Department of Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

May 10, 2001

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. Mark J. Hornick
General Manager
Tampa Electric Company / Polk Power Station
P.O. Box 111
Tampa, Florida 33601-0111

Re: DEP File No. PSD-FL-194F
Polk Power Station
Unit 1 SCR Installation

Dear Mr. Hornick:

The Department is in receipt of your "Notice of Waiver of 90-Day Period" which was dated May 1. As indicated in our meeting of April 3rd, the Department has determined that the application was complete as of February 15th. Information received after this date has not been requested by the Department, but rather it has been offered by you, the applicant, as additional (late) information. The Department believes that ample information exists at this time to allow the issuance of the Draft BACT Determination.

Enclosed is one copy of the Draft PSD Permit Modification and Draft BACT Determination for the referenced project at the Polk Power Station located at 9995 State Route 37 South, Mulberry, Polk County. The Department's Intent to Issue PSD Permit Modification and the "PUBLIC NOTICE OF INTENT TO ISSUE PSD PERMIT MODIFICATION" are also included.

The "PUBLIC NOTICE OF INTENT TO ISSUE PSD PERMIT MODIFICATION" has been submitted by the Department for publishing in a newspaper of general circulation in the area affected, pursuant to Chapter 50, Florida Statutes.

Please submit any written comments you wish to have considered concerning the Department's proposed action to A. A. Linero, P.E., Administrator, New Source Review Section or me at the above letterhead address. If you have any questions, you may also call Michael Halpin, P.E. at 850/921-9519.

Sincerely,

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

CHF/mph

Enclosures

"More Protection, Less Process"

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. Mark J. Hornick
General Manager
Polk Power Station
Tampa Electric Company
P.O. Box 111
Tampa, Florida 33601-0111

COMPLETE THIS SECTION ON DELIVERY

A. Received by *(Please Print Clearly)* MAY 17 2001 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)*
7099 3400 0000 1453 1934

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

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

7099 3400 0000 1453 1934

Article Sent To:

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

Postmark Here

Mr. Mark J. Hornick
General Manager
Polk Power Station
Tampa Electric Company
P.O. Box 111
Tampa, Florida 33601-0111

See Reverse for Instructions

TAMPA ELECTRIC

May 1, 2001

RECEIVED

MAY 02 2001

BUREAU OF AIR REGULATION

Mr. Clair Fancy
Florida Department of Environmental Protection
2600 Blair Stone Road
Twin Towers Office Building
Tallahassee, Florida 32399-2400

Via FedEx
Airbill No. 7909 2896 9447

Re: Tampa Electric Company (TEC) - Polk Power Station
Unit 1 NO_x BACT Determination
Notice of Waiver of 90-Day Period
FDEP Permit No. 1050233-001-AV

Dear Mr. Fancy:

With respect to the above referenced NO_x BACT Determination, Tampa Electric Company (the Company) is hereby granting a waiver of the 90-day period in which the Florida Department of Environmental Protection (Department) is required to act on a permit pursuant to Section 120.60(1), Florida Statutes. This waiver is granted to allow the Company to submit additional relevant information regarding this project, and will extend the period for Department action to and including July 1, 2001.

Please let me know if you have any questions. You can contact Shannon Todd or me at (813) 641-5125.

Sincerely,

Mark J. Hornick

Mark J. Hornick
General Manager
Polk Power Station

EP\gm\SKT251

c: Mr. Al Linero - FDEP
Mr. Jerry Kissel - FDEP SW

In the Matter of an
Application for Permit by:

Mr. Mark J. Hornick
General Manager, Polk Power Station
Tampa Electric Company
P.O. Box 111
Tampa, Florida 33601-0111

Facility I.D. No. 0530233
DEP Permit No. PSD-FL-194F
Polk Power Station
Polk County

______________________________/

INTENT TO ISSUE PSD PERMIT MODIFICATION

The Department of Environmental Protection (Department) gives notice of its intent to issue a permit modification under the requirements for the Prevention of Significant Deterioration of Air Quality (copy of Draft PSD Permit Modification attached) for the proposed project, detailed in the application specified above, for the reasons stated below.

