Department of Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

January 8, 2001

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. Steven F. Gilliland, Sr. Vice President
Duke Energy North America
5400 Westheimer Court
Houston, TX 77056-5310

Re: Request for Additional Information No. 2
Project No. 1110100-001-AC (PSD-FL-302)
Duke Energy Fort Pierce, LLC

Dear Mr. Gilliland:

On December 14, 2000, the Department received additional information with regard to the Duke Energy application for a PSD air permit to construct a new 640 MW electrical generating station located approximately ½ mile east of the Florida Turnpike and 1 mile north of Midway Road in St. Lucie County, Florida. The application remains incomplete. To continue processing your application, the Department will need the additional information requested below. Should your response to any of these items require new calculations, please submit the new calculations, assumptions, reference material and appropriate revised pages of the application form.

1. PSD Class I Impact Analysis: The additional information included a report entitled, "CALPUFF Results Report Proposed Power Generating Facility" which is based on the CALPUFF Lite screening model. The Department has concerns with the following ambient impacts summarized in the report:

   - There are several occasions when the ambient SO_2 concentrations in the Everglades National Park are predicted to exceed the Class I Significant Impact Level for the 24-hour averaging period due to the proposed project.
   - There are several incidents predicted to exceed the "5% Change in Extinction Level" in the Everglades National Park due to haze from the proposed project.

   The Department discussed the modeling results with the National Park Service (NPS) on January 5th. NPS is concerned with the number of days the project is predicted to adversely impact the Everglades National Park as well as the levels of impact. As a result, please revise the modeling analysis to include a refined version of the CALPUFF model (utilizing the CALMET meteorological model) be used to evaluate the impacts on the Everglades National Park from the proposed project. Please refer the 1996 EPA report entitled. "Interagency Workgroup on Air Quality Modeling Phase 2 Summary Report and Recommendations for Modeling Long Range Transport Impacts", for more information on the required procedures for this modeling exercise. Other items for consideration include reducing the sulfur content of the backup distillate oil, reducing the hours of distillate oil firing during any 24-hour period, or switching the project back to firing only natural gas.

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 material changes to the application, please submit a new certification statement by the authorized representative or responsible official. Rule 62-4.055(1), F.A.C. now requires permit applicants to response to requests for information within 90 days. If there are any questions, please contact me at 850/414-7268. Questions regarding the air quality analysis should be directed to the project meteorologist, Cleve Holladay, at 850/921-8986.

Sincerely,

Jeffery J. Koerner

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

AAL/jfk

cc:

Mr. Nathan L. Plagens, Duke Energy North America
Ms. Pamela A. Lehr, CH2M HILL
Mr. Isidore Goldman, SED
Mr. John Bunyak, NPS
Mr. Gregg Worley, EPA Region 4

SENDER: *COMPLETE THIS SECTION*	*COMPLETE THIS SECTION ON DELIVERY*
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1. Article Addressed to: Mr. Steven F. Gilliland Senior Vice President Duke Energy North America 5400 Westheimer Court Houston, TX 77056-6310	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

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City, State, ZIP+4
Houston, TX 77056-5310

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CH2MHILL

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December 14, 2000

154648

Mr. Jeffrey F. Koerner, P.E.
Florida Department of Environmental Protection
Division of Air Resources Management
111 South Magnolia Street, Suite 4
Tallahassee, FL 32301

Subject: Request for Additional Information
Project No. 1110100-001-AC (PSD-FL-302)
Duke Energy Fort Pierce, LLC

Dear Mr. Koerner:

This letter is written in response to your October 26, 2000 letter summarizing FDEP's comments regarding Duke Energy's September 2000 permit application for a proposed power generating facility to be located near Fort Pierce, Florida in St. Lucie County. Our response to your comments are provided below:

FDEP Comment No. 1: Simple Cycle Operation - The application requests simple cycle operation only. Does Duke Energy plan to convert these units in the future to combined cycle operation? Do the engineering plans include any provisions for accommodating the future installation of heat recovery steam generators (HRSGs)? The Department intends to limit operation to simple cycle only. Any future request to add combined cycle operation will require a permit modification and PSD review for CO and NOx. Please plan accordingly.

Response: Duke Energy Fort Pierce currently has no plans to convert the proposed simple cycle units to combined cycle operation and there are no provisions in the current design to accommodate the future installation of HRSG's. Duke understands that the Facility will be limited to simple cycle operation and any conversion to combined cycle operation would require a permit modification.

FDEP Comment No. 2: Combustors and Control System - Please identify the model of dry low-NOx combustors that will be included with each unit. Please identify the model and describe the automated gas turbine control system that will be installed with each unit.

Response: The combustors for the GE 7121 EA turbines will be 9/42 DLN 1.0 Combustors. The GE gas turbines and generators are controlled by the Mark VI control system. It is a fully programmable control, protection and monitoring system, which was designed by GE turbine and control engineers. The Mark VI allows for the integration of all power island and balance-of-plant controls and is the product of more than 30 years experience.

The heart of the control system is the control module, which receives input through termination boards. The control module contains an "internal" communication card and a main processor card. The "internal" communication card is used to communicate between: I/O cards that are contained within its card rack; I/O cards that may be contained in expansion I/O racks called Interface Modules; I/O in backup Protection Modules; I/O in other Control Modules used in triple redundant configurations; and the main processor card. The main processor card executes the bulk of the application software.

The Mark VI also has an operator interface referred to as the HMI (Human Machine Interface). It is a PC running Microsoft Windows NT with a graphics display system, a Control System Toolbox for maintenance, and a software interface for the Mark VI and other control systems on the network. The HMI can be used as the primary operator interface for one or multiple units; a backup operator interface to the plant DCS operator interface; a gateway for communication links to other control systems; a permanent or temporary maintenance station; and/or an engineer's workstation.

FDEP Comment No. 3: Inlet Air-Cooling System - Please describe and detail the "air-cooled" auxiliary inlet air cooling system (page 2-5). The application also mentions an inlet fogging system to enhance power output during the summer months. Is this a high-pressure, direct water spray system? Please describe the system and identify the manufacturer, model, designed cooling reduction (°F), operating pressure, and water consumption rate.

Response: The air-cooled auxiliary cooling system described on page 2-5 is not for cooling inlet air, but for auxiliary plant equipment, primarily the combustion turbine lubricating system. This system will utilize a closed loop non-contact auxiliary cooling water system that will use a water/glycol mixture as the cooling medium and will include an expansion tank, pumps, and water-to-air fin fan heat exchangers. There will not be any air emissions associated with the operation of this system.

Each CTG will be equipped with an inlet fogging system (high pressure, direct water spray) to enhance the power produced from the generator. When the CTGs are burning fuel gas at 100% load, and ambient temperatures exceed 59 °F, the inlet fogging system will be implemented. While in operation, the fogging system pumps demineralized water (up to 38 gpm per turbine) from on-site storage tanks into the inlet air duct between the inlet filter and the compressor section of the CTG at a pressure of up to 2000 psi. The demineralized water mixes with the inlet air as a very fine mist, and causes the inlet air to approach its wet bulb temperature (up to 33 °F of cooling). The fogging systems are typically model number FPS-3850-6-11, supplied by Mee Industries Inc.

