from Wheelabrator Air Pollution Control (refer to Appendix E for the complete quotes).

These quotes are for complete systems, based on two cogeneration boilers, including the spray dryer absorber, lime delivery system, pulse jet fabric filter, and ancillary equipment. To install a lime spray drying system on the existing cogeneration boilers, upgraded PM/PM_{10} control equipment would be required due the increased particulate loading caused by the spray drying systems. SO_2 removal was specified as 90 percent. Fuel heating value and sulfur content were specified to result in uncontrolled SO_2 emissions of 0.06 lb/MMBtu, which is the proposed annual average limit for NHPP. A capacity factor of 90 percent was assumed for both baseline and future emissions, since it is not feasible for the NHPP boilers to operate at 100% load year-round. Capital recovery costs were based on 7-percent interest and a 20-year equipment life.

A project contingency of 25% of the purchased equipment cost was included to account for the fact that this would be a retrofit installation. Emissions of fluorides were also included in the cost effectiveness calculations since the FGD system will also control fluorides (refer to Section 5.6).

The cost analysis is presented in Tables 5-1 and 5-2. Based on the vendor quotes, the resulting capital costs range from $9,900,000 to greater than $12,000,000 per boiler. Based on uncontrolled emissions per boiler of SO_2 and HF of 181.9 tons per year, and assuming 90-percent removal, the total SO_2/HF removed is 163.7 TPY. The resulting cost effectiveness ranges from $10,000 to nearly $12,000 per ton of SO_2/HF removed.

Wet and regenerable FGD control systems would have higher capital and annual operating costs, with a resulting higher cost effectiveness, and therefore were not evaluated with a detailed cost estimate.

5.3.2.3 Previous BACT Determinations

A review was performed of previous SO_2 BACT determinations for similar biomass-fired industrial and electric utility boilers listed in the RACT/BACT/LAER Clearinghouse on EPA's web page. A summary of these BACT determinations for biomass-fired is presented in Appendix D, Table D-2. Only determinations issued within the last 10 years are shown. Note that one fluidized bed biomass boiler located in California (SAI Energy, Inc.) was not included in the table because of the distinct differences between NHPP's spreader stoker boilers and a fluidized bed boiler.

Previous BACT determinations have ranged from 0.016 to 0.46 lb/MMBtu SO_2. Three of these determinations were for bagasse-fired boilers. Bagasse is a fuel that exhibits lower and less variable sulfur content than wood. Four projects were located at paper mills, which predominantly obtain biomass from dedicated forests, with a consistent fuel quality. It is noted that the Grayling Generating Station determination listed is likely not a BACT determination, because total SO_2 emissions from the plant were less than 40 TPY. However, it was provided due to the recent issuance of this permit and its similarity to the NHPP project.

From the review of these previous BACT determinations, it is evident that SO_2 BACT determinations for biomass-fired boilers have been based solely on fuel specifications (i.e., use of low sulfur-containing fuels). Therefore, the emission limits are based on the prospective or actual fuel supply.

It is noted that the NHPP facility is believed to be significantly different than the wood/bark burning facilities shown in Table D-2. NHPP obtains its wood materials from a number of suppliers and sources throughout south Florida. Most of the sources shown in Table D-2 are not located in south Florida, and many are believed to have a dedicated fuel supply source, which means that the fuel is much more homogenous than NHPP's fuel supply.

Nevertheless, the proposed BACT emission limits have been based on the historical fuel supply for the NHPP cogeneration facility. The proposed annual SO_2 limit is 0.06 lb/MMBtu, based on a 12-month rolling average. A 30-day rolling average limit of 0.10 lb/MMBtu is proposed. A 24-hour average limit of 0.20 lb/MMBtu is proposed to account for the demonstrated variability of biomass fuel. All these limits are the same as the existing permit limits for NHPP. These limits were determined to be BACT for NHPP in February, 2002.

5.3.3 SUMMARY

In conclusion, NHPP's request for SO_2 emissions standards is reasonable based on the existing information from the NHPP cogeneration facility, the low sulfur content of biomass fuels, and BACT determinations for similar biomass power plants. The SO_2 emissions are a direct function of the fuel sulfur content, but are difficult to minimize on a short-term basis because of fuel sulfur variation and the unquantified SO_2 removal mechanism. The uncontrolled SO_2 emissions from biomass, No. 2 fuel oil and natural gas are very low, which renders any add-on control equipment as too costly. Further, there is inherent SO_2 removal in the boiler/PM control system, based on current operating and emissions data, in the range of 85 to 99 percent.

The retrofit of add-on flue gas desulfurization equipment is not appropriate for the existing units nor the requested heat input increase of the NHPP facility. Each of the alternative SO_2 control systems would result in significant capital and operating costs for NHPP. The cogeneration boilers and control equipment NHPP proposes to utilize are already in place and have been in use at the cogeneration site. The three cogeneration boilers would need to be "retrofitted" with these systems, substantially increasing costs. The cost effectiveness of an add-on lime spray drying system is estimated to range from $10,000 to nearly $12,000 per ton of SO_2/HF removed.

In addition, NHPP just received a BACT determination for SO_2 in February 2002. These existing BACT limits for SO_2 are proposed as BACT for the proposed heat input increase. Therefore, the following BACT standards are proposed based on the firing of low sulfur fuels.

- 24-hour SO_2 standard of 0.20 lb/MMBtu when firing biomass.
- 30-day rolling average standard of 0.10 lb/MMBtu when firing biomass.
- Annual average SO_2 standard of 0.06 lb/MMBtu based on a 12-month rolling average when firing biomass.
- 24-hour and 12-month rolling SO_2 standard of 0.05 lb/MMBtu when firing fuel oil.

In summary, the proposed BACT for the NHPP cogeneration boilers is the continued use of very low sulfur fuels, i.e., biomass, No. 2 fuel oil, and natural gas.

5.4 <u>NITROGEN OXIDES</u>

5.4.1 EXISTING AND PROPOSED CONTROL TECHNOLOGY

The existing cogeneration boilers at the NHPP cogeneration facility utilize selective non-catalytic reduction (SNCR) systems to reduce NO_x emissions. SNCR is a system that injects urea into the boiler to reduce NO_x emissions. In this process, urea is injected into the flue gas stream in the boiler and reacts with NO_x to form nitrogen and water vapor. For the NHPP cogeneration boilers, urea is injected into each boiler at average and maximum rates of 25 gallons per hour (gph) and 65 gph, respectively.

The proposed BACT for NO_x is the continued use of the existing SNCR system. The proposed BACT emission limit for NO_x is 0.15 lb/MMBtu based on a 30-day rolling average for biomass, No. 2 fuel oil, and natural gas. For each boiler, this limit is equivalent to 499.3 TPY of NO_x.

5.4.2 BACT ANALYSIS

Two control alternatives, SCR and SNCR, have been determined to be technically feasible NO_x control systems for the cogeneration boilers. NHPP already utilizes SNCR to control NO_x emissions. SCR systems, as well as increased NO_x removal using SNCR, are discussed in the following sections.

5.4.2.1 Previous BACT Determinations

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 is presented in Appendix D, Table D-3. Note that one fluidized bed biomass boiler located in California (SAI Energy, Inc.) was not included in the table because of the distinct differences between NHPP's proposed 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-percent wood. 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 is technically and economically feasible for this facility (see further discussion below).

5.4.2.2 Selective Catalytic Reduction

Technical Feasibility

SCR is an add-on technology in which ammonia is injected into the exhaust gas stream in the presence of a catalyst. The ammonia combines with NO_x in the gas stream in a reduction reaction, forming nitrogen and water. For the reaction to proceed satisfactorily, the exhaust gas temperature must be maintained between 450°F and 850°F. SCR systems are stated to achieve from 70 to 90 percent NO_x reduction.

Although SCR is commercially available, this technology has never been applied to a biomass boiler. As shown in Table D-3, SCR has never been specified as BACT for a biomass-fired boiler. In a paper presented at the 2001 AWMA Annual Conference on Orlando, it was reported that there are now ten coal-fired plants in the U.S. that employ SCR. In addition, there were an estimated 40 additional plants with SCR units either under construction or in the procurement process (A. Johnson and C. Lockert, 2002). Weaknesses in these conventional SCR units were reported to include lag time of feedback NO_x signal from the stack CEM, and system response to step changes in NO_x concentrations. Other issues include air heater fouling, catalyst poisoning, stack opacity, and flyash contamination.

Technical difficulties associated with applying SCR include no operating experience on bagasse or wood fuels, and likely premature catalyst deactivation due to chemical poisoning of the catalyst due to the alkali content of the ash. The high moisture content of wood fuels, and particularly bagasse (approx. 50-percent moisture), could also be a concern for catalyst operation. High particulate loading prior to the mechanical collectors would also be a concern. This could lead to catalyst fouling and reduced NO_x removal efficiency. These technical difficulties are evidenced by the fact that only one supplier of SCR systems was willing to provide a cost quote on a biomass-fired boiler (see Economic Analysis below).

In addition, the SCR catalyst operating temperature range is between 600°F and 900°F, within which the NO_x reduction process takes place. The cogeneration boiler outlet temperature is approximately 400°F. Placement of the SCR can only be after the ESP because of possible chemical poisoning of the catalyst due to the alkali content of the ash and due to the reaction of the ash with gaseous components in the flue gas that blind the catalyst. As a result, a heat exchanger will be required, located downstream of the ESP and prior to the SCR system, to increase the ESP exit temperature from 400°F to 700°F.

In comparison, SNCR has been proven to operate satisfactorily on the existing cogeneration boilers and other boilers similar to NHPP while burning the same fuels.

Economic Analysis

One complete year 2002 SCR vendor quote was obtained from Hamon Research-Cottrell for PBPC's proposed cogeneration boilers. As discussed in Section 5.3, NHPP's boilers are identical to PBPC's proposed boilers, and will burn the same type fuels. A copy of the cost quote is provided in Appendix E. Attempts were made to obtain SCR cost quotes from various other vendors resulting in either no response or rejection of our request due to technical feasibility issues. A summary of correspondences with SCR vendors is provided in Appendix E.

The cost analysis for SCR is presented in Table 5-3. The total estimated capital cost of SCR for one NHPP cogeneration boiler is \$4,200,000. The total annualized cost of applying SCR is estimated at \$4,200,000 per year.

Uncontrolled baseline NO_x emissions are based on published factors for wood-fired boilers of 0.36 lb/MMBtu and for bagasse-fired boilers of 0.17 lb/MMBtu. Based on firing approximately 50 percent wood and 50 percent bagasse, the average emission rate is 0.26 lb/MMBtu. A capacity factor of 90 percent was assumed for both baseline and maximum future emissions, since it is not feasible for the NHPP boilers to operate at 100 percent capacity factor year-around.

For maximum controlled emissions, a controlled NO_x emission rate of 0.08 lb/MMBtu was assumed. The previously discussed technical issues and lack of operating experience make the SCR removal efficiency of 90 percent quoted by the SCR vendor highly questionable. Based on an uncontrolled NO_x emission rate of 0.26 lb/MMBtu from the PBPC boilers, a 90 percent reduction would equate to a controlled NO_x emission rate of 0.026 lb/MMBtu. This is an extremely low level of NO_x emissions, which has not been demonstrated in practice.

For comparison, a review of BACT determinations for NO_x emissions from coal-fired boilers was performed. The results of this review are shown in Appendix B. As shown, the lowest BACT determination was also the most recent: Kansas Power & Light- Hawthorn Station. This determination was for SCR and resulted in a NO_x emissions limit of 0.08 lb/MMBtu.

For the NHPP boilers, this represents a 70 percent reduction in uncontrolled NO_x emissions. It is questionable as to whether a NO_x reduction efficiency of greater than 70 percent can be achieved in practice on a biomass-fired boiler.

The resulting cost effectiveness of adding SCR with this level of control is estimated at $7,800 per ton of NO_x removed. The existing SNCR system, using urea as the reactant, is much less costly than SCR.

From the review of these previous BACT determinations, it is evident that NO_x BACT determinations for biomass-fired boilers have been based solely on combustion controls alone, or combustion controls with SNCR. SCR has never been specified as BACT for biomass-fired boilers.

Energy Impacts

Energy penalties occur with SCR. As discussed previously, placement of the SCR can only be after the ESP because of possible chemical poisoning of the catalyst. As a result, a heat exchanger will be required to increase the exit ESP temperature from 400°F to 700°F. The resulting reheat requirement is approximately 100 MMBtu/hr with an annual operating cost of approximately $2.6 million.

Environmental Impacts

SCR will require the construction and maintenance of storage vessels for ammonia for use in the reaction. Ammonia has potential health effects, and the construction of ammonia storage facilities triggers the application of a least three major standards: Clean Air Act (section 112), Occupational Safety and Health Administration (OSHA) 29 CFR 1910.1000, and OSHA 29 CFR 1910.119.

5.4.2.3 <u>Enhanced SNCR</u>

As discussed previously, the SNCR control efficiency for the Multitrade facility is stated as 50 percent, requiring a very high urea injection rate of up to 130 gal/hr of 50-percent urea solution. To achieve the proposed NO_x BACT of 0.15 lb/MMBtu, the NHPP SNRC control efficiency is approximately 42 percent, based on EPA AP-42 uncontrolled NO_x emission factors for bagasse and wood-fired boilers. For NHPP to achieve a more effective use of SNCR, increased urea injection will be required.

Boiler experience at Osceola Power (now Palm Beach Power Corp.) and Okeelanta Power (now NHPP) indicates that higher urea injection rates accelerate superheater tube failure, resulting in lost electric generation and substantial repair costs. For example, the existing boilers at NHPP have not experienced nearly the degree of superheater tube replacement as the Osceola Power boilers when operating. The Osceola Power boiler urea usage rates ranged from an average of approximately 35 gal/hr to peaks of 70 gal/hr per boiler. The NHPP boilers use approximately 25 gph of urea.

The NHPP boilers are identical in size to the Osceola Power boilers, burn the same fuels, and are operated in the same manner. The only significant difference in the operations was the lower NO_x emission limit for the Osceola Power boilers, requiring higher urea injection rates. The increased urea usage was about 40 percent higher for Osceola Power's boilers to meet the NO_x emission limit of 0.12 lb/MMBtu, compared to NHPP's boilers, which have an emission limit of 0.15 lb/MMBtu. Although many factors can contribute to superheater tube failure, the only significant difference in operation between the Osceola Power and NHPP facilities was the amount of urea injection required due to the different NO_x limits. As a result, it is concluded that the superheater tube failures are accelerated by the higher urea injection rates.

A cost analysis was performed to evaluate higher urea injection rates for NHPP. The costs to Osceola Power of the higher injection rates include the cost of urea, repair of the superheater tubes, and loss of revenue due to lost electric generation. A detailed analysis is presented in Table 5-4. This analysis is based on actual costs incurred for two boilers over the period of December 1996 through March 1997 and were prorated to an annual basis. As shown in Table 5-4, the total annual cost of higher urea injection is estimated to be \$3.8 million per year. The reduction in NO_x emissions due to the higher injection is calculated based upon the difference between limits of 0.12 and 0.15 lb/MMBtu. This results in an emission reduction of 150 TPY of NO_x. Thus, the incremental cost effectiveness of the higher urea injection is over \$25,000/ton of NO_x removed.

Higher urea usage would also result in increased emissions of urea's decomposition products, which include ammonia slip and carbon dioxide. High ammonia slip can lead to ammonium bisulfate formation, which can cause fouling of the air preheater and ESP. High ammonia slip can also combine with hydrogen chloride in the flue gas to form ammonium chloride. The ammonium chloride can form a detached plume of high opacity.

As described previously, Multitrade is operated as a peaking unit. As such, the typical operating factor is about 20 percent. Multitrade's limited hours of operation decreases the frequency of superheater failures compared to what would result if NHPP were required to meet a NO_x emission limit of 0.10-0.12 lb/MMBtu on a continuous basis. In summary, the more effective use of SNCR as demonstrated by Multitrade in Virginia is not appropriate for NHPP due to the associated technical problems associated with high urea injection rates over long-term operation, and associated economic impact.

In addition, the Multitrade boilers have a heat input rate of approximately 374 MMBtu/hr, approximately half the size of the NHPP boilers, which will have a maximum heat input rate of 760 MMBtu/hr. These differences in fuel use, boiler size, and operation methods demonstrate that the Multitrade facility is significantly different than the NHPP facility. As a result, the review of previous BACT determinations supports the proposed BACT limit of 0.15 lb/MMBtu NO_x (30-day rolling average).

5.4.3 SUMMARY

Aside from one exception, previous BACT determinations for NO_x from biomass-fired boilers have ranged from 0.14 to 0.46 lb/MMBtu. This includes the most recent determination for Grayling Generating Station, which resulted in a BACT limit of 0.15 lb/MMBtu. Previous NO_x BACT determinations for biomass-fired boilers have been based solely on combustion controls alone, or combustion controls with SNCR.

For NHPP, SNCR can achieve the maximum amount of emission reduction economically feasible, is technically feasible, and is demonstrated in practice. SCR should be rejected as BACT for the NHPP cogeneration boilers for the following reasons:

- SCR has never been applied to a biomass-fired boiler;
- SCR has never been specified as BACT for a biomass-fired boiler;
- SCR catalyst operating temperature range is between 600°F and 900°F within which the NO_x reduction process takes place. The cogeneration boilers ESP outlet temperature is approximately 400°F. The implementation of SCR would require flue gas heating to 700°F through the use of a heat exchanger with a heat input requirement of approximately 100 MMBtu/hr;
- NO_x removal efficiency obtained with an SCR system applied to a wood/bagasse boiler is uncertain due to lack of operating experience;
- Capital cost of SCR is estimated at \$4.2 million per cogeneration boiler, with annual operating costs of \$4.2 million/year;
- Cost effectiveness of SCR is estimated at over \$7,800 per ton of NO_x removed.

- Due to technical difficulties, uncertainties, and the unproven nature of SCR as applied to biomass-fired boilers, only one SCR vendor would provide a quote.
- Catalyst life guaranteed for only 10,000 hours (Hamon Research-Cottrell). SCR vendors expressed concerns of catalyst poisoning from biomass-fired boilers. Short catalyst life results in high annual operation costs.

Therefore, the proposed NO_x BACT limit for NHPP is based on the existing SNCR system and operating experience at the cogeneration facility: 30-day rolling NO_x standard of 0.15 lb/MMBtu when firing any 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). Use of the SNCR system and good combustion practices constitute BACT for the proposed NHPP cogeneration boilers.

5.5 CARBON MONOXIDE AND VOLATILE ORGANIC COMPOUNDS

5.5.1 EXISTING AND PROPOSED CONTROL TECHNOLOGY

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

The proposed BACT for CO and VOC is based on the existing control techniques: proper furnace design and good combustion practices. The proposed CO emission limits for the cogeneration boilers are: 0.50 lb/MMBtu as a 30-day rolling average; and, 0.35 lb/MMBtu as a 12-month rolling average for biomass firing. The proposed VOC emission limit for the cogeneration boilers is 0.06 lb/MMBtu for biomass firing.

5.5.2 BACT ANALYSIS

The proposed CO BACT limits of 0.50 lb/MMBtu as a 30-day rolling average and 0.35 lb/MMBtu as a 12-month rolling average were recently issued as BACT for NHPP on February 1, 2002 (PSD-FL-196M). Since NHPP has demonstrated compliance with these emission limits, and there are no physical changes to the cogeneration boilers as part of this project, the existing emission limits and controls of proper furnace design and good combustion practices constitute BACT for CO and VOC.

As part of the BACT analysis, a review was performed of previous CO and 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, Tables D-4 and D-5. The CO emission limits for biomass-fired industrial and electric utility boilers range from 0.03 to 6.5 lb/MMBtu. 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 CO and VOC BACT determinations for biomass-fired industrial and electric utility boilers have been good combustion practices and boiler design.

The NHPP proposed emission limits are with in the range of previous determinations. The cogeneration boilers will minimize CO and VOC through proper furnace design and good combustion practices, including: control of combustion air and combustion temperature; controlled distribution of fuel on the combustion gate; and better controls over the furnace loads and transient conditions. This level of control is consistent with previous determinations.

Emission data during startup are variable and are not available in the form of guarantees from the vendor. For this reason cold startup emissions are based on CEM data from the cogeneration facility. The six cold startup events exhibiting the highest 1-hr and 8-hr CO emissions are shown in Appendix E. The New Hope Power Partnership has identical ABB/CE cogeneration units and combusts similar biomass fuel. Cold startups are expected to occur infrequently. However, experience with wood/bagasse boilers indicates that these events do occur and good combustion practice will be employed to minimize emissions during these events. The highest 1-hour average CEM CO levels from New Hope Power Partnership occurred during a cold startup with a maximum level of 6.5 lb/MMBtu. This was a one-time occurrence, and many other cold startups have resulted in much lower CO emissions, as shown in Appendix E.

Cold startup is defined in Permit No. 0990332-014-AC/PSD-FL-196M as a startup after the boiler has been shutdown for 24 hours or more. Shutdown is defined as the cessation of the operation of a boiler for any purpose after steam generation drops below 150,000 lb/hr. The current permit allows for CO emission data exclusions during periods of startup, shutdown, or documented malfunctions. No more than six hourly CO emission rate values can be excluded in a 24-hour period due to a cold startup, and for each cogeneration boiler, no more than 183 hourly emission values can be excluded during any calendar quarter. NHPP proposes the current allowable CO emission data exclusions during periods of cold startup, shutdown and malfunction.

5.6 FLUORIDES

5.6.1 EXISTING AND PROPOSED CONTROL TECHNOLOGY

The existing and proposed control technology for fluorides for the NHPP cogeneration boilers is the use of biomass fuels with a mechanical collector and an ESP for PM control. The fuels burned in the NHPP cogeneration boilers may contain trace levels of F. Stack testing of both wood and bagasse fuels have indicated very low, although detectable, levels of F in the stack gases of the boilers. Fuel oil can also contain trace levels of F. F contained in the fuels is converted to hydrogen fluoride (HF) in the furnace. HF is an acid gas, and will behave similar to SO_2 in the furnace and downstream control equipment. Thus, as discussed for SO_2, HF will be adsorbed onto the alkaline ash particles existing in the flue gas. The ash is then removed in the downstream mechanical collectors and electrostatic precipitator, resulting in inherent F control.

5.6.2 BACT ANALYSIS

5.6.2.1 Control Technology Feasibility

Since HF is an acid gas, and will behave similar to SO_2 in the furnace and in downstream control equipment, FGD technologies are technically feasible fluoride control alternatives. FGD technologies for NHPP were discussed in Section 5.2.

5.6.2.2 Economic Analysis

To evaluate the cost effectiveness of FGD applied to the proposed NHPP, cost estimates for SO_2 control presented in Section 5.2 were utilized. Fluoride removal was assumed to be 90 percent with the FGD system. Based on these cost estimates, the resulting capital costs range from \$9,900,000 to greater than \$12,000,000. Annualized costs ranged from \$1,600,000 to \$2,000,000 per year.

The cost effectiveness is based on the combined removal of SO_2 and HF. Based on an uncontrolled emission rate of 181.9 TPY SO_2 and HF, the total SO_2/HF removed is 163.7 TPY (90-percent removal). The resulting cost effectiveness ranges from \$10,000 to nearly \$12,000/ton of SO_2/HF removed. See Tables 5-1 and 5-2 for detailed calculations.

5.6.2.3 Previous BACT Determinations

As part of the BACT analysis, a review was performed of previous F BACT determinations for biomass-fired industrial electric utility boilers listed in the RACT/BACT/LAER Clearinghouse on EPA's web page. A summary of the only BACT determination for biomass-fired industrial and electric utility boilers from this review is presented in Appendix D, Table D-6. The sole F emission limit for a biomass-fired electric utility boiler is 1.7E-03 lb/MMBtu. By comparison, measured F emissions for the NHPP boilers have been less than 7.0E-04 lb/MMBtu for both wood and bagasse (refer to Tables C-1 through C-3 for stack test data). These represent extremely low levels of F emissions. The same control techniques identified to control SO_2 emissions at NHPP also control F emissions.

5.6.3 SUMMARY

In conclusion, add-on fluoride removal equipment is not appropriate for the NHPP facility. HF control systems would result in significant capital and operating costs for NHPP. In addition to low fluoride fuel content, HF removal is inherent to the process of combustion biomass. The fly ash produced during firing is alkaline in nature and acts as a dry scrubber, absorbing HF from the exhaust stream.

It is also emphasized that the HF emission factor for NHPP (7.0E-04 lb/MMBtu) is based on the expected maximum emission rate, based on NHPP test data. The maximum expected emission rate is specified in the event that the FDEP sets an emission limit for HF. If an emission limit is set, NHPP must demonstrate compliance with the limit each and every time that compliance testing is required. Biomass fuels display variability, as witnessed from the NHPP test data. However, based on the test data shown in Appendix F, average HF levels at NHPP have actually been 3.1E-04 lb/MMBtu for wood firing; and 2.9E-04 for bagasse firing. Therefore, actual annual HF emissions for NHPP are expected to average about 3.0E-04 lb/MMBtu, resulting in actual annual emissions of less than 3.0 TPY, which is less than the PSD significant emission rate of 3.0 TPY.

The proposed control technology for fluorides for the NHPP cogeneration boilers is the use of biomass fuels with a mechanical collector and an ESP for PM control. Fluoride contained in the fuels is converted to HF in the furnace. HF is an acid gas, and will behave similar to SO_2 in the furnace and downstream control equipment. Thus, as discussed for SO_2, HF will be absorbed onto the alkaline ash particles existing in the flue gas. The ash is then removed in the downstream mechanical collectors and electrostatic precipitators, resulting in inherent F control.

5.7 SULFURIC ACID MIST

5.7.1 EXISTING AND PROPOSED CONTROL TECHNOLOGY

The proposed BACT for SAM emissions is the use of low sulfur fuels. Emissions of SAM are related to SO_2 emissions. SO_2 and SAM emissions will be controlled by burning low sulfur biomass fuel and low sulfur content fuel oil. Biomass fuel, low sulfur fuel oil, and natural gas are inherently low in sulfur, and therefore produce low SAM emissions.

5.7.2 BACT ANALYSIS

Since emissions of SAM are related to SO_2 emissions, BACT for SO_2 also represents BACT for SAM. The maximum potential emissions for SAM emissions are 0.0036 lb/MMBtu (annual average basis) for biomass firing, 0.003 lb/MMBtu for No. 2 fuel oil, and 0.000348 lb/MMBtu for natural gas. This is equivalent to a maximum of 36.0 TPY of SAM emissions for all three cogeneration boilers combined.

Previous BACT determinations for SAM emissions from biomass-fired industrial and electric utility boilers are presented in Appendix D, Table D-7. Combustion control is the only control method employed in these boiler BACT determinations for SAM. Emission limits of 0.001 and 0.003 lb/MMBtu without any add-on control constitutes BACT for these previous determinations. Although there is no limit proposed for SAM, the estimated NHPP cogeneration boiler maximum emissions for SAM are consistent with these determinations.

5.8 LEAD

5.8.1 PROPOSED CONTROL TECHNOLOGY

The proposed BACT for Pb emissions is control by the existing mechanical dust collectors and ESPs. Pb emissions are emitted in the solid phase from the NHPP cogeneration boilers. Pb emissions are a function of the Pb content of the biomass fuels. Maximum Pb emissions from the three cogeneration boilers combined will be 1.5 TPY. The maximum emissions are due to biomass firing.

5.8.2 BACT ANALYSIS

As part of the BACT analysis, a review of previous Pb BACT determinations for biomass-fired industrial and electric utility boilers listed in the RACT/BACT/LAER Clearinghouse on EPA's web page was performed. A summary of the BACT determinations for biomass-fired industrial and electric utility boilers from this review is presented in Appendix D, Table D-8. The Pb emission limits for these determinations were in the range of 0.000038 lb/MMBtu to 0.0004 lb/MMBtu. From this review, it is evident that the Pb BACT determinations are typically based on cyclones, ESPs, and clean fuels.

The proposed emission limit for the NHPP cogeneration boilers is 1.5E-04 lb/MMBtu. This limit is based on actual stack test data (refer to Tables C-1 through C-3). This limit represents an upper limit based on the stack testing. Actual average emissions are expected to be lower than this limit. It would not be economical to install any add-on control equipment to decrease Pb emissions any further than what is achievable through burning clean fuels (i.e., biomass, natural gas, and No. 2 fuel oil with a maximum sulfur content of 0.05 percent). Therefore, clean fuels are proposed as BACT for Pb emissions.

It is also emphasized that the proposed Pb emission rate for NHPP (1.5E-04 lb/MMBtu) is based on the expected <u>maximum</u> emission rate, based on NHPP test data. The maximum expected emission rate is specified in the event that the FDEP sets emission limits for Pb. If an emission limit is set, NHPP must demonstrate compliance with the limit each and every time that compliance testing is required. Biomass fuels display variability, as witnessed from the NHPP test data. However, based on the test data from NHPP (see Appendix C), average Pb levels at NHPP have been 1.9E-05 lb/MMBtu for combination bagasse/wood burning; 3.6E-05 for wood firing; and 1.7E-05 for bagasse firing. Therefore, actual annual Pb emissions for NHPP are expected to average approximately 2.6E-05 lb/MMBtu. This would result in annual Pb emissions of less than 0.3 TPY for the NHPP facility, which is less than the PSD significant emission rate of 0.6 TPY.

Table 5-1. Cost Effectiveness of Lime Spray Drying FGD for SO_2 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
Freight	5% of PEC	198,000
Taxes	Florida sales tax, 6%	237,600
Total PEC:		4,395,600
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	527,472
Water/air/electrical supply & piping	10% of PEC	439,560
Thermal insulation and lagging	Estimate	50,000
ID Fan	Estimate	100,000
Total Direct Installation:		4,077,032
Total DCC (PEC + Direct Installation):		8,472,632
INDIRECT CAPITAL COSTS (ICC):		
Engineering	2% of PEC (for excluded items)	87,912
Construction and field expenses	2% of PEC (for excluded items)	87,912
Contractor Fees	2% of PEC (for excluded items)	87,912
Startup	1% of PEC	43,956
Performance test	1% of PEC	43,956
Contingencies	25% of PEC (for retrofit application)	1,098,900
Total ICC:		1,450,548
TOTAL CAPITAL INVESTMENT (TCI):	DCC + ICC	9,923,180
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	99,232
Insurance	1% of total capital investment	99,232
Administration	2% of total capital investment	198,464
Total IOC:		409,016
CAPITAL RECOVERY COSTS (CRC):	CRF of 0.0944 times TCI (20 yrs @ 7%)	936,748
ANNUALIZED COSTS (AC):	DOC + IOC + CRC	1,638,392
BASELINE SO2 AND HF EMISSIONS (TPY) :	0.06 (lb SO_2)/MMBtu, 0.0007 (lb HF)/MMBtu; 760 MMBtu/hr; 90% capacity factor	181.9
MAXIMUM SO2 AND HF EMISSIONS (TPY) :	90% reduction	18.2
REDUCTION IN SO2 AND HF EMISSONS (TPY):		163.7
COST EFFECTIVENESS:	$ per ton of SO2 Removed	10,011

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.
Does not include excluded items shown below.

Table 5-2. Cost Effectiveness of Lime Spray Drying FGD for SO_2 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
Freight	5% of PEC	268,750
Taxes	Florida sales tax, 6%	322,500
Total PEC:		5,966,250
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	715,950
Water/air/electrical supply & piping	10% of PEC	596,625
Thermal insulation and lagging	Estimate	50,000
ID Fan	Estimate	100,000
Total Direct Installation:		4,722,575
Total DCC (PEC + Direct Installation):		10,688,825
INDIRECT CAPITAL COSTS (ICC):		
Engineering	2% of PEC (for excluded items)	119,325
Construction and field expenses	2% of PEC (for excluded items)	119,325
Contractor Fees	2% of PEC (for excluded items)	119,325
Startup	1% of PEC	47,226
Performance test	1% of PEC	47,226
Contingencies	25% of PEC (for retrofit installation)	1,180,644
Total DCC:		1,633,070
TOTAL CAPITAL INVESTMENT (TCI):	DCC + ICC	12,321,895
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	123,219
Insurance	1% of total capital investment	123,219
Administration	2% of total capital investment	246,438
Total IOC:		504,965
CAPITAL RECOVERY COSTS (CRC):	CRF of 0.0944 times TCI (20 yrs @ 7%)	1,163,187
ANNUALIZED COSTS (AC):	DOC + IOC + CRC	1,960,779
BASELINE SO2 AND HF EMISSIONS (TPY) :	0.06 (lb SO_2)/MMBtu, 0.0007 (lb HF)/MMBtu; 760 MMBtu/hr; 8,760 hr/yr	181.9
MAXIMUM SO2 AND HF EMISSIONS (TPY) :	90% reduction	18.2
REDUCTION IN SO2 AND HF EMISSONS (TPY):		163.7
COST EFFECTIVENESS:	$ per ton of SO2 Removed	11,980

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.

Table 5-3. Cost Effectiveness of SCR, NHPP Cogeneration Boilers

Cost Items		Cost Factors[a]	Cost per Cogen Boiler ($)
DIRECT CAPITAL COSTS (DCC):			
	SCR Basic Process	Vendor quote[b]	1,700,000
	Ammonia Storage System	Vendor quote[c], 30,000 galllon storage tank + valves	160,864
	Auxilary Equipment (Reheat)	10% of SCR equipment cost	170,000
	Emissions Monitoring	15% of SCR equipment cost	170,000
	Foundation and Structure Support	8% of SCR equipment cost	136,000
	Control Room and Enclosures	4% of SCR equipment cost, engineering estimate	68,000
	Transitiön Ducts to and from SCR	4% of SCR equipment cost, engineering estimate	68,000
	Wiring and Conduit	2% of SCR equipment cost, engineering estimate	34,000
	Insulation	2% of SCR equipment cost, engineering estimate	34,000
	Motor Control and Motor Starters	4% SCR of equipment cost, engineering estimate	68,000
	SCR Bypass Duct	$127 per MMBtu/hr	96,520
	Taxes	Florida sales tax, 6%	102,000
	Total DCC:		2,807,384
INDIRECT CAPITAL COSTS (ICC):			
	General Facilities	5% of DCC	140,369
	Engineering Fees	10% of DCC	280,738
	Performance test	1% of DCC	28,074
	Process Contingencies	5% of DCC	140,369
	Total ICC:		589,551
Project Contingencies		25% of DCC + ICC (for retrofit installation)	849,234
TOTAL CAPITAL INVESTMENT (TCI):		DCC + ICC + Project Contingencies	4,246,168
DIRECT OPERATING COSTS (DOC):			
(1)	Operating Labor		
	Operator	24 hours/week, $16/hr, 52 weeks/yr	$19,968
	Supervisor	15% of operator cost	2,995
(2)	Maintenance	Engineering estimate, 5% of catalyst replacement cost	44,737
(3)	SCR Energy Requirement	80 kW/hr for SCR @ $0.04/kW-hr	28,032
(5)	Ammonia Cost	$580 per ton NH3, 19% Aqueous, NH3 = NOx * 17/46 * 1.1 (110% of theoretical NH3)	183,660
(6)	Catalyst Replacement and disposal[c]	10,000 hours; est. 1.14 years	894,737 [d]
(7)	Reheat Energy Requirements	100 MMBtu/hr, 8760 hr/yr, $3/MMBtu	2,636,332
Total DOC:			3,810,461
CAPITAL RECOVERY COSTS (CRC):		CRF of 0.0944 times TCI (20 yrs @ 7%)	400,838
ANNUALIZED COSTS (AC):		DOC + CRC	4,211,300
BASELINE NO_x EMISSIONS (TPY) :		0.26 lb/MMBtu; 760 MMBtu/hr; 90% capacity factor	778.9 [e]
MAXIMUM NO_x EMISSIONS (TPY) :		0.08 lb/MMBtu; 760 MMBtu/hr; 90% capacity factor	239.7
REDUCTION IN NO_x EMISSONS (TPY):			539.3
COST EFFECTIVENESS:		$ per ton of NO_x Removed	7,809

Footnotes:

[a] Unless otherwise specified, factors and cost estimates reflect OAQPS Cost Manual, Section 4, Sixth edition.

[b] 2002 Hamon Research-Cottrell cost quote, 3 units = $4,250,000, includes SCR, ammonia flow control unit, and ammonia injection system. 1 cogeneration unit = $1,700,000

[c] $457 per ton of ammonia used per year (based on vendor quote).

[d] SCR catalyst replacement estimated to be 60% (based on experience with Englehard SCR systems) of the initial capital cost, with replacement every 1.14 years.

[e] Based on EPA AP-42, Fifth Edition, Volume 1, Bagasse and Wood Fired Boiler Emission Factors (50% Bagasse/50% Wood)

Table 5-4. Cost Effectiveness of Using Increased Urea Injection in Osceola Power's Cogeneration Boilers

Cost Item	Cost Factors	Estimated Cost ($)
DIRECT OPERATING COSTS (DOC):		
(1) Maintenance (a)	$600,000 maintenance cost over 4 months, prorated to annual basis	1,800,000
(2) Chemicals and Materials (b)		
Urea based chemical	10 gal/hr/boiler @ $1.00/gal	175,200
(3) Lost Generation (c)	37,800 Mw-hrs lost over 4 months @ $16.40/Mw-hr, prorated to annual basis	1,859,760
Total DOC:	(1) + (2) + (3)	3,834,960
CONTROLLED NOx EMISSIONS (TPY) @ 0.12 lb/MMBtu; two boilers		477
CONTROLLED NOx EMISSIONS (TPY) @ 0.15 lb/MMBtu; two boilers		627
TOTAL NOx REMOVED (TPY):		150
COST EFFECTIVENESS:	$ per ton of NOx Removed	25,566

Notes:
(a) Based on actual contract labor and replacement boiler tubers incurred during 4 month period, projected to annual basis, for Osceola Power L. P.
(b) Represents increased urea usage compared to NHPP (Okeelanta Power). Based on actual urea usage for 4 month period.
(c) Based on actual lost generation incurred during 4 month period, projected to annual basis,

6.0 AIR QUALITY IMPACT ANALYSIS

6.1 GENERAL APPROACH

The general modeling approach followed the EPA and the FDEP modeling guidelines for determining compliance with AAQS and PSD increments. For all criteria pollutants that will be emitted in excess of the PSD significant emission rate due to a proposed project, a significant impact analysis is performed to determine whether the emission and/or stack configuration changes due to the project alone will result in predicted impacts that are in excess of the EPA significant impact levels at any location beyond the plant's restricted boundaries.