In accordance with the conditions of the existing PSD permit, a determination of Best Available Control Technology (BACT) for Nitrogen Oxides (NO_X) was required to be completed following a pre-defined "demonstration period". The permit condition reads as follows: "*One month after the test period ends (estimated to be by June 1, 2001), the Permittee will submit to the Department a NO_X recommended BACT Determination as if it were a new source using the data gathered on this facility, other similar facilities and the manufacturer's research. The Department will make a determination on the BACT for NO_X only and adjust the NO_X emission limits accordingly.*" The Department has determined that the demonstration (test) period ended during November 2000. Based upon the Department's evaluation, PPS Unit 1 will be required to install an SCR unit in order to control NO_X emissions from the IGCC unit as per the conditions outlined in the draft permit modification. The facility is located at 9995 State Route 37 South, Mulberry, Polk County.

The Department has permitting jurisdiction under the provisions of Chapter 403, Florida Statutes (F.S.), and Florida Administrative Code (F.A.C.) Chapters 62-4, 62-210, and 62-212. The above actions are not exempt from permitting procedures. The Department has determined that a permit under the provisions for the Prevention of Significant Deterioration (PSD) of Air Quality is required for the proposed work.

The Department intends to issue this PSD permit modification based on the belief that reasonable assurances have been provided 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. and 40 CFR 52.21.

Pursuant to Section 403.815, F.S., and Rule 62-110.106(7)(a)1., F.A.C., the Department will publish the enclosed ""Public Notice of Intent to Issue PSD 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. 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.

The Department will issue the final permit modification 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 concerning the proposed permit issuance action for a period of 14 (fourteen) days from the date of publication of "Public Notice of Intent to Issue PSD Permit Modification". Written comments 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 of the Florida Statutes. The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department at 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 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) of the Florida Statutes must be filed within fourteen days of publication of the public notice or within fourteen days of receipt of this notice of intent, whichever occurs first. Under section 120.60(3), however, any person who asked the Department for notice of agency action may file a petition within fourteen 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 of the Florida Administrative Code.

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, as well as the rules and statutes, which entitle the petitioner to relief; and (f) A demand for relief.

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

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. 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.

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

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this INTENT TO ISSUE PSD PERMIT MODIFICATION (including the PUBLIC NOTICE, Draft BACT Determination, and the DRAFT permit modification) was sent by certified mail (*) and copies were mailed by U.S. Mail before the close of business on 5/11/01 to the person(s) listed:

Mark J. Hornick, TEC*
Gregg Worley, EPA
John Bunyak, NPS
Bill Thomas, DEP SWD
Mr. Jeff Spence, Polk County ESD
Buck Oven, DEP PPSO
Thomas W. Davis, P.E, ECT

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.

Charlotte J Hayes 5/11/01
(Clerk) (Date)

PUBLIC NOTICE OF INTENT TO ISSUE PSD PERMIT MODIFICATION

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

DEP File No. 1050233-007-AC, PSD-FL-194F

TEC Polk Power Station
Polk County

The Department of Environmental Protection (Department) gives notice of its intent to issue a PSD permit modification for the TEC Polk Power Station (PPS) located in Polk County. The applicant's mailing address is: P.O. Box 111, Tampa, Florida 33601-0111. A Best Available Control Technology (BACT) Determination was required pursuant to Rule 62-212.400, F.A.C. and 40 CFR 52.21, Prevention of Significant Deterioration (PSD).

This is an existing facility consisting of an integrated gasification combined cycle (IGCC) unit, referred to as Unit 1. Major components of PPS Unit 1 include solid fuel handling and gasification systems, a sulfuric acid plant for processing of the solid fuel gasification system gas cleanup stream, an auxiliary boiler fired with No. 2 distillate fuel oil, and one integrated gasification combined cycle (IGCC) General Electric (GE) 7F combustion turbine (CT) fired with synthetic natural gas (syngas) or No. 2 distillate fuel oil. The unit is additionally authorized to burn syngas produced from the gasification of fuel blends of up to 60 percent petroleum coke. The unit has a PSD Permit (1050233-001-AC) issued by the State of Florida.