FDEP Comment No. 4: Fuel Tanks - What is the size (gallons) of each of the four fuel oil tanks to be installed?

Response: The four fuel oil storage tanks will be identical in size and will each be capable of storing approximately 1 million gallons of oil. Each storage tank will have a 67-foot diameter and be 48 feet tall. Maximum liquid height in the storage tanks will not exceed 46 feet, therefore, the total storage capacity of all four tanks will be approximately 4.8 million gallons.

FDEP Comment No. 5: CO Emissions Standards - Although the application requests a CO standard for gas firing of 25.0 ppmvd, the Department is aware of actual field data showing CO emissions to be less than 10 ppmvd, particularly at typical stack test conditions near 100% base load. The Department has recently permitted GE 7EA units with the following CO emissions standards for gas firing:

- 25.0 ppmvd @ 15% oxygen based on a 3-hour test at 100% base load, first year of operation
- 20.0 ppmvd @ 15% oxygen based on a 3-hour test at 100% base load, after first year of operation

Table 3-3 indicates CO emissions of 42.0 ppmvd (58.0 lb/hour) at 60% of base load and an inlet temperature of 101° F. Is this correct? Please comment on these items.

Response: Duke has experienced difficulty during warm weather conditions in achieving sustained CO emissions from GE 7FA turbines below 20 to 25 ppmvd. As a result of their operational experience, Duke would prefer to limit CO emissions to a minimum of 20 ppm and is agreeable to the Department's recent permit limits for other 7EA units (i.e., 25 ppmvd during first year and 20 ppmvd thereafter). The CO emission limit of 42 ppmvd shown in Table 3-3 is correct as stated, and is based on the best information available to Duke at this time. At relatively low load levels (i.e., approaching 50 – 60 percent), emissions of CO have been observed in practice to vary significantly. The 42 ppmvd emission rate shown is for an extreme summer temperature condition and should not necessarily be considered reliable, however it represents the best information available to us at this time. It should be noted that Duke does not intend to operate the proposed units at load levels as low as 60% on a consistent basis, but it is possible that they could be operated at these levels for several hours at a time.

FDEP Comment No. 6: NOx Emissions Standards - The application requests a NOx emission standard for gas firing of 12.0 ppmvd corrected to 15% oxygen for the General Electric 7EA gas turbine. The Department has emissions performance data from General Electric that indicates NOx emissions for this unit will be 9.0 ppmvd corrected to 15% oxygen. The Department has recently permitted GE 7EA units with the following NOx emissions standards:

- 9.0 ppmvd @ 15% oxygen based on a 3-hour test at 100% base load, and 9.0 ppmvd @ 15% oxygen based on a 24-hour block CEMS average of available operating hours
- 9.0 ppmvd @ 15% oxygen based on a 3-hour test at 100% base load, and 10.0 ppmvd @ 15% oxygen based on a 3-hour rolling CEMS average

Please comment.

Response: Duke recognizes that General Electric performance data indicates that 7EA units are capable of achieving a NOx emission rate of 9 ppmvd at 15% oxygen during steady state operating conditions. Steady state operating conditions are defined as the condition of the turbine where the rotor is in thermal equilibrium and the load on the unit is not changing by greater than 0.5%. Rotor thermal equilibrium is defined as less than a 5 degree F change in wheel spacings in any 15 minute interval. The unit load change is defined as less than a 0.5% change in fuel flow of the unit within 2 minutes prior to emissions sampling and one minute after sampling. Duke's experience with operational equipment is such that the ability to achieve 9 ppmvd is feasible only during steady state operating conditions and 12 ppmvd is a more feasible emission limit on a *short-term* basis (i.e., 1 to 3 hour average). If the Department does not feel that a 12 ppmvd limit is appropriate (for all averaging periods), Duke would like to request that its NOx emissions for the 7EA units be limited to 10.5 ppmvd (during gas-fired operation) on a continuous basis, with compliance to be assessed on a *long-term* basis. Oil-fired operation will continue to be limited to 1000 hours per year per turbine, with a NOx emission limit of 42 ppmvd.

FDEP Comment No. 7: SAM Emissions - Page 5-21 states that approximately 10% of the SO_2 emissions are oxidized to SO_3, eventually forming sulfuric acid mist (H_2SO_4, SAM). Based on the application, the project would result in 27.4 tons of SAM per year. Table 62-212.400-2, F.A.C. identifies "7.0 tons per year" as the PSD Significant Emission Rate for SAM. Please provide a BACT analysis for SAM emissions.

Response: The statement on page 5-21 is intended to reflect the understanding that only a very small amount of SO_2 emissions from the Facility would be oxidized to SO_3, only some of which in turn could eventually form H_2SO_4 under favorable atmospheric conditions. FDEP's estimate of 27.4 tons of SAM would therefore be a very high (and unlikely) estimate of the amount of SAM resulting from the project. The methods for controlling SAM emissions/formation would be the same as the methods used to control SO_2 emissions. SO_2/SAM control strategies can generally be classified into five categories: fuel/material sulfur content limitation, absorption by a solution (wet scrubbing), adsorption on a solid bed, direct conversion to sulfur, or direct conversion to sulfuric acid.

A review of the BACT determinations for combustion turbines contained in the BACT clearinghouse illustrates that the exclusive use of low sulfur fuels constitutes the top level of of control for SO_2. For this project, Duke proposes as BACT the use of pipeline natural gas and 0.05% sulfur oil as a backup fuel. This BACT proposal is consistent with other recent determinations for similar facilities in Florida and elsewhere in the country.

Additionally, Duke believes that the formation of SAM will be well below the conservative estimate of 27.4 tons per year because of the limited oil consumption and the typical natural gas in Florida that contains less than 2 grains of sulfur per 100 standard cubic feet (gr S/100 scf). This value is well below the "default" maximum value of 20 gr S/100 scf, but high enough to require a BACT determination.

FDEP Comment No. 8: VOC Standard - Please correct the VOC emissions rate from "ppmvw" to "ppmvd corrected to 15% oxygen".

Response: The requested information is provided in Attachment 1.

FDEP Comment No. 9: SCR and CO Oxidation Catalyst Cost Analyses - The application indicates an incremental cost effectiveness of $50,602 per ton of NOx removed for the installation of SCR and an incremental cost effectiveness of $21,832 per ton of CO removed for the installation of an oxidation catalyst. After reviewing information for similar projects, the Department believes these estimates are inaccurate. In fact, a similar Duke Energy project in Madison, Ohio involved the General Electric Model 7EA with annual operation of 2500 hour of gas firing and 500 hours of oil firing. The agency's permit documentation (July 1999) indicates an incremental cost effectiveness of $19,000 per ton of NOx removed for the installation of SCR and an incremental cost effectiveness of $9000 per ton of CO removed for the installation of an oxidation catalyst. Other projects in the United States have estimated the cost effectiveness of each of these technologies to be much lower than presented in this application.

Response: Tables 5-2 (Combustion Turbine NOx BACT Analysis) and 5-5 (Combustion Turbine CO and VOC BACT Analysis) have been revised to reflect the Department's comments and are provided as an attachment to this letter. While the cost effectiveness calculations indicate higher than average costs ($/ton) for the control technologies in question, we attribute this to the lower than average emission rates associated with the GE 7EA turbines.