Generally, if the facility undergoing the modification is within 200 kilometers of a PSD Class I area, then a significant impact analysis is also performed to evaluate the impact due to the project alone at the PSD Class I area. Because the ENP is a PSD Class I area that is located within 200 km of the proposed project, the maximum predicted impacts at the ENP are compared to the EPA's proposed significant impact levels for PSD Class I areas. These recommended levels have never been promulgated as rules but are the currently accepted criteria to determine whether a proposed project will result in a significant impact on a PSD Class I area.

If the project-only impacts are above the significant impact levels in the vicinity of the facility, then two additional and more detailed air modeling analyses are required. The first analysis demonstrates compliance with federal and Florida ambient air quality standards (AAQS), and the second analysis demonstrates compliance with allowable PSD Class II increments.

If the project-only impacts at the PSD Class I area are above the proposed the EPA PSD Class I significant impact levels, then an analysis is performed to demonstrate compliance with allowable PSD Class I impacts at the PSD Class I area. In addition, the proposed project's maximum emission increases are evaluated at the PSD Class I area to support the AQRV analysis, including evaluations of regional haze degradation and nitrogen and sulfur deposition.

Generally, when using five years of meteorological data for the analysis, the highest annual and the HSH short-term concentrations are compared to the applicable AAQS and allowable PSD increments. [Note that for determining compliance with the 24-hour AAQS for particulate matter only, the sixth highest predicted concentration in 5 years (i.e., H6H), instead of the HSH, is used to compare to the applicable 24-hour AAQS.]

The HSH concentration is calculated for a receptor field by:

1. Eliminating the highest concentration predicted at each receptor,
2. Identifying the second-highest concentration at each receptor, and
3. Selecting the highest concentration among these second-highest concentrations.

The HSH approach is consistent with air quality standards and allowable PSD increments, which permit a short-term average concentration to be exceeded once per year at each receptor.

To develop the maximum short-term concentrations for the proposed project, the modeling approach was divided into screening and refined phases to reduce the computation time required to perform the modeling analysis. For this study, the only difference between the two modeling phases is the density of the receptor grid spacing employed when predicting concentrations. Concentrations are predicted for the screening phase using a coarse receptor grid and a 5-year meteorological data record.

If the original screening analysis indicates that the highest concentrations are occurring in selected area(s) of the grid, and if the area's total coverage is too vast to directly apply a refined receptor grid, then additional screening grid(s) will be used over that area. The additional screening grid(s) will employ a greater receptor density than the original screening grid.

Refinements of the maximum predicted concentrations are typically performed for the receptors of the screening receptor grid at which the highest and/or HSH concentrations occurred over the 5-year period. Generally, if the maximum concentrations from other years in the screening analysis are within 10 percent of the overall maximum concentration, then those other concentrations are refined as well. Typically, if the highest and HSH concentrations are in different locations, concentrations in both areas are refined.

A more detailed description of the model, along with the emission inventory, meteorological data, and screening receptor grids, is presented in the following sections.

6.2 SIGNIFICANT IMPACT ANALYSIS

The FDEP policies stipulate that the highest annual average and highest short-term (i.e., 24 hours or less) concentrations are to be compared to the applicable significant impact levels both in the vicinity of the project and at the PSD Class I area. Based on the screening modeling analysis results in the vicinity of the project, additional modeling refinements are performed, if necessary, to obtain the maximum concentration with a receptor grid spacing of 100 meters (m) or less.

In this analysis, one source, representing the three NHPP cogeneration boilers and an area source representing the particulate fugitive emissions, was modeled to represent the proposed future case at NHPP. Current actual emissions and future maximum emissions were modeled to determine if the proposed project would have a significant impact on off-site receptors. The significant impact analysis is used to determine pollutants for which more detailed modeling analyses are required. This analysis is also used to determine the geographic area within which other background sources will be considered for inclusion in the modeling analysis. This area is referred to as "the screening area". The screening area extends 50 km beyond the significant impact distance, from the NHPP location.

6.3 AAQS AND PSD CLASS II ANALYSES

For each pollutant for which a significant impact is predicted in the vicinity of the project, AAQS and PSD Class II analyses are required. The AAQS analysis is a cumulative source analysis that evaluates whether the post-project concentrations from all sources will comply with the AAQS. All sources include the post-project source configuration at the project site, the impacts from other sources within the significant impact area, and a background concentration to account for sources not included explicitly in the modeling analysis. Large sources (greater than 1,000 TPY emissions) outside of the significant impact area were also included in the modeling analysis.

The PSD Class II analysis is a cumulative source analysis that evaluates whether the post-project PSD increment concentrations due to all increment-affecting sources will comply with the allowable PSD Class II increments. All sources include the post-project PSD increment-affecting sources at the project site, plus the impacts from all other PSD increment-affecting sources located within the significant impact area.

6.4 PSD CLASS I ANALYSIS

For each pollutant for which a significant impact is predicted at the PSD Class I area, a PSD Class I analysis is required. The PSD Class I analysis is a cumulative source analysis that evaluates whether the post-project PSD increment concentrations for all increment-affecting sources located within the air shed domain of the PSD Class I area will comply with the allowable PSD Class I increments. All sources include the post-project PSD increment-affecting sources at the project site, plus the impacts from all PSD increment-affecting sources located within the air shed domain of the Class I area. Based on previous PSD modeling studies performed for South Florida, the domain for the ENP extends to the north of the ENP to include Martin, Lee, and Hendry counties.

6.5 MODEL SELECTION

The Industrial Source Complex Short-term (ISCST3, Version 00101) dispersion model (EPA, 2000) was used to evaluate the pollutant impacts due to the proposed project in areas within 50-km of the NHPP facility. This model is maintained by the EPA on its internet web site, Support Center for Regulatory Air Models (SCRAM), within the Technical Transfer Network (TTN). A listing of ISCST3 model features is presented in Table 6-1. The ISCST3 model is designed to calculate hourly concentrations based on hourly meteorological data (i.e., wind direction, wind speed, atmospheric stability, ambient temperature, and mixing heights). The ISCST3 model is applicable to sources located in either flat or rolling terrain where terrain heights do not exceed stack heights. These areas are referred to as simple terrain. The model can also be applied in areas where the terrain exceeds the stack heights. These areas are referred to as complex terrain.

In this analysis, the EPA regulatory default options were used to predict all maximum impacts. The ISCST3 model can be executed in the rural or urban land use mode. The mode affects stability dispersion coefficients, wind speed profiles, and mixing heights. Land use can be characterized based on a scheme recommended by the EPA (Auer, 1978). If more than 50 percent land use within a 3-km radius around a project site is classified as industrial, commercial, or high-density residential, then the urban option should be selected. Otherwise, the rural option is appropriate. Based on the land use within a 3-km radius of the NHPP plant site (see Attachment NH-FI-C1), the rural dispersion coefficients were used in the modeling analysis. Also, since the terrain around the facility is flat to gently rolling, the simple terrain feature of the model was selected. The ISCST3 model was used to provide maximum concentrations for the annual and 24-, 8-, 3-, and 1-hour averaging times.

For predicting maximum impacts at the ENP PSD Class I area, the California Puff (CALPUFF) modeling system was used. CALPUFF, Version 5.5 (EPA, 2001), is a Lagrangian puff model that is recommended by the FDEP, in coordination with the Federal Land Manager (FLM) for the ENP, for predicting pollutant impacts at PSD Class I areas that are beyond 50 km from a project site. A listing of CALPUFF model features is presented in Table 6-2.

6.6 METEOROLOGICAL DATA

Meteorological data used in the ISCST3 model to determine air quality impacts consisted of a concurrent 5-year period of hourly surface weather observations and twice-daily upper air soundings from the National Weather Service (NWS) office located at the Palm Beach International Airport (PBI). The 5-year period of meteorological data was from 1987 through 1991. The NWS office at PBI is located approximately 64 km east of the site and is the closest primary weather station to the study area considered to have meteorological data representative of the project site. The PBI station meteorological data have been approved by the FDEP and used for numerous air modeling studies submitted as part of air construction permit application for sources located in Palm Beach County.

Meteorological data used with the CALPUFF model consist of a CALMET-developed wind field covering all of south Florida. A detailed description of the CALMET wind field is provided in Appendix G.

6.7 EMISSION INVENTORY

6.7.1 SIGNIFICANT IMPACT ANALYSIS

Stack parameters, emissions, and area source parameters used in the significant impact analysis for NHPP are shown in Tables 6-3, 6-4, and 6-5, respectively. The physical and operational stack parameters for each cogeneration boiler stack are summarized in Table 6-3. The current actual and future maximum emission rates for all three cogeneration boilers combined are summarized in Table 6-4. The emission rate, location, and dimensions of the source representing the fugitive dust emission sources are presented in Table 6-5. Those sources were modeled as a single area source. The future and current actual emissions for each pollutant were modeled. These tables are based on emissions and stack parameters presented in Section 2.0. The current actual short-term emissions are based on three boilers operating at 715 MMBtu/hr and stack test data, continuous emission monitoring (CEM) data, and current permit limits. The current actual annual emissions are based on 2000 and 2001 AOR data.

The current and future CO short-term emissions are based on normal operation since the cold-startup operation and emissions for the boilers are not changing as part of this project. The increase in heat input rate will only affect the normal operation emission rates.

NHPP cogeneration Boiler B stack was used as the modeling origin. This modeling origin has been used in previous PSD applications for NHPP.

Based on the results of the significant impact analysis, the proposed project was predicted to be significant for SO_2 only (refer to Section 6.11.1). It was further determined that the project was significant out to 11 km from the facility.

6.7.2 AAQS AND PSD CLASS II ANALYSES

A listing of background SO_2 sources used in the AAQS and PSD Class II modeling analyses and their locations relative to NHPP is provided in Table 6-6. All facilities were evaluated using the North Carolina screening technique. Based on this technique, facilities whose annual (i.e., TPY) emissions are less than the threshold quantity, Q, are eliminated from the modeling analysis. Q is equal to 20 x (D-SIA), where D is the distance in km from the facility to NHPP and SIA is the distance of the proposed project's SO_2 significant impact area (11 km). The SO_2 emitting facilities that were not eliminated in the screening analysis are available for inclusion in the AAQS and/or PSD Class II analyses. Large sources (greater than 1,000 TPY emissions) located outside the screening area were included in the modeling analysis.

Detailed SO_2 background source data that were used for the AAQS and/or PSD Class II analyses are presented in Appendix H. Non-NHPP SO_2 PSD sources were obtained from the FDEP and were supplemented with current and historical information available within Golder.

6.7.3 PSD CLASS I ANALYSIS

A listing of background SO_2 sources that were used in the PSD Class I analysis and their locations relative to the ENP PSD Class I area is provided in Table 6-7. All PSD sources located within 200 km of the ENP were included in the PSD Class I modeling analysis. Detailed SO_2 background source data that were used for the PSD Class I analysis are presented in Appendix H.

6.8 RECEPTOR LOCATIONS

6.8.1 SITE VICINITY

To determine the SO_2 significant impact area for the proposed project, concentrations were predicted using polar receptor grids. The receptor grids were comprised of 36 radials, spaced at 10-degree intervals, that began at the plant property and extended out to 10 km. Additional receptors were located out to 35 km to identify the significant impact distance for the 3-hour and 24-hour SO_2 concentrations. An additional 393 Cartesian grid receptors, spaced at 100 m, were used to predict impacts along the fence line areas. A summary of the fence line receptors are presented in Table 6-8.

At the off-property areas between the fence line and the innermost ring distance of 4.0 km, 79 discrete polar receptors were used, spaced at 10-degree intervals and at distances of 4, 5, 6, 7, 8, 9, and 10 km from the origin. All receptor locations are relative to the cogeneration Boiler B (center stack) stack location, an origin which has been used for historical modeling analyses for NHPP.

Based on the results of the significant impact analysis, a maximum receptor distance of 11 km, based on the 24-hour and 3-hour emissions, was used for SO_2 for the screening grids for the AAQS and PSD Class II analyses. The receptor locations out to 11 km from the facility, along with the plant property boundary and the modeling origin, are shown in Figure 6-1.

Because the proposed project was determined to be insignificant for PM_{10}, CO, and NO_x, further modeling was not performed for these pollutants (refer to Section 6.11.1).

6.8.2 CLASS I AREA

Maximum SO_2, NO_x, SAM, PM_{10}, F, CO, and Pb concentrations were predicted at the ENP with the CALPUFF model using 126 discrete receptors located along the border of the ENP PSD Class I area. Impacts for the proposed project only were compared to both the proposed EPA Class I significance levels, the regional haze degradation criteria of 5 percent, and the nitrogen and sulfur deposition thresholds. The SO_2, NO_x, SAM, PM_{10}, F, CO, and Pb impacts were used to assess the proposed project's impacts on the ENP AQRVs. A listing of Class I receptors used in the modeling analysis is provided in Table 6-9.

6.9 BACKGROUND CONCENTRATIONS

To estimate total air quality concentrations in the site vicinity, a background concentration must be added to the AAQS modeling results. The background concentration is considered to be the air quality concentration contributed by sources not included in the modeling evaluation.

The derivation of the background concentration for the modeling analysis was presented in Section 4.0. Based on this analysis, the SO_2 background concentrations were determined to be 5, 13, and 47 $\mu g/m^3$ for the annual, 24-hour, and 3-hour averaging periods, respectively. These background levels were added to model-predicted concentrations to estimate total air quality levels for comparison to AAQS.

6.10 BUILDING DOWNWASH EFFECTS

All significant building structures within NHPP's existing plant area were determined by a site plot plan. The plot plan of the proposed project was presented in the permit application (Attachment NH-FI-C2). All building structures were processed in the EPA Building Profile Input Program (BPIP, Version 95086) program to determine direction-specific building heights and widths for each 10-degree azimuth direction for each source that was included in the modeling analysis. A listing of dimensions for each structure is presented in Table 6-10. A plot plan of the facility, showing the major structures and stacks in relation to the modeling origin, is provided in Figure 6-2.

6.11 MODEL RESULTS

6.11.1 SIGNIFICANT IMPACT ANALYSIS

A summary of the predicted maximum SO_2, PM_{10}, NO_2, and CO concentrations for the proposed project-only for the significant impact analysis is presented in Table 6-11. The modeling results indicated that maximum predicted concentrations due to the proposed project are above the significant impact levels for only SO_2. It was further determined that the significant impact area for the proposed project's SO_2 emissions extends out approximately 11 km from NHPP. As a result, additional modeling analyses were performed for SO_2 to address compliance with AAQS and PSD increments.

6.11.2 AAQS ANALYSIS

A summary of the maximum annual, HSH 24-hour, and HSH 3-hour average SO_2 concentrations predicted for all sources from the screening analysis is presented in Table 6-12. Based on the screening analysis results, modeling refinements were performed. The results of the refined modeling analysis are presented in Table 6-13.

The maximum predicted annual, HSH 24-hour, and HSH 3-hour SO_2 concentrations are 25.1, 145, and 517 $\mu g/m^3$, respectively. These concentrations include ambient non-modeled annual, 24-hour, and 3-hour concentrations of 5, 13, and 47 $\mu g/m^3$, respectively. The maximum predicted annual, HSH 24-hour, and HSH 3-hour average SO_2 concentrations are below the Florida AAQS of 60, 260, and 1,300 $\mu g/m^3$, respectively.

6.11.3 PSD CLASS II ANALYSIS

Summaries of the maximum SO_2 PSD increment consumption predicted for all sources for the screening analysis is presented in Table 6-14. Based on the screening analysis results, modeling refinements were performed. The results of the refined modeling analysis are presented in Table 6-15.

The maximum predicted annual, HSH 24-hour, and HSH 3-hour SO_2 increment consumption concentrations of 5.6, 62, and 218 $\mu g/m^3$, respectively, are less than the allowable PSD Class II increments of 20, 91, and 512 $\mu g/m^3$, respectively.

6.11.4 PSD CLASS I ANALYSIS

The maximum SO_2, PM_{10}, and NO_2, concentrations predicted for the proposed project only at the ENP PSD Class I area are compared with the EPA's proposed PSD Class I significance levels in Table 6-16. All maximum predicted impacts were below the significant impact levels except for SO_2. The maximum 24-hour and 3-hour SO_2 impacts were 0.45 and 1.1 $\mu g/m^3$, respectively, which are above the proposed Class I significant impact levels of 0.2 and 1.0 $\mu g/m^3$, respectively. Therefore, a full PSD Class I incremental analysis was performed for SO_2.

The maximum 24-hour and 3-hour SO_2 PSD Class I increment consumption, due to all increment affecting sources, is summarized in Table 6-17. The maximum predicted HSH 24-hour and HSH 3-hour SO_2 increment consumption concentrations of 3.99 and 12.2 $\mu g/m^3$, respectively, are below the allowable PSD Class I increments of 5 and 25 $\mu g/m^3$, respectively.

6.11.5 FLUORIDE IMPACTS

There are no AAQS or PSD increments for fluorides. However, fluoride impacts are required for the additional impact analysis. Maximum fluoride concentrations due to the proposed project in the site vicinity are presented in Table 6-18, for the annual, 24-, 8-, 3-, and 1-hour averaging times. In the site vicinity, the maximum predicted annual, 24-, 8-, 3-, and 1-hour fluoride concentrations are 0.0037, 0.017, 0.030, 0.046, and 0.09 $\mu g/m^3$, respectively.

Fluoride impacts are also required for the AQRV analysis for the PSD Class I area. This analysis and fluoride impacts at the ENP are presented in Section 7.0.

6.11.6 SAM IMPACTS

There are no AAQS or PSD increments for SAM. However, SAM impacts are required for the additional impact analysis. Maximum SAM concentrations due to the proposed project in the site vicinity are presented in Table 6-19, for the annual, 24-, 8-, 3-, and 1-hour averaging times. In the site vicinity, the maximum predicted annual, 24-, 8-, 3-, and 1-hour SAM concentrations are 0.015, 0.57, 0.97, 1.50, and 2.92 $\mu g/m^3$, respectively.

SAM impacts are also required for the AQRV analysis for the PSD Class I area. This analysis and SAM impacts at the ENP are presented in Section 7.0.

6.11.7 LEAD IMPACTS

There are no significant impact levels or PSD increments for Pb. Therefore, further AAQS and PSD increment modeling is not required. However, Pb impacts are required for the additional impact analysis. Maximum Pb concentrations due to the proposed project in the site vicinity are presented in Table 6-20, for the annual, 24-, 8-, 3-, and 1-hour averaging times. In the site vicinity, the maximum predicted annual, 24-, 8-, 3-, and 1-hour Pb concentrations are 0.0011, 0.007, 0.012, 0.018, and 0.035 $\mu g/m^3$, respectively. The 3-month average predicted Pb concentration of 0.0044 $\mu g/m^3$ (refer to Table 3-4) is well below the AAQS of 15 $\mu g/m^3$.

Pb impacts are also required for the AQRV analysis for the PSD Class I area. This analysis and Pb impacts at the ENP are presented in Section 7.0.

Table 6-1. Major Features of the ISCST3 Model

ISCST3 Model Features
• Polar or Cartesian coordinate systems for receptor locations
• Rural or one of three urban options which affect wind speed profile exponent, dispersion rates, and mixing height calculations
• Plume rise due to momentum and buoyancy as a function of downwind distance for stack emissions (Briggs, 1969, 1971, 1972, and 1975; Bowers, et al., 1979).
• Procedures suggested by Huber and Snyder (1976); Huber (1977); and Schulman and Scire (1980) for evaluating building wake effects
• Procedures suggested by Briggs (1974) for evaluating stack-tip downwash
• Separation of multiple emission sources
• Consideration of the effects of gravitational settling and dry deposition on ambient particulate concentrations
• Capability of simulating point, line, volume, area, and open pit sources
• Capability to calculate dry and wet deposition, including both gaseous and particulate precipitation scavenging for wet deposition
• Variation of wind speed with height (wind speed-profile exponent law)
• Concentration estimates for 1 hour to annual average times
• Terrain-adjustment procedures for elevated terrain including a terrain truncation algorithm for ISCST3, a built-in algorithm for predicting concentrations in complex terrain
• Consideration of time-dependent exponential decay of pollutants
• The method of Pasquill (1976) to account for buoyancy-induced dispersion
• A regulatory default option to set various model options and parameters to the EPA recommended values (see text for regulatory options used)
• Procedure for calm-wind processing including setting wind speeds less than 1 m/s to 1 m/s.

Note: ISCST3 = Industrial Source Complex Short-Term.

References:

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Schulman, L.L. and J.S. Scire. 1980. Buoyant Line and Point Source (BLP) Dispersion Model User's Guide. Document P-7304B, Environmental Research and Technology, Inc., Concord, MA.

Table 6-2. Major Features of the CALPUFF Model, Version 5.5

CALPUFF Model Features
• Source types: Point, line (including buoyancy effects), volume, area (buoyant, non-buoyant) • Non-steady-state emissions and meteorological conditions (time-dependent source and emission data; gridded 3-dimensional wind and temperature fields; spatially-variable fields of mixing heights, friction velocity, precipitation, Monin-Obukhov length; vertically and horizontally-varying turbulence and dispersion rates; time-dependent source and emission data for point, area, and volume sources; temporal or wind-dependent scaling factors for emission rates) • Efficient sampling function [integrated puff formulation; elongated puff (slug) formation] • Dispersion coefficient options (Pasquill-Gifford (PG) values for rural areas; McElroy-Pooler values (MP) for urban areas; CTDM values for neutral/stable; direct measurements or estimated values) • Vertical wind shear (puff splitting; differential advection and dispersion) • Plume rise (buoyant and momentum rise; stack-tip effects; building downwash effects; partial plume penetration above mixing layer) • Building downwash effects (Huber-Snyder method; Schulman-Scire method) • Complex terrain effects (steering effects in CALMET wind field; puff height adjustments using ISC model method or plume path coefficient; enhanced vertical dispersion used in CTDMPLUS) • Subgrid scale complex terrain (CTSG option) (CTDM flow module; dividing streamline as in CTDMPLUS) • Dry deposition (gases and particles; options for diurnal cycle per pollutant, space and time variations with a resistance model, or none) • Overwater and coastal interaction effects (overwater boundary layer parameters; abrupt change in meteorological conditions, plume dispersion at coastal boundary; fumigation; option to use Thermal Internal Boundary Layers (TIBL) into coastal grid cells) • Chemical transformation options (Pseudo-first-order chemical mechanisms for SO_2, SO_4, HNO_3, and NO_3; Pseudo-first-order chemical mechanisms for SO_2, SO_4, NO, NO_2, HNO_3, and NO_3 (RIVAD/ARM3 method); user-specified diurnal cycles of transformation rates; no chemical conversions) • Wet removal (scavenging coefficient approach; removal rate as a function of precipitation intensity and type) • Graphical user interface • Interface utilities (scan ISCST3 and AUSPLUME meteorological data files for problems; translate ISCST3 and AUSPLUME input files to CALPUFF input files

Note: CALPUFF = California Puff Model.
Source: EPA, 2001.

Table 6-3. Stack Parameters[a] for New Hope Power Partnership Boilers

ISCST ID	Heat Input Rate (MMBtu/hr)	Stack/Vent Release Height		Stack/Vent Diameter		Gas Flow Rate (acfm)	Gas Exit Temperature		Velocity	
		ft	m	ft	m		°F	K	ft/sec	m/sec
Current										
COGENC	715	199	60.66	10	3.05	300,000	352	450.93	63.6	19.39
Future										
COGENF	760	199	60.66	10	3.05	319,000	352	450.93	67.7	20.63

[a] Representative of all 3 boiler stacks.

Table 6-4. Cogeneration Boiler Emission Rates for New Hope Power Partnership--Total all Three Boilers

Pollutant	Current Total Heat Input Rate[a] (MMBtu/hr)	CURRENT ACTUAL EMISSIONS Emission Factor (lb/MMBtu)	Short-Term Emissions lb/hr	Short-Term Emissions g/sec	Annual Average Emissions[f] TPY	Annual Average Emissions[f] g/sec	FUTURE POTENTIAL EMISSIONS Short-Term Emissions[g] lb/hr	Short-Term Emissions[g] g/sec	Annual Average Emissions[h] TPY	Annual Average Emissions[h] g/sec
Particulate (PM_{10})--24-hr Average	2,145	0.018 [b]	38.61	4.86	--	--	68.4	8.62	--	--
--Annual Average	--	--	--	--	108.02	3.11	--	--	299.6	8.62
Sulfur Dioxide--3-hr Average	2,145	0.17 [c]	364.65	45.95	--	--	684.0	86.18	--	--
--24-hr Average	2,145	0.10 [c]	214.50	27.03	--	--	456.0	57.46	--	--
--Annual Average	--	--	--	--	191.90	5.52	--	--	599.2	17.24
Nitrogen Oxides--24-hr Average	2,145	0.15 [e]	321.75	40.54	--	--	456.0	57.46	--	--
--Annual Average	--	--	--	--	756.60	21.76	--	--	1,498.0	43.09
Carbon Monoxide--1-hr Average	2,145	1.0 [c]	2,145.0	270.3	--	--	2,280.0	287.3	--	--
--8-hr Average	2,145	1.0 [c]	2,145.0	270.3	--	--	2,280.0	287.3	--	--
--Annual Average	--	--	--	--	1,335.4	38.42	--	--	3,495.2	100.55
Sulfuric Acid Mist--24-hr Average	2,145	0.012 [e]	25.74	3.24	--	--	41.04	5.17	--	--
--Annual Average	--	--	--	--	15.71	0.45	--	--	35.95	1.034
Fluorides--24-hr Average	2,145	5.3E-04 [b]	1.1369	0.1432	--	--	1.60	0.20	--	--
--Annual Average	--	--	--	--	2.163	0.062	--	--	6.99	0.201
Lead--24-hr Average	2,145	7.5E-05 [b]	0.1607	0.020	--	--	0.34	0.043	--	--
--Annual Average	--	--	--	--	0.098	0.0028	--	--	1.50	0.043

[a] Three boilers at the current heat input rate of 715 MMBtu/hr each.
[b] Based on 2001 stack test data.
[c] Based on CEM data.
[d] Based on current permit limit (30-day rolling average).
[e] Based on 6% of SO_2 emissions (Permit No. 0990332-014-AC).
[f] Actual annual emissions from Appendix A, Table A-1.
[g] Future potential emissions from Table 2-2.
[h] Future potential emissions from Table 2-3.

Table 6-5. Fugitive Dust Emissions and Area Source Modeling Parameters for Biomass and Ash Handling System, New Hope Power Partnership

ISCST3 Source ID	PM_{10} Annual Emission Rate		Southwest Corner Location		Height	Length		Area Source Size	Area Source Emission Rate
	TPY	g/s	X (m)	Y (m)	(m)	X dimension (m)	Y Dimension (m)	(m^2)	(g/m^2-s)
MATHAND	3.496 [a]	0.101	110	-12	6.1	171	137	23,420	0.0000043

[a] Refer to Table 2-4 for derivation.

Table 6-6. Summary of SO_2 Facilities Considered for Inclusion in the AAQS and PSD Class II Air Modeling Analyses, New Hope Power Partnership

			UTM Coordinates		Relative to Palm Beach Power [a]				Maximum SO_2	Q, Emission	Include in
AIRS Number	Facility	County	East (km)	North (km)	X (km)	Y (km)	Distance (km)	Direction (deg)	Emissions (TPY)	Threshold [b] (Dist - SIA) x 20	Modeling Analysis ?
0990005	Okeelanta Corp.	Palm Beach	525.0	2937.4	0.1	-2.7	2.7	178	39	SIA	YES
0990086	Glades Correctional Institute	Palm Beach	523.4	2955.2	-1.5	15.1	15.2	354	98	83.5	YES
0990594	El Paso Belle Glade Generating Station	Palm Beach	533.5	2954.1	8.6	14.0	16.4	32	69	108.6	NO
0990026	Sugar Cane Growers	Palm Beach	534.9	2953.3	10.0	13.2	16.6	37	2,555	111.2	YES
0510001	Everglades Sugar	Hendry	509.6	2954.2	-15.3	14.1	20.8	313	1,216	196.1	YES
0510003	U.S. Sugar Clewiston	Hendry	506.1	2956.9	-18.8	16.8	25.2	312	7,806	284.3	YES
0990016	Atlantic Sugar	Palm Beach	552.9	2945.2	28.0	5.1	28.5	80	954	349.2	YES
0990349	South Florida WMD--Pump Stn. G-310/S-6	Palm Beach	554.2	2940.5	29.3	0.4	29.3	89	5	366.1	NO
0990061	U.S. Sugar -Bryant	Palm Beach	537.8	2969.2	12.9	29.1	31.8	24	2,698	415.9	YES
	Palm Beach Power Corp. (Osceola Power)	Palm Beach	544.4	2967.4	19.5	27.3	33.5	0	451	451.0	NO
0990019	Osceola Farms	Palm Beach	544.2	2968.0	19.3	27.9	33.9	0	1,467	458.5	YES
0510015	Southern Gardens Citrus	Hendry	487.6	2957.6	-37.3	17.5	41.2	295	409	604.0	NO
0990021	Pratt & Whitney (United Technologies)	Palm Beach	562.0	2960.0	37.1	19.9	42.1	62	504	622.0	NO
0850102	Bechtel Indiantown	Martin	545.6	2991.5	20.7	51.4	55.4	22	2,629	888.2	YES
0850001	FPL - Martin	Martin	543.1	2992.9	18.2	52.8	55.8	19	22,982	897.0	YES
0990234	Palm Beach Resource Recovery [c]	Palm Beach	585.8	2960.2	60.9	20.1	64.1	72	1,533	1062.6	YES
0990350	South Florida WMD--Pump Stn. S-9	Broward	555.9	2882.2	31.0	-57.9	65.7	152	2	1093.2	NO
0112534	Enron/Deerfield Beach Energy Center	Broward	583.1	2907.9	58.2	-32.2	66.5	119	166	1110.3	NO
0112545	El Paso Broward Energy Center	Broward	583.3	2908.0	58.4	-32.1	66.6	119	87	1112.8	NO
0110120	North Broward Resource Recovery	Broward	583.6	2907.6	58.7	-32.5	67.1	119	896	1121.9	NO
0990045	Lake Worth Utilities [c]	Palm Beach	592.8	2943.7	67.9	3.6	68.0	87	7,415	1139.9	YES
0990568	Lake Worth Generating	Palm Beach	592.8	2943.7	67.9	3.6	68.0	87	54	1139.9	NO
0112515	Enron/Pompano Energy Center	Broward	583.7	2905.5	58.8	-34.6	68.2	120	166	1144.5	NO
0990042	FPL -Riviera Beach [c]	Palm Beach	594.2	2960.6	69.3	20.5	72.3	74	73,475	1225.4	YES
0112119	South Broward Resource Recovery [c]	Broward	579.6	2883.3	54.7	-56.8	78.9	136	1,318	1357.1	YES
0110037	FPL -Lauderdale [c]	Broward	580.1	2883.3	55.2	-56.8	79.2	136	47,858	1364.1	YES
1110103	CPV Cana, LTD.	St. Lucie	550.9	3018.1	26.0	78.0	82.2	18	76	1424.4	NO
0110036	FPL -Port Everglades [c]	Broward	587.4	2885.3	62.5	-54.8	83.1	131	170,215	1442.4	YES
0850021	Stuart Contracting	Martin	575.2	3006.8	50.3	66.7	83.5	37	100	1450.8	NO
0250020	Tarmac [c]	Dade	562.9	2861.7	38.0	-78.4	87.1	154	2,792	1522.5	YES
0250348	Dade Co. Resource Recovery	Dade	564.3	2857.4	39.4	-82.7	91.6	155	857	1612.1	NO
0710019	Lee County Resource Recovery	Lee	424.2	2945.7	-100.7	5.6	100.9	273	163	1797.1	NO
0710000	FPL - Fort Myers [c]	Lee	422.1	2952.9	-102.8	12.8	103.6	277	22,702	1851.9	YES
1110003	Fort Pierce Utilities [c]	St. Lucie	566.8	3036.3	41.9	96.2	104.9	24	1,497	1878.6	YES
0550018	TECO-Phillips [c]	Highlands	464.3	3035.4	-60.6	95.3	112.9	328	4,053	2038.7	YES
0550004	TECO-Sebring/Dinner Lake [c]	Highlands	456.8	3042.5	-68.1	102.4	123.0	326	1,313	2239.5	YES
0610029	Vero Beach Power [c]	St. Lucie	567.1	3056.5	42.2	116.4	123.8	20	10,274	2256.3	YES

Note: deg = degrees
km = kilometers
SIA = significant impact area
TPY = tons per year

[a] New Hope Power Partnership's East and North Coordinates (km) are: 524.9 and 2940.1 , respectively.

[b] Based on North Carolina Screening Technique for annual average basis. "Dist" is the distance the facility is located from the project.
"SIA" is the significant impact area. The project's 24-hour, 3-hour, and annual SO_2 concentrations are predicted to be significant out to 11 km from the project.

[c] Large source with annual emissions greater than 1,000 TPY located beyond the screening area (61 km) that were included in the inventory.

Table 6-7. Summary of SO_2 Facilities Included in the PSD Class I Air Modeling Analysis, New Hope Power Partnership

AIRS Number	Facility	County	UTM Coordinates East (km)	UTM Coordinates North (km)	Relative to Everglades National Park x (km)	y (km)	Distance [a] (km)	Direction (deg)
0250348	Dade Co. Resource Recovery	Dade	564.3	2857.4	14.3	8.8	16.8	58
0250020	Tarmac	Dade	562.9	2861.7	12.9	13.1	18.4	45
0112119	South Broward Resource Recovery	Broward	579.6	2883.3	29.6	34.7	45.6	40
0110037	FPL -Lauderdale	Broward	580.1	2883.3	30.1	34.7	45.9	41
0112515	Enron/Pompano Energy Center	Broward	583.7	2905.5	33.7	56.9	66.1	31
0110120	North Broward Resource Recovery	Broward	583.6	2907.6	33.6	59.0	67.9	30
0112534	Enron/Deerfield Beach Energy Center	Broward	583.1	2907.9	33.1	59.3	67.9	29
0112545	El Paso Broward Energy Center	Broward	583.3	2908.0	33.3	59.4	68.1	29
0710019	Lee County Resource Recovery	Lee	424.0	2946.0	-30.0	82.8	88.1 [b]	340
0990005	Okeelanta Corp.	Palm Beach	525.0	2937.4	-25.0	88.8	92.3	344
0710000	FPL - Fort Myers	Lee	422.1	2952.9	-31.9	89.7	95.2 [b]	340
0990332	New Hope Power Partnership (Okeelanta)	Palm Beach	524.9	2940.1	-25.1	91.5	94.9	345
0990016	Atlantic Sugar	Palm Beach	552.9	2945.2	2.9	96.6	96.6	2
0990568	Lake Worth Utilities	Palm Beach	592.8	2943.7	42.8	95.1	104.3	24
0990568	Lake Worth Generating	Palm Beach	592.8	2943.7	42.8	95.1	104.3	24
0990026	Sugar Cane Growers Coop.	Palm Beach	534.9	2953.3	-15.1	104.7	105.8	352
0990594	El Paso Belle Glade Generating Station	Palm Beach	533.5	2954.1	-16.5	105.5	106.8	351
0510003	U.S. Sugar Clewiston	Hendry	506.1	2956.9	-43.9	108.3	116.9	338
0990234	Palm Beach Resource Recovery	Palm Beach	585.8	2960.2	35.8	111.6	117.2	18
	Palm Beach Power Corp.	Palm Beach	544.4	2967.4	-5.6	118.8	118.9	357
0990019	Osceola Farms	Palm Beach	544.2	2968.0	-5.8	119.4	119.5	357
0990061	U.S. Sugar -Bryant	Palm Beach	537.8	2969.2	-12.2	120.6	121.2	354
0510015	Southern Gardens Citrus	Hendry	487.6	2957.6	-62.4	109.0	125.6	330
0990021	Pratt & Whitney	Palm Beach	559.2	2978.3	9.2	129.7	130.0	4
0850102	Bechtel Indiantown	Martin	545.6	2991.5	-4.4	142.9	143.0	358
0850001	FPL -Martin	Martin	543.1	2992.9	-6.9	144.3	144.5	357

[a] Distance from the northeastern corner of the Everglades National Park, UTM East and North coordinates (km) of 550.0 and 2848.6 , respectively, unless noted.
[b] Distance from the northwestern corner of the Everglades National Park, UTM East and North coordinates (km) of 454.0 and 2863.2 , respectively.