In accordance with the conditions of the PSD permit, a determination of Best Available Control Technology (BACT) for Nitrogen Oxides (NO_X) was required to be completed following a pre-defined "demonstration period". The permit condition reads as follows: "*One month after the test period ends (estimated to be by June 1, 2001), the Permittee will submit to the Department a NO_X recommended BACT Determination as if it were a new source using the data gathered on this facility, other similar facilities and the manufacturer's research. The Department will make a determination on the BACT for NO_X only and adjust the NO_X emission limits accordingly.*" The Department has determined that the demonstration (test) period ended during November 2000. Based upon the Department's evaluation, PPS Unit 1 will be required to install an SCR unit in order to control NO_X emissions from the IGCC unit as per the conditions outlined in the draft permit.

No annual increases of regulated pollutants will occur as a result of the modification and emissions of NO_X will be reduced.

The Department will issue the Final permit modification in accordance with the referenced draft permit 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 concerning the proposed permit issuance action for a period of 14 days from the date of publication of this Public Notice of Intent to Issue PSD Permit Modification. Written comments 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 of the Florida Statutes. The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department at 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 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) of the

Florida Statutes must be filed within fourteen days of publication of the public notice or within fourteen days of receipt of this notice of intent, whichever occurs first. Under section 120.60(3), however, any person who asked the Department for notice of agency action may file a petition within fourteen 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 of the Florida Administrative Code.

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

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	Department Environmental Protection	Polk County Environmental Services
Bureau of Air Regulation	Southwest District Office	Natural Resources & Drainage Division
Suite 4, 111 S. Magnolia Drive	3804 Coconut Palm Drive	4177 Ben Durrance Road
Tallahassee, Florida, 32301	Tampa, Florida 33619-8218	Bartow, Florida 33830
Telephone: 850/488-0114	Telephone: 813/744-6100	Telephone: 941/534-7377
Fax: 850/922-6979	Fax: 813/744-6084	Fax: 941/534-7374

The complete project file includes the information submitted by the responsible official, exclusive of confidential records under Section 403.111, F.S. Interested persons may contact the Administrator, New Source Review Section, or the Department's reviewing engineer for this project, at 111 South Magnolia Drive, Suite 4, Tallahassee, Florida 32301, or call 850/488-0114, for additional information.

PERMITTEE

Tampa Electric Company
Post Office Box 111
Tampa, Florida 33601-0111

Authorized Representative:
Mark J. Hornick, General Manager
Polk Power Station

DEP File No. 1050233-007-AC
Permit No. PSD-FL-194F
Unit No. 1 SCR Installation
SIC No. 4911
Expires: July 31, 2003

PROJECT AND LOCATION

Modified permit to require the installation of an SCR unit for Unit No. 1.

The unit is located at the Polk Power Station, 9895 State Road 37 South, Mulberry, Polk County. The UTM coordinates are Zone 17, 402.45 km E and 3067.35 km N.

STATEMENT OF BASIS

This 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.). The above named permittee is authorized to modify the facility in accordance with the conditions of this permit and as described in the application, approved drawings, plans, and other documents on file with the Department of Environmental Protection (Department).

ATTACHED APPENDICES MADE A PART OF THIS PERMIT

Appendix BD-2001	BACT Determination for NO_X dated 05/xx/01
Appendix GC	Construction Permit General Conditions

Howard L. Rhodes, Director
Division of Air Resources Management

FACILITY DESCRIPTION

Tampa Electric Company (TEC) Polk Power Station (PPS) Unit 1 located in Polk County, Florida is a nominal 260-megawatt (MW) electric generation facility. Major components of PPS Unit 1 include solid fuel handling and gasification systems, a sulfuric acid plant for processing of the solid fuel gasification system gas cleanup stream, an auxiliary boiler fired with No. 2 distillate fuel oil, and one integrated gasification combined cycle (IGCC) General Electric (GE) 7F combustion turbine (CT) fired with synthetic natural gas (syngas) or No. 2 distillate fuel oil, and fitted with an SCR unit. The unit is additionally authorized to burn syngas produced from the gasification of fuel blends of up to 60 percent petroleum coke.