Responses to each of DEP's specific comments are provided below.

For projects requesting operating limits on "groups" of gas turbines instead of individual units, EPA requires calculating the "cost effectiveness" based on the maximum operation for a given unit. For example, based on the application provided, this would be 7760 hours per year of gas firing and 1000 hours per year of oil firing. This would result in annual NOx emissions of 239 tons per year and a potential NOx reduction from SCR of 167 tons per year based on 71% control efficiency. Please base the NOx and CO cost effectiveness calculations ($/ton pollutant removed) on the worst case requested. If the worst case is for oil firing, then include emissions from oil firing based on the same control efficiency. The worst case may be different for the SCR analysis and oxidation catalyst analysis. Note: In addition to the caps requested on total operation of the 8 gas turbines, the Department is considering an operating limit of 5000 hours per year for each turbine.

Response: Duke's application requested a 2,500 hour individual and 20,000 aggregate hourly limit for the 8 simple cycle units, with the intent that individual units could operate up to about 2,500 hours (+/-). It is understood that the Department is considering limiting operation to 5,000 hours per unit. For the purpose of this application, the worst case scenario should be considered to be 2,500 hours operation per unit, of which up to 1,000 hours could be on backup fuel oil. Since NOx control by SCR is not considered to be feasible during fuel oil firing, the worst case BACT analysis for NOx emissions is therefore based on 2,500 hours per turbine per year, with all 8 turbines running simultaneously. Since CO emission rates during natural gas firing are greater than during fuel oil firing (i.e., 52 lb/hr vs. 42 lb/hr per unit at full load), the worst case BACT analysis for CO emissions is therefore based on 2,500 hours per turbine per year. Although VOC emissions are slightly greater during fuel oil firing than during natural gas firing (i.e., 4.5 lb/hr vs. 1.8 lb/hr per unit at full load), the BACT economic analysis of an oxidation catalyst for CO and VOC control is dominated by the much larger reduction of CO emissions that are predicted to occur through the catalyst unit. Therefore, the worst case BACT scenario (for all pollutants) is based on 2,500 hours per turbine per year, with all 8 units operating simultaneously.

a. Please provide the actual vendor's quotes (with equipment listed) for the SCR system and for the oxidation catalyst system.

Response: The cost information for the hot SCR and CO Catalyst systems were obtained from a recent similar project being developed by Duke in Mississippi (i.e., the Southaven Energy Facility). Quotes for capital equipment costs were obtained from Engelhard, a copy of which is attached to this letter as Attachment 2. Engelhard's quote of $3,600,000 is for a complete system including instrumentation assuming 3,500 hours of operation, and this estimate was proportioned among various equipment. To replicate this figure, add $2,037,250 (hot SCR from Table 5-2), $203,700 (instrumentation for SCR from Table 5-2), $1,241,875 (Oxidation Catalyst from Table 5-5), and $124,200 (instrumentation from Table 5-5). Note that there are approximation variances attributable to proportioning the costs between the two systems, which are combined in practice. Instrumentation and freight costs were estimated using EPA's OAQPS Control Cost Guidance Manual, which estimates 10% of capital for instrumentation and 5% of capital for freight.

b. Please describe the "instrumentation" that would be provided for the SCR system ($203,700) and for the oxidation catalyst system ($124,200). Is this instrumentation already included in the vendor quotes? If no instrumentation is proposed, please remove these costs.

Response: The instrumentation associated with the hot SCR system are integrated into Engelhard's quote for the capital cost of the equipment that is discussed in the previous comment and response. The OAQPS guidance was used to isolate a figure for the instrumentation. At this stage of the design, the details on instrumentation are not fully defined, but the estimated cost of 10% of capital is not inconsistent with Duke's experience at other facilities. Instrumentation will consist primarily of control systems for monitoring system performance and the general operation of the system.

c. Please revise the SCR cost analysis and the oxidation catalyst cost analysis for the following items:

Capital Cost Items

- Revise the state sales tax from 7% to 6% (Florida); verify that there will actually be a sales tax for the purchased equipment;

Response: The state sales tax in Tables 5-2 and 5-5 has been revised to 6%. It is assumed that a sales tax will be assessed on purchased equipment. There is no information available at this time to indicate that sales tax will not be assessed on purchased equipment.

- Revise the "contingency" factor under indirect capital costs for hot SCR from 0.20 to 0.10; and

Response: The "contingency factor in Tables 5-2 and 5-5 has been revised to 0.10.

- Remove the cost for "simple interest during construction";

Response: The cost for "simple interest during construction" has been removed from Tables 5-2 and 5-5.

Annual Cost Items

- Revise the cost for "power loss due to pressure drop across the catalyst" based on $0.04 / kWh or provide supporting documentation for $0.065 / kWh;

Response: The cost for "power loss due to pressure drop across the catalyst" has been revised in Tables 5-2 and 5-5, and is now based on $0.04/kWh.

- Revise the cost for "operating labor" based on 625 hours of labor per year (2500 hr/yr* / 12 hr/shift x 3 hr labor/shift);

Response: The cost for "operating labor" has been revised in Tables 5-2 and 5-5 to reflect 625 annual hours (3 hours per shift) for SCR operation, and 208 annual hours (1 hour per shift) for the Oxidation Catalyst.

- Revise cost for "supervisory labor" accordingly;

Response: The cost for "supervisory labor" has been revised in Tables 5-2 and 5-5 to reflect the changes in operating labor described above.

- Revise the cost for "maintenance labor" based on 833 hours of labor per year (2500 hr/yr* / 12 hr/shift x 4 hr labor/shift);

Response: The cost for "maintenance labor" has been revised in Tables 5-2 and 5-5 to reflect 833 annual hours (4 hours per shift) for SCR maintenance, and 208 annual hours (1 hour per shift) for the Oxidation Catalyst.

- Revise the cost for "maintenance materials" accordingly;

Response: The cost for "maintenance materials" has been revised in Tables 5-2 and 5-5 to reflect the changes in maintenance labor described above.

- Remove the cost for "revenue loss during catalyst replacement" (can be scheduled during normal down time);

Response: The cost for "revenue loss during catalyst replacement" has been removed from Table 5-2 and 5-5, to reflect replacement during normal down time.

- Remove the costs for "catalyst cleaning" and "catalyst replacement labor";

Response: Duke notes that the costs associated with catalyst cleaning and catalyst replacement labor are costs that will actually be incurred against the project during its lifetime and they should be included in the analyses; however, at your request we have removed these costs from the analysis in Tables 5-2 and 5-5.

- Revise the state sales tax from 7% to 6% (Florida); verify that there will actually be a sales tax for the purchased catalyst;

Response: The state sales tax in Tables 5-2 and 5-5 has been revised to 6%. It is assumed that a sales tax will be assessed on purchased catalyst. There is no information available at this time to indicate that sales tax will not be assessed on purchased equipment.

- Revise the "overhead" costs based on previous changes; and

Response: The "overhead" costs in Tables 5-2 and 5-5 have been revised based on the previous changes.