Table 6-8. New Hope Power Partnership (NHPP) Property Boundary Receptors[a] Used In the Modeling Analysis

Coordinates[b]		Coordinates[b]		Coordinates[b]		Coordinates[b]		Coordinates[b]	
X (m)	Y (m)	X (m)	Y (m)	X (m)	Y (m)	X (m)	Y (m)	X (m)	Y (m)
-9699.6	444.2	-9509.5	3738.7	-6259.5	3791.6	-2959.5	3791.6	340.5	3791.6
-9693.9	544.0	-9459.5	3791.6	-6159.5	3791.6	-2859.5	3791.6	440.5	3791.6
-9688.1	643.9	-9359.5	3791.6	-6059.5	3791.6	-2759.5	3791.6	540.5	3791.6
-9682.3	743.7	-9259.5	3791.6	-5959.5	3791.6	-2659.5	3791.6	640.5	3791.6
-9676.6	843.5	-9159.5	3791.6	-5859.5	3791.6	-2559.5	3791.6	740.5	3791.6
-9670.8	943.4	-9059.5	3791.6	-5759.5	3791.6	-2459.5	3791.6	840.5	3791.6
-9665.1	1043.2	-8959.5	3791.6	-5659.5	3791.6	-2359.5	3791.6	940.5	3791.6
-9659.3	1143.0	-8859.5	3791.6	-5559.5	3791.6	-2259.5	3791.6	1040.5	3791.6
-9653.5	1242.9	-8759.5	3791.6	-5459.5	3791.6	-2159.5	3791.6	1140.5	3791.6
-9647.8	1342.7	-8659.5	3791.6	-5359.5	3791.6	-2059.5	3791.6	1240.5	3791.6
-9642.0	1442.5	-8559.5	3791.6	-5259.5	3791.6	-1959.5	3791.6	1340.5	3791.6
-9636.3	1542.4	-8459.5	3791.6	-5159.5	3791.6	-1859.5	3791.6	1440.5	3791.6
-9630.5	1642.2	-8359.5	3791.6	-5059.5	3791.6	-1759.5	3791.6	1540.5	3791.6
-9624.7	1742.0	-8259.5	3791.6	-4959.5	3791.6	-1659.5	3791.6	1640.5	3791.6
-9619.0	1841.9	-8159.5	3791.6	-4859.5	3791.6	-1559.5	3791.6	1740.5	3791.6
-9613.2	1941.7	-8059.5	3791.6	-4759.5	3791.6	-1459.5	3791.6	1840.5	3791.6
-9607.5	2041.5	-7959.5	3791.6	-4659.5	3791.6	-1359.5	3791.6	1940.5	3791.6
-9601.7	2141.4	-7859.5	3791.6	-4559.5	3791.6	-1259.5	3791.6	2040.5	3791.6
-9595.9	2241.2	-7759.5	3791.6	-4459.5	3791.6	-1159.5	3791.6	2140.5	3791.6
-9590.2	2341.0	-7659.5	3791.6	-4359.5	3791.6	-1059.5	3791.6	2240.5	3791.6
-9584.4	2440.9	-7559.5	3791.6	-4259.5	3791.6	-959.5	3791.6	2306.1	3757.2
-9578.7	2540.7	-7459.5	3791.6	-4159.5	3791.6	-859.5	3791.6	2306.1	3657.2
-9572.9	2640.5	-7359.5	3791.6	-4059.5	3791.6	-759.5	3791.6	2306.1	3557.2
-9567.1	2740.4	-7259.5	3791.6	-3959.5	3791.6	-659.5	3791.6	2306.1	3457.2
-9561.4	2840.2	-7159.5	3791.6	-3859.5	3791.6	-559.5	3791.6	2306.1	3357.2
-9555.6	2940.0	-7059.5	3791.6	-3759.5	3791.6	-459.5	3791.6	2306.1	3257.2
-9549.9	3039.9	-6959.5	3791.6	-3659.5	3791.6	-359.5	3791.6	2306.1	3157.2
-9544.1	3139.7	-6859.5	3791.6	-3559.5	3791.6	-259.5	3791.6	2306.1	3057.2
-9538.3	3239.5	-6759.5	3791.6	-3459.5	3791.6	-159.5	3791.6	2306.1	2957.2
-9532.6	3339.4	-6659.5	3791.6	-3359.5	3791.6	-59.5	3791.6	2306.1	2857.2
-9526.8	3439.2	-6559.5	3791.6	-3259.5	3791.6	40.5	3791.6	2306.1	2757.2
-9521.1	3539.0	-6459.5	3791.6	-3159.5	3791.6	140.5	3791.6	2306.1	2657.2
-9515.3	3638.9	-6359.5	3791.6	-3059.5	3791.6	240.5	3791.6	2306.1	2557.2

[a] Receptors were selected at 100-meter spacing along property boundary.

[b] Distances are relative to the NHPP Boiler B stack.

Note: m = meter

Table 6-8. New Hope Power Partnership Property Boundary Receptors[a] Used In the Modeling Analysis (continued)

Coordinates[b]		Coordinates[b]		Coordinates[b]		Coordinates[b]		Coordinates[b]	
X (m)	Y (m)	X (m)	Y (m)	X (m)	Y (m)	X (m)	Y (m)	X (m)	Y (m)
2306.1	2457.2	3448.7	299.8	3696.1	-2838.9	396.1	-2838.9	-2903.9	-2838.9
2306.1	2357.2	3448.7	199.8	3596.1	-2838.9	296.1	-2838.9	-3003.9	-2838.9
2306.1	2257.2	3448.7	99.8	3496.1	-2838.9	196.1	-2838.9	-3103.9	-2838.9
2306.1	2157.2	3448.7	-0.2	3396.1	-2838.9	96.1	-2838.9	-3203.9	-2838.9
2366.8	2117.9	3448.7	-100.2	3296.1	-2838.9	-3.9	-2838.9	-3303.9	-2838.9
2466.8	2117.9	3448.7	-200.2	3196.1	-2838.9	-103.9	-2838.9	-3403.9	-2838.9
2566.8	2117.9	3448.7	-300.2	3096.1	-2838.9	-203.9	-2838.9	-3503.9	-2838.9
2666.8	2117.9	3448.7	-400.2	2996.1	-2838.9	-303.9	-2838.9	-3603.9	-2838.9
2766.8	2117.9	3448.7	-500.2	2896.1	-2838.9	-403.9	-2838.9	-3703.9	-2838.9
2866.8	2117.9	3448.7	-600.2	2796.1	-2838.9	-503.9	-2838.9	-3803.9	-2838.9
2966.8	2117.9	3448.7	-700.2	2696.1	-2838.9	-603.9	-2838.9	-3903.9	-2838.9
3066.8	2117.9	3448.7	-800.2	2596.1	-2838.9	-703.9	-2838.9	-4003.9	-2838.9
3166.8	2117.9	3448.7	-900.2	2496.1	-2838.9	-803.9	-2838.9	-4103.9	-2838.9
3266.8	2117.9	3448.7	-1000.2	2396.1	-2838.9	-903.9	-2838.9	-4203.9	-2838.9
3366.8	2117.9	3448.7	-1100.2	2296.1	-2838.9	-1003.9	-2838.9	-4303.9	-2838.9
3448.7	2099.8	3448.7	-1200.2	2196.1	-2838.9	-1103.9	-2838.9	-4403.9	-2838.9
3448.7	1999.8	3448.7	-1300.2	2096.1	-2838.9	-1203.9	-2838.9	-4503.9	-2838.9
3448.7	1899.8	3448.7	-1400.2	1996.1	-2838.9	-1303.9	-2838.9	-4603.9	-2838.9
3448.7	1799.8	3448.7	-1500.2	1896.1	-2838.9	-1403.9	-2838.9	-4703.9	-2838.9
3448.7	1699.8	3448.7	-1600.2	1796.1	-2838.9	-1503.9	-2838.9	-4803.9	-2838.9
3448.7	1599.8	3448.7	-1700.2	1696.1	-2838.9	-1603.9	-2838.9	-4903.9	-2838.9
3448.7	1499.8	3448.7	-1800.2	1596.1	-2838.9	-1703.9	-2838.9	-5003.9	-2838.9
3448.7	1399.8	3448.7	-1900.2	1496.1	-2838.9	-1803.9	-2838.9	-5103.9	-2838.9
3448.7	1299.8	3448.7	-2000.2	1396.1	-2838.9	-1903.9	-2838.9	-5203.9	-2838.9
3448.7	1199.8	3448.7	-2100.2	1296.1	-2838.9	-2003.9	-2838.9	-5303.9	-2838.9
3448.7	1099.8	3483.0	-2191.1	1196.1	-2838.9	-2103.9	-2838.9	-5403.9	-2838.9
3448.7	999.8	3532.4	-2278.0	1096.1	-2838.9	-2203.9	-2838.9	-5503.9	-2838.9
3448.7	899.8	3581.8	-2365.0	996.1	-2838.9	-2303.9	-2838.9	-5603.9	-2838.9
3448.7	799.8	3631.2	-2451.9	896.1	-2838.9	-2403.9	-2838.9	-5703.9	-2838.9
3448.7	699.8	3680.6	-2538.9	796.1	-2838.9	-2503.9	-2838.9	-5803.9	-2838.9
3448.7	599.8	3730.0	-2625.8	696.1	-2838.9	-2603.9	-2838.9	-5903.9	-2838.9
3448.7	499.8	3779.4	-2712.8	596.1	-2838.9	-2703.9	-2838.9	-6003.9	-2838.9
3448.7	399.8	3828.8	-2799.7	496.1	-2838.9	-2803.9	-2838.9	-6103.9	-2838.9

[a] Receptors were selected at 100-meter spacing along property boundary.

[b] Distances are relative to the NHPP Boiler B stack.

Note: m = meter

Table 6-8. New Hope Power Partnership Property Boundary Receptors[a] Used In the Modeling Analysis (continued)

Coordinates[b]		Coordinates[b]	
X (m)	Y (m)	X (m)	Y (m)
-6203.9	-2838.9	-9120.5	-2368.5
-6303.9	-2838.9	-9140.7	-2270.6
-6403.9	-2838.9	-9160.9	-2172.6
-6503.9	-2838.9	-9181.0	-2074.7
-6603.9	-2838.9	-9201.2	-1976.7
-6703.9	-2838.9	-9221.4	-1878.8
-6803.9	-2838.9	-9241.5	-1780.9
-6903.9	-2838.9	-9261.7	-1682.9
-7003.9	-2838.9	-9281.9	-1585.0
-7103.9	-2838.9	-9302.0	-1487.0
-7203.9	-2838.9	-9322.2	-1389.1
-7303.9	-2838.9	-9342.3	-1291.1
-7403.9	-2838.9	-9362.5	-1193.2
-7503.9	-2838.9	-9382.7	-1095.2
-7603.9	-2838.9	-9402.8	-997.3
-7703.9	-2838.9	-9423.0	-899.3
-7803.9	-2838.9	-9443.2	-801.4
-7903.9	-2838.9	-9463.3	-703.5
-8003.9	-2838.9	-9483.5	-605.5
-8103.9	-2838.9	-9503.7	-507.6
-8203.9	-2838.9	-9523.8	-409.6
-8303.9	-2838.9	-9544.0	-311.7
-8403.9	-2838.9	-9564.2	-213.7
-8503.9	-2838.9	-9584.3	-115.8
-8603.9	-2838.9	-9604.5	-17.8
-8703.9	-2838.9	-9624.7	80.1
-8803.9	-2838.9	-9644.8	178.1
-8903.9	-2838.9	-9665.0	276.0
-9003.9	-2838.9	-9685.2	373.9
-9039.9	-2760.3		
-9060.0	-2662.4		
-9080.2	-2564.4		
-9100.4	-2466.5		

[a] Receptors were selected at 100-meter spacing along property boundary.
[b] Distances are relative to the NHPP Boiler B stack.
Note: m = meter

Table 6-9. Everglades National Park Receptors Used in the PSD Class I Modeling Analysis

UTM Coordinates (m)		UTM Coordinates (m)		UTM Coordinates (m)		UTM Coordinates (m)	
East	North	East	North	East	North	East	North
557000	2789000	538000	2848600	514500	2837000	470000	2860000
556600	2792000	537000	2848600	514500	2836000	469000	2860000
556000	2796000	536000	2848600	514500	2835000	468000	2860000
553000	2796500	535000	2848600	514500	2834000	467000	2860000
548000	2796500	534000	2848600	514500	2833000	466000	2860000
542700	2796500	533000	2848600	514500	2832500	465000	2860000
542700	2800000	532000	2848600	510000	2832500	464000	2860000
542700	2805000	531000	2848600	509000	2832500	463000	2860000
542700	2810000	530000	2848600	508000	2832500	462000	2860000
542000	2811000	529000	2848600	507000	2832500	461000	2860000
541300	2814000	528000	2848600	506000	2832500	460000	2860000
542700	2816000	527000	2848600	505000	2832500	459500	2863200
544100	2820000	526000	2848600	504000	2832500	459000	2863200
543500	2824600	525000	2848600	503000	2832500	458000	2863200
545000	2829000	524000	2848600	502000	2832500	457000	2863200
545700	2832200	523000	2848600	501000	2832500	456000	2863200
546200	2835700	522000	2848600	500000	2832500	455000	2863200
548600	2837500	521000	2848600	499000	2832500	454000	2863200
550300	2839000	520000	2848600	498000	2832500		
545000	2839000	519000	2848600	497000	2832500		
540000	2839000	518000	2848600	496000	2832500		
550500	2844000	517000	2848600	495000	2832500		
545000	2844000	516000	2848600	495000	2833000		
540000	2844000	515000	2848600	495000	2834000		
550300	2848600	514500	2848600	495000	2835000		
549000	2848600	514500	2848000	495000	2836000		
548000	2848600	514500	2847600	494500	2837000		
547000	2848600	514500	2846600	491500	2841000		
546000	2848600	514500	2845000	488500	2845500		
545000	2848600	514500	2844000	483000	2848500		
544000	2848600	514500	2843000	480000	2852500		
543000	2848600	514500	2842000	475000	2854000		
542000	2848600	514500	2841000	473500	2857000		
541000	2848600	514500	2840000	473000	2860000		
540000	2848600	514500	2839000	472000	2860000		
539000	2848600	514500	2838000	471000	2860000		

Note: New Hope Power Partnership's coordinates are 524900 m E, 2940100 m N.
m = meter

Table 6-10. New Hope Power Partnership Building Dimensions Used in the Modeling Analysis

Structure	Height		Length		Width	
	ft	m	ft	m	ft	m
Boiler Building	139	42.44	207	63.12	114	34.84
Electrostatic Precipitator Building No. 1	107	32.54	50	15.24	71	21.76
Electrostatic Precipitator Building No. 2	107	32.54	50	15.24	71	21.76
Electrostatic Precipitator Building No. 3	107	32.54	50	15.24	71	21.76

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Table 6-11. Maximum Predicted Pollutant Impacts For the Proposed Project Only,
New Hope Power Partnership

Pollutant/ Averaging Time	Concentration [a] ($\mu g/m^3$)	Receptor Location [b] Direction (degrees)	Distance (m)	Time Period (YYMMDDHH)	EPA Significant Impact Level ($\mu g/m^3$)
SO_2					
Annual	0.25	311.7	5,703	87123124	
	0.22	313.8	5,482	88123124	
	0.31	316.8	5,201	89123124	1
	0.28	314.5	5,410	90123124	
	0.27	309.7	5,930	91123124	
Highest 24-Hour	9.29	229.3	4,356	87110724	
	8.71	337.6	4,100	88012024	
	8.40	316.8	5,201	89031524	5
	8.95	324.0	4,690	90101024	
	8.40	341.6	3,995	91030224	
Highest 3-Hour	31.84	216.5	3,534	87053018	
	29.15	162.5	2,977	88012712	
	28.43	157.2	3,081	89120312	25
	29.97	170.1	2,882	90011315	
	26.53	311.7	5,703	91032124	
PM_{10}					
Annual	0.13	136.5	3,915	87123124	
	0.14	153.8	3,164	88123124	
	0.16	317.6	5,133	89123124	1
	0.14	314.5	5,410	90123124	
	0.14	310.4	5,854	91123124	
Highest 24-Hour	1.20	229.3	4,356	87110724	
	1.14	338.9	4,063	88012024	
	1.14	316.8	5,201	89031524	5
	1.16	324.0	4,690	90101024	
	1.10	341.6	3,995	91030224	
NO_2					
Annual	0.44	311.7	5,703	87123124	
	0.39	313.8	5,482	88123124	
	0.55	316.8	5,201	89123124	1
	0.50	306.3	6,403	90123124	
	0.48	309.7	5,930	91123124	

Table 6-11. Maximum Predicted Pollutant Impacts For the Proposed Project Only, New Hope Power Partnership

Pollutant/ Averaging Time	Concentration [a] (μg/m³)	Receptor Location [b] Direction (degrees)	Distance (m)	Time Period (YYMMDDHH)	EPA Significant Impact Level (μg/m³)
CO					
Highest 8-Hour	4.6	51.5	3,406	87062716	
	4.5	338.9	4,063	88030916	
	3.6	340.3	4,028	89050116	500
	4.0	323.0	4,749	90101024	
	5.0	331.5	4,315	91021916	
Highest 1-Hour	18.7	155.5	3,121	87042607	
	20.1	20.8	4,056	88012508	
	18.2	160.0	4,000	89112919	2,000
	21.5	166.2	2,923	90012612	
	20.4	143.6	3,529	91121509	

[a] Based on 5-year meteorological record, West Palm Beach, 1987 to 1991.

[b] Relative to New Hope Power Partnership Boiler B stack.

Note: YYMMDDHH = Year, Month, Day, Hour Ending

Table 6-12. Maximum Predicted SO_2 Impacts For All Sources, AAQS Screening Analysis, New Hope Power Partnership

Averaging Time	Concentration [a] ($\mu g/m^3$)	Receptor Location [b] Direction (degrees)	Distance (m)	Time Period (YYMMDDHH)
Annual	15.9	182.1	2,841	87123124
	18.8	360	11,000	88123124
	17.2	10	11,000	89123124
	18.1	182.1	2,841	90123124
	16.9	184.1	2,846	91123124
HSH 24-Hour	111.9	180.1	2,839	87100224
	130.1	360	11,000	88011424
	105.8	182.1	2,841	89041824
	105.0	182.1	2,841	90100824
	125.8	182.1	2,841	91061024
HSH 3-Hour	360.4	360	11,000	87032109
	351.8	360	10,000	88022621
	357.4	360	11,000	89041906
	351.7	360	11,000	90012306
	399.1	360	11,000	91100709

[a] Based on 5-year meteorological record, West Palm Beach, 1987 to 1991.

[b] Relative to New Hope Power Partnership Boiler B stack.

Note: YYMMDDHH = Year, Month, Day, Hour Ending
HSH = Highest, Second-Highest

Table 6-13. Maximum Predicted SO_2 Concentrations for All Sources Compared to the AAQS - Refined Analysis
New Hope Power Partnership

Averaging Time	Concentration (µg/m³) [a] Total	Modeled Sources	Background	Receptor Location [b] Direction (degree)	Distance (m)	Time Period (YYMMDDHH)	Florida AAQS (µg/m³)
Annual	25.1	20.1	5	2.0	11,000	88123124	
	22.2	17.2	5	9.0	11,000	89123124	60
	23.1	18.1	5	182.1	2,841	90123124	
HSH 24-Hour	145	132.1	13	359.5	11,000	88011024	260
	139	125.8	13	182.1	2,841	91061024	
HSH 3-Hour	414	366.8	47	355.0	11,000	87010718	1,300
	517	470.3	47	360.0	11,000	91100709	

[a] Based on 5-year meteorological record, West Palm Beach, 1987 to 1991.

[b] Relative to New Hope Power Partnership Boiler B stack.

Note: YYMMDDHH = Year, Month, Day, Hour Ending
HSH = Highest, Second-Highest

Table 6-14. Maximum Predicted SO_2 Impacts For All Sources,
PSD Class II Screening Analysis, New Hope Power Partnership

Averaging Time	Concentration [a] ($\mu g/m^3$)	Receptor Location [b] Direction (degree)	Distance (m)	Time Period (YYMMDDHH)
SO_2				
Annual	4.0	10	11,000	87123124
	5.1	360	11,000	88123124
	4.2	10	11,000	89123124
	2.3	360	11,000	90123124
	3.8	360	11,000	91123124
HSH 24-Hour	44.9	360	11,000	87101824
	60.3	360	11,000	88011024
	44.4	10	11,000	89021224
	42.0	10	10,000	90030624
	52.9	360	11,000	91121924
HSH 3-Hour	201.1	360	11,000	87021821
	156.7	350	11,000	88022415
	161.7	360	11,000	89041906
	141.8	360	11,000	90012306
	213.1	360	11,000	91011803

[a] Based on 5-year meteorological record, West Palm Beach, 1987 to 1991.

[b] Relative to New Hope Power Partnership Boiler B stack.

[c] Maximum concentrations were predicted to be less than zero at all receptors.

Note: YYMMDDHH = Year, Month, Day, Hour Ending
HSH = Highest, Second-Highest

Table 6-15. Maximum Predicted SO_2 Concentrations for All Sources Compared to the PSD Class II Increment Refined Analysis, New Hope Power Partnership

Averaging Time	Concentration [a] (μg/m³)	Receptor Location [b] Direction (degree)	Distance (m)	Time Period (YYMMDDHH)	PSD Increment (μg/m³)
Annual	5.6	2.0	11,000	88123124	20
HSH 24-Hour	62	359.5	11,000	88011024	91
HSH 3-Hour	201	359.5	11,000	87021821	512
	218	2.0	11,000	91111403	

[a] Based on 5-year meteorological record, West Palm Beach, 1987 to 1991.
[b] Relative to New Hope Power Partnership Boiler B stack.

Note: YYMMDDHH = Year, Month, Day, Hour Ending
HSH = Highest, Second-Highest

Table 6-16. Summary of Maximum Pollutant Concentrations Predicted for the Project Only Compared to the EPA Class I Significant Impact Levels and PSD Class I Increments New Hope Power Partnership

Pollutant	Averaging Time	Maximum Concentration[a] (μg/m³)	EPA Class I Significant Impact Levels (μg/m³)	Allowable PSD Class I Increments (μg/m³)
SO_2	Annual	0.0044	0.1	2
	24-Hour	0.45	0.2	5
	3-Hour	1.10	1.0	25
PM_{10}	Annual	0.0024	0.2	4
	24-Hour	0.064	0.3	8
NO_2	Annual	0.0047	0.1	2.5

[a] Highest concentration predicted with CALPUFF model and CALMET South Florida Domain, 1990.

Table 6-17. Maximum Predicted SO_2 Concentrations for PSD Sources at the Everglades National Park

Averaging Time	Maximum Concentration[a] ($\mu g/m^3$)	Receptor Location (m) UTM East	Receptor Location (m) UTM North	Period Ending (Julian day/ hour/year)	Allowable PSD Class I Increments ($\mu g/m^3$)
24-Hour	3.99	533000	2848600	(317/23/1990)	5
3-Hour	12.16	545000	2844000	(188/08/1990)	25

[a] Concentrations are second-highest predicted with CALPUFF model and CALMET South Florida Domain, 1990.

Note:
m = meter
UTM = Universal Transverse Mercator
$\mu g/m^3$ = micrograms per cubic meter

Table 6-18. Maximum Predicted Fluoride Impacts For the Proposed Project Only in the Site Vicinity, New Hope Power Partnership

Pollutant/ Averaging Time	Concentration [a] ($\mu g/m^3$)	Receptor Location [b] Direction (degrees)	Distance (m)	Time Period (YYMMDDHH)
Annual	0.0029	311.7	5,703	87123124
	0.0026	313.8	5,482	88123124
	0.0037	316.8	5,201	89123124
	0.0033	314.5	5,410	90123124
	0.0032	309.7	5,930	91123124
Highest 24-Hour	0.017	229.3	4,356	87110724
	0.016	337.6	4,100	88012024
	0.015	316.8	5,201	89031524
	0.017	324.0	4,690	90101024
	0.015	341.6	3,995	91030224
Highest 8-Hour	0.027	51.5	3,406	87062716
	0.026	330.3	4,363	88112716
	0.025	158.9	3,043	89120316
	0.030	322.0	4,810	90021608
	0.029	331.5	4,315	91021916
Highest 3-Hour	0.046	216.5	3,534	87053018
	0.040	162.5	2,977	88012712
	0.038	157.2	3,081	89120312
	0.041	170.1	2,882	90011315
	0.037	311.7	5,703	91032124
Highest 1-Hour	0.069	155.5	3,121	87042607
	0.077	20.8	4,056	88012508
	0.078	158.9	3,043	89112919
	0.090	166.2	2,923	90012612
	0.075	176.0	2,846	91101908

[a] Based on 5-year meteorological record, West Palm Beach, 1987 to 1991.

[b] Relative to New Hope Power Partnership Boiler B stack.

Note: YYMMDDHH = Year, Month, Day, Hour Ending

Table 6-19. Maximum Predicted Sulfuric Acid Mist Impacts For the Proposed Project Only in the Site Vicinity, New Hope Power Partnership

Pollutant/ Averaging Time	Concentration [a] (μg/m³)	Receptor Location [b] Direction (degrees)	Distance (m)	Time Period (YYMMDDHH)
Annual	0.012	311.7	5,703	87123124
	0.011	313.8	5,482	88123124
	0.015	316.8	5,201	89123124
	0.014	314.5	5,410	90123124
	0.013	309.7	5,930	91123124
Highest 24-Hour	0.57	229.3	4,356	87110724
	0.53	337.6	4,100	88012024
	0.51	316.8	5,201	89031524
	0.56	324	4,690	90101024
	0.51	341.6	3,995	91030224
Highest 8-Hour	0.90	51.5	3,406	87062716
	0.87	330.3	4,363	88112716
	0.85	158.9	3,043	89120316
	0.97	322	4,810	90021608
	0.95	331.5	4,315	91021916
Highest 3-Hour	1.50	216.5	3,534	87053018
	1.35	162.5	2,977	88012712
	1.30	157.2	3,081	89120312
	1.39	170.1	2,882	90011315
	1.23	311.7	5,703	91032124
Highest 1-Hour	2.23	155.5	3,121	87042607
	2.50	20.8	4,056	88012508
	2.55	158.9	3,043	89112919
	2.92	166.2	2,923	90012612
	2.42	176	2,846	91101908

[a] Based on 5-year meteorological record, West Palm Beach, 1987 to 1991.

[b] Relative to New Hope Power Partnership Boiler B stack.

Note: YYMMDDHH = Year, Month, Day, Hour Ending

Table 6-20. Maximum Predicted Lead Impacts For the Proposed Project Only in the Site Vicinity,
New Hope Power Partnership

Pollutant/ Averaging Time	Concentration [a] ($\mu g/m^3$)	Receptor Location [b] Direction (degrees)	Receptor Location [b] Distance (m)	Time Period (YYMMDDHH)
Annual	0.00086	311.7	5,703	87123124
	0.00077	313.8	5,482	88123124
	0.00110	316.8	5,201	89123124
	0.00099	314.5	5,410	90123124
	0.00095	309.7	5,930	91123124
Highest 24-Hour	0.0070	229.3	4,356	87110724
	0.0066	337.6	4,100	88012024
	0.0064	316.8	5,201	89031524
	0.0068	324.0	4,690	90101024
	0.0064	341.6	3,995	91030224
Highest 8-Hour	0.011	51.5	3,406	87062716
	0.011	153.8	3,164	88022508
	0.011	158.9	3,043	89120316
	0.012	322.0	4,810	90021608
	0.012	331.5	4,315	91021916
Highest 3-Hour	0.018	216.5	3,534	87053018
	0.017	162.5	2,977	88012712
	0.017	157.2	3,081	89120312
	0.017	170.1	2,882	90011315
	0.015	311.7	5,703	91032124
Highest 1-Hour	0.027	155.5	3,121	87042607
	0.030	20.8	4,056	88012508
	0.031	158.9	3,043	89112919
	0.035	166.2	2,923	90012612
	0.029	176.0	2,846	91101908

[a] Based on 5-year meteorological record, West Palm Beach, 1987 to 1991.

[b] Relative to New Hope Power Partnership Boiler B stack.

Note: YYMMDDHH = Year, Month, Day, Hour Ending

Figure 6-1. New Hope Power Partnership
Building, Stack, Property Boundary, and Receptor Locations

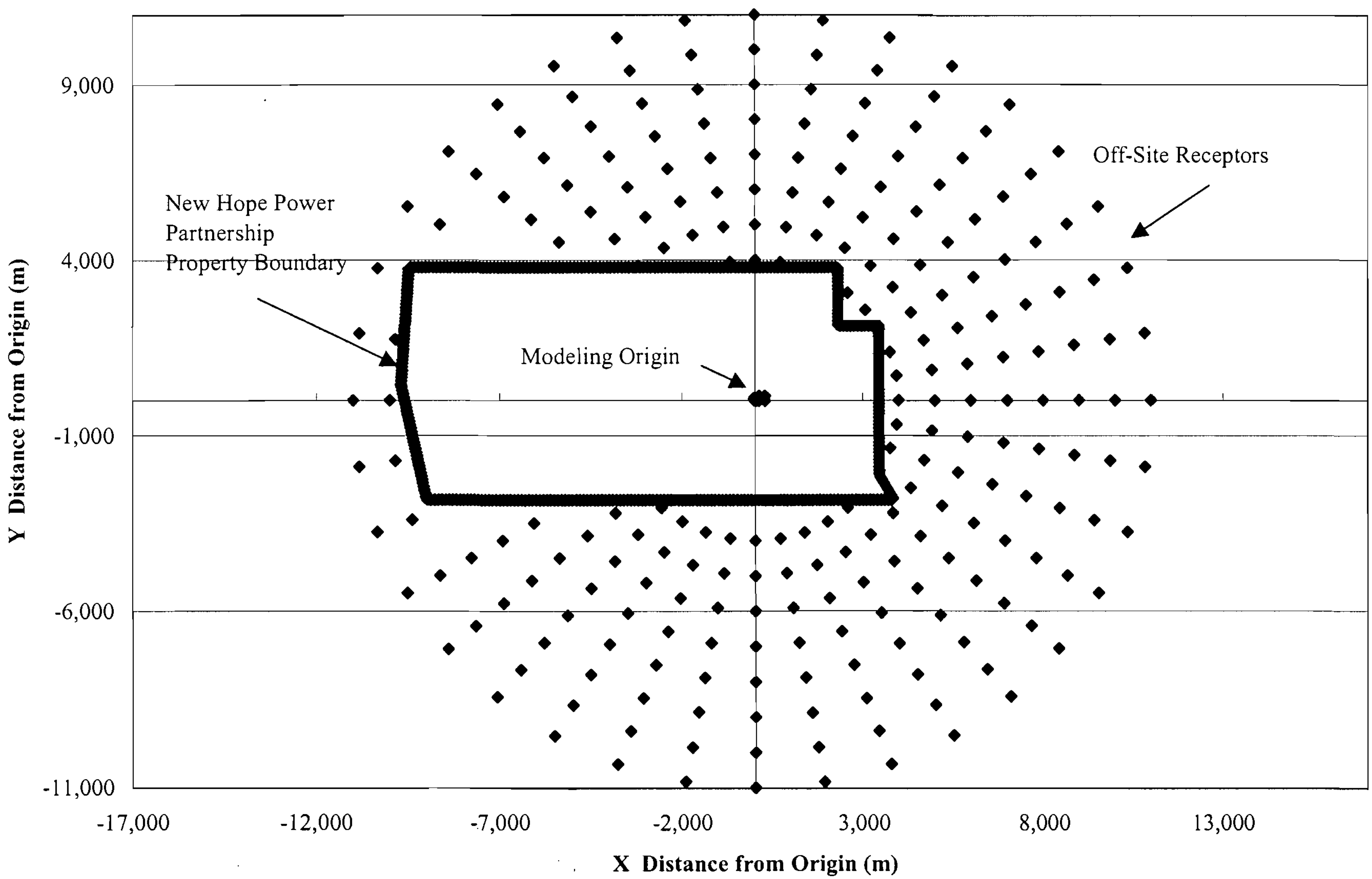
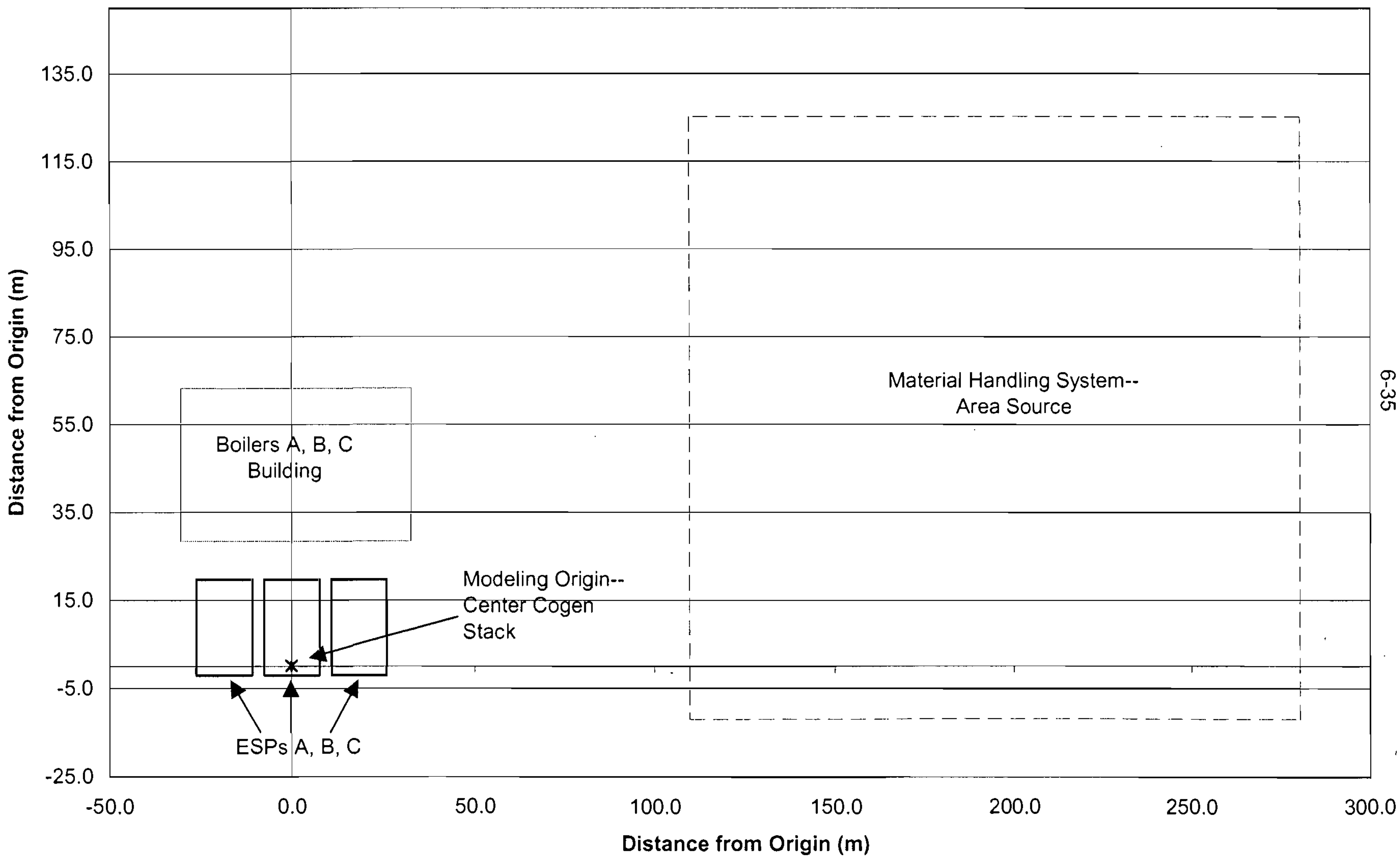


Figure 6-2. New Hope Power Partnership Building, Area Source, and Stack Locations



7.0 ADDITIONAL IMPACT ANALYSIS

7.1 VICINITY OF NHPP

7.1.1 VEGETATION AND SOILS

The primary vegetation, as well as agricultural crop, in the vicinity of NHPP is sugar cane. The mill is surrounded by sugar cane fields for a large distance in all directions. Some rice fields, vegetable farming, nurseries, and sod farms are also located in the general area. The Loxahatchee National Wildlife Refuge is located approximately 32 km to the east of the mill.

Soils in the area are primarily histosols, which are peat soils with high amounts of organic matter. The surrounding area is part of the Everglades Agricultural Area, which is noted for its "muck", i.e., rich, black soil which is very fertile.

As described in the air quality impact analysis (Section 6.0), the maximum predicted SO_2 concentrations in the vicinity of NHPP as a result of the proposed project are predicted to be below the AAQS. Since the AAQS are designed to protect the public welfare, including effects on soils and vegetation, no detrimental effects on soils or vegetation should occur in this area due to the proposed project.

No significant impacts on growth in the area are expected as a result of this project. The cogeneration boilers are existing boilers, and the proposed project is only to allow increased maximum heat input rates of the boilers. No new construction will occur.

7.1.2 VISIBILITY

No new emission sources will be created by the proposed project. The NHPP boilers are currently controlled by ESPs and dust collectors, and therefore, the visible plume characteristics from these sources will not change. The NHPP boilers are in compliance with opacity regulations and should remain in compliance after increasing the maximum annual heat input rate of the boilers. As a result, no adverse impacts upon visibility in the vicinity of NHPP are expected.

7.1.3 IMPACTS DUE TO ASSOCIATED GROWTH

Since the NHPP boilers are existing boilers and the proposed project does not require any physical modification to the boilers, there should be no increase in the number of workers. There will also be no increase in the number of permanent employees at NHPP as a result of the proposed project. Therefore, there will be no anticipated impacts on air quality caused by associated growth.

The NHPP facility is in a remote part of western Palm Beach County, surrounded by sugar cane fields for many miles in all directions. The extent of the sugar cane fields has not changed significantly since 1977. Therefore, there has been no commercial, residential, industrial or other growth in the immediate vicinity of NHPP during this time. NHPP will "affect" an area of approximately 10 km surrounding the facility, based on the significant impact analysis results. At the outer edge of the affected area are the towns of South Bay and Belle Glade. None of these towns has experienced significant growth since 1977. Based on this discussion, it is concluded that no significant growth has occurred in the area of the NHPP site that would affect air quality impacts. It is also noted that the conservative background concentrations used in the modeling analysis already account for any such changes.

The potential impacts of SO_2, NO_2, PM, CO, Pb, F, and SAM on soils, vegetation, wildlife, and visibility in the Everglades National Park Class I area are addressed in the following sections.

7.2 PSD CLASS I AREA

This section focuses on the ecological effects of the proposed facility modification on Air Quality Related Values (AQRV), as defined under PSD regulations, in the Everglades National Park (ENP). The ENP is the closest Class I area to NHPP, and is located approximately 92 km south of NHPP. The AQRVs are defined as being:

> All those values possessed by an area except those that are not affected by changes in air quality and include all those assets of an area whose vitality, significance, or integrity is dependent in some way on the air environment. These values include visibility and those scenic, cultural, biological, and recreational resources of an area that are affected by air quality. Important attributes of an area are those values or assets that make an area significant as a monument, preserve, or primitive area. They are the assets that are to be preserved if the area is to achieve the purposes for which it was set aside (Federal Register, 1978).