- Remove the cost for "property tax" for the control equipment.

Response: The cost for "property tax" has been removed from Table 5-2 and 5-5.

Emissions Reduction

- If the costs are estimated at 8760 hours per year, then the emissions reductions should be based on the same. * If a limit is requested for each simple cycle gas turbine of 5000 hours per year, substitute 5000 for 2500.

Response: The cost in Tables 5-2 and 5-5 have been revised and are based on 2,500 hours per year per turbine. The emissions reductions are based on 2,500 hours per year per turbine.

- Revise the oxidation catalyst control efficiency from 80% to 90% or provide a reference for the assumed 80% control efficiency.

Response: The oxidation catalyst control efficiency in Table 5-5 has been revised to 90% for CO emissions.

FDEP Comment No. 10: PSD Class I Impact Analysis - In July of 2000, representatives for Duke Energy met with representatives of the Department in a pre-application meeting to discuss various issues. During this meeting, Duke Energy questioned whether or not a PSD Class I Ambient Air Quality Impact Analysis for the Everglades National Park was necessary for a combustion turbine project fired completely with natural gas. The Department relayed a response to Duke Energy from the National Park Service that a PSD Class I Ambient Air Quality Impact Analysis was not necessary for the project, as described, fired solely with natural gas. The following table lists the annual emissions given to the Department at that time of the meeting as well as the annual potential emissions as submitted in the application:

Pollutant	Pre-Application TPY	Application TPY
CO	400	580
NOx	225	1010
PM_{10}	120	170
SO_2	100	274

Obviously, Duke Energy now intends to fire low sulfur distillate oil as a backup fuel based on an interruptible gas supply contract (page 2-7) and has requested up to 1000 hours of oil firing per gas turbine. Please submit the required PSD Class I Ambient Air Quality Impact Analysis for this project.

Response: On Duke's behalf, CH2M HILL has discussed the need for a PSD Class I analysis with a representative of the National Park Service (NPS) in Denver. The NPS subsequently requested that a screening analysis be conducted for the oil-fired operating scenario to evaluate potential impacts in the Everglades National Park. CH2M HILL has completed the modeling analysis and has submitted documentation to both NPS and FDEP modeling staff summarizing our modeling procedures and results. A copy of the documentation that was initially submitted to the NPS for review and comment was also provided to Chris Carlson of DEP by e-mail on 10/30/2000. Documentation summarizing the final methodology and results was sent to NPS and FDEP by e-mail on 12/14/2000. Copies of electronic files on CD-ROM are being sent separately to both NPS and FDEP.

FDEP Comment No. 11: Class II Building Downwash Analysis - The modeling files that were submitted with the application modeled all six combustion turbines as a single stack and building. The results were then multiplied by six to obtain the modeled concentration.

This configuration does not adequately address all building downwash concerns. Please resubmit a modeling analysis that models each of the six combustion turbines and their associated buildings explicitly. Also, please submit the input file for the BPIP program.

Response: The modeling analyses were based on conservative and generally accepted assumptions that can be expected to yield higher concentrations than if the stacks and structures would have been modeled at their respective locations. All eight units were modeled at a collocated location and the only significant structures in the vicinity of the stacks (i.e., relatively small inlet air filter housings) were located immediately adjacent to the stacks. In actual fact the inlet air filter housings will be located approximately 75 ft from each respective stack and each stack will be located approximately 75 to 150 ft from each adjacent stack. The separation of the units from one another is such that no more than two of the eight air filter structures are within "5L" of any one stack, where L is the characteristic building dimension provided in DEP and EPA modeling guidance. Since all stacks and structures were modeled at a single collocated location, the predicted concentrations can be expected to be higher than if the stacks and buildings were modeled at separate locations. Inasmuch as the predicted concentrations were determined to be "insignificant" at all locations (even with the conservative assumptions), a more detailed analysis was not justified.

A copy of the input file for the BPIP program are being e-mailed separately to Chris Carlson of DEP's modeling staff.

FDEP Comment No. 12: Modeled Annual NOx Concentrations - Please submit some example calculations that show how the modeled annual NOx concentrations for the oil scenario were derived from the conversion factors presented in Appendix B.

Response: Example Calculations for NOx and PM-10 for the oil-fired scenario are shown in Attachment 3. The information provided with the original application was for the gas-fired scenario. The calculations shown for the oil-fired scenario are consistent with those shown in Appendix B of the original application for the gas-fired case.

FDEP Comment No. 13: NSPS Monitoring - Is Duke Energy proposing an Alternate Monitoring Plan to demonstrate compliance with the NSPS Subpart GG monitoring requirements for NOx and SO_2? Which proposed emission units would be subject to 40 CFR 60 Subpart Dc requirements as indicated on page 4-6?

Response: As discussed in Section 4.4.2.3 in the Application, Duke would like to utilize a custom fuel monitoring schedule for natural gas in lieu of daily sampling as provided for in the provisions of 40 CFR 60.334(b)(2). Prior to operation, Duke will submit a monitoring plan, which will be certified by Duke's Acid Rain Designated Representative that will commit to using pipeline natural gas as the primary fuel (sulfur content less than 20 gr/100 SCF per 40 CFR 75.11(d)(2) and each unit will be monitored for SO2 using methods consistent with 40 CFR 75. For all bulk fuel oil shipments received at the facility, Duke will obtain copies of vendor analyses showing the sulfur and nitrogen content of the fuel, as well as documentation showing that the analysis methods are in compliance with 40 CFR 60.335(d). The Department should disregard the reference to Subpart Dc fuel monitoring requirements since there will not be any fuel burning sources at the Facility that will be subject to Subpart Dc.

FDEP Comment No. 14: Acid Rain - The application does not indicate whether or not the application for an Acid Rain permit has been submitted. The new gas turbines will be subject to the Acid Rain (Title IV) provisions. You are notified that an application for a Title IV Acid Rain Permit must be submitted at least 24 months before the date on which a new unit begins serving an electrical generator greater than 25 MW. The application must be submitted to the Region 4 office of the U.S. Environmental Protection Agency in Atlanta, Georgia with a copy to the Department's Bureau of Air Regulation in Tallahassee.

Response: An application for an Acid Rain Permit has not yet been submitted. However, an application and Certificate of Representation is currently being prepared and will be submitted in the near future. Our discussions with EPA Region IV staff indicated that Duke should submit the Certificate of Representation to EPA's Acid Rain Program Office in Washington, DC, and the Acid Rain Application should be submitted to FDEP. Duke requests that DEP confirm that this is correct.

On behalf of Duke Energy, we would like to request that you provide us with a written (or e-mail) acknowledgement that you have received this response, as well as concurrence that the information provided herein adequately addresses the questions and comments contained in your August 4, 2000 e-mail. If you should have any questions regarding the information provided herein or should you require any additional information, please contact me at (770) 604-9182 ext 355, or by e-mail at ghowroyd@ch2m.com, or Nathan Plagens at Duke Energy North America at (713) 627-5985.

Sincerely,

CH2M HILL

George Howroyd

George Howroyd, Ph.D., P.E.
Principal Engineer

ATL\Duke\Response to DEP Comments 10-26-00.doc

c: Nathan Plagens/Duke
Dan Runyan/Duke
Pamela A. Lehr/CH2M HILL
Bill Marsh/CH2M HILL
C. Carlson
J. Goldman, SED
EPA
NPS

Table 5-2 (Revised)
Combustion Turbine NOx BACT Analysis
71 Percent NOx Control Efficiency for a SCR system (Per Turbine)
Duke Energy Fort Pierce, LLC
Fort Pierce Generating Facility
Fort Pierce, Florida

Cost Item	Cost Factor	Reference	Cost ($1999)
Direct Costs (Dc)			
Purchased Equipment Costs (PEC)			
Basic Equipment & Auxiliaries	As Estimated, A	Vendor Quote	$2,037,250
Instrumentation	0.1 X A	(EPA, 1995a)	$203,700
State Sales Taxes	0.06 X A	State Sales Tax	$122,230
Freight	0.05 X A	(EPA, 1995a)	$101,900
PEC Subtotal (B)			**$2,465,080**
Direct Installation Costs (DIC)			
Foundations & Supports	0.08 X B	(Ulrich, 1984)	$197,200
Labor	0.14 X B	(EPA, 1990a)	$345,000
Electrical	0.04 X B	(EPA, 1990a)	$98,600
Piping	0.02 X B	(EPA, 1995a)	$49,300
Insulation	0.01 X B	(EPA, 1995a)	$24,700
Painting	0.01 X B	(EPA, 1990a)	$24,700
DIC Subtotal	0.3 X B	(EPA, 1990a)	**$739,500**
Total DIC	PEC+DIC	-	**$3,204,580**
Indirect Costs (IDC)			
Engineering	0.10 X B	(EPA,1990a)	$246,500
Construction Overhead	0.05 X B	(EPA,1990a)	$123,300
Contractor Fees	0.10 X B	(EPA,1990a)	$246,500
Contingencies	0.10 X B	(EPA,1990a)	$246,500
Start-Up	0.02 X B	(EPA,1990a)	$49,300
Performance Testing	0.01 X B	(EPA,1990a)	$24,700
Total IDC		-	**$936,800**
Total Capital Investment (TCI)	**DIC + IDC**		**$4,141,380**

Operating Cost Factors For The SCR

Cost Data

Interest Rate	7%	***CAPITAL RECOVERY FACTOR (CRF)***
Catalyst Life	3	0.380
Equipment Life	10	0.1440

Table 5-2 (Revised)
Combustion Turbine NOx BACT Analysis
71 Percent NOx Control Efficiency for a SCR system (Per Turbine)
Duke Energy Fort Pierce, LLC
Fort Pierce Generating Facility
Fort Pierce, Florida

Cost Item	Cost Factor	Reference	Cost ($1999)
Direct Annual Costs, $/Yr			
	FACTOR	**REFERENCE**	**COSTS, $/Yr**
Power Loss Due To Pressure Drop Across Catalyst	0.3% per inch of pressure drop @ $0.04/kWh and 245 KW loss	Vendor	$24,500
Operating Labor	$30/hr @ 3 hr/12-hr shift	Industry Average/Estimate	$18,750
Supervisory Labor	15 % of operating labor	(EPA,1993a)	$2,810
Maintenance Labor	$30/hr @ 4 hr/12-hr shift	Estimate	$25,000
Maintenance Materials	100 % of maintenance labor	(EPA,1993a)	$25,000
Catalyst Replacement (CR) (A)	$1,077,000 every 3 years including disposal	Vendor Quote	$1,077,000
Sales Tax (B)	6%	State Tax Rate	$64,620
Capital Recovery	[A+B] * CRF	(EPA, 1995a)	$433,816
TOTAL DIRECT ANNUAL COSTS, $/YR			**$529,875**
Indirect Annual Costs, $/Yr			
Overhead	60% of All Labor Main. Costs	(EPA,1990a)	$31,686
Insurance & Administration	3% of TCI	(EPA,1990a)	$124,241
Capital Recovery	CRF X TCI	N/A	$596,358
			$752,285
Total Annual Costs, $/Yr	**$1,282,160**		
Total Net NOx Reductions (TPY)	36	Natural gas operation, 71% removal, 2,500 hours/yr operation	
Incremental Cost Effectiveness, $/Ton	**$35,616**		

Table 5-5 (Revised)
Combustion Turbine CO and VOC BACT Analysis (Per Turbine)
Duke Energy Fort Pierce, LLC
Fort Pierce Generating Facility
Fort Pierce, Florida

Cost Item	Cost Factor	Reference	Cost ($1999)
Direct Costs (Dc)			
Purchased Equipment Costs (PEC)			
Basic Equipment & Auxiliary Equipment (A)	As Estimated	Vendor Quote	$1,241,875
Instrumentation	0.1 X A	(EPA, 1995a)	$124,200
State Sales Taxes	0.06 X A	State Sales Tax	$74,500
Freight	0.05 X A	(EPA, 1995a)	$62,100
PEC Subtotal (B)			**$1,502,675**
Direct Installation Costs (DIC)			
Foundations & Supports	0.08 X B	(Ulrich, 1984)	$120,200
Labor	0.14 X B	(EPA, 1990a)	$210,400
Electrical	0.04 X B	(EPA, 1990a)	$60,100
Piping	0.02 X B	(EPA, 1995a)	$30,100
Insulation	0.01 X B	(EPA, 1995a)	$15,100
Painting	0.01 X B	(EPA, 1990a)	$15,100
DIC Subtotal		(EPA, 1990a)	**$451,000**
Total DIC	PEC+DIC	-	**$1,953,675**
Indirect Costs (IDC)			
Engineering	0.10 X B	(EPA,1990a)	$150,300
Construction Overhead	0.05 X B	(EPA,1990a)	$75,200
Contractor Fees	0.10 X B	(EPA,1990a)	$150,300
Contingencies	0.03 X B	(EPA,1990a)	$45,100
Start-Up	0.02 X B	(EPA,1990a)	$30,100
Performance Testing	0.01 X B	(EPA,1990a)	$15,100
Total IDC		-	**$466,100**
Total Capital Investment (TCI)	**DIC + IDC**		**$2,419,775**

Operating Cost Factors For The Oxidation Catalyst

Cost Data

Interest Rate	7%	***CAPITAL RECOVERY FACTOR (CRF)***
Catalyst Life	3	0.38
Equipment Life	10	0.1440

Table 5-5 (Revised)
Combustion Turbine CO and VOC BACT Analysis (Per Turbine)
Duke Energy Fort Pierce, LLC
Fort Pierce Generating Facility
Fort Pierce, Florida