The AQRVs include freshwater and coastal wetlands, dominant plant communities, unique and rare plant communities, soils and associated periphyton, and the wildlife dependent on these communities for habitat. Rare, endemic, threatened, and endangered species of the national park and bioindicators of air pollution (e.g., lichens) are also evaluated.

The maximum predicted atmospheric concentrations due to the increase in emissions resulting from the proposed project are presented in Table 7-1. As shown, the predicted increase in impacts is very low for all pollutants considered.

7.2.1 IMPACTS TO SOILS

For soils, the potential and hypothesized effects of atmospheric deposition include:

- Increased soil acidification,
- Alteration in cation exchange,
- Loss of base cations, and
- Mobilization of trace metals.

The potential sensitivity of specific soils to atmospheric inputs is related to two factors. First, the physical ability of a soil to conduct water vertically through the soil profile is important in influencing the interaction with deposition. Second, the ability of the soil to resist chemical changes, as measured in terms of pH and soil cation exchange capacity (CEC), is important in determining how a soil responds to atmospheric inputs.

The soils of the Everglades National Park are generally classified as histosols or entisols. Histosols (peat soils) are organic and have extremely high buffering capacities based on their CEC, base saturation, and bulk density. Therefore, they would be relatively insensitive to atmospheric inputs. The entisols are shallow sandy soils overlying limestone, such as the soils found in the pinelands. The direct connection of these soils with subsurface limestone tends to neutralize any acidic inputs. Moreover, the groundwater table is highly buffered due to the interaction with subsurface limestone formations, which results in high alkalinity (as $CaCO_3$).

The relatively low sensitivity of the soils to acid inputs coupled with the extremely low ground-level concentrations of contaminants projected for the Everglades National Park from the NHPP facility emissions precludes any significant impact on soils.

7.2.2 IMPACTS TO VEGETATION

The maximum predicted gaseous concentrations ($\mu g/m^3$) of SO_2, NO_2, PM, CO, Pb, F, and SAM were used in the determination of impacts on vegetation. These compounds are believed to interact predominantly with foliage and this is considered the major route of entry into plants. In this assessment, 100 percent of the compound of interest was assumed to interact with the vegetation.

7.2.2.1 Sulfur Dioxide

Sulfur is an essential plant nutrient usually taken up as sulfate ions by the roots from the soil solution. When sulfur dioxide in the atmosphere enters the foliage through pores in the leaves, it reacts with water in the leaf interior to form sulfite ions. Sulfite ions are highly toxic. They interact with enzymes, compete with normal metabolites, and interfere with a variety of cellular functions (Horsman and Wellburn, 1976). However, within the leaf, sulfite is oxidized to sulfate ions, which can then be used by the plant as a nutrient. Small amounts of sulfite may be oxidized before they prove harmful.

SO_2 gas at elevated levels has long been known to cause injury to plants. Acute SO_2 injury usually develops within a few hours or days of exposure, and symptoms include marginal, flecked, and/or intercostal necrotic areas that appear water-soaked and dullish green initially. This injury generally occurs to younger leaves. Chronic injury usually is evident by signs of chlorosis, bronzing, premature senescence, reduced growth, and possible tissue necrosis (EPA, 1982). Background levels of SO_2 range from 2.5 to 25 $\mu g/m^3$. Observed SO_2 effect levels for several plant species and plant sensitivity groupings are presented in Tables 7-2 and 7-3, respectively.

Many studies have been conducted to determine the effects of high-concentration, short-term SO_2 exposure on natural community vegetation. Sensitive plants include ragweed, legumes, blackberry, southern pine, and red and black oak. These species are injured by exposure to 3-hour SO_2 concentrations of 790 to 1,570 $\mu g/m^3$. Intermediate plants include locust and sweetgum. These species are injured by exposure to 3-hour SO_2 concentrations of 1,570 to 2,100 $\mu g/m^3$. Resistant species (injured at concentrations above 2,100 $\mu g/m^3$ for 3 hours) include white oak and dogwood (EPA, 1982).

A study of native Floridian species (Woltz and Howe, 1981) demonstrated that cypress, slash pine, live oak, and mangrove exposed to 1,300 $\mu g/m^3$ SO_2 for 8 hours were not visibly damaged. This finding supports the levels cited by other researchers on the effects of SO_2 on vegetation. A corroborative study (McLaughlin and Lee, 1974) demonstrated that approximately 20 percent of a cross-section of plants ranging from sensitive to tolerant was visibly injured at 3-hour SO_2 concentrations of 920 $\mu g/m^3$.

Two lichen species indigenous to the park area exhibited signs of SO_2 damage in the form of decreased biomass gain and photosynthetic rate as well as membrane leakage when exposed to concentrations of 200 to 400 $\mu g/m^3$ for 6 hours/week for 10 weeks (Hart *et al.*, 1988).

When the 8-hour modeled incremental SO_2 increase from the proposed modification (0.73 $\mu g/m^3$) is added to the upper range of background SO_2 concentrations (0.72 $\mu g/m^3$; refer to Section 4.5), a maximum of 1.45 $\mu g/m^3$ of SO_2 would be expected at the point of maximum impact in the Everglades National Park. On comparison of this concentration to those causing injury to native species, it is evident that SO_2-sensitive species (or more tolerant species) would not be damaged by the predicted concentrations. By comparing the SO_2 concentration of 1.45 $\mu g/m^3$ with the concentrations that cause plant injury, it can be shown that the amount of SO_2 in the park area is less than 1 percent of the most conservative concentration (200 $\mu g/m^3$) that caused injury to SO_2-sensitive species.

The 24-hour and annual SO_2 concentrations predicted within the park due to the project only (0.45 and 0.0044 $\mu g/m^3$, respectively) when added to background concentrations of 0.72 and 0.13 $\mu g/m^3$, respectively, result in total SO_2 impacts of 1.17 and 0.13 $\mu g/m^3$, respectively. These levels are much lower than those known to cause damage to test species. Jack pine seedlings exposed to SO_2 concentrations of 470 to 520 $\mu g/m^3$ for 24 hours demonstrated inhibition of foliar lipid synthesis; however, this inhibition was reversible (Malhotra and Kahn, 1978). Black oak exposed to 1,310 $\mu g/m^3$ SO_2 for 24 hours a day for 1 week demonstrated a 48 percent reduction in photosynthesis (Carlson, 1979). By comparison of these levels, it is apparent that the modeled 24-hour incremental increase of SO_2 is well below (i.e., less than 2 percent) the concentrations that caused damage in SO_2-sensitive plants. The modeled annual incremental increase in SO_2 (0.0044 $\mu g/m^3$) adds slightly to background levels of this gas and poses no threat to area vegetation.

7.2.2.2 Nitrogen Dioxide

Nitrogen dioxide (NO_2) is another emission of concern for the proposed plant expansion. This compound can injure plant tissue with symptoms usually appearing as irregular white to brown collapsed lesions between the leaf veins and near the margins. Conversely, non-injurious levels of NO_2 can be absorbed by plants, enzymatically transformed into ammonia, and incorporated into plant constituents such as amino acids (Matsumaru *et al.*, 1979).

Plant damage can occur through either acute (short-term, high concentration) or chronic (long-term, relatively low concentration) exposure. For plants that have been determined to be more sensitive to NO_2 exposure than others, acute (1, 4, 8 hours) exposure caused 5 percent predicted foliar injury at concentrations ranging from 3,800 to 15,000 $\mu g/m^3$ (Heck and Tingey, 1979). Chronic exposure of selected plants (some considered NO_2-sensitive) to NO_2 concentrations of 2,000 to 4,000 $\mu g/m^3$ for 213 to 1,900 hours caused reductions in yield of up to 37 percent and some chlorosis (Zahn, 1975).

By comparison of published toxicity values for NO_2 exposure to short-term (i.e., 1-, 3-, and 8-hour averaging times) and long-term (annual averaging time) modeled concentrations, the possibility of plant damage in the park can be examined for both acute and chronic exposure situations, respectively. The 1-, 3-, and 8-hour estimated NO_2 concentrations due to the project only at the point of maximum impact in the park area are 0.52, 0.43, and 0.37 $\mu g/m^3$, respectively. These concentrations are approximately 0.002 to 0.01 percent of the levels that could potentially injure 5 percent of the plant foliage. For a chronic exposure, the annual estimated NO_2 concentration due to the project only at the point of maximum impact in the park (0.0047 $\mu g/m^3$) is 0.0001 to 0.0003 percent of the levels that caused minimal yield loss and chlorosis in plant tissue.

Although it has been shown that simultaneous exposure to SO_2 and NO_2 results in synergistic plant injury (Ashenden and Williams, 1980), the magnitude of this response is generally only 3 to 4 times greater than either gas alone and usually occurs at unnaturally high levels of each gas. Therefore, the concentrations within the park are still far below the levels that potentially cause plant injury for either acute or chronic exposure.

7.2.2.3 Particulate Matter

Although information pertaining to the effects of PM on plants is scarce, baseline concentrations are available (Mandoli and Dubey, 1988). Ten species of native Indian plants were exposed to levels of

PM that ranged from 210 to 366 μg/m^3 for an 8-hour averaging period. Damage in the form of a higher leaf area/dry weight ratio was observed at varying degrees for most plants tested. Concentrations of PM lower than 163 μg/m^3 did not appear to be injurious to the tested plants.

By comparison of published toxicity values for PM exposure (i.e., 8-hour averaging time) concentrations, the possibility of plant damage in the park due to the project can be determined. The 8-hour estimated PM concentration due to the project only at the point of maximum impact in the park area is 0.10 μg/m^3. This concentration is approximately 0.03 to 0.05 percent of the values that affected plant foliage. The extremely small additional impact the proposed project is predicted to have on the ENP will not cause any adverse affects to vegetation.

7.2.2.4 Carbon Monoxide

As with PM, information pertaining to the effects of CO on plants is scarce. The main effect of high concentrations of CO is the inhibition of cytochrome *c* oxidase, the terminal oxidase in the mitochondrial electron transfer chain. Inhibition of cytochrome *c* oxidase depletes the supply of ATP, the principal donor of free energy required for cell functions. However, this inhibition only occurs at extremely high concentrations of CO. Pollok *et al.* (1989) reported that exposure to $CO:O_2$ ratio of 25 (equivalent to an ambient CO concentration of 6.85×10^6 μg/m^3) resulted in stomatal closure in the leaves of the sunflower (*Helianthus annuus*). Naik *et al.* (1992) reported cytochrome *c* oxidase inhibition in corn, sorghum, millet, and Guinea grass at $CO:O_2$ ratios of 2.5 (equivalent to an ambient CO concentration of 6.85×10^5 μg/m^3). These plants were considered the species most sensitive to CO-induced inhibition of cytochrome *c* oxidase. The predicted annual average CO impact due to the proposed project only at the ENP (0.032 μg/m^3) is well below these published effects levels.

7.2.2.5 Fluoride

Fluoride is an inhibitor of plant metabolism. As fluoride accumulates in plants, it causes an inhibition of plant metabolism and chlorosis (a yellowing of the leaf). With further increases in accumulation of fluoride, the cells die and necrosis is observed. Leaf tips and margins accumulate the highest concentrations of fluoride and are the sites of initial visible injury. Gaseous fluoride is taken up primarily through the stomata of transpiring plants. There is negligible contribution to leaf fluoride content by uptake by roots (Applied Sciences Associates, Inc., 1978).

The sensitivity of plants varies widely. Presented in Table 7-4 are fluoride effect levels for various plant species. Gladiolus are considered the most sensitive. Visible symptoms are reported to occur when gladiolus have been exposed to concentrations >0.5 $\mu g/m^3$ for 5 to 10 days. More tolerant fruit tree species and conifers first showed symptoms at around 1 $\mu g/m^3$ at 10-day exposures (Treshow and Anderson, 1989). Plant sensitivities can range from 16 $\mu g/m^3$ of fluoride in sensitive plants to 500 $\mu g/m^3$ of fluoride in tolerant plants for 3-hour exposures. The lowest observed effect levels for sensitive plants are reported to be as follows (Applied Sciences Associates, Inc., 1978):

- 50 $\mu g/m^3$ for 1-hour exposures,
- 16 $\mu g/m^3$ for 3-hour exposures, and
- 1.6 $\mu g/m^3$ for 24-hour exposures.

Data suggest that a fluoride accumulation factor might be calculated under fumigation conditions with an uncertainty factor of less than 2. One study indicated that hydrogen fluoride concentrations of 0.3 $\mu g/m^3$ would lead to an accumulation of up to 20 ppm of fluoride in conifer foliage after 2 years of exposure (Treshow and Anderson, 1989).

The predicted maximum 1-hour, 3-hour, 8-hour, 24-hour, and annual incremental fluoride concentrations in the ENP due to the proposed project are 0.0021, 0.0017, 0.0015, 0.00094, 0.000072 $\mu g/m^3$, respectively (refer to Table 7-1). These predicted values are well below the lowest observed effect levels for sensitive vegetation. No significant adverse effects are predicted to occur to the vegetative AQRVs of ENP. Since the predicted annual concentration is very low, no measurable accumulation of fluoride will occur in vegetation that would be the prime forage of wildlife. Therefore, no significant adverse effects to wildlife AQRVs will occur (see also Section 7.2.3).

7.2.2.6 <u>Sulfuric Acid Mist</u>

Acidic precipitation or acid rain is coupled to SO_2 emissions mainly formed during the burning of fossil fuels. This pollutant is oxidized in the atmosphere and dissolves in rain forming sulfuric acid mist which falls as acidic precipitation (Ravera, 1989). Although concentration data are not available, sulfuric acid mist has been reported to yield necrotic spotting on the upper surfaces of leaves (Middleton *et al.*, 1950).

No significant adverse effects on vegetation are expected from the project's emissions because SO_2 concentrations, which lead directly to the formation of sulfuric acid mist concentrations, are predicted to be well below levels which have been documented as negatively affecting vegetation. During the last decade, much attention has been focused on acid rain. Acidic deposition is an ecosystem-level problem that affects vegetation because of some alterations of soil conditions such as increased leaching of essential base cations or elevated concentrations of aluminum in the soil water (Goldstein *et al.*, 1985). Although effects of acid rain in eastern North America have been well published and publicized, detrimental effects of acid rain on Florida vegetation are lacking documentation.

7.2.2.7 Lead

The maximum increase in 24-hour average ambient Pb concentrations due to the proposed project is predicted to be 0.00038 $\mu g/m^3$. Naturally occurring levels of Pb in plants range from 0.1 to 10 µg/g, with an average of 2 µg/g (Kabata-Pendias and Pendias, 1984). A Pb soil concentration of 30 to 100 µg/g generally retards the growth of plants (Gough et al, 1979). By comparison of these effects levels with the maximum predicted impacts due to the proposed project, it is concluded that the low levels of the Pb predicted from the proposed project are not expected to adversely affect vegetation.

7.2.2.8 Summary

In summary, the phytotoxic effects on the ENP from proposed increase in the NHPP boilers' emissions are expected to be minimal. It is important to note that the substances were evaluated with the assumption that 100 percent was available for plant uptake. This is rarely the case in a natural ecosystem.

7.2.3 IMPACTS TO WILDLIFE

A wide range of physiological and ecological effects to fauna has been reported for gaseous and particulate pollutants (Newman, 1981; Newman and Schreiber, 1988). The most severe of these effects have been observed at concentrations above the secondary ambient air quality standards. Physiological and behavioral effects have been observed in experimental animals at or below these standards. No observable effects to fauna are expected at concentrations below the values reported in Table 7-5.

The major air quality risk to wildlife in the United States is from continuous exposure to pollutants above the National Ambient Air Quality Standards. This occurs in non-attainment areas, e.g., Los Angeles Basin. Risks to wildlife also may occur for wildlife living in the vicinity of an emission source that experiences frequent upsets or episodic conditions resulting from malfunctioning equipment, unique meteorological conditions, or startup operations (Newman and Schreiber, 1988). Under these conditions, chronic effects (e.g., particulate contamination) and acute effects (e.g., injury to health) have been observed (Newman, 1981).

For impacts on wildlife, the lowest threshold values of SO_2, NO_x, and particulates which are reported to cause physiological changes are shown in Table 7-5. These values are up to orders of magnitude larger than maximum predicted concentrations for the Class I area.

No effects on wildlife AQRVs from SO_2, NO_x, CO, Pb, SAM, F, and PM emissions are expected due to the proposed project. These results are considered indications of the risk of other air pollutant emissions predicted from the facility.

7.2.4 IMPACTS ON VISIBILITY

<u>**Introduction**</u>

The CAA Amendments of 1977 provide for implementation of guidelines to prevent visibility impairment in mandatory Class I areas. The guidelines are intended to protect the aesthetic quality of these pristine areas from reduction in visual range and atmospheric discoloration due to various pollutants. Sources of air pollution can cause visible plumes due to emissions of PM_{10} and NO_x. A plume can be visible if its constituents scatter or absorb sufficient light so that the plume is brighter or darker than its viewing background (e.g., the sky or a terrain feature, such as a mountain). PSD Class I areas, such as national parks and wilderness areas, are afforded special visibility protection designed to prevent plume visual impacts to observers within a Class I area.

Visibility is an AQRV for the Everglades NP. Visibility can take the form of plume blight for nearby areas or regional haze for long distances (e.g., distances beyond 50 km). Because the Everglades NP is more than 50 km from the NHPP project site, the change in visibility is analyzed as regional haze. Currently, there are several air quality modeling approaches recommended by the Interagency Workgroup on Air Quality Models (IWAQM) to perform these analyses. The IWAQM consists of EPA and FLM of Class I areas who are responsible for ensuring that AQRVs are not adversely impacted by new and existing sources. These recommendations have been summarized in two documents:

- *Interagency Workgroup on Air Quality Models (IWAQM), Phase 2 Summary Report and Recommendations for Modeling Long Range Transport Impacts* (EPA, 1998), referred to as the IWAQM Phase 2 report; and
- *Federal Land Managers' Air Quality Related Values Workgroup (FLAG), Phase I Report,* USFS, NPS, USFWS (December, 2000), referred to as the FLAG document.

The methods and assumptions recommended in these documents were used to assess visibility impairment due to the proposed NHPP project.

Analysis Methodology

General

Based on the FLAG document, current regional haze guidelines characterize a change in visibility by the change in the light-extinction coefficient (b_{ext}). The b_{ext} is the attenuation of light per unit distance due to the scattering and absorption by gases and particles in the atmosphere. A change in the extinction coefficient produces a perceived visual change. An index that simply quantifies the percent change in visibility due to the operation of a source is calculated as:

$$\Delta\% = (b_{exts} / b_{extb}) \times 100$$

where: b_{exts} is the extinction coefficient calculated for the source, and
b_{extb} is the background extinction coefficient.

The purpose of the visibility analysis is to calculate the extinction at each receptor for each day (24-hour period) of the year due to the proposed project. The criteria to determine if the project's impacts are potentially significant are based on a change in extinction of 5 percent or greater for any day of the year.

Processing of visibility impairment for this study was performed with the CALPUFF model (see Appendix G) and the CALPUFF post-processing program CALPOST. The analysis was conducted in accordance with the most recent guidance from the FLAG report (December 2000). The CALPUFF postprocessor model CALPOST is used to calculate the combined visibility effects from the different pollutants that are emitted from the project. Daily background extinction coefficients are calculated on a hour-by-hour basis using hourly relative humidity data from CALMET and hygroscopic and non-hygroscopic extinction components specified in the FLAG document. CALPOST then predicts the percent extinction change for each day of the year.

Emission Inventory

Based on recommendations of the FLAG Phase I Report (December 2000), the regional haze analysis considered only the maximum 24-hour increase in emissions due to the NHPP cogeneration boilers. The emission rates and source parameters used in the regional haze analysis are presented in Section 6.0, Tables 6-3 through 6-5.

Building Wake Effects

The air modeling analysis included the same building structure dimensions to account for the effects of building-induced downwash on the emission sources as was used in the ISCST3 modeling analysis. Dimensions for all significant building structures were processed with the Building Profile Input Program (BPIP), Version 95086, and were included in the CALPUFF model.

Receptor Locations

Receptors for the refined analysis included 126 discrete receptors located at the ENP PSD Class I area, as described in Section 6.0. Because the area's terrain is flat, all receptors were assumed to be at zero elevation.

Background Visual Ranges and Relative Humidity Factors

The regional haze analysis was performed using the latest regulatory guidance as provided in the FLAG Phase I report. Using the hourly meteorological and relative humidity data used with the CALPUFF model, the daily change in background extinction is computed. The hygroscopic and dry non-hygroscopic components used for calculating the daily background extinction coefficients for the ENP were obtained from the FLAG report. For this analysis, the hygroscopic and dry non-hygroscopic values were 0.9 and 8.5 inverse millimeters (Mm^{-1}), respectively.

Meteorological Data

A CALMET wind field for the south Florida domain was used for this analysis. The year of data is 1990. A detailed description of the data used to develop the wind field is presented in Appendix G.

Chemical Transformation

The air modeling analysis included all chemical transformation processes that occur for the emitted species.

7.2.4.1 Results

A refined regional haze analysis was performed for the proposed project. The maximum predicted 24-hour visibility degradation is 3.52 percent. As this percentage is below the criteria value of 5 percent, it is concluded that proposed project poses no threat to visibility degradation in the Class I area.

7.2.5 SULFUR AND NITROGEN DEPOSITION

General Methods

As part of the AQRV analyses, total nitrogen (N) and sulfur (S) deposition rates were predicted at the Everglades NP Class I area. The deposition analysis thresholds (DAT) are based on the annual averaging period. The total deposition is estimated in units of kilogram per hectare per year (kg/ha/yr) of nitrogen or sulfur. The CALPUFF model is used to predict wet and dry deposition fluxes of various oxides of these elements.

For N deposition, the species include:

- Particulate ammonium nitrate (from species NO_3), wet and dry deposition;
- Nitric acid (species HNO_3), wet and dry deposition;
- NO_x, dry deposition; and
- Ammonium sulfate (species SO_4), wet and dry deposition.

For S deposition, the species include:

- SO_2, wet and dry deposition; and
- SO_4, wet and dry deposition.

The CALPUFF model produces results in units of $\mu g/m^2/s$. The modeled deposition rates are then converted to N or S deposition in kg/ha respectively, by using a multiplier equal to the ratio of the molecular weights of the substances (IWAQM Phase II report Section 3.3).

DAT for nitrogen and sulfur deposition of 0.01 kg/ha/yr were provided by the U.S. Fish and Wildlife Service (January 2002). A DAT is the additional amount of N or S deposition within a Class I area, below which estimated impacts from a proposed new or modified source are considered insignificant. The maximum N and S depositions predicted for the NHPP project are, therefore, compared to these DAT or significant impact levels.

Results

The maximum predicted N and S depositions predicted for the project in the PSD Class I area of the Everglades NP are summarized in Table 7-6. The total N and S deposition rates are predicted to be 0.0023 and 0.0039 kg/ha/yr, respectively. These maximum deposition rates are below the deposition threshold levels for N and S of 0.01 kg/ha/yr. As a result, the NHPP project is not expected to have a significant adverse effect on N and S deposition in the Class I area.

Table 7-1. Maximum Predicted Concentrations Due to the Project Only at the Class I Area of the Everglades National Park, New Hope Power Partnership

	Concentrations[a] (ug/m^3) for Averaging Times				
Pollutant	Annual	24-Hour	8-Hour	3-Hour	1-Hour
Sulfur Dioxide (SO_2)	0.0044	0.45	0.73	1.10	1.40
Nitrogen Dioxide (NO_2)	0.0047	0.20	0.37	0.43	0.52
Particulates (PM_{10})	0.0024	0.064	0.10	0.11	0.15
Carbon Monoxide (CO)	0.032	1.04	1.62	1.85	2.33
Fluorides (F)	0.000072	0.00094	0.0015	0.0017	0.0021
Sulfuric Acid Mist (SAM)	0.00030	0.032	0.050	0.057	0.071
Lead (Pb)	0.000021	0.00038	0.00060	0.00068	0.00086

[a] Highest Predicted with CALPUFF model and South Florida CALMET Windfield, 1990.

Table 7-2. SO_2 Effects Levels for Various Plant Species

Plant Species	Observed Effect Level ($\mu g/m^3$)	Exposure (Time)	Reference
Sensitive to tolerant	920 (20 percent displayed visible injury)	3 hours	McLaughlin and Lee, 1974
Lichens	200-400	6 hr/wk for 10 weeks	Hart *et al.*, 1988
Cypress, slash pine, live oak, mangrove	1,300	8 hours	Woltz and Howe, 1981
Jack pine seedlings	470-520	24 hours	Malhotra and Kahn, 1978
Black oak	1,310	Continuously for 1 week	Carlson, 1979

Table 7-3. Sensitivity Groupings of Vegetation Based on Visible Injury at Different SO_2 Exposures[a]

Sensitivity Grouping	SO_2 Concentration		Plants
	1-Hour	3-Hour	
Sensitive	1,310 - 2,620 µg/m^3 (0.5 - 1.0 ppm)	790 - 1,570 µg/m^3 (0.3 - 0.6 ppm)	Ragweed Legumes Blackberry Southern pines Red and black oaks White ash Sumacs
Intermediate	2,620 - 5,240 µg/m^3 (1.0 - 2.0 ppm)	1,570 - 2,100 µg/m^3 (0.6 - 0.8 ppm)	Maples Locust Sweetgum Cherry Elms Tuliptree Many crop and garden species
Resistant	>5,240 µg/m^3 (>2.0 ppm)	>2,100 µg/m^3 (>0.8 ppm)	White oaks Potato Upland cotton Corn Dogwood Peach

[a] Based on observations over a 20-year period of visible injury occurring on over 120 species growing in the vicinities of coal-fired power plants in the southeastern United States.

Source: EPA, 1982a.

Table 7-4. Fluoride Effect Levels for Various Plant Species

Plant Species	Observed Effect Level ($\mu g/m^3$)	Exposure Time	Reference
Sensitive to Tolerant Species	16-500	3-Hour	Applied Sciences Associates, Inc., 1978
Sensitive Species (represents the lowest observed effect level known)	50 16 1.6	1-Hour 3-Hour 24-Hour	Applied Sciences Associates, Inc., 1978
Gladiolus	0.5	5-10 days	Treshow and Anderson, 1989
Tolerant fruit tree species and conifers	1	10 day	Treshow and Anderson, 1989

Table 7-5. Examples of Reported Effects of Air Pollutants on Animals at Concentrations Below National Secondary Ambient Air Quality Standards

Pollutant	Reported Effect	Concentration ($\mu g/m^3$)	Exposure
Sulfur Dioxide[1]	Respiratory stress in guinea pigs	427 to 854	1 hour
	Respiratory stress in rats	267	7 hours/day; 5 day/week for 10 weeks
	Decreased abundance in deer mice	13 to 157	continually for 5 months
Nitrogen Dioxide[2,3]	Respiratory stress in mice	1,917	3 hours
	Respiratory stress in guinea pigs	96 to 958	8 hours/day for 122 days
Particulates[1]	Respiratory stress, reduced respiratory disease defenses	120 PbO_3	continually for 2 months
	Decreased respiratory disease defenses in rats, same with hamsters	100 $NiCl_2$	2 hours

Source: [1]Newman and Schreiber, 1988.
[2]Gardner and Graham, 1976.
[3]Trzeciak et al., 1977.

Table 7-6. Maximum Sulfur and Nitrogen Annual Deposition Predicted at the PSD Class I Area of the Everglades National Park, New Hope Power Partnership

	Total Deposition (Wet & Dry)		Deposition Analysis Threshold
Species/Operating Mode	($\mu g/m^2/s$)	(kg/ha/yr)[b]	(kg/ha/yr)
Nitrogen (N) Deposition	7.33E-06	2.31E-03	0.01
Sulfur (S) Deposition	1.24E-05	3.90E-03	0.01

[a] Conversion factor is used to convert $\mu g/m^2/s$ to kg/hectare (ha)/yr using following units:

$$
\begin{array}{rrl}
\mu g/m^2/s & \times & 0.000001 \text{ g}/\mu g \\
 & \times & 0.001 \text{ kg/g} \\
 & \times & 10000 \text{ m}^2/\text{hectare} \\
 & \times & 3600 \text{ sec/hr} \\
 & \times & 8760 \text{ hr/yr} = \text{kg/ha/yr} \\
 & \text{or} & \\
\mu g/m^2/s & \times & 315.36 = \text{kg/ha/yr}
\end{array}
$$

[b] Deposition analysis thresholds (DAT) for nitrogen and sulfur deposition provided by the U.S. Fish and Wildlife Service, January 2002. DAT is the additional amount of N or S deposition within a Class I area, below which estimated impacts from a proposed new or modified source are considered insignificant.

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APPENDIX A

BASIS OF ACTUAL EMISSIONS

Table A-1. Current Actual Emissions (January 2000 through December 2001), New Hope Power Partnership

Boiler	Operating Hours	Heat Input (MMBtu/yr)	Actual Annual Emissions (tons)[c] PM	PM_{10}	SO_2	NO_x	CO	VOC	Pb	Hg	F	SAM
Calendar Year 2000[a]												
Boiler A	6,602	3,785,865	289.77	52.34	73.62	276.36	376.69	20.92	0.0134	0.0007	0.5751	5.655
Boiler B	6,312	3,640,829	77.88	21.91	72.81	265.77	500.61	12.15	0.0129	0.0006	0.5471	5.438
Boiler C	6,788	3,957,456	272.63	51.17	72.60	288.88	417.50	18.23	0.0250	0.0011	0.6851	5.907
Total--*2000*	19,702	11,384,150	172.50 [c]	125.42	219.03	831.01	1,294.80	51.30	0.0513	0.0024	1.8072	17.000
Calendar Year 2001[b]												
Boiler A	5,455	3,056,969	28.62	30.07	55.02	217.04	360.71	7.43	0.0590	0.0016	0.9810	4.570
Boiler B	5,982	3,394,860	29.48	31.89	44.12	241.02	541.45	18.33	0.0440	0.0018	0.8310	5.078
Boiler C	6,321	3,202,078	25.31	28.65	65.63	224.14	473.89	10.79	0.0420	0.0013	0.7060	4.780
Total--*2001*	17,758	9,653,907	83.4	90.61	164.77	682.20	1,376.05	36.55	0.1450	0.0046	2.5181	14.427
Average												
Boiler A	6,029	3,421,417	159.19	41.20	64.32	246.70	368.70	14.17	0.0362	0.0011	0.7781	5.112
Boiler B	6,147	3,517,845	53.68	26.90	58.47	253.40	521.03	15.24	0.0285	0.0012	0.6891	5.258
Boiler C	6,555	3,579,767	148.97	39.91	69.12	256.51	445.70	14.51	0.0335	0.0012	0.6956	5.344
Average (Tons Per Year)	18,730	10,519,029	127.96	108.02	191.90	756.60	1,335.43	43.93	0.0982	0.0035	2.1627	15.714

[a] Obtained from 2000 Annual Operating Report.

[b] Obtained from 2001 Annual Operating Report.

[c] Annual emissions exceeded permit limit, therefore, permit limit was used.

APPENDIX B

BASIS OF FUGITIVE EMISSIONS

Table B-1. Estimation of Emission Factors and Rates For Vehicle Traffic on Unpaved Roads, New Hope Power Partnership

General Data	Pile Maintenance Front-end Loader
Vehicle Data	
Description	Biomass
Vehicle weight (W), tons- Loaded	27
- Unloaded	9
- Average	18
Vehicle miles traveled (VMT)- Annual	21,900 [a]
Speed (S), mph	5
General/ Site Characteristics	
Days of precipitation greater than or equal to 0.01 inch (p)- Annual	120
Silt content (s), %	5
Moisture Content Under Dry Conditions (M_{dry}), %	5.0
Particle size multiplier, PM (k), lb/VMT	10
Particle size multiplier, PM_{10} (k), lb/VMT	2.6
Emission Control Data	
Emission control method	Watering
Emission control removal efficiency, %	50
Calculated PM Emission Factor (EF)	
Uncontrolled EF, lb/VMT - Annual	0.75
Controlled (Final) EF,lb/VMT- Annual	0.38
Calculated PM_{10} Emission Factor (EF)	
Uncontrolled EF, lb/VMT - Annual	0.23
Controlled (Final) EF,lb/VMT- Annual	0.11
Estimated Emission Rate (ER)	
PM ER, lb/hr	1.88
TPY	4.110
PM_{10} ER, lb/hr	0.56
TPY	1.233

Emission Factor (EF) Equations

Uncontrolled EF (UEF) Equation:

$$UEF(lb/VMT) = [(k \times (s/12)^a \times (W/3)^b)/(M_{dry}/0.2)^c] \times [(365-p)/365)] \times [S/15]$$

Where constants a, b, c equal:

	PM	PM_{10}
a	0.8	0.8
b	0.5	0.4
c	0.4	0.3

Controlled (Final) EF (CEF) Equation:

$$CEF(lb/VMT) = UEF (lb/ton) \times (100 - Removal\ efficiency\ (\%))$$

[a] Based on vehicle operating 12 hrs/day, 365 days/yr at 5 mph.

Source: AP-42, Section 13.2.2, Unpaved Roads; September, 1998.

Table B-2. 2000 and 2001 Woodwaste and Bagasse Usage[a]
New Hope Power Partnership

Unit	Woodwaste		Bagasse		TOTAL	
	Tons	MMBtu	Tons	MMBtu	Tons	MMBtu
Boiler A	189,603	1,763,308	277,682	1,999,310	467,285	3,762,618
Boiler B	188,786	1,755,710	258,337	1,860,026	447,123	3,615,736
Boiler C	204,465	1,901,525	282,382	2,033,150	486,847	3,934,675
TOTAL	582,854	5,420,543	818,401	5,892,486	1,401,255	11,313,029
AVG Btu/lb	4,500		3,600			

Percent Heating Value from Wood = 47.9
Percent Heating Value from Bagasse = 52.1

New Hope Power Partnership Maximum Heat Input (3 boilers) = 19.97×10^{12} Btu/yr
Estimated Heat Input Due to Wood= 9.57E+12
Estimated Heat Input Due to Bagasse= 1.04E+13
Wood Usage (TPY) = 1,063,162
Bagasse Usage (TPY) = 1,444,659
Total Usage (TPY) = 2,507,821
Total Usage + 50% (TPY) = 3,761,731

fly ash = [(0.09 x 1,063,162) + (0.01 x 1,444,659)] x 0.20
= 110,131 TPY

[a] Represents maximum of either 2000 or 2001 data.

Spreadsheet as of 11:57:11 on 03-28-1995

ut Filename: bagpile.epc
..ventory area: Osceola Power L.P.
Source ID: Bagpile Filename: A:\Bagpile.EPC

Emissions estimate year: 94
Based on wind data year: 94
Fastest mile filename: westp94.met
System of units: English
Source life (inclusive days of year)
Start day: 1
End day: 365
F=flat area, PC=conical pile, PO=oval pile: PC
Pile height (ft) :30
Pile diameter (ft) :566
Area (sq ft): 252888.5
Material description: Bagasse/WW
Percent moisture content: 37
Percent silt content: 2.2
Threshold friction velocity, U*t, (cm/sec): 112
Roughness height (cm): 0.3
Mode (mm) of size distribution 3.533677# (# denotes calculated value)
Lc value (cf. Fig. 6-3 of reference manual):

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

Total emissions emitted over the period: 79243.23 g

Threshold velocity = 112 cm/s
Control: Effective windspeed ratio = 1

Us/Ur = .9 Disturbance interval = 1 days

Period 9 - 10 high on 10 1.2069 m/s 735.9493 g emitted
Period 10 - 11 high on 10 1.2069 m/s 735.9493 g emitted
Period 15 - 16 high on 16 1.12644 m/s 46.0676 g emitted
Period 16 - 17 high on 16 1.12644 m/s 46.0676 g emitted
Period 33 - 34 high on 34 1.16667 m/s 364.5446 g emitted
Period 34 - 35 high on 34 1.16667 m/s 364.5446 g emitted
Period 44 - 45 high on 45 1.32759 m/s 2167.734 g emitted
Period 45 - 46 high on 46 1.40805 m/s 3386.895 g emitted
Period 46 - 47 high on 46 1.40805 m/s 3386.895 g emitted
Period 61 - 62 high on 62 1.85058 m/s 13876.62 g emitted
I 62 - 63 high on 62 1.85058 m/s 13876.62 g emitted
d 67 - 68 high on 68 1.24713 m/s 1160.283 g emitted
eriod 68 - 69 high on 68 1.24713 m/s 1160.283 g emitted
Period 76 - 77 high on 77 1.16667 m/s 364.5446 g emitted
Period 77 - 78 high on 77 1.16667 m/s 364.5446 g emitted
Period 87 - 88 high on 88 1.12644 m/s 46.0676 g emitted

Period 88 - 89 high on 88 1.12644 m/s 46.0676 g emitted
Period 92 - 93 high on 93 1.24713 m/s 1160.283 g emitted
Period 93 - 94 high on 93 1.24713 m/s 1160.283 g emitted
Period 94 - 95 high on 94 1.16667 m/s 364.5446 g emitted
iod 139 - 140 high on 140 1.2069 m/s 735.9493 g emitted
riod 140 - 141 high on 141 1.24713 m/s 1160.283 g emitted
Period 141 - 142 high on 141 1.24713 m/s 1160.283 g emitted
Period 142 - 143 high on 142 1.2069 m/s 735.9493 g emitted
Period 167 - 168 high on 168 1.16667 m/s 364.5446 g emitted
Period 168 - 169 high on 168 1.16667 m/s 364.5446 g emitted
Period 191 - 192 high on 192 1.2069 m/s 735.9493 g emitted
Period 192 - 193 high on 193 1.56897 m/s 6460.352 g emitted
Period 193 - 194 high on 193 1.56897 m/s 6460.352 g emitted
Period 206 - 207 high on 207 1.2069 m/s 735.9493 g emitted
Period 207 - 208 high on 207 1.2069 m/s 735.9493 g emitted
Period 211 - 212 high on 212 1.32759 m/s 2167.734 g emitted
Period 212 - 213 high on 212 1.32759 m/s 2167.734 g emitted
Period 322 - 323 high on 323 1.2069 m/s 735.9493 g emitted
Period 323 - 324 high on 323 1.2069 m/s 735.9493 g emitted
Period 332 - 333 high on 333 1.12644 m/s 46.0676 g emitted
Period 333 - 334 high on 333 1.12644 m/s 46.0676 g emitted
Period 352 - 353 high on 353 1.16667 m/s 364.5446 g emitted
Period 353 - 354 high on 353 1.16667 m/s 364.5446 g emitted
Period 354 - 355 high on 354 1.12644 m/s 46.0676 g emitted

Summary for Us/Ur = .9 Disturbance Interval = 1
71139.55 Total g emitted over 1 - 365

Us/Ur = .6 Disturbance interval = 1 days

od 61 - 62 high on 62 1.23372 m/s 4051.837 g emitted
Period 62 - 63 high on 62 1.23372 m/s 4051.837 g emitted

Summary for Us/Ur = .6 Disturbance Interval = 1
8103.673 Total g emitted over 1 - 365

Us/Ur = .2 Disturbance interval = 1 days

Summary for Us/Ur = .2 Disturbance Interval = 1
0 Total g emitted over 1 - 365

Summary for entire source: 79243.23 g emitted over period 1 - 365

NOTE: For a variety of reasons given in the user manual, the erosion estimates presented above may be considered as CONSERVATIVELY HIGH. See the user manual for more information.