Cost Item	Cost Factor	Reference	Cost ($1999)
Direct Annual Costs, $/Yr			
Power Loss Due To Pressure Drop Across Catalyst	0.1% per inch of pressure drop @ $0.04/kWh and 245 KW loss	Vendor	$24,500
Operating Labor	$30/hr @ 1 hr/12-hr shift	Industry Average/Estimate	$6,250
Supervisory Labor	15 % of operating labor	(EPA,1993a)	$938
Maintenance Labor	$30/hr @ 1 hr/12-hr shift	Estimate	$6,250
Maintenance Materials	100 % of maintenance labor	(EPA,1993a)	$6,250
Catalyst Replacement (CR) (A)	$1,006,540 every 3 years including disposal	Vendor Quote	$1,006,540
Sales Tax (B)	6%	State Tax Rate	$60,392
Capital Recovery	[A+B] * CRF	(EPA, 1995a)	$405,434
TOTAL DIRECT ANNUAL COSTS, $/YR			**$449,622**
Indirect Annual Costs, $/Yr			
Overhead	60% of All Labor Main. Costs	(EPA,1990a)	$8,063
Insurance & Administration	3% of TCI	(EPA,1990a)	$72,594
Capital Recovery	CRF X TCI	N/A	$348,448
Property Tax	1% of TCI	Estimate	$24,198
TOTAL INDIRECT ANNUAL COSTS, $/YR			**$453,303**
Total Annual Costs, $/Yr	**$902,925**		
Total Net CO Reductions (TPY)	59	90% Removal Efficiency, 2,500 hours/yr operation	
Total Net VOC Reductions (TPY)	1	45% Removal Efficiency, 2,500 hours/yr operation	
Incremental Cost Effectiveness, $/Ton	**$15,048**		

Attachment 1
VOC Emission Rates Corrected to ppmvd at 15% Oxygen

Table 1
Estimated Plant Performance and VOC Emissions Data
Duke Energy Port Pierce Generating Station
Duke Energy Fort Pierce, LLC
Fort Pierce, FL

Combustion turbine load	100%					75%					60%					ISO
Ambient temperature (°F)	**101**	**82**	**74.6**	**66.8**	**27**	**101**	**82**	**74.6**	**66.8**	**27**	**101**	**82**	**74.6**	**66.8**	**27**	**59**
Relative humidity (%)	40	77	72	74	81	40	77	72	74	81	40	77	72	74	81	60
Firing Natural Gas																
VOC (ppmvw)	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	2	1.4	1.4	1.4	1.4	1.4
VOC (ppmvd @ 15% O2)	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.4	2.2	1.5	1.5	1.5	1.4	1.5
Firing Distillate Oil																
VOC (ppmvw)	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5
VOC (ppmvd @ 15% O2)	3.5	3.5	3.5	3.4	3.4	3.4	3.4	3.4	3.4	3.3	3.5	3.4	3.4	3.4	3.3	3.4

Attachment 2
Quotes for SCR and Oxidation Catalyst Emission Control Systems

ENGELHARD

101 WOOD AVENUE
ISELIN, NJ 08830
732-205-5000

POWER GENERATION SALES:
ENGELHARD CORPORATION
2205 CHEQUERS COURT
BEL AIR, MD 21015
PHONE 410-569-0297
FAX 410-569-1841
E-Mail Fred_Booth@ENGELHARD.COM

vember 13, 1998

:

Simple Cycle Turbines
Oxidation Catalyst Components
High Temperature SCR Catalyst System Components
Engelhard Budgetary Proposal EPB98283-Rev. 1

ear

e provide Engelhard Budgetary Proposal for Engelhard Camet® CO Oxidation Catalyst System omponents and NOxCAT ZNX™ High Temperature SCR Catalyst system components for the above projects. This is per your Xes of November 10 and 11, 1998.

ur Budgetary Proposal is based on:

iven data for GE 7EA, Westinghouse 501D5A, and Westinghouse 501F Gas Turbines operating in simple cycle mode for both 3,500 hours/year and 2,000 hours/year operation;

Oxidation Catalysts for CO reductions as noted;

Catalyst for NOx reductions as noted with ammonia slip of 5 ppmvd@15%O_2;

Delta P through CO and SCR systems of Nominal 4"WG;

Assumed internally insulated ducts with cross sections at the catalyst as illustrated. Note that all transitions are based on assumed turbine discharge cross section of 15 ft. x 15 ft.;

Scope as noted. Please note that we have assumed horizontal gas flow through the CO / SCR reactor and the use of 28% aqueous ammonia. The systems for the GE 7EA and Westinghouse 501F require the use of an ambient air cooling system to reduce the gas temperature to the SCR catalyst.

Three (3) Year Performance Guarantee (expected life five to seven years).

Ve request the opportunity to work with you on this project.

Sincerely yours,

ENGELHARD CORPORATION

Frederick A. Booth

Frederick A. Booth
Sales Engineer

cc: Nancy Ellison - Proposal Administrator

ENGELHARD

ENRON
Simple Cycle Turbines
CAMET® CO Catalyst Systems
ZNX™ SCR Catalyst Systems
Engelhard Budgetary Proposal EPB98283-Rev. 1
November 13, 1998

ENGELHARD CORPORATION
CAMET™ CO CATALYST SYSTEM
NOxCAT ZNX™ HIGH TEMPERATURE SCR NOx ABATEMENT CATALYST SYSTEM

gelhard Corporation ("Engelhard") offers to supply to Buyer the CAMET™ metal substrate CO Catalyst System components d the NOxCAT ZNX™ ceramic substrate SCR system components summarized herein.

xCAT ZNX™ High Temperature SCR Catalyst System: Scope of Supply

Engelhard CAMET® CO and NOxCAT ZNX™ SCR catalyst in modules;
Internal support structures for catalyst modules (frame);
Internally insulated reactor ductwork - with stainless steel liner sheets - to house CO catalyst modules, AIG, and SCR Catalyst modules;
Inlet and outlet transition duct sections - internally insulated with stainless steel liner - inlet flow straightener in inlet transition section;
Ammonia Injection Grid (AIG);
AIG manifold with flow control valves ;
NH_3/Air dilution skid: Anhydrous Ammonia to skid;
Ambient air cooling system components as required.

JDGET PRICES: Per Turbine- 3,500 hr/yr	GE 7EA	West. 501D5A	West. 501F
ms 1 - 7 above - complete system	$3,600,000	$5,000,000	$5,500,000
...acement CO Modules	$ 450,000	$ 750,000	$ 500,000 /0.75 = 667,000
cement ZNX Modules	$1,400,000	$2,000,000	$1,800,000

Per Turbine- 2,000 hr/yr	GE 7EA	West. 501D5A	West. 501F
ms 1 - 7 above - complete system	$3,000,000	$3,600,000	$3,800,000
eplacement CO Modules	$ 360,000	$ 450,000	$ 420,000
eplacement ZNX Modules	$1,000,000	$1,500,000	$1,400,000

ARRANTY AND GUARANTEE:

Mechanical Warranty:	One year of operation* or 1.5 years after catalyst delivery, whichever occurs first.
Performance Guarantee:	Three (3) years of operation* or 3.5 years after catalyst delivery, whichever occurs first. Catalyst warranty is prorated over the guaranteed life

OCUMENT / MATERIAL DELIVERY SCHEDULE

rawings / Documentation - 6 - 8 weeks after notice to proceed and Engelhard receipt of all engineering specifications and details
perating manuals
aterial Delivery 20 - 24 weeks after approval and release for fabrication

YSTEM DESIGN BASIS:

as Flow from:	GE Fr7 and Westinghouse 501F - with ambient air cooling
as Flow from:	Westinghouse 501D5A
as Flow:	Assumed Horizontal
uel:	Natural Gas
as Flow Rate (At catalyst face):	See Performance data
emperature (At catalyst face):	See Performance data
O Concentration (At catalyst face):	See Performance data
Reduction:	See Performance data
Ox Concentration (At catalyst face):	See Performance data
IOx Reduction:	See Performance data
IH3 Slip:	5 ppmvd@15%O_2
ressure Drop through SCR	Nom. 4"WG

Simple Cyc. urbines
CAMET® CO Catalyst Systems
ZNX™ SCR Catalyst Systems
Engelhard Budgetary Proposal I
November 13, 1998

Performance Date GE 7EA No. Units - 8 3,600 hr / yr

AMBIENT	59	20	40	90	95	90	90	90	90
LOAD	BASE	BASE	BASE	BASE	BASE	BASE	75%	52%	35%
TURBINE EXHAUST TEMPERATURE, F	969	972	1,012	1,019	1,023	1,019	1,080	1,180	1,064
TURBINE EXHAUST FLOW, lb/hr	2,358,000	2,674,000	2,240,000	2,181,000	2,161,000	2,181,000	1,725,000	1,487,000	1,328,000
TURBINE EXHAUST GAS ANALYSIS, % VOL. N2	74.66	75.45	74.11	73.53	73.16	73.53	73.45	73.57	73.77
O2	13.85	13.69	13.71	13.59	13.60	13.69	13.38	13.71	14.29
CO2	3.15	3.20	3.12	3.10	3.09	3.10	3.19	3.04	2.76
H2O	7.22	6.65	8.15	8.90	9.35	8.90	9.09	8.79	8.27
Ar	0.90	0.91	0.88	0.88	0.88	0.88	0.88	0.89	0.89
AMBIENT AIR FLOW, lb/hr	0	0	0	0	0	0	111,578	129,392	60,909
TOTAL FLOW - TURBINE EXHAUST + AMBIENT - lb/hr	2,358,000	2,674,000	2,240,000	2,181,000	2,161,000	2,181,000	1,836,578	1,596,392	1,388,909
AMBIENT + EXHAUST GAS ANALYSIS, % VOL. N2	74.66	75.45	74.11	73.63	73.16	73.63	73.91	74.18	74.00
O2	13.85	13.69	13.71	13.59	13.50	13.69	13.70	14.12	14.48
CO2	3.15	3.20	3.12	3.10	3.09	3.10	3.00	2.80	2.69
H2O	7.22	6.65	8.19	8.90	9.35	8.90	8.68	8.09	7.01
Ar	0.90	0.91	0.88	0.88	0.88	0.88	0.84	0.82	0.85
CALCULATED AIR + GAS MOL. WT.	28.40	28.54	28.36	28.27	28.22	28.27	28.29	28.32	28.33
GIVEN: TURBINE CO, ppmvd	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0
CALC.: TURBINE CO, lb/hr	53.6	59.0	50.8	49.2	48.4	49.2	35.6	33.1	30.1
GIVEN: TURBINE NOx, ppmvd @ 15% O_2	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	42.0
CALC.: TURBINE NOx, lb/hr	53.7	59.6	50.6	49.2	48.5	49.2	40.1	32.5	76.0
CALC.: CO, ppmvd@15%O2 - AT CATALYST FACE	24.7	24.4	24.7	24.7	24.8	24.7	23.3	24.3	27.2
CALC. NOx, ppmvd@15%O2 - AT CATALYST FACE	15.0	15.0	15.0	15.0	15.0	15.0	14.7	14.5	41.2
FLUE GAS TEMP @ SCR CATALYST, F	969	972	1,012	1,019	1,023	1,019	1,025	1,025	1,025
DESIGN REQUIREMENTS									
CO CATALYST CO OUT, ppmvd@15%O2	7.4	7.3	7.4	7.4	7.4	7.4	7.0	7.3	8.2
SCR CATALYST NOx OUT, ppmvd@15%O2	4.5	4.5	4.5	4.5	4.5	4.5	4.4	4.4	12.4
NH3 SLIP, ppmvd@15%O2	5	5	5	5	5	5	5	5	5
CO and SCR PRESSURE DROP, 4.0 "WG - Max.									
GUARANTEED PERFORMANCE DATA									
CO CATALYST CO CONVERSION - % Max.	70.0%	75.0%	70.0%	70.0%	70.0%	70.0%	70.0%	70.0%	70.0%
CO OUT, ppmvd@15%O2 - Max.	7.4	6.1	7.4	7.4	7.4	7.4	7.0	7.3	8.2
CO OUT, lb/hr - Max.	16.1	14.8	15.2	14.8	14.6	14.8	11.7	9.9	9.0
CO PRESSURE DROP, 0.8 "WG - Max.									
SCR CATALYST NOx CONVERSION, % - Min.	70.0%	70.0%	70.0%	70.0%	70.0%	70.0%	70.0%	70.0%	70.0%
NOx OUT, lb/hr - Max.	16.1	17.9	15.2	14.8	14.6	14.8	12.0	9.7	22.8
NOx OUT, ppmvd@15%O2 - Max.	4.5	4.5	4.5	4.5	4.5	4.5	4.4	4.4	12.4
EXPECTED AQUEOUS NH3 (28% SOL.) FLOW, lb/hr	73	81	69	67	66	67	55	45	61
NH3 SLIP, ppmvd@15%O2 - Max.	5	5	5	5	5	5	5	5	5

Simple Cycle Turbines
CAMET® CO Catalyst Systems
ZNX™ SCR Catalyst Systems
Engelhard Budgetary Proposal
November 13, 1998

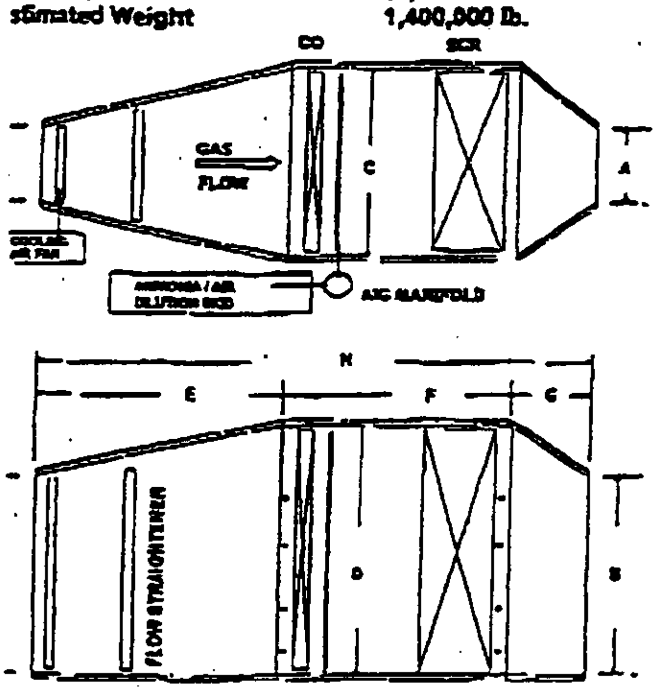
he equipment supplied is installed by others in accordance with the Engelhard design and installation instructions.