APPENDIX C

SUMMARY OF NHPP STACK TESTS

Table C-1. Summary of New Hope Power Stack Tests - Biomass Firing

Pollutant	Stack Testing: 02/12/02 - 02/14/02 Post-Mechanical Dust Collectors		
	Unit A Biomass (lb/MMBtu)	Unit B Biomass (lb/MMBtu)	Unit C Biomass (lb/MMBtu)
Particulate (TSP)	0.008	0.010	0.011
Particulate (PM_{10})	0.008	0.010	0.011
VOCs	0.007	0.036	0.020
Lead	2.08E-05	1.41E-05	2.09E-05
Mercury	1.65E-06	9.70E-07	3.68E-06

Sources: Air Consulting Engineering, Inc., 2002; Golder, 2002
Note: Biomass firing consisted of approximately 50% wood and 50% bagasse.

Table C-2. Okeelanta Power/New Hope Power Stack Tests - Wood Firing

Pollutant	Stack Testing: 01/99-02/99 Pre-Mechanical Dust Collectors			Stack Testing: 12/99-01/00 Pre-Mechanical Dust Collectors			Stack Testing: 01/3/01-01/23/01 Post-Mechanical Dust Collectors		
	Unit A Wood (lb/MMBtu)	Unit B Wood (lb/MMBtu)	Unit C Wood (lb/MMBtu)	Unit A Wood (lb/MMBtu)	Unit B Wood (lb/MMBtu)	Unit C Wood (lb/MMBtu)	Unit A Wood (lb/MMBtu)	Unit B Wood (lb/MMBtu)	Unit C Wood (lb/MMBtu)
Particulate (TSP)	0.14	0.08	0.43	0.138	0.053	0.078	0.022	0.013	0.022
Particulate (PM_{10})	0.02	0.02	0.05	0.0266	0.0148	0.0158	0.025	0.0135	0.023
Sulfur Dioxide	0.03	0	0	0.031	0.0217	0.0357	0.032	0.019	0.03
Nitrogen Oxides	0.13	0.117	0.14	0.152	0.15	0.161	0.18	0.15	0.15
Carbon Monoxide	0.14	0.34	0.35	0.130	0.290	0.267	0.16	0.31	0.22
VOCs	0.004	0.005	0.006	0.012	0.006	0.006	0.002	0.014	0.003
Arsenic	4.80E-05	9.92E-05	4.88E-04[a]	1.53E-05	9.05E-06	1.60E-05	1.13E-04	2.50E-05	3.78E-05
Beryllium	<4.28E-07	5.09E-07	6.09E-07[a]	<2.56E-07	<2.61E-07	<2.68E-07	<1.16E-07	<1.10E-07	<1.05E-07
Chromium	2.36E-05	4.35E-05	3.11E-04[a]	8.72E-06	2.12E-05	1.11E-05	4.12E-05	2.04E-05	2.71E-05
Copper	4.78E-05	7.31E-05	2.89E-04[a]	2.60E-05	1.61E-05	3.08E-05	3.76E-05	1.42E-05	2.13E-05
Lead	3.00E-05	8.40E-05	4.00E-04[a]	1.19E-05	7.97E-06	1.75E-05	7.49E-05	1.97E-05	3.91E-05
Mercury	1.20E-06	1.50E-06	3.60E-06	6.25E-07	4.28E-07	6.52E-07	8.07E-07	8.09E-07	7.41E-07
Fluorides	9.38E-05	5.07E-05	1.13E-04	1.50E-04	1.60E-04	3.10E-04	7.00E-04	6.00E-04	6.00E-04
Sulfuric Acid Mist									

Sources: Air Consulting Engineering, Inc., 2001; Golder, 2001

[a] Results may not be representative due to high PM emissions.

Table C-3. Summary of Okeelanta Power/New Hope Power Stack Tests - Bagasse Firing

Pollutant	Stack Testing: 1/22/99-2/5/99 Pre-Mechanical Dust Collectors			Stack Testing: 12/99 - 01/00 Pre-Mechanical Dust Collectors			Stack Testing: 01/3/01-01/23/01 Post-Mechanical Dust Collectors		
	Unit A (lb/MMBtu)	Unit B (lb/MMBtu)	Unit C (lb/MMBtu)	Unit A (lb/MMBtu)	Unit B (lb/MMBtu)	Unit C (lb/MMBtu)	Unit A (lb/MMBtu)	Unit B (lb/MMBtu)	Unit C (lb/MMBtu)
Particulate (TSP)	0.27	0.12	0.20	0.221	0.039	0.230	0.016	0.021	0.010
Particulate (PM_{10})	0.02	0.01	0.02	0.0282	0.0092	0.0308	0.0153	0.0232	0.0131
Sulfur Dioxide	0.02	0	0	0.0011	0.0080	0.0143	0.022	0.019	0.014
Nitrogen Oxides	0.13	0.12	0.13	0.138	0.142	0.179	0.19	0.17	0.17
Carbon Monoxide	0.16	0.26	0.28	0.377	0.354	0.299	0.24	0.21	0.24
Volatile Organic Compounds	0.01	0.02	0.007	0.010	0.007	0.012	0.007	0.008	0.01
Arsenic	3.18E-05	6.50E-06	4.92E-06	1.40E-06	5.42E-06	8.46E-06	6.34E-05	4.17E-05	4.40E-05
Beryllium	<3.77E-07	<3.94E-07	<1.25E-07	<2.22E-07	<2.34E-07	<2.52E-07	<1.10E-07	<1.07E-07	1.76E-07
Chromium	9.33E-06	5.85E-06	5.40E-06	2.15E-06	4.54E-06	6.57E-06	5.22E-05	2.91E-05	2.41E-05
Copper	2.55E-05	1.03E-05	1.33E-05	8.67E-06	1.43E-05	2.67E-05	2.38E-05	2.23E-05	1.18E-05
Lead	2.00E-05	7.30E-06	6.30E-06	3.41E-06	6.68E-06	9.77E-06	3.81E-05	4.76E-05	1.63E-05
Mercury	4.41E-07	3.83E-07	5.41E-07	1.26E-07	1.68E-07	5.34E-07	1.29E-06	1.41E-06	8.38E-07
Fluorides	7.06E-05	4.07E-05	3.04E-05	3.70E-04	4.40E-04	3.90E-04	6.00E-04	4.00E-04	3.00E-04

Sources: Air Consulting Engineering, Inc., 2001; Golder, 2001

APPENDIX D

SUMMARY OF PREVIOUS BACT DETERMINATIONS

Table D-1. BACT Determinations for PM/PM_{10} for Biomass-Fired Industrial and Electric Utility Boilers

Company	State	RBLC ID	Permit Date	Throughput	Emission Limits: As Provided in LAER/BACT Clearinghouse	Emission Limits: Converted to lb/MMBtu[a]	Control Equipment Description	% Efficiency
Industrial Boilers								
ATLANTIC SUGAR ASSOCIATION	FL	PSD-FL-078B[b]	6/7/01	255.3 MMBtu/hr	0.15 lb/MMBtu	0.15	Wet scrubbers/Good Combustion Practices	--
US Sugar Corp.--Clewiston Blr No. 4	FL	PSD-FL-272A[b]	5/18/01	633 MMBtu/hr	0.15 lb/MMBtu	0.15	Wet scrubber; Good combustion practices	--
Newman Paper Co.	PA	PA-0093	10/14/98	129 MMBtu/hr	0.1 lb/MMBtu	0.1	Baghouse	--
GULF STATES PAPER CORP	AL	AL-0122	10/14/98	98 MMBtu/hr	0.1 lb/MMBtu	0.1	Multicyclone and ESP	99
Sierra Pacific Industries--Quincy	CA	CA-0930	5/13/98	245.3 MMBtu/hr	0.035 lb/MMBtu	0.035	Multicyclone and ESP	--
Champion International	AL	AL-0112	12/9/97	710 MMBtu/hr	0.03 lb/MMBtu	0.03	ESP	--
Vaughan Furniture Company	VA	VA-0237	8/28/96	28 MMBtu/hr	36.8 TPY [a]	0.3	Multicyclones, equip. w/ device to cont. measure differ. press. drop	90
Willamette Industries - Marlboro Mill	SC	SC-0045	4/17/96	470 MMBtu/hr	0.05 lb/MMBtu	0.05	ESP	--
U.S. SUGAR CORP--Clewiston	FL	FL-0094	1/31/95	738 MMBtu/hr	0.03 lb/MMBtu	0.03	ESP	--
Weyerhaeuser Co.	AL	AL-0079	12/23/94	91 MMBtu/hr	0.15 lb/MMBtu	0.15	Venturi Scrubber (Zurn Ind. Model MTSA-35-11.5 CVTA-STD)	--
KES CHATEAUGAY PROJECT	NY	NY-0055	12/19/94	275 MMBtu/hr	0.038 lb/MMBtu	0.038	ZURN MULTICLONE, ESP	99
Gulf States Paper Corp	AL	AL-0122	10/28/94	98 MMBtu/hr	0.1 lb/MMBtu	0.1	Multicyclone and ESP	--
WEYERHAEUSER CO.	AL	AL-0079	10/28/94	91 MMBtu/hr	0.15 lb/MMBtu	0.15	Venturi Scrubber (Zurn Ind. Model MTSA-35-11.5 CVTA-STD)	97
Scott Paper Company	WA	WA-0276	7/1/93	718 MMBtu/hr	0.0084 gr/dscf @ 7% O_2 for PM_{10}	--	Baghouse	--
NEWMAN PAPER CO.	PA	PA-0093	4/24/92	129 MMBtu/hr	0.1 lb/MMBtu	0.1	BAGHOUSE	99
Scott Paper Company	WA	WA-0276	4/24/92	718 MMBtu/hr	0.011 gr/dscf @ 7% O_2 for PM	--	Baghouse	--
Electric Utility Boilers								
New Hope Power Partnership	FL	FL-0069	1/31/02	715 MMBtu/hr	0.03 lb/MMBtu	0.03	Good combustion practices, ESP	--
MEAD CONTAINERBOARD	AL	AL-0099	1/15/97	620 MMBtu/hr	0.03 lb/MMBtu	0.03	Multicyclone and ESP	99.2
Multitrade Limited Partnership	VA	VA-0183	2/21/92	373.7 MMBtu/hr	0.02 lb/MMBtu	0.02	Multicyclone and ESP	99.7

Reference: RACT/BACT/LAER Clearinghouse on EPA's Webpage, 2001.

[a] To convert from lb/hr, the emission limit was divided by the throughput rate.
[b] This information obtained from actual PSD permit, not Clearinghouse.

Table D-2. BACT Determinations for SO_2 and SO_x for Biomass-Fired Industrial and Electric Utility Boilers

Company	State	RBLC ID	Permit Date	Throughput	Emission Limits: As Provided in LAER/BACT Clearinghouse	Emission Limits: Converted to lb/MMBtu[a]	Control Equipment Description	% Efficiency
Industrial Boilers								
US Sugar Corp.--Clewiston Blr No. 4	FL	PSD-FL-272A[c]	5/18/01	633 MMBtu/hr	0.06 lb/MMBtu	0.06	Fuel oil S limit; bagasse firing	--
GULF STATES PAPER CORPORATION	AL	AL-0116	12/10/97	775 MMBtu/hr	355.7 lb/hr	0.46	Proper design & oper. Wood ash alkalinity acts as scrubbing media.	--
Champion International	AL	AL-0112	12/9/97	710 MMBtu/hr	0.03 lb/MMBtu	0.03	Wet scrubber with soda ash	95
Vaughan Furniture Company	VA	VA-0237	8/28/96	28 MMBtu/hr	66.599 TPY[b]	0.54	Fuel spec: 0.75% sulfur coal and throughput limit	--
Willamette Industries - Marlboro Mill	SC	SC-0045	4/17/96	470 MMBtu/hr	0.1 lb/MMBtu	0.1	No controls feasible	--
Scott Paper Company	WA	WA-0276	3/9/95	718 MMBtu/hr	70 lb/hr 12 mo. avg.	0.10	Fuel spec: backup fuel limited to 0.05% sulfur distillate	--
KES CHATEAUGAY PROJECT	NY	NY-0055	12/19/94	275 MMBtu/hr	0.03 lb/MMBtu	0.03	Fuel spec. oil less than 0.08% by wgt. sulfur content	--
Electric Utility Boilers								
New Hope Power Partnership	FL	FL-0069	1/31/02	715 MMBtu/hr	0.20 lb/MMBtu (24-hr avg.)	0.20	Low S suppl. Fuel; ESP; SNCR; carbon injection	--
					0.06 lb/MMBtu (Annual avg.)	0.06	Low S suppl. Fuel; ESP; SNCR; carbon injection	--
Grayling Generating Station L.P.	MI	MI-882-89E	9/18/01	523 MMBtu/hr	11.2 lb/hr (24-hr avg.)	0.02	Multicyclones, ESP, SNCR	--
MEAD CONTAINERBOARD	AL	AL-0099	1/15/97	620 MMBtu/hr	0.02 lb/MMBtu	0.02	Combustion control	--
OKEELANTA POWER LIMITED PARTNERSHIP	FL	FL-0069	9/27/93	715 MMBtu/hr	0.02 lb/MMBtu 30-day avg.	0.02	FUEL SPEC: LOW S SUPP. FUEL APCE INCLUDES	--
							ESP, SNCR, AND CARBON INJECTION.	--
OSCEOLA POWER LIMITED PARTNERSHIP	FL	FL-0070	9/27/93	665 MMBtu/hr	0.02 lb/MMBtu 30-day avg.	0.02	FUEL SPEC: LOW SULFUR SUPPLEMENTAL FUEL	--
Wheelabrator Ridge Energy Inc.	FL	FL-0198	9/29/92	630 MMBtu/hr	0.1 lb/MMBtu	0.1	Limespray dryer absorber	--
Multitrade Limited Partnership	VA	VA-0183	2/21/92	373.7 MMBtu/hr	0.016 lb/MMBtu	0.016	No controls feasible	--

Reference: RACT/BACT/LAER Clearinghouse on EPA's Webpage, 2001.

[a] To convert from lb/hr, the emission limit was divided by the throughput rate. To convert from lb/day, assumed 24 hr/day operation.

[b] Assumed 8,760 hr/yr.

[c] This information obtained from actual PSD permit, not Clearinghouse.

Table D-3. BACT Determinations for NO_x and NO_2 for Biomass-Fired Industrial and Electric Utility Boilers

Company	State	RBLC ID	Permit Date	Throughput	Emission Limits: As Provided in LAER/BACT Clearinghouse	Emission Limits: Converted to lb/MMBtu[a]	Control Equipment Description	% Efficiency
Industrial Boilers								
US Sugar Corp.--Clewiston Blr No. 4	FL	PSD-FL-272A[c]	5/18/01	633 MMBtu/hr	0.20 lb/MMBtu	0.20	Bagasse firing	--
Atlantic Sugar Association	FL	PSD-FL-078B[c]	6/7/01	255.3 MMBTU/HR	0.16 lb/MMBtu	0.16	Wet Scrubbers/Good Combustion Practices	--
GULF STATES PAPER CORP	AL	AL-0122	10/14/98	98 MMBTU/HR	0.3 lb/MMBtu	0.3		--
POTLATCH CORPORATION	MN	MN-0033	6/24/98	140 MMBTU/HR	0.3 lb/MMBtu	0.3	Water vapor inj. & staged combustion	--
WELLBORN CABINET INC	AL	AL-0107	2/3/98	29.5 MMBTU/HR	13.57 lb/hr	0.46	Boiler design & comb. Control: oxygen trim, staged comb., steam injection, & overfire air.	31
GULF STATES PAPER CORPORATION	AL	AL-0116	12/10/97	775 MMBTU/HR	0.3 lb/MMBtu	0.3	Low Nox natural gas & fuel oil burner	50
Champion International	AL	AL-0112	12/9/97	710 MMBtu/hr	0.25 lb/MMBtu	0.25	Addition of tertiary air system	30
PLUM CREEK MFG - EVERGREEN FACILITY	MT	MT-0007	2/15/97	225 MMBTU/HR	104 lb/hr	0.46		--
Vaughan Furniture Company	VA	VA-0237	8/28/96	28 MMBtu/hr	24 TPY[b]	0.20	No controls feasible	--
Willamette Industries - Marlboro Mill	SC	SC-0045	4/17/96	470 MMBtu/hr	0.3 lb/MMBtu	0.3	Good combustion control	--
U.S. SUGAR CORP--Clewiston	FL	FL-0094	1/31/95	738 MMBTU/HR	0.25 lb/MMBtu	0.25	LOW NOX BURNERS	--
Scott Paper Company	WA	WA-0276	12/21/94	718 MMBtu/hr	150 ppm @ 7% O_2 30/day avg	--	Combustion controls	--
KES CHATEAUGAY PROJECT	NY	NY-0055	12/19/94	275 MMBTU/HR	0.23 lb/MMBtu	0.23	NO CONTROLS	--
WEYERHAEUSER CO.	AL	AL-0079	10/28/94	91 MMBTU/HR	0.23 lb/MMBtu	0.23		--
NEWMAN PAPER CO.	PA	PA-0093	4/24/92	129 MMBTU/HR	0.3 lb/MMBtu	0.3	LOW NOX BURNERS	--
Electric Utility Boilers								
Grayling Generating Station L.P.	MI	882-89E	9/18/01	523 MMBTU/HR	78.5 lb/hr (24-hr avg.)	0.15	Multicyclones, ESP, SNCR	--
MEAD CONTAINERBOARD	AL	AL-0099	1/15/97	620 MMBTU/HR	0.25 lb/MMBtu	0.25	COMBUSTION CONTROL	--
WEYERHAEUSER COMPANY	MS	MS-0026	5/9/95	90 MMBTU HR	0.23 lb/MMBtu	0.23	COMBUSTION CONTROLS	--
GEORGIA PACIFIC CORP. - GLOSTEE FACILITY	MS	MS-0023	4/11/95	244 MMBTU/HR	0.3 lb/MMBtu	0.3		--
Wheelabrator Ridge Energy Inc.	FL	FL-0198	9/29/92	630 MMBtu/hr	0.14 lb/MMBtu	0.14	SNCR	--
Multitrade Limited Partnership	VA	VA-0183	2/21/92	373.7 MMBtu/hr	0.1 lb/MMBtu	0.1	SNCR, Urea injection system	50

Reference: RACT/BACT/LAER Clearinghouse on EPA's Webpage, 2001.

[a] To convert from lb/hr, the emission limit was divided by the throughput rate. To convert from lb/day, assumed 24 hr/day operation.

[b] Assuming 8,760 hr/yr.

[c] This information obtained from actual PSD permit, not Clearinghouse.

Table D-4. BACT Determinations for CO for Biomass-Fired Industrial and Electric Utility Boilers

Company	State	RBLC ID	Permit Date	Throughput	Emission Limits As Provided in LAER/BACT Clearinghouse	Emission Limits Converted to lb/MMBtu[a]	Control Equipment Description
Industrial Boilers							
US Sugar Corp.--Clewiston Blr No. 4	FL	PSD-FL-272A[c]	5/18/01	633 MMBtu/hr	6.5 lb/MMBtu	6.5	Good combustion practices
Atlantic Sugar Association	FL	PSD-FL-078B[c]	6/7/01	255.3 MMBtu/hr	6.5 lb/MMBtu	6.5	Wet Scrubbers/Good Combustion Practices
GULF STATES PAPER CORP	AL	AL-0122	10/14/98	98 MMBtu/hr	0.5 lb/MMBtu	0.5	
WELLBORN CABINET INC	AL	AL-0107	2/3/98	29.5 MMBtu/hr	23.6 lb/hr	0.8	Boiler design & comb. Control: oxygen trim, staged comb., steam injections, & overfire air.
Champion International	AL	AL-0112	12/9/97	710 MMBtu/hr	0.03 lb/MMBtu	0.03	Proper design and good combustion practices
PLUM CREEK MFG - EVERGREEN FACILITY	MT	MT-0007	2/15/97	225 MMBtu/hr	506 lb/hr	2.25	GOOD COMBUSTION
Vaughan Furniture Company	VA	VA-0237	8/28/96	28 MMBtu/hr	104.2 TPY[b]	0.85	No controls feasible
Sugar Cane Growers Coop.	FL	FL-0220	6/4/96	504 MMBtu/hr	5.5 lb/MMBtu	5.5	Good combustion practices.
Willamette Industries - Marlboro Mill	SC	SC-0045	4/17/96	470 MMBtu/hr	0.3 lb/MMBtu	0.3	Good combustion control
PLUM CREEK MFG LP-COLUMBIA FALLS OP'N	MT	MT-0005	7/26/95	292.4 MMBtu/hr	468 lb/hr	1.60	Good combustion controls
WEYERHAEUSER COMPANY	MS	MS-0026	5/9/95	90 MMBtu/hr	0.4 lb/MMBtu	0.4	Good combustion controls
U.S. SUGAR CORP--Clewiston	FL	FL-0094	1/31/95	738 MMBtu/hr	6.5 lb/MMBtu	6.5	Good combustion practices.
KES CHATEAUGAY PROJECT	NY	NY-0055	12/19/94	275 MMBtu/hr	0.35 lb/MMBtu	0.35	NO CONTROLS
Scott Paper Company	WA	WA-0276	7/1/93	718 MMBtu/hr	511 ppm @ 7% O_2	--	Combustion control, boiler design
NEWMAN PAPER CO.	PA	PA-0093	4/24/92	129 MMBtu/hr	0.3 lb/MMBtu	0.3	Good combustion practices.
Electric Utility Boilers							
New Hope Power Partnership	FL	FL-0069	1/31/02	715 MMBtu/hr	0.5 lb/MMBtu, 30-day avg.	0.5	Good combustion practices
MEAD CONTAINERBOARD	AL	AL-0099	1/15/97	620 MMBtu/hr	0.4 lb/MMBtu	0.4	COMBUSTION CONTROL
WEYERHAEUSER CO.	AL	AL-0079	10/28/94	91 MMBtu/hr	1.4 lh/MMBtu	1.4	
Wheelabrator Ridge Energy Inc.	FL	FL-0198	9/29/92	630 MMBtu/hr	0.32 lh/MMBtu	0.32	Good combustion practices
Multitrade Limited Partnership	VA	VA-0183	2/21/92	373.7 MMBtu/hr	0.35 lb/MMBtu	0.4	Boiler design

Reference: RACT/BACT/LAER Clearinghouse on EPA's Webpage, 2001.

[a] To convert from lb/hr, the emission limit was divided by the throughput rate.

[b] Assuming 8,760 hr/yr.

[c] This information obtained from actual PSD permit, not Clearinghouse.

Table D-5. BACT Determinations for VOC for Biomass-Fired Industrial and Electric Utility Boilers

Company	State	RBLC ID	Permit Date	Throughput	Emission Limits: As Provided in LAER/BACT Clearinghouse	Emission Limits: Converted to lb/MMBtu[a]	Control Equipment Description
Industrial Boilers							
US Sugar Corp.--Clewiston Blr No. 4	FL	PSD-FL-272A[b]	5/18/01	633 MMBtu/hr	0.50 lb/MMBtu	0.50	Good combustion practices
Atlantic Sugar Association	FL	PSD-FL-078B[c]	6/7/01	255.3 MMBtu/hr	0.25 lb/MMBtu	0.25	Wet Scrubbers/Good Combustion Practices
Scott Paper Company	WA	WA-0276	10/14/98	718 MMBtu/hr	34.5 lb/hr	0.05	Combustion control, boiler design
GULF STATES PAPER CORP	AL	AL-0122	10/14/98	98 MMBtu/hr	0.1 lb/MMBtu	0.1	Multicyclone and ESP
Sierra Pacific Industries--Quincy	CA	CA-0930	5/13/98	245.3 MMBtu/hr	12.3 lb/hr	0.05	High pressure overfire air
GULF STATES PAPER CORPORATION	AL	AL-0116	12/10/97	775 MMBtu/hr	0.03 lb/MMBtu	0.03	Proper boiler design and operation
Champion International	AL	AL-0112	12/9/97	710 MMBtu/hr	0.03 lb/MMBtu	0.03	Good design and operation
Vaughan Furniture Company	VA	VA-0237	8/28/96	28 MMBtu/hr	1.7 TPY	--	Combustion control, boiler design
Willamette Industries - Marlboro Mill	SC	SC-0045	4/17/96	470 MMBtu/hr	0.1 lb/MMBtu	0.1	Good combustion control
SOUTHERN SOYA CORPORATION	SC	SC-0035	10/2/95	58.2 MMBtu/hr	0.05 lb/MMBtu	0.05	Good combustion practices
PLUM CREEK MFG LP-COLUMBIA FALLS OP'N	MT	MT-0004	7/26/95	50 MMBtu/hr	131.1 lb/hr	2.62	Good combustion practices
KES CHATEAUGAY PROJECT	NY	NY-0055	12/19/94	275 MMBtu/hr	0.1 lb/MMBtu	0.1	NO CONTROLS
Plum Creek MFG LP-Columbia Falls Op'n	MT	MT-0004	10/28/94	50 MMBtu/hr	131.1 lb/hr	2.6	Good combustion practices
WEYERHAEUSER CO.	AL	AL-0079	10/28/94	91 MMBtu/hr	0.05 lb/MMBtu	0.05	
Weyerhaeuser Co.	AL	AL-0079	7/1/93	91 MMBtu/hr	0.05 lb/MMBtu	0.05	--
Gulf States Paper Corp	AL	AL-0122	7/1/93	98 MMBtu/hr	0.1 lb/MMBtu	0.1	Multicyclone and ESP
Electric Utility Boilers							
New Hope Power Partnership	FL	FL-0069	1/31/02	715 MMBtu/hr	0.06 lb/MMBtu, 30-day avg.	0.06	Clean fuels
MEAD CONTAINERBOARD	AL	AL-0099	1/15/97	620 MMBtu/hr	0.03 lb/MMBtu	0.03	COMBUSTION CONTROL
GEORGIA PACIFIC CORP. - GLOSTEE FACILITY	MS	MS-0023	4/11/95	244 MMBtu/hr	0.02 lb/MMBtu	0.02	
Wheelabrator Ridge Energy Inc.	FL	FL-0198	9/29/92	630 MMBtu/hr	0.035 lb/MMBtu	0.035	Good combustion practices
Multitrade Limited Partnership	VA	VA-0183	2/21/92	373.7 MMBtu/hr	0.07 lb/MMBtu	0.07	Boiler Design

Reference: RACT/BACT/LAER Clearinghouse on EPA's Webpage, 2001.

[a] To convert from lb/hr, the emission limit was divided by the throughput rate.

[b] This information obtained from actual PSD permit, not Clearinghouse.

Table D-6. Summary of BACT Determinations for Fluorides Emissions from Biomass-Fired Electric Utility Boilers

					Emission Limits		
Company Name	State	RBLC ID	Permit Issue Date	Throughput Per Unit	As provided in BACT/LAER Clearinghouse	Converted to lb/MMBtu	Control Technology/Comment
Multitrade Limited Partnership	VA	VA-0183	2/21/92	373.7 MMBtu/hr	0.64 lb/hr	1.7E-03	No controls feasible

Reference: RACT/BACT/LAER Clearinghouse on EPA's Webpage, 2001

[a] Assumed 8,760 hr/yr.

Table D-7. BACT Determinations for Sulfuric Acid Mist for Biomass-Fired Electric Utility Boilers

Company	State	RBLC ID	Permit Date	Throughput	Emission Limits: As Provided in LAER/BACT Clearinghouse	Emission Limits: Converted to lb/MMBtu[a]	Control Equipment Description
Grayling Generating Station L.P.	MI	882-89E	9/18/01	523 MMBtu/hr	0.003 lb/MMBtu	0.003	Multicyclones, ESP, SNCR
MEAD CONTAINERBOARD	AL	AL-0099	1/15/97	620 MMBtu/hr	0.001 lb/MMBtu	0.001	COMBUSTION CONTROL

Reference: RACT/BACT/LAER Clearinghouse on EPA's Webpage, 2001.

[a] To convert from lb/hr, the emission limit was divided by the throughput rate.

Table D-8. BACT Determinations for Lead for Biomass-Fired Electric Utility Boilers

Company	State	RBLC ID	Permit Date	Throughput	Emission Limits: As Provided in LAER/BACT Clearinghouse	Emission Limits: Converted to lb/MMBtu[a]	Control Equipment Description	% Efficiency
New Hope Power Partnership	FL	FL-0069	1/31/02	715 MMBtu/hr	0.00015 lb/MMBtu, 30-	0.00015	Clean fuels, ESP	--
GRAYLING GENERATING STATION	MI	882-89E	9/18/01	523 MMBtu/hr	0.02 lb/hr (3-hr avg.)	3.8E-05	MULTICYCLONE, ESP, SNCR	--
Wheelabrator Ridge Energy Inc.	FL	FL-0198	9/29/92	630 MMBtu/hr	0.25 lb/hr	0.0004	--	--

Reference: RACT/BACT/LAER Clearinghouse on EPA's Webpage, 2001.

[a] To convert from lb/hr, the emission limit was divided by the throughput rate.

[b] Assuming 8,760 hr/yr.

Table D-9. Summary of BACT Determinations for Nitrogen Oxide Emissions from Coal-Fired Boilers

Company Name	State	RBLC ID	Permit Issue Date	No. of Units	Throughput Per Unit	Emission Limits: As Provided in BACT/LAER Clearinghouse	Emission Limits: Converted to lb/MMBtu	Control Technology/Comment	Efficiency %
Kansas City Power & Light Company - Hawthorn Station	MO	MO-0050	8/17/99	1	384 TPH	0.08 lb/MMBtu 30 day avg.	0.08	SCR and Good Combustion Practice	--
Deseret Generation and Transmission Company	UT	UT-0053	3/16/98	1	500 MW	0.55 lb/MMBtu 30 day avg.	0.55	Boiler Design	99.599
Two Elk Generation Partners, Limited Partnership	WY	WY-0039	2/27/98	1	250 MW	0.15 lb/MMBtu 30 day roll avg.	0.15	Low NO_x Burners with Overfire Air and SCR	75
Encoal Corporation - Encoal North Rochelle Facility	WY	WY-0047	10/10/97	1	240 MW	0.15 lb/MMBtu	0.15	Low NO_x Burners with Overfire Air and SCR	60
Encoal Corporation - Encoal North Rochelle Facility	WY	WY-0047	10/10/97	1	3960 MMBtu/hr	0.16 lb/MMBtu	0.16	Low NO_x Burners with Flue Gas Recirculation.	--
Wygen, Inc. - Wygen Unit One	WY	WY-0048	9/6/96	1	1014 MMBtu/hr	0.22 lb/MMBtu 30 day roll avg.	0.22	Low NO_x Burners and Overfire Air	56
Sonoco Products Company	SC	SC-0043	11/2/95	1	173.4 MMBtu/hr	0.3 lb/MMBtu	0.3	SNCR	--
Mon Valley Energy Limited Partnership	PA	PA-0133	8/8/95	1	966 MMBtu/hr	0.15 lb/MMBtu	0.15	SCR with Low NO_x Burners	50
International Paper Co. Hammermill Papers Div.	PA	PA-0101	12/27/94	2	350 MMBtu/hr	0.7 lb/MMBtu	0.7	Annual Tune-up	--
VPI & State University	VA	VA-0225	12/12/94	1	146.7 MMBtu/hr	75.7 TPY	0.12	Low Excess Air/Staged Combustion	--
Fort Drum HTW Cogen Facility	NY	NY-0070	3/1/94	3	651 MMBtu/hr	0.6 lb/MMBtu	0.6	No Controls	--
Crown/Vista Energy Project (CVEP)	NJ	NJ-0019	10/1/93	2	1789 MMBtu/hr	0.17 lb/MMBtu	0.17	SCR with Low NO_x Burners	48
Seminole Kraft	FL	FL-0077	7/7/93	1	174.7 MMBtu/hr	0.2 lb/MMBtu	0.2	Good Combustion	--
Black Hills Power and Light Company - Neil Simpson U	WY	WY-0046	4/14/93	1	1013 MMBtu/hr	0.23 lb/MMBtu 30 day roll avg.	0.23	Combustion Control	--
Indelk Energy Services of Otsego	MI	MI-0228	3/16/93	1	778 MMBtu/hr	0.25 lb/MMBtu	0.25	SNCR/Dry Control	50
Roanoke Valley Project II	NC	NC-0057	11/20/92	1	517 MMBtu/hr	0.17 lb/MMBtu	0.17	Low NO_x, AOF, SNCR	--
South Carolina Electric and Gas Company	SC	SC-0027	7/15/92	3	385 MW	0.32 lb/MMBtu	0.32	Low NO_x Burners with Overfire Air	--
Cogentrix of Dinwiddie	VA	VA-0185	4/16/92	8	375 MMBtu/hr	0.25 lb/MMBtu	0.25	SCR	58.3
Energy New Bedford Cogeneration Facility	MA	MA-0009		2	1671 MMBtu/hr	0.15 lb/MMBtu	0.15	SNCR	--
Milwaukee County Power Plant	WI	WI-0061		1	157 MMBtu/hr	0.16 lb/MMBtu	0.16	Ammonia Injection	60
						AVERAGE:	0.25		
						MAXIMUM:	0.7		
						MINIMUM:	0.08		

Source: RACT/BACT/LAER Clearinghouse on EPA's Webpage, 2002

Note: The boilers included in this table may be commercial, industrial or utility.

APPENDIX E

SUMMARY OF CORRESPONDENCE AND SCR AND FGD VENDOR QUOTES

SCR Vendor Correspondences

- Spoke with Frederick Booth of Engelhard Corp. (410-569-0297) on May 20, 2002. Mr. Booth stated that Engelhard does not provide SCR for biomass-fired boilers.

- Spoke with Phil Blazer of Babcock & Wilcox (B&W) (704-334-4742) on May 23, 2002. Mr. Blazer told me that B&W does provide SCR, but that SCR is not feasible for biomass-fired equipment. He further stated that B&W was not interested in preparing a quotation for this type of fuel burning boiler since B&W concentrates on SCR for CTs.

- Called Durr Environmental/Crawford Equipment and Engineering (407-851-0993) and left several messages. Was not able to reach anyone or to get anyone to return phone calls.

- Spoke with Mr. Mukund Kavia and corresponded through emails with Mrs. Kusum Kavia of Combustion Associates Inc. (909-272-6999). Initial email to Mr. Kavia was sent on May 23, 2002. Mrs. Kavia responded to the email requesting further information on May 28. In that email Mrs. Kavia stated that once all of the information was received, I would receive a price quote within two days. An email was sent back to Mrs. Kavia containing all of the requested information the same day. After not receiving the price quote phone calls were placed to Mr. Kavia on June 4, June 6, June 21, June 22, and June 27, 2002. Mr. Kavia returned my phone call on June 6 and June 22 stating that the quote was almost complete and that he would send it the following day. Mr. Kavia did not return my phone call of June 27 after not receiving a price quote.

- Spoke with Mike Sandel of Wheelabrator A.P.C. (412-562-7630) on May 24, 2002. Mr. Sandel declined to bid on the SCR since Wheelabrator only provides SCR for utility industry.

- Spoke with Flemming Hansen of Haldor Topsoe (281-228-5120) on May 24, 2002. Mr. Hansen stated that Haldor Topsoe may be able to help, but that he was concerned with the fact that SCR does not work well with biomass-fired equipment due to problems with potassium and sodium poisoning the catalyst. Mr. Hansen requested the equipment and operating parameters. A fax was sent out on May 24 with the requested information to Mr. Hansen. On May 31 Mr. Hansen called back stating that Haldor Topsoe would not be able to guarantee the life of the catalyst since the catalyst could die within a few thousand hours. To follow-up the phone conversation, Mr. Hansen sent an email on June 7, recommending that the SCR be installed downstream of the ESP, due to the likely potassium catalyst poisoning.

- Spoke with Mario Gialanella of Hamon Research-Cottrell, Inc. (770-844-1072) on May 23, 2002. Sent an email and fax with requested information to Mr. Gialanella on May 23. Mr. Gialanella stated that the quote would be ready in about two weeks. Called Mr. Gialanella on June 10 to check status of the quote, and was told that it should be sent out by June 14. Called Mr. Gialanella back on June 18 after not receiving quote, and was told that it should be sent out by June 21. Quote was received on June 21—see attached quote.

FGD/SO_2 Control Vendor Correspondences

- Called AirPol (973-599-4400) on May 20, May 23, and May 24,2002, and left messages. Could not reach anyone or get anyone to return my phone calls regarding SO_2 control.