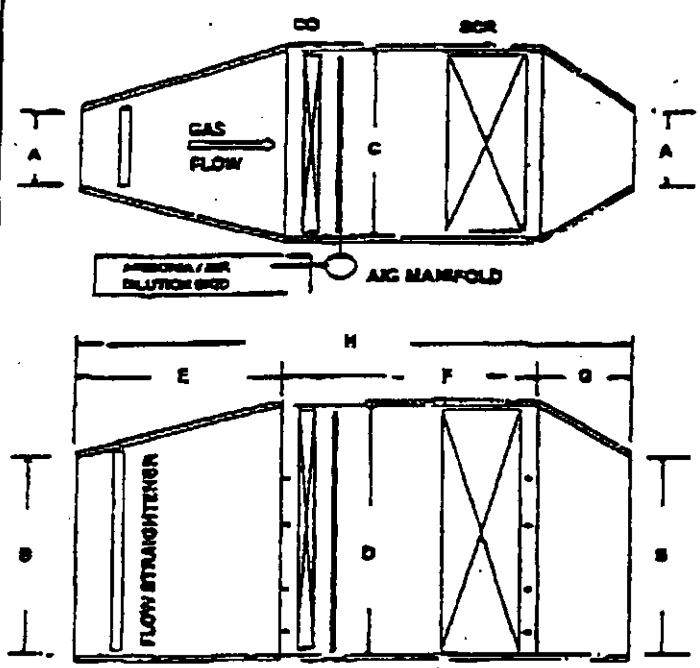
ssumed Dimensions / Sketch:

:E7EA	3,500 hr/yr
urbine Discharge Width (A) 15'-0"	
urbine Discharge Height	(B) 15'-0"
eactor Inside Liner Width	(C) 41'-6"
eactor Inside Liner Height	(D) 32'-3"
let Transition Length	(E) 31'-0"
eactor Depth	(F) 15'-0"
utlet Transition Length	(G) 13'-3"
otal Depth	(H) 59'-3"
stimated Weight	1,100,00 lb.

West. 501D5A	3,500 hr/yr
Turbine Discharge Width (A) 15'-0"	
Turbine Discharge Height	(B) 15'-0"
Reactor Inside Liner Width	(C) 58'-3"
Reactor Inside Liner Height	(D) 35'-6"
Inlet Transition Length	(E) 38'-6"
Reactor Depth	(F) 15'-0"
Outlet Transition Length	(G) 21'-6"
Total Depth	(H) 75'-0"
Estimated Weight	1,400,000 lb.

Vest. 501F	3,500 hr/yr
urbine Discharge Width (A) 15'-0"	
urbine Discharge Height	(B) 15'-0"
eactor Inside Liner Width	(C) 55'-6"
eactor Inside Liner Height	(D) 35'-6"
let Transition Length	(E) 36'-3"
eactor Depth	(F) 15'-0"
utlet Transition Length	(G) 20'-3"
otal Depth	(H) 71'-6"
stimated Weight	1,400,000 lb.





Attachment 3
Example Calculations – NOx and PM-10 (Oil-Fired Scenario)

Duke Energy - St. Lucie

100% Oil Load

Summer Scenario	1987	1988	1989	1990	1991
NO_x - Annual Avg.	0.0449	0.0459	0.0486	0.0512	**0.0526**
CO - 1-hr. Avg.	10.276	10.013	12.069	13.775	**14.266**
- 8-hr. Avg.	**3.342**	3.055	3.000	2.870	2.870
PM-10 - Annual Avg.	0.067	0.069	0.073	0.077	**0.079**
- 24-hr.	0.811	0.799	0.804	0.837	**0.897**
SO_2 - Annual Avg.	0.124	0.127	0.134	0.141	**0.145**
- 24-hr. Avg.	1.493	1.470	1.479	1.539	**1.651**
- 3-hr. Avg.	6.111	6.172	5.828	5.694	**8.773**

Average Scenario	1987	1988	1989	1990	1991
NO_x - Annual Avg.	0.0461	0.0472	0.0499	0.0527	**0.0540**
CO - 1-hr. Avg.	10.978	10.694	12.912	**14.746**	14.390
- 8-hr. Avg.	**3.421**	3.175	3.099	2.964	2.985
PM-10 - Annual Avg.	0.064	0.065	0.069	0.073	**0.074**
- 24-hr.	0.784	0.771	0.776	0.804	**0.842**
SO_2 - Annual Avg.	0.127	0.130	0.138	0.145	**0.149**
- 24-hr. Avg.	1.567	1.542	1.552	1.608	**1.683**
- 3-hr. Avg.	6.386	6.441	6.260	5.942	**9.470**

Winter Scenario	1987	1988	1989	1990	1991
NO_x - Annual Avg.	0.0484	0.0501	0.0528	0.0549	**0.0565**
CO - 1-hr. Avg.	12.133	11.816	14.308	13.659	**14.606**
- 8-hr. Avg.	**3.539**	3.359	3.259	3.108	3.127
PM-10 - Annual Avg.	0.061	0.063	0.066	0.069	**0.071**
- 24-hr.	0.776	0.757	0.763	0.784	**0.791**
SO_2 - Annual Avg.	0.135	0.140	0.147	0.153	**0.158**
- 24-hr. Avg.	1.731	1.690	1.701	1.748	**1.766**
- 3-hr. Avg.	6.986	7.010	7.144	6.466	**7.156**

Example Calculations

NO_x Annual Average, 1988 Winter Scenario

NO_x (ug/m^3) = (0.0239 ug/m^3)*(1456 lb/hr/79.36508 lb/hr)*(1000 hrs/8760 hrs)

= 0.050 ug/m^3

PM-10 24-hr, 1988 Winter Scenario

PM-10 (ug/m^3) = (0.289 ug/m^3)*(208 lb/hr/79.36508 lb/hr)

= 0.76 ug/m^3

Duke Energy - St. Lucie   100% Oil Load

Summer Scenario   Conversion Factors

Averages	1987	1988	1989	1990	1991
Annual	0.0267	0.0273	0.0289	0.0305	0.0313
24-hr	0.322	0.317	0.319	0.332	0.356
8-hr	0.850	0.777	0.763	0.730	0.730
3-hr	1.318	1.331	1.257	1.228	1.892
1-hr	2.614	2.547	3.070	3.504	3.629

Average Scenario   Conversion Factors

Averages	1987	1988	1989	1990	1991
Annual	0.0252	0.0258	0.0273	0.0288	0.0295
24-hr	0.311	0.306	0.308	0.319	0.334
8-hr	0.808	0.750	0.732	0.700	0.705
3-hr	1.267	1.278	1.242	1.179	1.879
1-hr	2.593	2.526	3.050	3.483	3.399

Winter Scenario   Conversion Factors

Averages	1987	1988	1989	1990	1991
Annual	0.0231	0.0239	0.0252	0.0262	0.0270
24-hr	0.296	0.289	0.291	0.299	0.302
8-hr	0.747	0.709	0.688	0.656	0.660
3-hr	1.195	1.199	1.222	1.106	1.224
1-hr	2.561	2.494	3.020	2.883	3.083