- Spoke with Mike Sandel of Wheelabrator A.P.C. (412-562-7630) on May 24, 2002. Mr. Sandel referred me to John Jones, Regional Sales Manager (678-513-4555) for assistance with SO_2 control. Sent email to Mr. Jones with boiler and operating information and requested a quote on May 24. Jerry Parks, the Florida sales representative, left a message stating that he was working on the price quote. Did not hear back from Mr. Parks and did not have the phone number for him, so called John Jones back on June 18 and June 21, leaving a message for him to call back. On June 21, Mr. Jones left a message stating that it was not feasible for Wheelabrator to take the time to provide a price quote since the installation of FGD would require a complete retrofit of the existing system that would cost at $2.5-$3.5 million. Since the ESP was built by another company Wheelabrator could not guarantee the performance of the FGD. On July 19, received quote, see attached.

- Spoke with Neil Dahlberg of Hamon Research-Cottrell, Inc. (617-244-5613) on May 23, 2002. Mr. Dahlberg returned the phone call and on June 4 the requested boiler and other operating parameters were emailed and faxed to him. Mr. Dahlberg stated that he may be able to provide the quote in about two weeks. Called Mr. Dahlberg back on June 10 and June 18 to check status and was told that he would try to send the quote by June 21. Called Mr. Dahlberg back on June 21 and June 27, but have not been able to reach him. The price quote was never received.

- Spoke with Jerry Childers of McGill Air Clean Corp. (614-542-2505) on May 17, 2002. Mr. Childers faxed a list of necessary information to provide a quote on May 17. The fax was returned to Mr. Childers on May 23 containing all of the requested information. Mr. Childers stated that a full proposal should be completed in 2 weeks. On June 10 Mr. Childers called with additional questions, which were answered. Mr. Childers passed project along to Matt Lawrence (614-443-0192), who was supposed to finish the quote and send it out by June 14. Called Matt Lawrence on June 21 after not receiving the quote. Mr. Lawrence stated that he was referring it back to Mr. Childers and he would have it out by July 1. Called Mr. Childes back on July 9 after not receiving the quote. Mr. Childers stated that he would try to get it out on July 9. Still have not received quote.

VENDOR CORRESPONDENCES

SCR VENDOR QUOTES

BUDGETARY
PROPOSAL

Florida Crystal

SELECTIVE CATALYTIC REDUCTION SYSTEMS

HAMON

HAMON RESEARCH-COTTRELL
PROPOSAL NO. P-6171
June 20, 2002

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Appendices

1.0 DESCRIPTIVE NARRATIVE

This descriptive narrative is presented to provide Florida Crystal with an overview of the offering submitted by Hamon Research-Cottrell, the descriptions of the components of the entire SCR system, and the additional information required for a complete evaluation of our offering. The engineering criteria, parameters and methodology for the design of the entire SCR system are set out separately in the Design Parameters section.

Each SCR consists of the following major components:

- **One (1)- Selective Catalytic Reduction (SCR)**
- **One (1)- Aqueous Ammonia Flow Control Unit (skid mounted) and ammonia injection system**
- **Engineering, Project Management, 10 days of Startup Support**
- **One sootblower**

2.0 INTRODUCTION

Selective Catalytic Reduction

The Selective Catalytic Reduction (SCR) system is based on proven performance of the selected catalyst with many operating units in similar applications. Long term reliable operation and catalyst reactivity has been demonstrated in these plants. The system will incorporate automatic control features to minimize ammonia slip while maintaining the required NOx removal efficiency.

SCR Process Description

The most effective method of controlling NOx from combustion sources is Selective Catalytic Reduction (SCR). It is the only commercially available flue gas treatment technology that has been demonstrated to remove over 90% of the NOx contained in combustion system exhaust gas. SCR is widely used for different types of combustion systems. Most experience is with base-metal catalysts using trace amounts of vanadium, molybdenum, and tungsten, and formulations using combinations of these.

Chemistry

SCR technology involves reaction of ammonia with NOx in the presence of oxygen and a catalyst to form nitrogen and water. The major chemical reactions are:

$$4\,NO + 4\,NH_3 + O_2 \rightarrow 4N_2 + 6H_2O$$
$$6\,NO_2 + 8\,NH_3 + O_2 \rightarrow 7N_2 + 12H_2O$$

It is important to note that oxygen is necessary for this reaction to occur. Below about 0.5% oxygen concentration, the SCR reaction becomes much less effective. Depending upon the catalyst used, the technology can be operated from about 400°F to over 1000°F. Oxides of vanadium, titanium, and tungsten (V_2O_5, TiO_2, and WO_3) are widely used as commercial catalysts for ceramic monolith and composite catalysts.

When sulfur-bearing fuels are used, the control of oxidation of SO_2 to SO_3 becomes an important performance characteristic. Unreacted ammonia reagent can react with SO_3 to form ammonium bisulfate, which could reduce catalyst activity by deposition on active surfaces. It can also cause corrosion and plugging of downstream heat-exchange equipment. This problem has been addressed by formulating the catalysts to minimize the use of vanadium while maintaining high catalyst activity for NOx removal.

Other causes of catalyst deactivation include erosion of catalyst washcoat, plugging with particulate matter, poisoning by arsenic and other metal compounds, and acidic decomposition. The most challenging conditions for a catalyst are in the high dust, high acid conditions that exist in some coal-fired power stations and downstream of waste incinerators. In general, however, experience with SCR has shown that catalysts have adequate lifetimes and good resistance to deactivation.

Experience has shown that the ability to properly distribute ammonia in the exhaust gas stream and the ability to properly distribute the exhaust gas across the catalyst face are key elements in the achievement of good process performance. Design of the ammonia distribution system, catalyst chamber, transitions, and the catalyst ductwork are effectively addressed through computer analysis or physical flow modeling of the system.

Technical Approach

The major aspects of SCR system design are the following:

- Catalyst Selection and Sizing
- Gas Flow Modeling
- Reagent Injection System Design
- Structural Design
- Control System Design

The following paragraphs describe our design philosophy for SCR systems.

Catalyst Selection and Sizing

Hamon Research-Cottrell's philosophy regarding catalyst selection is to use the most appropriate catalyst for a given application. Because different SCR applications can have a wide range of constraints, the best catalyst for one application may not be the best for another application. SCR catalysts come in several varieties and can be composed of a range of materials. The catalyst reactors can also be configured in many different ways.

For most applications there are two primary configurations - plate and honeycomb. Plate catalysts are constructed by coating a catalytic material onto a thin sheet-metal substrate. The metal sheets are configured in a parallel and/or corrugated fashion. Honeycomb catalysts are formed by the coating of a honeycomb metal plate or by extrusion of a ceramic material into a honeycomb matrix. The honeycomb ceramic matrix may be made entirely of catalyst (homogeneous) or it can be made from an inert ceramic material that is coated with catalyst. The catalytic coatings of coated catalysts have been known to wear off in some applications. Honeycomb catalysts offer the advantage of higher catalytic surface area in a given volume than plate catalysts, often allowing less catalyst to be used. The ceramic honeycomb catalysts also weigh less than metal plate catalysts, reducing structural support requirements.

Both catalyst types have seen wide use on coal, gas, and oil-fired applications. The cleanliness of the fuel will dictate the plate spacing or cell pitch. In general, the dirtier the application, the larger the plate spacing or cell pitch.

Catalyst Formulations

SCR catalyst materials include base metals, precious metals, and zeolites. Precious metal catalysts are rarely used because of their high cost and their tendency to be poisoned. Catalysts composed of base metal oxides are most often used. Base metals that are commonly used include vanadium, molybdenum, and titanium. The formulation selected depends largely upon the temperature range where the catalyst will be used. Base metal catalysts are commonly used in the temperature range of 550F to 850F.

Of particular concern in selecting the proper catalyst formulation is presence of SO_2 and metals such as vanadium or arsenic in the flue gas.Vanadium catalysts are particularly susceptible to enhancing oxidation of SO_2 to SO_3, which is undesirable because it can react with ammonia to form ammonium salts that can plug catalyst sites and render the catalyst inactive. This can impose operating or design limitations for some systems with high sulfur fuels. For such systems, it is preferred to operate the SCR at temperatures well above 600 F to minimize the use of vanadium.

Space Velocity

Space Velocity (SV) is a characteristic that represents the treatment time for the flue gas in the SCR reactor. A high value for SV relates to a low treatment time. SV is defined as:

$$SV = \frac{\text{Total Gas Flow } (ft^3/\text{hour})}{\text{Catalyst Volume } (ft^3)}$$

Although the SV selected for a particular application will depend upon many variables, including the catalyst formulation and catalyst type, the following generalizations are true. High NOx reductions and low ammonia slips require low SV's. Because of the need for catalysts with large spacing and less catalytic area per volume, dirty fuels such as coal require lower SV's than clean fuels like gas.

Reagent Injection

Proper distribution of ammonia reagent is essential for achieving good performance from an SCR system. This is especially true in cases requiring high levels of NOx reduction. Poor distribution can result in low NOx reduction and/or high ammonia slip.

A cardinal point in SCR system design is the proper location of the ammonia injection grid (AIG). This must be located the proper distance upstream of the catalyst to enable even mixing of ammonia with the flue gas. The AIG is designed to allow complete manual adjustment during system start-up and optimization.

Ammonia is normally injected in the gaseous form and is diluted with a carrier gas. Hamon Research-Cottrell employs flow modeling for the design of the reagent injection system. This design methodology has been used to design flue gas conditioning systems and other gas treatment systems for numerous applications.

Gas Flow

In SCR systems, it is essential to minimize flow mal-distribution and distribute the gas flow evenly through the catalyst. Otherwise, a portion of the gas will have inadequate treatment time which may result in poor NOx reduction and/or high ammonia slip. Uniform gas flow is achieved by carefully designed ductwork that may include guide vanes and flow straighteners. For large reactors a flow straightener is used immediately upstream of the catalyst.

Hamon Research-Cottrell performs computer modeling and/or physical modeling in the laboratory to develop design of the gas flow distribution devices. HRC has its own in-house fluid dynamics group with these capabilities.

The benefits of this modeling capability include:

- Proper design of the system for high reduction and low ammonia slip.
- Accurate prediction of pressure drops.

This laboratory has world-renowned recognition and is frequently utilized by A&E's, Universities, and private concerns.

Temperature Considerations

In some applications the temperature of the flue gas is sufficiently high to prevent utilization of conventional catalysts. When this occurs, either a high temperature catalyst may be employed or air may be introduced into the flue gas stream to provide cooling. In this latter case, Hamon Research-Cottrell utilizes an ungula system to introduce cooling air. This system minimizes the pressure drop while at the same time maximizing the mixing of the cooling air with the hot flue gas.

Structural Design

The catalyst for a large SCR system can weight hundreds of thousands of pounds. It must be supported by a structure designed to operate at the high temperatures encountered in these systems. The catalyst modules are supported by a gridwork of horizontal "I" or box beams. Stiffener beams span between the major horizontal support steel. The horizontal support beams and stiffener beams are configured to frame and support the catalyst modules, sealing the gas around them. Ceramic fiber material seals the space between the catalyst module and the frame. These horizontal beams and the catalyst reactor casing are support by outer and inner intermediate vertical supports. The reactor casing is of A-36; steel exposed to flue gas temperature is all of grade ASTM – A 242.

Controls

Control of each SCR system is performed by a Programmable Logic Controller (PLC) which modulates ammonia flow based upon several monitored signals. The control systems can operate in either a Forward Control Mode, where the ammonia injection rate is primarily controlled on a feed-forward basis using the inlet NOx concentration signal, or in a Feed Back "Trim" Mode, where the ammonia rate is trimmed using outlet NOx concentration signal. The NOx analyzers are to be provided by the Purchaser.

3.0 SCOPE OF SUPPLY

SCOPE OF SUPPLY BY HRC

The scope of supply provided by HRC is outlined below. A detailed matrix is provided in Appendix 1 in the "Scope of Supply' Table.

- SCR Catalyst
- SCR Catalyst Housing
- Ammonia Vaporizer
- Ammonia Flow Control Skid
- Ammonia Injection Grid (AIG)
- Reactor Box
- PLC
- Instrumentation as indicated herein
- Flow Modeling
- Project Management
- Engineering
- QA/QC
- Field Service/Erection Consultant – on a per diem basis
- Start-up assistance – 10 days (additional available on a per diem basis)
- Freight – FOB Jobsite

SCOPE OF SUPPLY BY OTHERS

Equipment and services, which shall be provided by others, are generally assumed as indicated below. A more complete scope of supply by Others matrix is provided in Appendix 1.

- Installation material, labor, and supervision.
- Demolition of Existing Equipment (if required).
- Foundations and anchor bolts
- All Field wiring and conduit
- All Field piping and pipe hangers, unless otherwise stated herein
- Ammonia, water, air, calibration gas, compressed air, steam, or other consumables required for system start-up and system operation
- Motor Control Centers, motor starters, etc.
- NOx analyzers upstream of Catalyst
- CEMS System
- Performance and/or Acceptance Testing - per diem (except as otherwise provided herein)
- Ammonia Storage Tank

- Control room and any other enclosures
- Flow Straighteners
- Expansion Joints
- Transition Duct to and from the SCR
- Structural Support
- Insulation

6.0 PERFORMANCE PARAMETERS

The proposed NOx system design and performance is based on the information provided by Golder Associates. The system is designed to meet the NOx removal requirements as indicated in this technical specification description. A summary is provided in Table 1 below.

TABLE 1

Emissions Source	Cogen Boiler	Package Boiler
Number of Boilers	2	1
Fuel	Biomass	Biomass
Gas Conditions at Inlet to SCR		
Gas Flow, acfm	326,000	88,200
Gas Temp. at SCR catalyst, °F	700	700
NOx at SCR Inlet, ppmvd @ 15% O_2	210	210
Design Requirements		
SCR Catalyst – NOx Conversion (%)	90	90
System Pressure Drop inches w.c.	5	5
Catalyst Performance		
NOx at Outlet, ppmvd @ 15% O_2 –Max	21	21
Ammonia Slip, ppmvd @ 15% O_2 -Max	5	5
Catalyst LIfe	10,000 hrs	10,000 hrs
Approximate NOx Catalyst Volume (m3)	30	10
SCR Dimensions, Ft, LxWxH	20x20x20	10x12x20
Flue Gas Flow Direction	Down	Down

7.0 DESIGN PARAMETERS

The following Table 2 represents expected operating design parameters for the HRC supplied SCRs.

TABLE 2

PARAMETER	UNITS	VALUE
Structural Design Temperature	Deg F	900
Structural Design Pressure	Inches W.C.	-12 / +14
Wind Load	Mph	100
Snow Load	Psf	0
Input Voltage	Volts/Phase/Hz	480/3/60
Electrical Classification	Type	Non Hazardous

8.0 MATERIALS OF CONSTRUCTION

The following Table 3 represents the anticipated materials of construction for the HRC supplied SCRs.

TABLE 3

ITEM DESCRIPTION	MATERIAL	Inch Thick	PAINT SYSTEM
Vessel	ASTM A-36	¼	B
Access Steel Framing	ASTM A-36	Shapes	B
A.I.G. Internal Piping	ASTM A-304	To suit	D
A.I.G. External Manifolds	ASTM A-36	To suit	B
NOx Catalyst Support Frame	ASTM A-242	Shapes	D

9.0 PAINTING SYSTEM

The following Table 4 represents the anticipated painting system for the HRC supplied SCRs.

TABLE 4

Category (From Above)	Surface Prep. SSPC	Prime Coat	Finish Coat
A	SP-3	3 mils Red Oxide 1side	None
B	SP-6	3 mils Zinc Rich	None
C	SP-6	Galvanized	N/A
D	SP-1	None	None

10.0 SCHEDULE

The following schedule listed in Table 5 is anticipated as part of this proposal. HRC will work with the buyer to optimize this schedule based on specific needs of the project.

Table 5

Item	Weeks ARO
General Arrangement	4
Loads	6
Electrical One-Line	8
Design Drawings	16
Start SCR ship	32
End SCR ship	40
Start Catalyst Delivery	40
End Catalyst Delivery	42

11.0 PRICING AND COMMERCIAL TERMS

Pricing for the supply of three SCR NOx removal with the scope of supply outlined herein is as follows:

$ 4,250,000
FOB jobsite

- The above price does not include taxes of any kind.
- This price is submitted based on Hamon Research-Cottrell's standard warranty, which is 12 months from operation or 18 months from date of shipment, whichever is shorter.
- This proposal is submitted based on Hamon Research-Cottrell's Standard Terms and Conditions as outlined in Appendix 4. HRC is prepared to review these terms in conjunction with the Buyer at the appropriate time prior to award.
- This proposal is submitted based on Hamon Research-Cottrell's standard payment terms, which include 10% of the contract value upon receipt of purchase order and the balance in progress payments based on agreed upon milestones. Invoice payments will be based on net 30 days.

LaRocca, David

From: Howard, Fawn
Sent: Tuesday, July 30, 2002 11:21 AM
To: LaRocca, David
Subject: FW: Florida Crystal, P-6171, Price Breakout

Fawn Howard
Staff Engineer
Golder Associates Inc.
Gainesville, FL
(352) 224-1141 direct
(352) 336-5600 main
(352) 336-6603 fax
email: FHoward@golder.com

PRIVILEGED AND CONFIDENTIAL
ATTORNEY/CLIENT COMMUNICATION OR WORK PRODUCT

-----Original Message-----
From: DRABNIS Alfred [mailto:alfred.drabnis@hamon.com]
Sent: Thursday, June 27, 2002 1:26 PM
To: 'fhoward@golder.com'
Cc: GIALANELLA Mario
Subject: Florida Crystal, P-6171, Price Breakout

Ms. Howard,

Breakout price for the SCR for the package boiler is $850,000. Let me know
if I can help in any other way.

Regards,

Al Drabnis

12.0 DISCUSSION OF BID

12.1 The price quoted in this proposal is based upon the current market conditions for carbon steel, stainless & nickel alloys. Due to the volatility in stainless alloys and the possibility of significant import tariffs being imposed by the U.S. government on certain carbon steel products, we reserve the right to adjust our price in the event there is a material increase in steel prices. In the event of a change in steel prices, we will fully document the change in price to the customer and re-price accordingly.

12.2 Note that transitions from existing ductwork to each SCR shall be by Others.

12.3 CO Catalyst is not included.

13.0 Appendix 1

SCOPE OF SUPPLY SHEET

ITEM	BY HAMON BASE	BY HAMON OPTION	BY OTHERS	NOT REQ'D
1. DESIGN				
1.1 BASIC DESIGN	X			
1.2 DETAIL DESIGN FOR CATALYST MODULES	X			
1.3 DETAIL DESIGN FOR SCR HOUSING	X			
1.4 DETAIL DESIGN FOR NH3 INJECTION SYSTEM	X			
1.5 DETAIL DESIGN FOR AMMONIA STORAGE SYSTEM		X		
1.6 CONTROL LOGIC (narrative description)	X			
1.7 INSTRUCTION and O&M MANUALS	X			
2. CATALYST				
2.1 SCR CATALYST MODULES	X			
2.2 FUTURE CATALYST MODULES			X	
2.3 DISPOSAL OF SPENT CATALYST MODULES			X	
3. SCR HOUSING				
3.1 SCR HOUSING	X			
3.2 INLET & OUTLET TRANSITIONS w/ EXTERNAL INSULATION			X	
3.3 CATALYST SUPPORT FRAMES w/ SEAL DEVICES	X			
3.4 SPACE FOR FUTURE CATALYST MODULES	X			
3.5 HOIST & MONORAIL w/ SUPPORT STRUCTURES				X
3.6 INTERNAL PLATFORM w/ LADDERS			X	
3.7 EXTERNAL PLATFORM FOR CATALYST LOADING HATCH			X	
3.8 ACCESS DOORS	X			
3.9 INSTRUMENT and SAMPLING TAPS	X			
3.10 SLIDE PLATES FOR FOUNDATION			X	
3.11 FOUNDATION BOLTS			X	
3.12 THERMOCOUPLES (1 SET)	X			
3.13 DIFFERENTIAL PRESSURE TRANSMITTER (1 SET)	X			
3.14 EXPANSION JOINTS			X	

	BASE	OPTION	BY OTHERS	NOT REQ'D

4. AMMONIA INJECTION GRID-AIG

	BASE	OPTION	BY OTHERS	NOT REQ'D
5.1 HEADER w/ CONNECTION PIPES	X			
5.2 FLOW CONTROL DAMPERS (MANUAL)	X			
5.3 FLOW ORIFICES	X			
5.4 MANOMETERS or PDIS w/ ISOLATION VALVES	X			
5.5 PRESSURE INDICATOR	X			
5.6 TEMPERATURE INDICATOR	X			
5.7 THERMOCOUPLE	X			
5.8 DRAIN VALVE	X			
5.9 INSULATION			X	
5.10 SUPPORT LEGS	X			

6. AQUEOUS AMMONIA FLOW CONTROL SKID

	BASE	OPTION	BY OTHERS	NOT REQ'D
6.1 DILUTION AIR FANS w/ MOTORS, FILTERS & SILENCERS	X			
(100% CAPACITY X 2)				
6.2 DILUTION FLUE GAS PIPING & DAMPERS (shipped loose)	X			
6.3 DILUTION FLUE GAS FLOW ELEMENT & TRANSMITTER	X			
6.4 NH3/FLUE GAS VAPORIZER/MIXER	X			
6.5 DILUTION FLUE GAS PIPING PURGE CONTROLS	X			
6.6 LIQUID NH3 PIPING & VALVES (integral to skid)	X			
6.7 NH3 FLOW SHUT-OFF VALVE (integral to skid)	X			
6.8 NH3 FLOW SPRAY ORIFICE & TRANSMITTER	X			
6.9 NH3 PRESSURE INDICATOR	X			
6.10 NH3 PRESSURE TRANSMITTER	X			
6.11 NH3 TEMPERATURE TRANSMITTER	X			
6.12 NH3 STRAINER	X			
6.13 INSTRUMENT AIR PIPING & VALVES	X			
6.14 INSTRUMENT AIR PRESSURE SWITCH	X			

7. AQUEOUS AMMONIA STORAGE FACILITY

	BASE	OPTION	BY OTHERS	NOT REQ'D
7.1 AQUEOUS AMMONIA STORAGE FACILITY			X	
7.2 TANK TRUCK LOADING STATION			X	
7.3 LIQUID NH3 PIPING & VALVES			X	
7.4 NH3 CONTROL PANEL			X	
7.5 NH3 ACCUMULATOR w/ PRV			X	

	BASE	OPTION	BY OTHERS	NOT REQ'D
8. EXTERNAL PIPE (shipped loose)				
8.3 DISTRIBUTION NH3/DILUTION AIR PIPE (HEADER & AIG)	X			
8.4 SUPPORTS FOR DISTRIBUTION PIPE	X			
8.5 AQUEOUS AMMONIA PIPE (TANK-VAPORIZER-TANK)			X	
8.6 AQUEOUS AMMONIA PIPE (UNLOADING STATION-TANK)			X	
8.7 AQUEOUS AMMONIA PIPE (TANK-FLOW CONTROL SKID)			X	
8.8 SUPPORTS FOR AQUEOUS AMMONIA PIPE			X	
9. CONTROL & ELECTRICAL SYSTEM				
9.1 MOTOR CONTROL CENTER			X	
9.2 POWER SUPPLY OF ELECTRICAL EQUIPMENT			X	
9.3 PLC	X			
10. SCR INLET NOx/O2/CO ANALYZER				
10.1 ANALYZER			X	
10.2 CEM SYSTEM			X	
11. SCR OUTLET NOx/NH3/CO ANALYZER				
11.1 ANALYZER W/ PROBE			X	
11.2 CEM SYSTEM			X	
12. SURFACE TREATMENT				
12.1 SURFACE PREP SSPC-SP6	X			
12.2 SHOP PRIME	X			
12.3 FINISH PAINT			X	
13. FIELD WORK				
13.1 FOUNDATIONS AND ANCHOR BOLTS			X	
13.2 ERECTION			X	
13.3 SETTING CATALYST MODULES			X	
13.4 START-UP SCR SYSTEM			X	
13.5 PERFORMANCE TEST			X	
13.6 FIELD PAINT & TOUCH-UP PAINTING			X	
14. SUPERVISORY SERVICE				
14.1 INSTALLATION (10 days)	X			

Appendix 2

CODES AND STANDARDS

Following are the codes and standards that Hamon Research-Cottrell Inc. will use in the design and fabrication of all equipment. Applicable portions of the latest issue of these codes will be used.

ANSI -	American National Standards Institute, Building Code Requirements for Minimum Design Loads, A58.1
AWS -	American Welding Society, Structural Welding Code
AISC -	American Institute of Steel Construction specifications for Design, Fabrication and Erection of Structural Steel Buildings
UBC -	Uniform Building Code
NEC -	National Electric Code
ASME -	American Society of Mechanical Engineers
OSHA -	Federal Occupational Safety and Health Administration
NBS -	National Bureau of Standards
NFPA -	National Fire Protection Association
IGCI -	Industrial Gas Cleaning Institute
SBC -	Standard Building Code
ASTM -	American Society for Testing and Materials
EPA -	Environmental Protection Agency
NEMA -	National Electrical Manufacturer's Association
ISA -	Instrument Society of America
IEEE -	Institute of Electrical and Electronic Engineers

Hamon Research-Cottrell Inc. takes exception to compliance with any inconsistent or differing codes, including foreign gov ernment, province, state or local codes. In addition the IBC-2000 code is not being utilized. If in the design, fabrication, or erection of this equipment, Hamon Research-Cottrell Inc. is required to comply with any codes differing from or inconsistent with the aforementioned, Hamon Research-Cottrell Inc. shall be entitled to an equitable adjustm ent in both schedule and price to reflect increased costs incurred thereby , and a reasonable overhead and profit. Responsibility for investigating code requirem ents will be by Purchaser.

Appendix 3

Conditions of Sale For Field Services

All Field Services shall be furnished by Hamon Research-Cottrell, Inc. (hereinafter referred to as Contractor) to act in an advisory capacity in accordance with the following terms and conditions of sale and any contract made by and between Contractor and (hereinafter referred to as "Purchaser") includes as a part thereof these conditions of sale:

1.0 **RATES**

1.1 **On-Site Activities:**

a. From the hour the representative leaves his basing point up to and including the hour of his return to his basing point, payment shall be made at the U.S. fund rates listed below.

b. A work day is defined as any day, Monday through Friday, whether actual work is performed or not. Also, any travel time from the base point to the job site location or from the job site location to the base point is considered a work day. The work day is to be 8 hours and the work week 40 hours, Monday through Friday for which the straight time rate of **$110** per hour will be charged. All hours worked in excess of 8 hours per day or on Saturday will be charged at the rate of **$165** per hour. For work performed on Sundays and holidays the rate of **$220** per hour will be charged.

The minimum work day charge where work is performed will be based on a full eight (8) hour day. For "holdover" days where the representative is required to be on standby, but no actual work is performed, a charge of **$ 500** per day will apply.

1.2 **Service Reports**

A detailed field inspection report (including photos, drawings, sketches, etc., where applicable) will be prepared after the completion of on-site work. Since this work will occur offsite, standard billing rates will be charged for this activity. The rates for report preparation are:

On-site Service Days	Charge
1 – 2	4 hours x $110
3 – 5	6 hours x $110
6 – 10	8 hours x $110
10 – 20	12 hours x $110

This report will be issued within 10 days of the completion of the on-site visit.

1.3 **Export**

a. From the day the representative leaves his basing point up to and including the day of his return to his basing point, payment shall be made, in U.S. funds at the rates below.

Straight time rate: **$137.50**
Overtime rate: **$200.00**
Sundays & Holidays: **$287.50**

b. The hours of work shall be mutually agreed upon by the Purchaser and the representative and shall not be in excess of the hours of work described for domestic rates unless mutually agreed upon by Contractor at it's main office.

c. International air travel in excess of 12 hours shall be business class.

2.0 **EXPENSES**

2.1 **Transportation**

Round trip transportation to and from the job-site location will be billed at cost.

2.2 **Room, Board and Local Transportation**

Meals will be billed at $35/day. Living expenses, such as lodging, laundry, etc., will be billed at cost. Local car rental will be billed at cost.

3.0 **MISCELLANEOUS**

3.1 **Rate Adjustments**

Rates will be adjusted to those in effect at the time the service is performed, unless otherwise specified in the proposal.

3.2 **Lay-Over Expense**

Where circumstances require that a service representative be held over on weekends, during which no work is performed charges for living expenses will be billed per section 2.

3.3 **Cancellation**
In the event a service requirement is canceled less than three (3) working days from a previously agreed upon start date, a cancellation fee of one day's service will be charged.

3.4 **Engineering Services Charges**
Services requiring investigation, research or Engineering services will be billed at $90/hour.

4.0 INDEPENDENT CONTRACTOR

Contractor shall be considered an independent contractor in respect to all work herein provided. No actions taken hereunder are intended to establish any relationship of agency, partnership or joint venture between Contractor and Purchaser.

5.0 DISCLAIMER OF CONSEQUENTIAL DAMAGES
The Contractor SHALL NOT be liable to Purchaser for indirect or consequential damages including, but not limited to, loss of profits or revenue, loss of use of equipment, costs of replacement power, additional expenses incurred in the use of equipment or facilities, or the claims of third parties. This disclaimer shall apply to consequential damages based upon any cause of action whatsoever asserted against Contractor, including one arising out of any breach of warranty, express or implied, guarantees, products liability, negligence, tort, or any other cause pertaining to performance or non-performance of this proposal or contract by Contractor.

6.0 IMPLIED WARRANTIES DISCLAIMER
The Warranties furnished by Contractor as expressly included herein constitute Contractor's sole obligation hereunder and are in lieu of any other warranties or guarantees, express or implied, including warranties of merchantability or fitness for a particular purpose.

7.0 INDEMNITY
Contractor SHALL NOT be responsible for losses or damages arising out of the negligence of the Purchaser, its employees, agents or assigns or for losses for which the Purchaser has agreed to provide insurance. Contractor specifically disclaims responsibility for damages, injury or other costs resulting from the efforts performed by others including the manner of erection and safe execution thereof, and to which Contractor is providing direction and assistance. Purchaser shall indemnify Contractor with respect to any and all claims, suits or actions arising out of the work performed hereunder, except for those which under a final and unappealable order of a court with jurisdiction are determined to be the result of the sole negligence of Contractor. Both the Contractor and the purchaser hereby agree to mutually waive any rights which each may have against the other with respect to subrogation under any policy of insurance relating to the equipment or services provided under this contract.

8.0 TERMS OF PAYMENT
Unless otherwise agreed, payment shall be made within thirty (30) days of presentation of an invoice which shall be issued upon the completion of the assignment or at the end of each month if the assignment duration is in excess of the one month period. All payments not received by the due date shall be subject to a monthly interest charge at the rate of 2% per month or the maximum allowed by law, whichever is less, due and payable until the payment is received.

9.0 FORCE MAJEURE
Contractor shall not be liable for any loss or damage arising out of delay in performance under this contract due to causes beyond its reasonable control such as, but not limited to, acts of God, acts of purchaser, acts of civil or military authorities, priorities, fire, smoke interference, strikes, floods, epidemics, quarantine restrictions, war, riot, delays in transportation, car shortages, work stoppages or Contractor's inability to obtain necessary labor. In the event of such delay, the date of performance shall be extended for a period equal to the time lost by reason of such delay. Contractor shall be entitled to an equitable adjustment in the contract price for increased costs incurred due to the aforementioned causes.

10.0 LIMITATION ON LIABILITY OF CONTRACTOR
In no event will Contractor's liability to the Purchaser for any and all claims, including property damage and personal injury claims, allegedly resulting from breach of contract, tort, or any other theory of liability exceed the amount paid hereunder to Contractor.

11.0 HAZARDOUS MATERIALS
The Purchaser's facilities may contain hazardous materials, including asbestos bearing materials. Contractor's services do not include directly or indirectly performing or arranging for the detection, monitoring, handling, storage, removal, transportation, disposal or treatment of petroleum or petroleum products (collectively called "Oil") or of any hazardous, toxic, radioactive or infectious substances, including any substances regulated under RCRA or any other Federal or State environmental laws (collectively called "Hazardous Materials"). If any such materials are encountered, Contractor shall have no obligation to remove or remediate them in the absence of a separate agreement (including separate consideration to Contractor) for such work. If Contractor's representative is required to perform work within or immediately adjacent to any facilities that are determined to contain hazardous materials and/or asbestos, and the said work must be interrupted to allow for the remediation or removal of such materials by others, Contractor shall be entitled to any and all costs and other expenses associated with such interruption in

work. Purchaser shall fully defend, hold harmless and indemnify Contractor and its agents from and against any claims arising out of exposure to such hazardous and/or asbestos bearing material.

12.0 **SAFETY**

Contractor shall not be responsible for health or safety programs or precautions related to Purchaser's activities or operations, Purchaser's other contractors, the work of any other person or entity, or Purchaser' site conditions. Contractor shall not be responsible for inspecting or correcting health or safety conditions or deficiencies of Purchaser or others at Purchaser's site, and Purchaser agrees to indemnify, hold harmless, and defend Contractor against any claims arising out of such conditions or deficiencies. So as not to discourage Contractor from voluntarily addressing health or safety issues by making observations, reports, suggestions, or otherwise, it is understood and agreed that Contractor shall nevertheless have no liability or responsibility arising on account thereof.

13.0 **CONTRACT INTERPRETATION**

If any of the provisions of these Conditions of Sale (including the proposal) conflict with any provisions in the Purchaser's documents, the former shall govern unless Contractor expressly agrees to the contrary in writing. No changes in or modifications of these Conditions of Sale which form part of the contract between Contractor and Purchaser shall be binding upon the parties unless accepted by Contractor in writing.

14.0 **SEVERABILITY**

Should any part of this Agreement be declared invalid or unenforceable, such decision shall not affect the validity of any remaining portion, which remaining portion, shall remain in full force and effect, and Seller shall have the right to replace the part declared invalid or unenforceable with a provision which serves as much as validly possible the same commercial purpose as the part determined to be invalid or unenforceable.

15.0 **SERVICES EXCLUDED**

Services not expressly set forth in writing in this Agreement are excluded from Contractor's services, and Contractor assumes no duty to the Purchaser to perform such duties.

16.0 **SUSPENSION**

Failure by Purchaser to make timely payments of Contractor invoice shall entitle Contractor to suspend performance of services under this Agreement. Unless payment in full is received by Contractor within seven (7) days of the date of the suspension is mailed to the Purchaser by Contractor, the suspension shall take effect without further notice. Contractor shall not be liable for any damages or delays caused by such suspension.

17.0 **TERMINATION**

Contractor may terminate this Agreement, in whole or in part, at its election upon seven (7) days written notice to the Purchaser upon one or more of the following events: (1) invoices for services remain unpaid for over thirty (30) days, (2) an "unexpected contingency" occurs which shall mean (a) strikes, lockouts, riots, unavoidable accidents, acts of God or of the public enemy, or unavailability of transportation; (b) any lawful order issued by the United States, stat or local governmental authority; (c) the purchaser becomes bankrupt or insolvent or goes or is put into liquidation or dissolution, either voluntarily or involuntarily, or petitions for an arrangement or reorganization under the Bankruptcy Act, or makes a general assignment for the benefit of creditors or otherwise acknowledges insolvency; or (d) any other cause beyond Contractor's reasonable ability to carry out its obligations herein. Upon termination of this Agreement by Contractor under this section, Contractor shall be compensated for its services performed prior to the date of such termination, and for other expenses reasonably or necessarily incurred in connection with such termination.

18.0 **LAWS**

This Agreement and all rights and obligations of the parties hereunder, and any disputes hereunder, shall be construed and governed by the state of New Jersey.

Appendix 4

STANDARD TERMS AND CONDITIONS

The following terms and conditions form part of each proposal submitted by (SELLER) hereinafter called "Contractor" for the sale of equipment or services to a Client/Customer hereinafter called "Purchaser" and any contract made by and between the parties includes as a part thereof these terms and conditions.

MATERIAL WARRANTY

1.1 **Warranty**
Contractor warrants to Purchaser that the equipment manufactured by it is free from defects in material, workmanship and design under normal use and service for a period of eighteen (18) months after shipment or twelve (12) months after initial operation, whichever occurs first. Initial operation is defined as the date of first heat load of the equipment. All auxiliary equipment not manufactured by Contractor carries such warranty as given by the manufacturer thereof and which is hereby assigned to Purchaser.

1.2 **Terms**
Contractor's obligation under this warranty is to supply, pursuant to the delivery terms of the proposal, at Contractor's sole option repaired or replacement parts for those parts which are shown to Contractor's satisfaction to have been defective as to material, workmanship or design, provided that:

a. Written notice of such defect is given to Contractor within thirty (30) calendar days of discovery thereof;
b. The equipment has been operated in accordance with the operating and maintenance instructions provided by Contractor; and
c. No alterations or substitutions have been made in the equipment without the express written authorization of Contractor.

1.0 **PURCHASER'S ACTS VOIDING WARRANTIES**

2.1 The warranty furnished by Contractor herein will be rendered void and of no further force or effect by the Purchaser's use and operation of the equipment in a manner which, in Contractor's reasonable judgment is inconsistent with recommendations contained in Contractor's Operation and Maintenance manual issued for the equipment including but not limited to improper erection, damage caused by abrasion, corrosion or excess temperature or other operational causes. Additionally, the warranty is voided by the Purchaser's unauthorized alteration of, or making of substitutions to the equipment herein supplied. The Purchaser shall defend, hold harmless and indemnify Contractor and its officers, directors, employees and agents from and against any liability for personal injury or property damage arising out of the above-mentioned causes as well as from any fires internal to the equipment supplied under this contract.

3.0 **PATENT WARRANTY**
Contractor shall defend at its expense any suit or proceeding brought against Purchaser based on any claim that the equipment covered herein, except for equipment/material manufactured and/or designed to Purchaser's specifications, infringes any United States patent issued as of the date of this proposal and pay any court imposed damages and costs finally awarded against Purchaser, but not to exceed the amount theretofore paid to Contractor by Purchaser hereunder provided:

a. Contractor is promptly notified by Purchaser in writing of such claim; and
b. Contractor is given full authority, information, and assistance by Purchaser which Contractor deems necessary for the conduct of such defense.

Contractor shall have the right and option at any time in order to avoid such claims or actions and minimize potential liability to:

a. Procure for the Purchaser the right to use the equipment; or
b. modify the equipment so that it no longer infringes; or replace the equipment with non-infringing equipment

4.0 **DELAYS AND DAMAGES - FORCE MAJEURE**
In the event of delays or damages due to conditions beyond Contractor's reasonable control, including, but not limited to, Acts of God, Acts of Purchaser or Purchaser's Customer or of other Contractor's employed by Purchaser, Acts of Civil or Military Authority, priorities, fire, strikes, floods, epidemics, quarantine restrictions, war, riot, delays in transportation, car shortages, and Contractor's inability to obtain necessary labor, materials or manufacturing facilities. In the event of such delay, the Contract dates shall be extended by an equitable period of time and Contractor shall be entitled to an equitable adjustment in the Contract price.

5.0 **PERFORMANCE GUARANTEE**
Contractor's sole guarantees are those contained in its proposal to Purchaser. These guarantees are contingent upon the correctness and accuracy of the information provided by the Purchaser and are based upon the operating conditions specified in Contractor's proposal. These guarantees will be deemed satisfied by successful completion of performance tests in accordance

with applicable standard procedures as specified in the proposal and in effect on the date of this proposal. Performance tests shall be conducted by the Purchaser and witnessed by Contractor within 90 days of the date of initial operation of the equipment. In the event the said tests are not conducted within 90 days of initial operation or within six (6) months of shipment whichever is earlier and through no fault of the Contractor, the equipment shall be deemed accepted by the Purchaser and in compliance with all contractual requirements. In the event the equipment fails to meet the contract performance guarantees as verified by certified test results, Contractor will supply, at its sole option, repaired or replacement parts pursuant to the delivery terms of the proposal subject to the limitations stated in Article

6.0 **IMPLIED WARRANTIES DISCLAIMER**

The warranties furnished by Contractor as expressly included herein constitute Contractor's sole obligation hereunder and are in lieu of any other warranties or guarantees, express or implied, including warranties of merchantability or fitness for a particular purpose.

7.0 **DISCLAIMER OF CONSEQUENTIAL DAMAGES**

The Contractor shall not be liable to Purchaser for indirect or consequential damages including, but not limited to, loss of profits or revenue, loss of use of equipment, costs of replacement power, or product, additional expenses incurred in the use of equipment or facilities, or the claims of third parties. This disclaimer shall apply to consequential damages based upon any cause of action whatsoever asserted against Contractor, including one arising out of any Breach of Warranty or Guarantee, Products Liability, Negligence, Tort, or any other cause of action.

8.0 **PURCHASER'S NEGLIGENCE AND INSURANCE**

Contractor shall not be responsible for losses or damages arising out of the negligence of the Purchaser, its employees, agents or architects or losses for which the Purchaser has agreed to provide insurance. In the event that both the Contractor and the Purchaser are negligent and the negligence of both is proximate cause of the accident, then in such event each party will be responsible for their portion of the liability or damages (excluding consequential or indirect damages which are disclaimed by the Contractor) resulting therefrom equal to such party's comparative share of the total negligence. Both the Contractor and the Purchaser hereby agree to mutually waive any rights which each may have against the other with respect to subrogation under any policy of insurance relating to the equipment or services provided under this contract.

9.0 **LIMITATION OF LIABILITY**

In no event will Contractor's liability to the Purchaser for any and all claims, including property damage and personal injury claims, allegedly resulting from breach of contract, tort, or any other theory of liability exceed the amount of the initial purchase price paid to the Contractor.

10.0 **PRICE ADJUSTMENT - EQUIPMENT, MATERIALS & LABOR**

Unless otherwise noted in the Contractor's proposal, equipment and material prices set forth in the proposal are firm for delivery in accordance with the Schedule therein. In the event the Schedule is modified due to acts of Purchaser or conditions beyond Purchaser's control and contract costs escalate, an equitable adjustment to the Contract price shall be granted to Purchaser.

11.0 **TAXES**

Sales Tax, Personal Property Tax, Use Tax, Excise Tax, or other taxes imposed by Federal, State or municipal authority and incurred by Contractor through performance on the contract shall be to the Purchaser's account and are in addition to the prices quoted in the proposal. Contractor shall not be responsible for any additional costs associated with the Purchasers tax exemption certificate and the governing body's acceptance of same.

12.0 **DELIVERY**

12.1 **Title**

Title to all equipment shall pass to Purchaser at the FOB point or points of shipment and risk of loss will thereafter be borne by Purchaser.

12.2 **Storage**

If the Purchaser declines or is unable to take delivery at the time(s) specified in the proposal or contract, Contractor will have the equipment stored for Purchaser at Purchaser's risk and account, and the materials shall be considered "shipped".

13.0 **PAYMENT**

13.1 **Terms of Payment**

Unless otherwise agreed, the payment schedule shall be as outlined herein and payments shall be made within thirty (30) days of presentation of an invoice. Payments not received by the due date shall be subject to a monthly interest charge at the rate of 2% per month or the maximum allowed by law, whichever is less, due and payable until the payment is received.

13.2 **Payment Schedule**

a. 10% down with the order
b. Engineering progress payments (monthly, based upon percent completed)
c. Material & Equipment delivered to project (monthly, based upon percent shipped)

In the event a retention value is required and agreed, it shall accrue interest at the rate of 1% per month on the outstanding balance until exchanged for a letter of credit or paid to Contractor. Contractor retains the unqualified option to provide Purchaser with a letter of credit in lieu of retention at any time during the performance of the contract.

13.3 **Default In Payment**

a. If any payment due to Contractor is more than thirty (30) days past due, Contractor shall have the right at its sole option to accelerate the payment of all outstanding amounts, including, but not limited to, amounts previously retained pursuant to the agreement, by notifying Purchaser in writing that all outstanding amounts are immediately due and presenting Purchaser with an invoice for said amount. Contractor shall also have the right in such event to discontinue all work on the project without incurring any liability to Purchaser for such action.

b. In the event the total aggregate amount of delinquent payments exceeds at any point during the term of the agreement ten (10%) of the total contract amount, Purchaser shall provide at Contractor's request, additional collateral, including but not limited to irrevocable letters of credit, sufficient to secure payment of all contract amounts.

c. The foregoing remedies of Contractor are in addition to all other remedies Contractor may have at law or in equity, including but not limited to the right to obtain liens on Purchaser's assets through legal or equitable proceedings.

13.4 **Payment of Retained Amounts**

a. If this contract permits Purchaser to withhold final payment, and acceptance is not based upon performance tests, such final payments shall be due and payable within thirty (30) days after the equipment is ready for operation.

b. If such deferred payment is contingent upon tests and such tests are delayed through no fault of Contractor for more than thirty (30) days after the equipment is first ready for operation, final payment shall be due and payable upon expiration of such thirty (30) day period.

14.0 **CANCELLATION**

Purchaser's cancellation of the contract is subject to a cancellation charge of 10% of the total price of the contract, plus Contractor's actual expenses and expenses to which Contractor has become committed for fulfillment of the contract before notice of cancellation is received.

15.0 **SUSPENSION**

In the event Purchaser suspends the execution of work on this contract, Purchaser shall reimburse Contractor for all costs incurred by Contractor as a result of such suspension, including, without limitation, all borrowing and opportunity costs. In the event the suspension exceeds 180 days in duration, in addition to being entitled to full reimbursement of costs as aforesaid, Contractor shall have the unqualified right to cancel the unfinished portion of the contract without liability to Purchaser of any kind. Should the contract be canceled the provisions of Article 13.0 shall apply.

16.0 **OSHA - FEDERAL, STATE AND LOCAL**

Contractor agrees to comply with the Federal OSHA requirements in effect as of the date of this proposal relative to the design of the equipment furnished within its scope of supply as defined in this proposal. Where state or local safety and health requirements differ from the Federal OSHA requirements, modifications or changes in design to meet state or local safety and health requirements will be incorporated at Purchaser's request. Additional costs arising from such requests and from erection procedures required by state or local safety and health regulations which deviate from Federal OSHA requirements will be for Purchaser's account.

17.0 **PROPRIETARY AND CONFIDENTIAL MATERIALS**

All drawings, patterns, specifications and information included in Contractors proposal or contract and all other information otherwise supplied by Contractor as to design, manufacture, erection, operation and maintenance of the equipment shall be the proprietary and confidential property of Contractor and shall be returned to Contractor at its request. Purchaser shall have no rights in Contractors proprietary and confidential property and shall not disclose such proprietary and confidential property to others or allow others to use such property, except as required for the Purchaser to obtain service, maintenance, and installation for the equipment purchased from the Contractor. This clause shall survive the termination of this contract and be in effect as long as the Purchaser has possession of any of the Contractor's proprietary or confidential property.

18.0 **ASSIGNMENT**

Contractor retains the right to assign this contract to any subsidiary or affiliated company of Contractor without the Purchaser's prior approval. All other assignments by either Contractor or Purchaser require the prior written consent of the other party.

19.0 **HAZARDOUS MATERIALS**

The Purchaser's facilities may contain hazardous materials, including asbestos bearing materials. Contractor's services do not include directly or indirectly performing or arranging for the detection, monitoring, handling, storage, removal, transportation, disposal or treatment of petroleum or petroleum products (collectively called "Oil") or of any hazardous, toxic, radioactive or infectious substances, including any substances regulated under RCRA or any other Federal or State environmental laws (collectively called "Hazardous Materials"). If any such materials are encountered, Contractor shall have no obligation to remove or remediate them in the absence of a separate agreement which includes separate consideration to Contractor for such work. If Contractor or any of its subcontractors is required to perform work within or immediately adjacent to any facilities that are determined to contain hazardous materials and/or asbestos, and the said work must be interrupted to allow for the remediation or removal of such materials by others, Contractor shall be entitled to any and all costs and other expenses associated with such interruption in work. Purchaser shall fully defend, hold harmless and indemnify Contractor and its agents from and against any claims arising out of exposure to such hazardous and/or asbestos bearing materials.

20.0 **SAFETY**
Contractor shall not be responsible for health or safety programs or precautions related to Purchaser's activities or operations, Purchaser's other contractors, the work of any other person or entity, or Purchaser' site conditions. Contractor shall not be responsible for inspecting or correcting health or safety conditions or deficiencies of Purchaser or others at Purchaser's site, and Purchaser agrees to indemnify, hold harmless, and defend Contractor against any claims arising out of such conditions or deficiencies. So as not to discourage Contractor from voluntarily addressing health or safety issues by making observations, reports, suggestions, or otherwise, it is understood and agreed that Contractor shall nevertheless have no liability or responsibility arising on account thereof.

21.0 **DISPUTES**
In the event of a dispute arising hereunder, the parties will attempt to amicably resolve the dispute. If after good faith negotiations, the parties cannot reach agreement, then the matter shall be resolved in a court having jurisdiction.

22.0 **CONTRACT INTERPRETATION**

22.1 If any of the provisions of these Standard Conditions of Sale (including statements made in the proposal) conflict with any provisions in the Purchaser's documents, the former shall govern unless Contractor expressly agrees to the contrary in writing. Any contract resulting from this proposal shall be construed, and the legal regulations of the Contractor and Purchaser shall be determined in accordance with the laws of the State of New Jersey, U.S.A.

22.2 All communications, written and verbal, between the parties hereto with reference to the subject of this proposal prior to the date of its acceptance are merged herein and this proposal, when duly accepted and approved, shall constitute the sole and entire agreement and contract between the parties as to the subject matter thereof. No changes in or modifications of said agreement shall be binding upon the parties of either of them, unless they shall be in writing duly accepted by the Purchaser and approved in writing by Contractor.

23.0 **ACCEPTANCE**
This proposal is subject to acceptance by the Purchaser within thirty (30) days and shall constitute a binding agreement with Contractor only when thereafter approved by Contractor and signed by an authorized officer.

24.0 **SEVERABILITY**
Should any part of this Agreement be declared invalid or unenforceable, such decision shall not affect the validity of any remaining portion, which remaining portion, shall remain in full force and effect, and Seller shall have the right to replace the part declared invalid or unenforceable with a provision which serves as much as validly possible the same commercial purpose as the part determined to be invalid or unenforceable.

25.0 **CHANGES/ADDITIONAL WORK**
Contractor is not obligated to incur any expense or do any work in excess of that reasonably anticipated unless the Purchaser issues a Change Order for such expense or work with mutually acceptable terms and conditions.

RM Technologies
Aqueous Ammonia Storage Tank Vendor Budget Estimate

Vendor:	RM Technologies Laurel Corporate Center 8000 Midlantic Drive, Suite 110S Mt. Laurel, NJ 08054-1548	Date: 7/31/02

Storage Tank Type:

Stainless Steel, Horizontal, includes valves and transfer station.

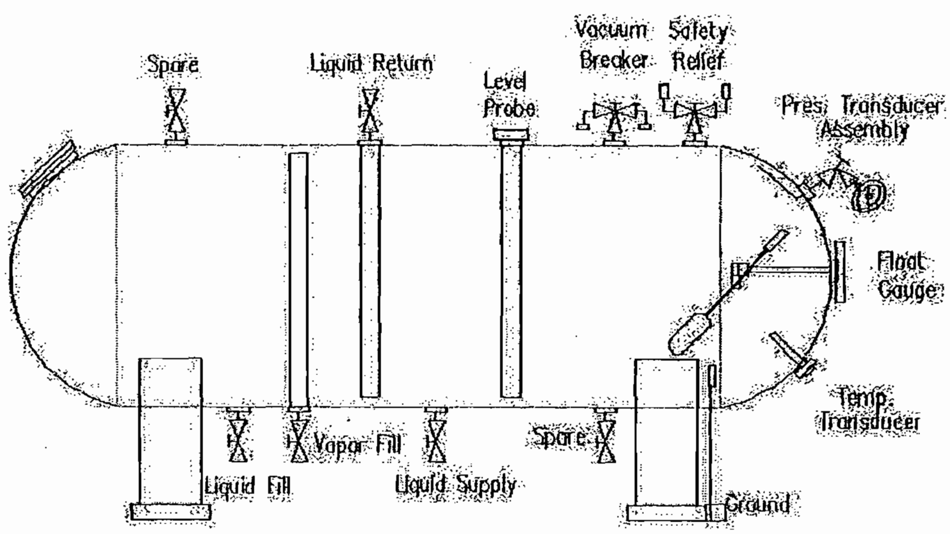
Budget Estimates:

Size	Budget Estimate
10,000 Gallon	\$160,000 - \$170,000
30,000 Gallon	\$210,000 - \$220,000

Aqua Storage Tanks

Aqua ammonia storage tanks are of the above ground, horizontal type, with spherical heads, having capacities ranging from 8,000 to 30,000-water gallon. They are constructed of 304 Stainless Steel and are built in accordance with the latest edition of the ASME Code for Unfired Pressure Vessels, Section VIII, Division 1, rated for 30 psi. and are registered with National Board. The tanks can be supplied completely fitted in accordance with industry and regulatory standards. Typical tank fittings include a 2" vapor fill connection with dip tube, 2" liquid fill connection, 2" service to point of use connection, ½" pressure gauge connection, 2 ½" level gauge connection, ½" thermowell connection, 2" safety relief connection, 2" vacuum breaker connection, 2" liquid drain connection, manway, 2" spare vapor connection, 2" liquid return connection with dip tube, 2" level probe connection with dip tube, lifting lugs, and 10" high saddles. Tanks can be supplied with all necessary trim as per customers' requirements.

Typical Aqua Storage



Tan

Send mail to rmtech@bellatlantic.net with questions or comments about

this web site or Contact us at 609-702-8260.

Last modified: March 19, 2000

Abstract - May 2002 DOE/NETL Pittsburgh Conference on SNCR and SCR

SNCR System - Design, Installation, and Operating Experience

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Summary

SNCR is a mature technology for moderate, i.e. 40-60% reduction, of uncontrolled NOx in high temperature combustion gasses. The techinique was originally pioneered by Exxon using ammonia as the reagent. The patents on this technology expired in the late 80's. In the early 1980's, EPRI received two process patents for the same basic techniques, only using urea instead. One was for the oxygen rich environment and the other for fuel rich at even higher temperatures. These basic patents have now also expired. The mechanics of the two techniques differ mainly in that ammonia injection is gaseous and urea is liquid. Otherwise, both use very similar fluid injection and control techniques.

SNCR systems are often the technology of choice for applications requiring moderate, i.e., 40-60% NOx reduction and has been proven many times over. Broken down into its most basic chemistry, the technique requires thorough mixing of the reagent into the furnace chamber with at least 0.5 seconds of residence time at a temperature above 1600F and below 2100F. Optimally, the reagent is usually injected into the furnace at approximately 1900 - 1950F which is a good tradeoff between the competing reaction of oxidation of ammonia to NOx and maximizing the residence time prior to the low temperature limit. Hence the location, design, and atomization characteristics of the injectors are critical considerations.

Under laboratory conditions, NOx reductions in excess of 90% has been demonstrated. Unfortunately, these conditions are never observed in reality. The closest approach to these ideals are seen in waste incinerators, wood fired units, and some CFB's. These units have in common ample residence time

above the minimum reaction temperature, base loaded conditions, and furnace dimensions which allow for effective dispersion of the reactant through the entire furnace cross section. In broad terms, these units routinely demonstrate 50% NOx reduction at a Normalized Stoichiometric Ratio (NSR) of 1.0 with less than 10 ppm ammonia slip.

Larger utility boilers have reported lower performance mainly due to the size of the units, inaccessible areas for injection, and load following control issues. NOx reductions in the range of 25 - 50% are common.

The most common side effects of SNCR are injector burn-out, localized boiler corrosion, and plume formation. At solid waste incinerators, a combination of high temperatures, high chlorides, and slagging operation have been known to reduce injector lifespans to 6-10 weeks. The net result on Operations has been frequent tip replacement and operation with a fraction of the optimum number of injectors. Often 25 MW boilers operate with as few as four wall injectors and accept the lower performance/higher slip which result. Alternate designs are now being used which improve on this situation by using higher classes of mettalurgy with greater wall thickness and easily replaceable lances.

Localized boiler corrosion is most noted with liquid reagents. In particular, waterwall thinning is common in the immediate vicinity of the injectors. This is suspected to be caused by droplet impingement on the unprotected tubes from localized eddies. The operating solution is to overlay the immediate areas with Inconnel, further extend the injection tips into the furnace, and higher energy atomization. This concern also applies to convective surfaces located within 0.1 - 0.2 seconds of an injection nozzle.

The key to minimizing plume formation is to reduce the amount of ammonia slip. This requires a thorough knowledge of the boiler temperature profile and should be the first thing checked. Nozzles placed to high in the boiler will operate on the left side of the effective temperature curve and results in high slip. Nozzles arranged non-symmetrically will tend to overdose parts of the gas stream and under dose others. Low carrier air or steam flows can create droplets which are too large to evaporate quick enough as well as poor penetration into the middle of the furnace cavity. Prior to the availability of accurate and inexpensive in-situ ammonia monitors, on-going process detective work was limited to reagent consumption and controlled NOx concentrations from a CEM. This only told half of the story and limited the certainty in any optimization evaluation. With them installed, the operator can better correlate cause and effect as well as better manage reagent consumption and plume formation.

The life cycle cost of an SNCR system is one of the better values associated with NOx controls, especially on existing units. The capital cost could be as low as $5 per kW on very large facilities, or those base-loaded facilities not in need of sophisticated controls. More typical is a capital cost in the range of $10 - 20/kW. The system can be installed in 6-8 weeks with minimal boiler down-time - often tying in during scheduled 3 day outages. An operating cost in the neighborhood of $500 per ton of NOx removed is typical, due almost exclusively to reagent cost. This is cheaper than the installation of low-NOx burners and OFA injection, and achieves the approximate same end result.

Lately, there has been very promising results from combining SNCR with combustion modifications to achieve high NOx reduction without committing to the high capital cost of an SCR system. In most cases, SNCR and combustion modifications are quite compatible, yielding a combined NOx removal of 70-75 % NOx reduction at a capital cost of approximately $50/kW. This technique, in combination with NOx credits, will have broad appeal to medium power boilers in pursuit of NOx compliance at the minimum cost.

NOx Control for Power Generation Overview

Presented to TCET

May 21th, 2002

Tony Facchiano, Program Manager

Boiler Performance and NOx Control

EPRI

NOx Destruction (e.g., Post-Combustion) Technologies

Technology	NOx Reduction (%)	Cost ($/kW)
Reburning	25-40 (lean) 45-65 (conv.)	3-6 (lean) 15-30 (conv.)
SNCR	15-40	10-20
SCR	50-95	60-140
Hybrids	50-95	SNCR<hybrid<SCR

EPRI

FGD VENDOR QUOTES

GOLDER ASSOCIATES
GAINSVILLE, FLORIDA

FOR

FLORIDA CRYSTALS

FGD BAGHOUSE SUPPLY & INSTALLATION

HAMON RESEARCH-COTTRELL, INC.

BUDGET PROPOSAL NO. P- 9030

JULY 9, 2002

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I HAMON RESEARCH-COTTRELL INTRODUCTION

Hamon Research-Cottrell's professionals are air pollution control specialists. Our regional technical service representatives, our engineering and technical support staff, as well as international license affiliates and research and development engineers all work together to provide our clients with optimal solutions that work.

Other important features of the Hamon Research-Cottrell offering include:

Hamon Research-Cottrell Design and Engineering - Hamon Research-Cottrell has a significant number of APC system installations around the world, on both industrial as well as utility combustion applications. Hamon Research-Cottrell is one of the most recognized industry leaders in air pollution control, accommodating stringent particulate control needs by providing both complete new systems and retrofit of existing systems with both ESP and Fabric Filtration Systems.

Project Management - The project team will be led by a Project Manager who will be the primary contact between the Buyer and Hamon Research-Cottrell. He will be assisted by a Project Engineer and the various department heads of Engineering, Purchasing, Construction, Health and Safety, and Finance.

Field Services - The success of any project lies not only with the proper design and engineering of the baghouse and associated equipment, but also with the completion of commissioning in a timely matter. Hamon Research-Cottrell will provide the services of a Field Service Representative who will conduct specialized training of Owner's operating and maintenance personnel and who will also check out and start up the fabric filter equipment.

Quality Assurance/Quality Control - Hamon Research-Cottrell also recognizes the importance of quality assurance and quality control in each of our projects and is committed to the implementation of an effective quality assurance program to control the production and inspection of all of the products and services we provide.

The purpose of Hamon Research-Cottrell's QA program is to provide, by means of planned and systematic actions, adequate confidence that materials and workmanship, during all stages of design and procurement, are in compliance with contract specifications. Hamon Research-Cottrell is an ISO 9000 Certified Company.

Conclusion

With our large scale utility fabric filter, electrostatic precipitator and FGD experience, the Hamon Research-Cottrell team stands ready to work with all parties involved in the implementation of an air pollution control strategy for this facility. We can assure you of a team effort with focus on technical proficiency, fiscal accountability and professional integrity. With our extensive utility fabric filter operating experience, our aim is not simply to satisfy your expectations in all aspects of job performance, but to exceed them and, by doing so, to demonstrate to you and your clients our corporate commitment to excellence and the ultimate success of this important project.

We as a company stand alone amongst our competitors and are uniquely qualified in our understanding of what is required to make this emissions reduction project successful.

II SYSTEM SCOPE OF SUPPLY

Hamon Research-Cottrell has developed a Dry Flue Gas Desulfurization (DFGD) proposal based on Marsulex Environmental Technologies' spray dryer absorber (SDA) and Hamon Research-Cottrell's fabric filter (PJFF) technology.
The scope of work included in this proposal includes the design, detailed engineering, procurement, manufacture and delivery of one (1) 100% capacity DFGD system for each boiler with common auxiliary subsystems as noted herein. A summary of the equipment scope is as follows otherwise unless noted:

- Two (2) 100% capacity Spray Dryer Absorber (SDA) vessels featuring rotary atomization
- One (1) common lime storage/preparation/slurry delivery system with dedicated slurry preparation trains for each boiler unit
- Two (2) 100% capacity Low Pressure/High Volume Pulse Jet Fabric Filter
- Connecting ductwork from SDA outlets to fabric filter inlets
- Structural support steel for the scope
- Stairs, ladders, platforms and walkways for the scope
- Process piping and valves
- DFGD system control instrumentation
- On-site training
- Site start-up advisory services (per diem)

III. DRY SCRUBBER DESCRIPTION

1.0 TECHNICAL PARAMETERS

1.1 Process Description

HRC's Dry FGD system will be designed to treat the total flue gas stream being discharged from two (2) cogeneration biomass burning boilers. One hundred percent of each boiler flue gas is introduced into one (1) SDA vessel, sized to treat 100% of the maximum gas flow through specially designed inlet gas distributors. Upon entering the reaction chamber, the flue gas comes into intimate contact with finely atomized droplets of fresh lime reagent and by-product recycle slurries which absorb and neutralize the SO_2 and other acid gases contained in the flue gas stream. The fresh lime and by-product recycle slurries are atomized to the desired droplet size by rugged and reliable rotary atomizer units. The atomizer system proposed for this project is an APV Anhydro direct drive design that is based on over 40 years of spray drying experience and 3,000 atomizer units in operation. Through contacting the atomized sprays, the hot flue gas is cooled to a pre-set temperature due to the evaporation of the precisely controlled water quantity input with the reagent and by-product slurries. This pre-set temperature is 30°F above the approach to adiabatic saturation temperature of the flue gas stream.
The scrubbed flue gas and 85% to 90% of the resulting particulate matter exit each SDA vessel through a single outlet duct that connects to the fabric filter inlet manifold. Upon entering the fabric filter inlet manifold, the flue gas is distributed between the operating fabric filter compartments where final particulate removal is performed along with additional SO_2 removal as the gas passes through the collected dust layer. The cleaned flue gas enters the fabric filter outlet manifold where it is conveyed to the ID fans and then discharged to the stack inlet.

The spray dryer absorbers are designed as a single atomizer system per vessel for highest system reliability and minimum operating components. Recognizing the difficulties in operating with lime slurries in a hot flue gas environment, it is normal preventative maintenance practice to perform atomizer rotation on a scheduled frequency of two to four weeks between inspections.

During this time period, the atomizer scheduled for inspection is removed from operation and the standby atomizer installed and immediately placed into service. This one vessel out of service time is typically less than one hour during which the overall DFGD system SO_2 removal performance drops below the design removal efficiency. However, once the standby atomizer begins operation, SO_2 removal performance returns to the specified levels.

2.0 EQUIPMENT DESCRIPTION

2.1 System Design Feature Highlights

The DFGD System incorporates several unique design features, which should be considered in evaluating the reliability and cost effectiveness of a flue gas desulfurization plant. The following is a brief summary of these features.

2.1.1 SDA Vessel Design

The MET spray dryer absorber design incorporates a single rotary atomizer and a specially designed inlet gas distributor. The cyclonic inlet gas distributor with internal directional vanes is designed for uniform mixing of the entering flue gas with the atomized slurry spray pattern. Due to the symmetrical spray pattern and absence of internal ducts projecting into the reaction zone, the potential for material build-up inside the vessel is greatly reduced. Since all the flue gas enters at the top of the absorber vessel, the full cylindrical vertical height is available to provide sufficient drying of reaction products prior to entering the downstream fabric filter. With the sectionalized gas inlet arrangement, optimized gas/slurry mixing can be maintained at flow rates as low as 25% of the design operation point while also meeting performance requirements at all load ranges. Operation below the 25% load point is also easily accommodated albeit at a less efficient lime utilization rate.

2.1.2 Inlet Gas Distributor

The MET spray dryer absorber design incorporates a single rotary atomizer and a specially designed, scroll type inlet gas distributor. The rotary atomizer is mounted on the centerline axis of the absorber with the complete flue gas flow introduced concentrically to the atomizer wheel. Internal adjustable guide vanes and directional vanes located at the discharge of the inlet gas distributor provide uniform mixing of the flue gas with the atomized slurry immediately upon entering the reaction zone. These vanes are critical in maintaining proper gas/slurry mixing as well as constraining the reaction zone within the vessel diameter and preventing wall and ceiling buildup and deposits.

The gas distributor is tapered in cross-section to provide a relatively constant gas velocity around the circumference of the vessel inlet gas passages. An optimized operating turndown ratio is efficiently accomplished by dividing the inlet gas distributor into separate flow paths. A louver type damper is installed to control flow through each of the separate flow paths. As process load varies, the pneumatically operated louver blades are sequentially closed or opened to maintain appropriate flue gas velocities through the inlet gas distributor. The annular entry opening closest to the atomizer wheel is always open and discharging flue gas into the SDA vessel.

The separate path inlet gas distributor and the control distinction between increasing and decreasing flue gas flow conditions allows for optimization of the MET spray dryer absorber performance throughout the design operating range. MET's inlet gas distributor design and control technology improves operation at all boiler load ranges along with minimizing lime consumption rates. Automatic control by the DFGD control system integrates operation of these damper blades with the actual operation of the upstream process.

2.1.3 Atomizer Lubrication System

The atomizer spindle and motor bearings are lubricated by an automatic lubrication system. The system operates with volumetric dosing of a very small flow of lubricating oil from a central storage reservoir by a proportioning dosing valve directly to the bearings. After passing through the bearings, the oil is collected in a small reservoir in the atomizer body, from where it is pumped back to a waste oil storage tank for eventual disposal.
The lubrication system includes all necessary controls to ensure safe and continuous atomizer operation, as well as provisions for automatic atomizer shutdown for low oil pressure or lubrication component malfunction. The lubrication system is designed to provide lubrication service in the event of atomizer shutdown or emergency trip. The atomizer also includes provisions for manual lubrication in the event of a lubrication system malfunction.

2.1.4 Rotary Atomizer Design

The Anhydro DFGD atomizer design uses a direct drive system for atomizers rated at 200 HP and above. This approach was chosen to increase component life, improve operating reliability, and reduce power transmission losses, which are encountered in conventional gear-driven units. As an added benefit, the use of a variable frequency drive provides a low inrush current to the atomizer motor, resulting in reduced motor thermal stresses.

The Direct Drive Atomizer System consists of a variable frequency drive unit powering an AC induction motor, which is directly coupled via a flexible diaphragm coupling to the rotary atomizer drive spindle.

The variable frequency drive (VFD) unit controls the motor speed up through 7,800 rpm to achieve the proper slurry atomization tip speed at the atomizer wheel discharge point. During normal operation, the atomizer unit operates at a constant rotation speed of 7,800 RPM, regardless of boiler load or inlet gas conditions.

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

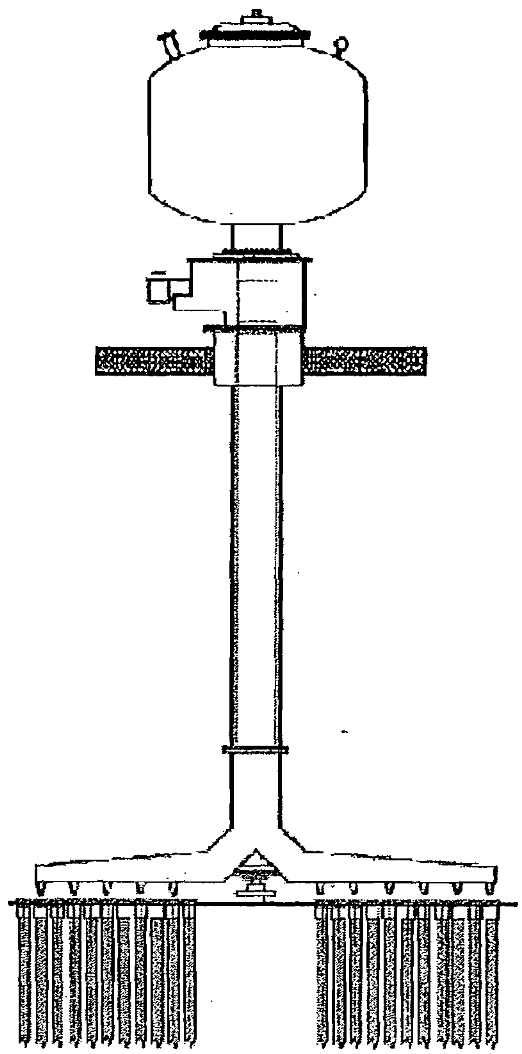


Figure 1

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, only six (6) diaphragm valves are required, that is, one per compartment. In contrast, a conventional pulse jet design could require at least 27 valves per compartment assuming a maximum of 20 bags per valve, equating to 162 valves. 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.

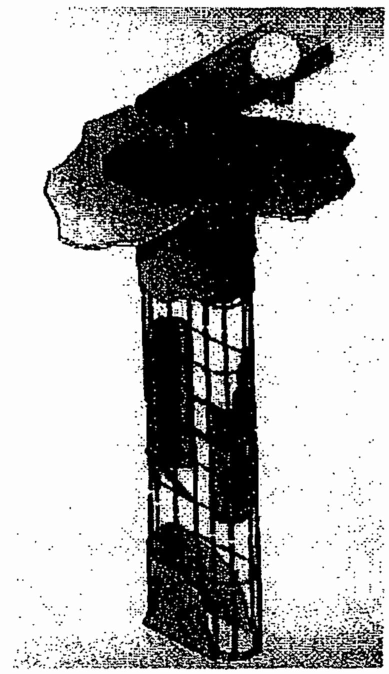
The volume of each cleaning air pulse is derived from theoretical gas laws as well as the number and length of bags being cleaned. The frequency of cleaning, and therefore the required flow rate of cleaning air, is determined from formulae derived from empirical data that has been gathered from an extensive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

Bag Inspection and Replacement

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

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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

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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

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

ATTACHMENT B – DETAIL OF SUPPLY

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.

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

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

APPENDIX F

CO EMISSIONS DURING COLD STARTUP CONDITIONS

Okeelanta Cogeneration Facility

Summary of CO Emissions - Maximum 8-hour Average (lbs/MMBtu)

Boiler B				**Boiler A**		
Date:	Time:	CO		Date:	Time:	CO
12/27/1999	04:00	4.880		10/16/1999	04:00	1.027
12/27/1999	05:00	5.800		10/16/1999	05:00	1.388
12/27/1999	06:00	5.886		10/16/1999	06:00	1.835
12/27/1999	07:00	5.934		10/16/1999	07:00	1.294
12/27/1999	08:00	6.012		10/16/1999	08:00	0.520
12/27/1999	09:00	4.090		10/16/1999	09:00	0.259
12/27/1999	10:00	1.104		10/16/1999	10:00	1.120
12/27/1999	11:00	0.538		10/16/1999	11:00	0.791
Average		4.280		Average		1.029
Boiler A				**Boiler C**		
Date:	Time:	CO		Date:	Time:	CO
8/25/1999	09:00	3.265		11/10/1999	08:00	0.734
8/25/1999	10:00	3.064		11/10/1999	09:00	0.817
8/25/1999	11:00	2.938		11/10/1999	10:00	0.698
8/25/1999	12:00	2.618		11/10/1999	11:00	0.596
8/25/1999	13:00	2.758		11/10/1999	12:00	0.814
8/25/1999	14:00	2.749		11/10/1999	13:00	0.781
8/25/1999	15:00	2.480		11/10/1999	14:00	0.798
8/25/1999	16:00	1.657		11/10/1999	15:00	0.837
Average		2.691		Average		0.759
Boiler C				**Boiler C**		
Date:	Time:	CO		Date:	Time:	CO
9/20/1999	05:00	6.497		10/29/1999	12:00	0.859
9/20/1999	06:00	6.327		10/29/1999	13:00	0.888
9/20/1999	07:00	0.865		10/29/1999	14:00	0.884
9/20/1999	08:00	0.207		10/29/1999	15:00	0.554
9/20/1999	09:00	0.154		10/29/1999	16:00	0.494
9/20/1999	10:00	0.329		10/29/1999	17:00	0.689
9/20/1999	11:00	0.385		10/29/1999	18:00	0.822
9/20/1999	12:00	0.307		10/29/1999	19:00	0.849
Average		1.883		Average		0.754

APPENDIX G

CALPUFF MODEL DESCRIPTION AND METHODOLOGY

CALPUFF MODEL DESCRIPTION AND METHODOLOGY

G.1 INTRODUCTION

As part of the new source review requirements under Prevention of Significant Deterioration (PSD) regulations, new sources are required to address air quality impacts at PSD Class I areas. As part of the PSD analysis report submitted to the Florida Department of Environmental Protection (FDEP), the air quality impacts due to the potential emissions of the proposed New Hope Power Partnership project are required to be addressed at the PSD Class I area of the Everglades National Park (ENP). The ENP is located approximately 92.3 km south of the facility site and is the nearest Class I area to the facility.

The evaluation of air quality impacts are not only concerned with determining compliance with PSD Class I increments, but also assessing a source's impact on Air Quality Related Values (AQRVs), such as regional haze. Further, compliance with PSD Class I increments can be evaluated by determining if the source's impacts are less than the proposed U.S. Environmental Protection Agency (EPA) Class I significant impact levels. The significant impact levels are threshold levels that are used to determine the type of air impact analyses needed for the facility. If the new source's impacts are predicted to be less than significant, then the source's impacts are assumed not to have a significant adverse affect on air quality and additional modeling with other sources is not required. However, if the source's impacts are predicted to be greater than the significant impact levels, additional modeling with other sources is required to demonstrate compliance with Class I increments.

Currently there are several air quality modeling approaches recommended by the Interagency Workgroup on Air Quality Models (IWAQM) to perform these analyses. The IWAQM consists of the EPA and the Federal Land Managers (FLM) of Class I areas who are responsible for ensuring that AQRVs are not adversely impacted by new and existing sources. These recommendations have been summarized in two documents:

- *Interagency Workgroup on Air Quality Models (IWAQM), Phase 2 Summary Report and Recommendations for Modeling Long Range Transport Impacts* (EPA, 1998), referred to as the IWAQM Phase 2 report.
- *Federal Land Managers' Air Quality Related Values Workgroup (FLAG), Phase I Report,* USFS, NPS, USFWS (12/00), referred to as the FLAG document.

For the Proposed Project, air quality analyses were performed that assess the facility's impacts in the PSD Class I area of the ENP using the refined modeling approach from the IWAQM Phase 2 report for:

- Significant impact analysis;
- SO_2 PSD Class I increment analysis;
- Regional haze analysis; and
- Sulfur (S) and nitrogen (N) deposit analysis.

The refined analysis approach was used instead of the screening analysis approach since the air quality impacts are based on generally more realistic assumptions, including more detailed meteorological data, and are estimated at locations at the Class I area.

G.2 GENERAL AIR MODELING APPROACH

The general modeling approach was based on using the long-range transport model, California Puff model (CALPUFF, Version 5.5). At distances beyond 50 km, the ISCST3 model is considered to over-predict air quality impacts, because it is a steady-state model. At those distances, the CALPUFF model is recommended for use. Recently, the FLM have requested that air quality impacts, such as for regional haze, for a source located more than 50 km from a Class I area be predicted using the CALPUFF model. The FDEP has also recommended that the CALPUFF model be used to assess if the source has a significant impact at a Class I area located beyond 50 km from the source. As a result, a significant impact, regional haze, SO_2 PSD Class I increment, and S and N deposition analyses were performed using the CALPUFF model to assess the facility's impacts at the ENP.

The methods and assumptions used in the CALPUFF model were based on the latest recommendations for a refined analysis as presented in the IWAQM Phase 2 Summary Report and the FLAG documents.

A regional haze analysis was performed to determine the affect that the facility's emissions will have on background regional haze levels at the ENP. In the regional haze analysis, the change in visual range, as calculated by a deciview change, was estimated for the facility in accordance with the IWAQM recommendations. Based on those recommendations, the CALPUFF model is used to predict the maximum 24-hour average sulfate (SO_4), nitrate (NO_3), and fine particulate (PM_{10}) concentrations as well as ammonium sulfate [$(NH_4)_2SO_4$] and ammonium nitrate (NH_4NO_3) concentrations. The change in visibility due to a source, estimated as a percentage, is then calculated based on the change from background data.

The following sections present the methods and assumptions used to assess the refined significant impact and regional haze analyses performed for the proposed Project. The results of these analyses are presented in Sections 6.0 and 7.0 of the PSD report.

G.3 MODEL SELECTION AND SETTINGS

The California Puff (CALPUFF, version 5.5) air modeling system was used to model and assess the proposed Project's impacts at the PSD Class I area for comparison to the PSD Class I significant impact levels and to the regional haze visibility criteria. CALPUFF is a non-steady state Lagrangian Gaussian puff long-range transport model that includes algorithms for building downwash effects as well as chemical transformations (important for visibility controlling pollutants), and wet/dry deposition. The CALPUFF meteorological and geophysical data preprocessor (CALMET, Version 5.2), a preprocessor to CALPUFF, is a diagnostic meteorological model that produces a three-dimensional field of wind and temperature and a two-dimensional field of other meteorological parameters. CALMET was designed to process raw meteorological, terrain, and land-use databases to be used in the air modeling analysis. The CALPUFF modeling system uses a number of FORTRAN preprocessor programs that extract data from large databases and converts the data into formats suitable for input to CALMET. The processed data produced from CALMET was input to CALPUFF to assess the pollutant specific impact. Both CALMET and CALPUFF were used in a manner that is recommended by the IWAQM Phase 2 and FLAG reports.

G.3.1 CALPUFF MODEL APPROACHES AND SETTINGS

The IWAQM has recommended approaches for performing Phase 2 refined modeling analyses that are presented in Table 1. These approaches involve the use of meteorological data, selection of receptors and dispersion conditions, and processing of model output.

The specific settings used in the CALPUFF model are presented in Table 2.

G.3.2 EMISSION INVENTORY AND BUILDING WAKE EFFECTS

The CALPUFF model included the facility's emission, stack, and operating data as well as building dimensions to account for the effects of building-induced downwash on the emission sources. Dimensions for all significant building structures were processed with the Building Profile Input Program (BPIP), Version 95086, and were included in the CALPUFF model input. The PSD Report presents a listing of the facility's emissions and structures included in the analysis.

G.4 RECEPTOR LOCATIONS

For the refined analyses, pollutant concentrations were predicted in an array of 126 discrete receptors located at the ENP area. These receptors are the same as those used in the PSD Class I analysis performed for the PSD Report.

G.5 METEOROLOGICAL DATA

G.5.1 REFINED ANALYSIS

CALMET was used to develop the gridded parameter fields required for the refined modeling analyses. The follow sections discuss the specific data used and processed in the CALMET model.

G.5.2 CALMET SETTINGS

The CALMET settings contained in Table 3 were used for the refined modeling analysis. With the exception of hourly precipitation data files, all input data files needed for CALMET were developed by the FDEP staff.

G.5.3 MODELING DOMAIN

A rectangular modeling domain extending 450 km in the east-west (x) direction and 470 km in the north-south (y) direction was used for the refined modeling analysis. The southwest corner of the domain is the origin and is located at 23.8 degrees north latitude and 83.5 degrees west longitude. This location is in the Gulf of Mexico approximately 110 km west of Venice, Florida. For the processing of meteorological and geophysical data, the domain contains 90 grid cells in the x-direction and 94 grid cells in the y-direction. The domain grid resolution is 5 km. The air modeling analysis was performed in the UTM coordinate system.

G.5.4 MESOSCALE MODEL – GENERATION 4 (MM4) DATA

Pennsylvania State University in conjunction with the NCAR Assessment Laboratory developed the MM4 data set, a prognostic wind field or "guess" field, for the United States. The hourly meteorological variables used to create this data set (wind, temperature, dew point depression, and geopotential height for eight standard levels and up to 15 significant levels) are extensive and only allow for one data base set for the year 1990. The analysis used the MM4 data to initialize the CALMET wind field. The MM4 data have a horizontal spacing of 80 km and are used to simulate atmospheric variables within the modeling domain.

The MM4 subset domain was provided by FDEP and consisted of a 7 x 7- cell rectangle, with 80 km grid resolution, extending from the MM4 grid points (50,6) to (57,13). These data were processed to create a MM4.DAT file, for input to the CALMET model.

The MM4 data set used in the CALMET, although advanced, lacks the fine detail of specific temporal and spatial meteorological variables and geophysical data. These variables were processed into the appropriate format and introduced into the CALMET model through the additional data files obtained from the following sources.

G.5.5 SURFACE DATA STATIONS AND PROCESSING

The surface station data processed for the CALPUFF analyses consisted of data from eight NWS stations or Federal Aviation Administration (FAA) Flight Service stations for Orlando, Fort Myers, Daytona Beach, Vero Beach, Key West, Miami, Tampa, and West Palm Beach. A summary of the surface station information and locations are presented in Table 4. The surface station parameters include wind speed, wind direction, cloud ceiling height, opaque cloud cover, dry bulb temperature, relative humidity, station pressure, and a precipitation code that is based on current weather conditions. The surface station data were processed by FDEP into a SURF.DAT file format for CALMET input.

Because the modeling domain extends largely over water, C-Man station data from Venice, Sombrero Key, and Lake Worth was obtained. These data were processed by Florida DEP into an over-water surface station format (i.e., SEA*.DAT) for input to CALMET. The over-water station data include wind direction, wind speed and air temperature.

G.5.6 UPPER AIR DATA STATIONS AND PROCESSING

The analysis included three upper air NWS stations located in Ruskin, Key West, and West Palm Beach. Data for each station were obtained from the Florida DEP in a format for CALMET input.

The data and locations for the upper air stations are presented in Table 4.

G.5.7 PRECIPITATION DATA STATIONS AND PROCESSING

Precipitation data were processed from a network of hourly precipitation data files collected from primary and secondary NWS precipitation-recording stations located within the latitude and longitudinal limits of the modeling domain. Data for 23 stations were obtained in NCDC TD-3240 variable format and converted into a fixed-length format. The utility programs PXTRACT and PMERGE were then used to process the data into the format for the PRECIP.DAT file that is used by CALMET. A listing of the precipitation stations used for the modeling analysis is presented in Table 5.

G.5.8 GEOPHYSICAL DATA PROCESSING

The land-use and terrain information data were developed by the FDEP for the modeling domain and were provided in a GEO.DAT file format for input to CALMET. Terrain elevations for each grid cell of the modeling domain were obtained from Digital Elevation Model (DEM) files obtained from US Geographical Survey (USGS). The DEM data was extracted for the modeling domain grid using the utility extraction program LCELEV. Land-use data were obtained from the USGS GIS.DAT which is based on the ARM3 data. The resolution of the GIS.DAT file is one-eighth of a degree in the east-west direction and one-twelfth of a degree in the north-south direction. Land-use values for the domain grid were obtained with the utility program CAL-LAND. Other parameters processed for the modeling domain by CAL-LAND include surface roughness, surface Albedo, Bowen ratio, soil heat flux, and leaf index field. The land-use parameter values were based on annual averaged values.

Table 1. Refined Modeling Analyses Recommendations[a]

Model Input/Output	Description
Meteorology	Use CALMET (minimum 6 to 10 layers in the vertical; top layer must extend above the maximum mixing depth expected); horizontal domain extends 50 to 80 km beyond outer receptors and sources being modeled; terrain elevation and land-use data is resolved for the situation.
Receptors	Within Class I area(s) of concern; obtain regulatory concurrence on coverage.
Dispersion	1. CALPUFF with default dispersion settings. 2. Use MESOPUFF II chemistry with wet and dry deposition. 3. Define background values for ozone and ammonia for area.
Processing	1. For PSD increments: use highest, second highest 3-hour and 24-hour average SO_2 concentrations; highest, second highest 24-hour average PM_{10} concentrations; and highest annual average SO_2, PM_{10} and NO_x concentrations. 2. For haze: process, on a 24-hour basis, compute the source extinction from the maximum increase in emissions of SO_2, NO_x and PM_{10}; compute the daily relative humidity factor [f(RH)], provided from an external disk file; and compute the maximum percent change in extinction using the FLM supplied background extinction data in the FLAG document. 3. For significant impact analysis: use highest annual and highest short-term averaging time concentrations for SO_2, PM_{10}, and NO_x.

[a] IWAQM Phase II report (12/98) and FLAG document (12/00)

Table 2. CALPUFF Model Settings

Parameter	Setting
Pollutant Species	SO_2, SO_4, NO_x, HNO_3, and NO_3, PM_{10}, CO, Pb and F
Chemical Transformation	MESOPUFF II scheme, hourly ozone data
Deposition	Include both dry and wet deposition, plume depletion
Meteorological/Land Use Input	CALMET
Plume Rise	Transitional, Stack-tip downwash, Partial plume penetration
Dispersion	Puff plume element, PG /MP coefficients, rural mode, ISC building downwash scheme
Terrain Effects	Partial plume path adjustment
Output	Create binary concentration file including output species for SO_4, NO_3, PM_{10}, SO_2, NO_x, F, Pb, and CO
Model Processing	For haze: highest predicted 24-hour extinction change (%) for the year For significant impact analysis: highest predicted annual and highest short-term averaging time concentrations for SO_2, NO_x, and PM_{10}
Background Values [a]	Ozone: 80 ppb; Ammonia: 0.5 ppb

[a] Recommended values by the Florida DEP.

Table 3. CALMET Settings

Parameter	Setting
Horizontal Grid Dimensions	450 by 470 km, 5 km grid resolution
Vertical Grid	9 layers
Weather Station Data Inputs	8 surface, 3 upper air, 23 precipitation stations
Wind model options	Diagnostic wind model, no kinematic effects
Prognostic wind field model	MM4 data, 80 km resolution, 7 x 7 grid, used for wind field initialization
Output	Binary hourly gridded meteorological data file for CALPUFF input

Table 4. Surface and Upper Air Stations Used in the CALPUFF Analysis

Station Name	Station Symbol	WBAN Number	UTM Coordinates Easting (km)	UTM Coordinates Northing (km)	Zone	Anemometer Height (m)
Surface Stations						
Tampa	TPA	12842	349.20	3094.25	17	6.7
Daytona Beach	DAB	12834	495.14	3228.05	17	9.1
Orlando	ORL	12815	468.96	3146.88	17	10.1
Vero Beach	VER	12843	557.52	3058.36	17	6.7
Fort Myers	FMY	12835	413.65	2940.38	17	6.1
Miami	MIA	12839	566.82	2857.20	17	7.0
Key West	EYW	12836	424.03	2715.14	17	18.3
West Palm Beach	PBI	12844	587.87	2951.43	17	10.1
Upper Air Stations						
Ruskin	TBW	12842	349.20	3094.28	17	NA
West Palm Beach	PBI	12844	587.87	2951.42	17	NA
Key West	EYW	12836	424.03	2715.14	17	NA

Table 5. Hourly Precipitation Stations Used in the CALPUFF Analysis

Station Name	Station Number	UTM Coordinate Easting (km)	UTM Coordinate Northing (km)	Zone
Belle Glade HRCN GT 4	80616	528.19	2953.03	17
Boca Raton	80845	588.75	2916.52	17
Canal Point Gate 5	81271	536.43	2971.51	17
Clewiston US Engineers	81654	546.19	2912.73	17
Fort Myers FAA/AP	83186	413.99	2940.71	17
Homestead Exp Stn	84091	550.26	2820.21	17
Key West Intl AP	84570	423.67	2715.51	17
Miami WSCMO Airport	85663	570.20	2856.17	17
Moore Haven Lock 1	85895	491.61	2967.80	17
North New River Canal #	86323	546.58	2912.48	17
Ortona Lock 2	86657	470.17	2962.27	17
Parrish	86880	366.99	3054.39	17
Pennsuco 5 WNW	86988	554.70	2867.81	17
Port Mayaca S 1 Canal	87293	538.04	2984.44	17
St Lucie New Lock 1	87859	571.04	2999.35	17
St Petersburg	87886	339.61	3071.99	17
Tamiami Trail 40 Mi BEN	88780	517.64	2849.04	17
Tampa WSCMO AP	88788	348.48	3093.67	17
Trail Glade Ranges	89010	551.57	2849.99	17
Venice	89176	357.59	2998.18	17
Venus	89184	467.27	3001.22	17
Vero Beach 4 W	89219	554.27	3056.50	17
West Palm Beach Int AP	89525	589.61	2951.63	17

APPENDIX H

SO_2 AAQS, PSD CLASS I AND II INVENTORY

Table H-1. Summary of SO_2 Sources Included in the Air Modeling Analysis, New Hope Power Partnership

AIRS Number	Facility Units	Modeling ID Name	Relative Location X (m)	Relative Location Y (m)	Stack Height (m)	Diameter (m)	Temper. (K)	Velocity (m/s)	Emission Rate(g/s) 3-Hour	Emission Rate(g/s) 24-Hour	PSD Source? (EXP/CON)	Modeled in AAQS	Modeled in Class II	Modeled in Class I
0990005	Okeelanta Corp.[a]													
	Boiler 4 PSD Baseline	OKBLR4B	-201	58	22.9	2.29	333.0	7.36	-10.95	-10.95	EXP	No	Yes	Yes
	Boiler 5 PSD Baseline	OKBLR5B	-201	37	22.9	2.29	333.0	12.07	-15.64	-15.64	EXP	No	Yes	Yes
	Boiler 6 PSD Baseline	OKBLR6B	-201	23	22.9	2.29	334.0	8.74	-15.64	-15.64	EXP	No	Yes	Yes
	Boiler 10 PSD Baseline	OKBLR10B	-201	9	22.9	2.29	334.0	10.35	-17.15	-17.15	EXP	No	Yes	Yes
	Boiler 11 PSD Baseline	OKBLR11B	-201	67	22.9	2.29	342.0	9.89	-16.79	-16.79	EXP	No	Yes	Yes
	Boiler 16 PSD	OKBLR16	-223	18	22.9	1.52	483.0	22.86	1.47	1.47	CON	Yes	Yes	Yes
0990086	Glades Correctional Institute	GLADCORR	525,000	2,937,400	9.8	0.40	389.0	11.28	2.82	2.82	NO	Yes	No	No
0990026	Sugar Cane Growers[a]													
	Unit 1&2	SUGCN12	533,500	2,954,100	45.7	1.87	339.0	21.75	41.20	41.20	CON	Yes	Yes	Yes
	Unit 3	SUGCN3	533,500	2,954,100	27.4	1.52	339.0	22.25	16.20	16.20	CON	Yes	Yes	Yes
	Unit 4 PSD	SUGCN4	533,500	2,954,100	54.9	2.44	339.0	21.73	38.20	38.20	CON	Yes	Yes	Yes
	Unit 5	SUGCN5	533,500	2,954,100	45.7	2.30	339.0	15.94	27.90	27.90	CON	Yes	Yes	Yes
	Unit 8 PSD	SUGCN8	533,500	2,954,100	47.2	2.90	339.0	13.62	23.50	23.50	CON	Yes	Yes	Yes
	Unit 1&2 PSD Baseline	SUGCN12B	533,500	2,954,100	24.4	1.40	344.0	11.40	-24.20	-24.20	EXP	No	Yes	Yes
	Unit 3 PSD Baseline	SUGCN3B	533,500	2,954,100	24.4	1.60	344.0	15.60	-4.40	-4.40	EXP	No	Yes	Yes
	Unit 4 PSD Baseline	SUGCN4B	533,500	2,954,100	25.9	1.63	344.0	11.20	-24.20	-24.20	EXP	No	Yes	Yes
	Unit 5 PSD Baseline	SUGCN5B	533,500	2,954,100	24.4	1.40	344.0	15.20	-16.20	-16.20	EXP	No	Yes	Yes
	Unit 6&7 PSD Baseline	SUGCN67B	533,500	2,954,100	12.2	1.52	606.0	11.20	-51.00	-51.00	EXP	No	Yes	Yes
0510001	Everglades Sugar[b] Main Boiler	EVERGLAD	562,000	2,960,000	21.9	1.10	477.0	10.10	34.90	34.90	NO	Yes	No	No
0510003	US Sugar - Clewiston[d]													
	PSD Baseline (On-crop season only)													
	Unit 1 PSD Baseline	USSBRL1B	545,600	2,991,500	23.1	1.86	344.0	30.20	-79.86	-58.21	EXP	No	Yes	Yes
	Unit 2 PSD Baseline	USSBLR2B	545,600	2,991,500	23.1	1.86	343.0	35.70	-79.86	-58.21	EXP	No	Yes	Yes
	Unit 3 PSD Baseline	USSBLR3B	545,600	2,991,500	27.4	2.29	342.0	14.70	-48.30	-33.20	EXP	No	Yes	Yes
	East Pellet Plant PSD Baseline	EPELLET	545,600	2,991,500	12.2	1.52	347.0	8.54	-10.30	-10.30	EXP	No	Yes	Yes
	West Pellet Plant PSD Baseline	WPELLET	545,600	2,991,500	15.7	1.52	347.0	8.54	-10.30	-10.30	EXP	No	Yes	Yes
	On-crop season future													
	Unit 1	USSBRL1N	545,600	2,991,500	65.0	2.44	347.0	15.36	78.79	73.73	CON	Yes	Yes	Yes
	Unit 2	USSBLR2N	545,600	2,991,500	65.0	2.44	338.0	13.86	78.49	73.44	CON	Yes	Yes	Yes
	Unit 3	USSBLR3N	545,600	2,991,500	65.0	2.44	333.2	6.78	47.08	47.08	CON	Yes	Yes	Yes
	Unit 4	USSBLR4N	545,600	2,991,500	45.7	2.51	344.3	20.28	21.53	3.68	CON	Yes	Yes	Yes
	Unit 7	USSBLR7N	545,600	2,991,500	68.6	2.59	405.4	20.77	13.91	12.65	CON	Yes	Yes	Yes

Table H-1. Summary of SO_2 Sources Included in the Air Modeling Analysis, New Hope Power Partnership

AIRS Number	Facility	Units	Modeling ID Name	Relative Location X (m)	Relative Location Y (m)	Stack and Operating Parameters Height (m)	Diameter (m)	Temper. (K)	Velocity (m/s)	Emission Rate(g/s) 3-Hour	24-Hour	PSD Source? (EXP/CON)	Modeled in AAQS	Class II	Class I
		Off-crop season future													
		Unit 1	USSBRL1F	545,600	2,991,500	65.0	2.44	347.0	14.05	51.64	24.29	CON	Yes	Yes	Yes
		Unit 2	USSBLR2F	545,600	2,991,500	65.0	2.44	338.0	12.68	51.27	24.02	CON	Yes	Yes	Yes
		Unit 3	USSBLR3F	545,600	2,991,500	65.0	2.44	333.2	6.20	30.74	30.20	CON	Yes	Yes	Yes
		Unit 4	USSBLR4F	545,600	2,991,500	45.7	2.51	344.3	0.00	0.00	0.00	CON	Yes	Yes	Yes
		Unit 7	USSBLR7F	545,600	2,991,500	68.6	2.59	405.4	23.60	17.39	15.81	CON	Yes	Yes	Yes
0990016	Atlantic Sugar [a]														
		Unit 1	ATLSUG1	552,900	2,945,200	27.4	1.83	346.0	17.97	16.28	16.28	CON	Yes	Yes	Yes
		Unit 2	ATLSUG2	552,900	2,945,200	27.4	1.83	350.0	23.36	16.28	16.28	CON	Yes	Yes	Yes
		Unit 3	ATLSUG3	552,900	2,945,200	27.4	1.83	350.0	21.56	16.02	16.02	CON	Yes	Yes	Yes
		Unit 4	ATLSUG4	552,900	2,945,200	27.4	1.83	344.0	25.16	16.21	16.21	CON	Yes	Yes	Yes
		Unit 5 PSD [b]	ATLSUG5	552,900	2,945,200	27.4	1.68	339.0	19.24	8.41	8.04	CON	Yes	Yes	Yes
		Unit 1 PSD Baseline	ATLSUG1B	552,900	2,945,200	18.9	1.92	506.0	12.71	-17.24	-17.24	EXP	No	Yes	Yes
		Unit 2 PSD Baseline	ATLSUG2B	552,900	2,945,200	18.9	1.92	511.0	10.89	-22.52	-22.52	EXP	No	Yes	Yes
		Unit 3 PSD Baseline	ATLSUG3B	552,900	2,945,200	21.9	1.83	522.0	17.52	-16.88	-16.88	EXP	No	Yes	Yes
		Unit 4 PSD Baseline	ATLSUG4B	552,900	2,945,200	18.3	1.83	344.0	15.03	-16.88	-16.88	EXP	No	Yes	Yes
0990061	US Sugar-Bryant [a]														
		Unit 5 PSD	USSBRY5	523,400	2,955,200	45.7	2.90	334.3	14.80	62.40	62.40	CON	No	Yes	Yes
		Unit 5 AAQS	USSBRY5	523,400	2,955,200	45.7	2.90	334.3	14.80	77.25	77.25	No	Yes	No	No
		Unit 1,2&3 PSD	USBRY123	523,400	2,955,200	19.8	1.64	344.3	34.60	160.68	160.68	CON	No	Yes	Yes
		Unit 1,2&3 AAQS	USBRY123	523,400	2,955,200	19.8	1.64	344.3	34.60	199.71	199.71	No	Yes	No	No
		Unit 1 PSD Baseline	USSBRY1B	523,400	2,955,200	19.8	1.68	494.0	44.30	-36.50	-36.50	EXP	No	Yes	Yes
		Unit 2&3 PSD Baseline	USBRY23B	523,400	2,955,200	19.8	1.68	344.0	37.90	-73.00	-73.00	EXP	No	Yes	Yes
0990019	Osceola Farms PSD Baseline [a]														
		Unit 2	OSBLR2	544,200	2,968,000	27.4	1.52	341.0	15.82	12.58	11.43	CON	Yes	Yes	Yes
		Unit 3	OSBLR3	544,200	2,968,000	27.4	1.91	342.0	16.86	9.82	2.00	CON	Yes	Yes	Yes
		Unit 4	OSBLR4	544,200	2,968,000	27.4	1.83	340.0	16.67	9.73	1.92	CON	Yes	Yes	Yes
		Unit 5	OSBLR5	544,200	2,968,000	27.4	1.52	341.0	15.50	12.96	11.79	CON	Yes	Yes	Yes
		Unit 6	OSBLR6	544,200	2,968,000	27.4	1.88	341.0	18.19	2.87	2.59	CON	Yes	Yes	Yes
		Unit 1 PSD Baseline	OSBLR1B	544,200	2,968,000	22.0	1.52	342.0	8.98	-5.07	-5.07	EXP	No	Yes	Yes
		Unit 2 PSD Baseline	OSBLR2B	544,200	2,968,000	22.0	1.52	342.0	14.22	-16.32	-16.32	EXP	No	Yes	Yes
		Unit 3 PSD Baseline	OSBLR3B	544,200	2,968,000	22.0	1.93	342.0	11.23	-7.26	-7.26	EXP	No	Yes	Yes
		Unit 4 PSD Baseline	OSBLR4B	544,200	2,968,000	22.0	1.83	342.0	13.35	-13.61	-13.61	EXP	No	Yes	Yes
0850102	Bechtel Indiantown PSD		BECHTIND	506,100	2,956,900	150.9	4.88	333.2	30.50	75.64	75.64	CON	Yes	Yes	Yes

Table H-1. Summary of SO_2 Sources Included in the Air Modeling Analysis, New Hope Power Partnership

AIRS Number	Facility	Units	Modeling ID Name	Relative Location X (m)	Relative Location Y (m)	Stack and Operating Parameters Height (m)	Diameter (m)	Temper. (K)	Velocity (m/s)	Emission Rate(g/s) 3-Hour	Emission Rate(g/s) 24-Hour	PSD Source? (EXP/CON)	Modeled in AAQS	Modeled in Class II	Modeled in Class I
0850001	FPL Martin														
		Units 1&2	MART12	537,800	2,969,160	152.1	7.99	420.9	21.03	1743.79	1743.79	NO	Yes	No	No
		Aux Blr PSD	MARTAUX	537,800	2,969,160	18.3	1.10	535.4	15.24	12.90	12.90	CON	Yes	Yes	Yes
		Diesel Gens PSD	MARTGEN	537,800	2,969,160	7.6	0.30	785.9	39.62	0.51	0.51	CON	Yes	Yes	Yes
		Units 3&4 PSD	MART34	537,800	2,969,160	64.9	6.10	410.9	18.90	470.40	470.40	CON	Yes	Yes	Yes
		Unit 8	MART8	537,800	2,969,160	36.6	5.79	397.6	13.59	12.99	12.99	CON	Yes	Yes	Yes
0990234	Palm Beach Co. Resource Recovery[c]														
		1&2 PSD	PBCRRF	543,100	2,992,900	76.2	2.04	505.2	24.90	85.05	85.05	CON	Yes	Yes	Yes
0990568	Lake Worth Utilities[c]														
		Unit 3	LAKWTHU3	583,300	2,908,000	38.1	2.13	408.2	7.71	103.95	103.95	NO	Yes	No	No
		Unit 4	LAKWTHU4	583,300	2,908,000	35.1	2.29	418.2	17.00	129.85	129.85	NO	Yes	No	No
		Unit 5	LAKWTHU5	583,300	2,908,000	22.9	0.94	450.4	18.29	11.59	11.59	NO	Yes	No	No
		HRSG	LAKWTHHR	583,300	2,908,000	45.7	5.49	377.6	13.74	12.79	12.79	CON	Yes	Yes	Yes
0990042	FPL Riviera[c]														
		Units 3&4 at 2.5%s fuel oil	RIVU34	555,860	2,882,200	90.8	4.88	401.5	18.90	2113.65	2113.65	NO	Yes	No	No
0112119	South Broward RRF PSD [c]		SBCRRF	575,200	3,006,800	59.4	3.96	381.0	18.01	37.91	37.91	CON	Yes	Yes	Yes
0110037	FPL - Lauderdale [c]														
		CTs 1-4 PSD	LAUDU45	562,900	2,861,700	45.7	5.49	438.7	14.60	271.15	271.15	CON	Yes	Yes	Yes
		GT 1-12 (0.5% fuel oil)	LDGT1_12	562,900	2,861,700	13.7	2.37	733.2	114.31	552.80	552.80	NO	Yes	No	No
		GT 13-24 (0.5% fuel oil)	LDGT1324	562,900	2,861,700	13.4	4.75	733.2	28.43	552.80	552.80	NO	Yes	No	No
		4&5 PSD Baseline	FTLAU45B	562,900	2,861,700	46.0	4.27	422.0	14.63	-457.00	-457.00	EXP	No	Yes	Yes
0110036	FPL Port Everglades [c]														
		Units 1&2 at 2.5%s fuel oil	PTEVU12	564,300	2,857,400	104.5	4.27	415.9	26.72	1593.90	1593.90	NO	Yes	No	No
		Units 3&4 at 2.5%s fuel oil	PTEVU34	564,300	2,857,400	104.5	5.52	414.8	23.88	2772.00	2772.00	NO	Yes	No	No
		GT 1-12 (0.5% fuel oil)	PTEVGTS	564,300	2,857,400	13.4	4.75	733.2	28.43	530.70	530.70	NO	Yes	No	No
0250020	Tarmac [c]														
		Kiln 1 PSD Baseline	TARMC1	422,100	2,952,900	61.0	2.44	465.0	12.84	-5.71	-5.71	EXP	No	Yes	Yes
		Kiln 2 PSD Baseline	TARMC2B	422,100	2,952,900	61.0	2.44	465.0	12.84	-5.71	-5.71	EXP	No	Yes	Yes
		Kiln 3 PSD Baseline	TARMC3B	422,100	2,952,900	61.0	4.57	472.0	10.78	-2.76	-2.76	EXP	No	Yes	Yes
		Kiln 2 PSD	TABMC2P	422,100	2,952,900	61.0	2.44	422.0	9.10	24.57	24.57	CON	Yes	Yes	Yes
		Kiln 3 PSD	TARMC3P	422,100	2,952,900	61.0	4.57	450.0	11.04	51.43	51.43	CON	Yes	Yes	Yes

Table H-1. Summary of SO_2 Sources Included in the Air Modeling Analysis, New Hope Power Partnership

AIRS Number	Facility Units	Modeling ID Name	Relative Location X (m)	Relative Location Y (m)	Stack Height (m)	Diameter (m)	Temper. (K)	Velocity (m/s)	Emission Rate(g/s) 3-Hour	Emission Rate(g/s) 24-Hour	PSD Source? (EXP/CON)	Modeled in AAQS	Modeled in Class II	Modeled in Class I
0710000	FPL Fort Myers [c]													
	Unit 1 PSD	FMU1	567,100	3,056,500	91.8	2.90	422.0	29.90	-585.50	-585.50	EXP	No	Yes	Yes
	Unit 2 PSD	FMU2	567,100	3,056,500	121.2	5.52	408.0	19.20	-1334	-1334.0	EXP	No	Yes	Yes
	HRSGs 1 - 6	FMYHR1_6	567,100	3,056,500	38.1	5.79	377.6	14.2	3.86	3.9	CON	Yes	Yes	Yes
	Gas Turbines 1 -12	FMYGT112	567,100	3,056,500	9.75	4.42	797.0	35.7	649.2	649.2	NO	Yes	No	No
1110003	Fort Pierce Utilities [c]													
	Units 6&7	FTPIER67	594,200	2,960,600	45.7	2.19	408.2	12.50	77.87	77.87	NO	Yes	No	No
0550018	TECO-Phillips [c]													
	Steam Boiler	TECOSB	424,200	2,945,700	18.90	0.67	ND	ND	0.7	0.7	NO	No	No	No
	Diesel Generator Unit 1	TECO1	424,200	2,945,700	45.72	1.83	441.0	24.1	58.0	29.0	NO	Yes	No	No
	Diesel Generator Unit 2	TECO2	424,200	2,945,700	45.72	1.83	450.0	24.1	58.0	29.0	NO	Yes	No	No
0550004	TECO-Sebring/Dinner Lake [c]													
	Steam Boiler	DINNSB	464,300	3,035,400	22.9	1.83	394.3	5.79	37.78	37.78	CON	Yes	Yes	No
0610029	Vero Beach Power [c]													
	Unit 1	VERBU1	587,400	2,885,300	60.96	1.07	437.0	32.42	28.77	28.77	NO	Yes	No	No
	Unit 2	VERBU2	587,400	2,885,300	60.96	1.07	434.3	37.57	84.21	84.21	NO	Yes	No	No
	Unit 3	VERBU3	587,400	2,885,300	60.96	1.83	440.4	19.93	142.07	142.07	NO	Yes	No	No
	Unit 4	VERBU4	587,400	2,885,300	60.96	2.13	425.4	24.36	69.05	69.05	NO	Yes	No	No
	Unit 5 Simple Cycle CT	VERBU5	587,400	2,885,300	38.10	3.35	416.5	19.56	15.50	15.50	CON	Yes	Yes	No
0250348	Dade County RRF PSD													
	Units 1&2	DCRRF12	566,800	3,036,300	76.2	3.66	405.4	15.86	26.41	12.32	CON	No [e]	No [e]	Yes
	Units 3&4	DCRRF34	566,800	3,036,300	76.2	3.66	405.4	15.86	26.41	12.32	CON	No [e]	No [e]	Yes
0112515	Enron Pompano Beach Energy Center													
	3-170 MW CTs	ENPMPCT	580,100	2,883,300	24.4	5.49	847.0	47.06	39.16	39.16	CON	No [e]	No [e]	Yes
0110120	North Broward RRF PSD	NBCRRF	579,600	2,883,300	58.5	3.96	381.0	18.01	35.40	35.40	CON	No [e]	No [e]	Yes
0112534	Enron Deerfield Beach Energy Center													
	3-170 MW CTs	ENDFCT	592,800	2,943,700	24.4	5.49	847.0	47.06	39.16	39.16	CON	No [e]	No [e]	Yes

Table H-1. Summary of SO_2 Sources Included in the Air Modeling Analysis, New Hope Power Partnership

AIRS Number	Facility Units	Modeling ID Name	Relative Location X (m)	Relative Location Y (m)	Stack Height (m)	Diameter (m)	Temper. (K)	Velocity (m/s)	Emission Rate(g/s) 3-Hour	Emission Rate(g/s) 24-Hour	PSD Source? (EXP/CON)	Modeled in AAQS	Modeled in Class II	Modeled in Class I
0112545	El Paso Broward													
	Combined Cycle CT CC-1	EPBRCT1	583,700	2,905,500	41.1	5.79	359.3	61.13	0.46	0.46	CON	No [e]	No [e]	Yes
	Simple Cycle SC-1	EPBRSC1	583,700	2,905,500	41.1	5.79	862.0	146.96	0.46	0.46	CON	No [e]	No [e]	Yes
	Simple Cycle SC-2	EPBRSC2	583,700	2,905,500	41.1	5.79	862.0	146.96	0.46	0.46	CON	No [e]	No [e]	Yes
	Simple Cycle SC-3	EPBRSC3	583,700	2,905,500	41.1	5.79	862.0	146.96	0.46	0.46	CON	No [e]	No [e]	Yes
0710019	Lee County RRF PSD	LEECORRF	456,800	3,042,500	83.8	1.88	388.5	19.81	14.00	14.00	CON	No [e]	No [e]	Yes
0990568	Lake Worth Generating													
	4-GE Frame 7FA CTs & HRSG	LWGENCT	583,600	2,907,600	45.7	5.49	377.6	24.29	51.16	51.16	CON	No [e]	No [e]	Yes
0990594	El Paso Belle Glade													
	Combined Cycle CT CC-1	EPBGLCT	534,900	2,953,300	41.1	5.79	359.3	61.13	0.46	0.46	CON	No [e]	No [e]	Yes
	Simple Cycle SC-1	EPBGSC1	534,900	2,953,300	41.1	5.79	862.0	146.96	0.46	0.46	CON	No [e]	No [e]	Yes
	Simple Cycle SC-2	EPBGSC2	534,900	2,953,300	41.1	5.79	862.0	146.96	0.46	0.46	CON	No [e]	No [e]	Yes
	Simple Cycle SC-3	EPBGSC3	534,900	2,953,300	41.1	5.79	862.0	146.96	0.46	0.46	CON	No [e]	No [e]	Yes
	Palm Beach Power Corp.													
	Cogen Boiler 1	PBPCBLR1	544,400	2,967,400	60.7	2.44	419.3	24.87	28.73	19.15	CON	No [e]	No [e]	Yes
	Cogen Boiler 2	PBPCBLR2	544,400	2,967,400	60.7	2.44	419.3	24.87	28.73	19.15	CON	No [e]	No [e]	Yes
	Package Boiler	PACKBLR	544,400	2,967,400	22.9	1.52	483.2	22.86	1.47	1.47	CON	No [e]	No [e]	Yes
0510015	Southern Gardens Citrus - PSD													
	Peel Dryer	SGARDDRY	488	2,958	38.1	1.73	316.0	7.45	5.29	5.29	CON	No [e]	No [e]	Yes
	Boilers 1-3	SGARDBLR	488	2,958	16.8	1.22	478.0	14.22	6.88	6.88	CON	No [e]	No [e]	Yes
990021	Pratt & Whitney (United Technologies)													
	Heater	PRATARCH	509,600	2,954,200	15.2	0.91	810.9	143.73	13.99	13.99	CON	No [e]	No [e]	Yes
	Boiler BO-12	PRATBO12	509,600	2,954,200	4.6	0.76	533.2	6.92	0.51	0.51	CON	No [e]	No [e]	Yes
	A-10 Test Stand	PRATA10	509,600	2,954,200	5.8	4.17	410.9	106.68	0.55	0.55	No	Yes	No	No

Note:
EXP = PSD expanding source
CON = PSD consuming source
NO = Source does not affect PSD increment
ND = No data available

[a] Facilities or sources within facilities that operate only during the October 1 through April 31 crop season.
[b] Sugar mill sources that operate all year.
[c] Large source with emissions greater than 1,000 TPY included in the AAQS or PSD Class II modeling even though the source is located outside of the screening area.
[d] Represents worst case emissions for May 1 through September 31 off-crop season operation, and October 1-April 30 for on-crop season.
Updated from PSD modeling information, Golder Associates (7/18/00). Baseline data represents November 1 though April 30.
[e] Not included in AAQS or Class II modeling analyses because they screened out.