REGULATORY CLASSIFICATION

This facility, TEC Polk Power Station, is classified as a Major or Title V Source of air pollution because emissions of at least one regulated air pollutant, such as particulate matter (PM/PM_{10}), sulfur dioxide (SO_2), nitrogen oxides (NO_X), carbon monoxide (CO), or volatile organic compounds (VOC) exceeds 100 tons per year (TPY).

This facility is within an industry included in the list of the 28 Major Facility Categories per Table 62-212.400-1, F.A.C. Because emissions are greater than 100 TPY for at least one criteria pollutant, the facility is also a Major Facility with respect to Rule 62-212.400, Prevention of Significant Deterioration (PSD).

PERMIT SCHEDULE

- 05/xx/01 Department published the Public Notice in the Tampa Tribune.
- 05/10/01 Department distributed initial Intent to Issue Permit.
- 02/15/01 Department received additional information; application deemed complete.
- 12/04/00 Department requested additional information.
- 11/17/00 Department received applicant's BACT submittal

RELEVANT DOCUMENTS

The documents listed below are the basis of the permit. They are specifically related to this permitting action. These documents are on file with the Department.

- Application received on November 17, 2000;
- Department's incompleteness letter dated December 4, 2000;
- TEC's response to Department's incompleteness letter received on February 15, 2001;
- Draft BACT Determination issued by the Department dated May 10, 2001
- Department's Intent to Issue and Public Notice Package dated May 10, 2001 and
- Permits PSD-FL-194, PSD-FL-194B, PSD- FL-194C, PSD-FL-194D and PSD-FL-194E

PERMIT SPECIFIC CONDITIONS

This permit addresses the following emissions unit:

E.U. ID No.	Brief Description
-001	Integrated Gasification Combined Cycle Unit No. 1

1. The provisions of the Title V Operating Permit 1050233-001-AV remain in effect. However, an application shall be submitted to revise that permit upon completion of construction and satisfactory emissions performance testing of the Unit 1 SCR.

2. The provisions of air construction permits PSD-FL-194, PSD-FL-194A, PSD-FL-194C, PSD-FL-194D and PSD-FL-194E are incorporated into this air construction permit except for the changes that follow in Specific Conditions F, H, J and M below.

   F. Fuel Consumption

   Solid fuels input to the solid fuel gasification plant shall consist of coal or coal/petroleum coke blends containing a maximum of 60.0 percent petroleum coke by weight. The maximum input of solid fuels to the solid fuel gasification plant shall not exceed 2,325 tons per day, on a dry basis. The maximum weight of the petroleum coke blended shall not exceed 1,395 tons per day, on a dry basis. The maximum sulfur content of the blended fuel shall not exceed 3.5 percent by weight.

   H. Emission Limits

   1. **EMISSIONS LIMITATIONS - 7F CT POST DEMONSTRATION PERIOD**

POLLUTANT	FUEL	BASIS$_a$	LB/HR*	TPY$_b$
NO_X	Oil	9 ppmvd***	74.1	32.5
	Syngas	5 ppmvd***	44.1	206.6
VOC[c]	Oil	0.028	32 lb/MMBtu	N/A
	Syngas	0.0017	3 lb/MMBtu	38.5
CO	Oil	40 ppmvd	99	N/A
	Syngas	25 ppmvd	98	430.1
PM/PM_{10}[d]	Oil	0.009 lb/MMBtu	17	N/A
	Syngas	0.013 lb/MMBtu	17	74.5
Pb	Oil	5.30E-5 lb/MMBtu	0.101	N/A
	Syngas	2.41E-6 lb/MMBtu	0.0035	0.067
SO_2	Oil	0.048 lb/MMBtu	92.2	N/A
	Syngas	0.17 lb/MMBtu	357	1563.7
V.E.	Syngas	10 percent opacity		
	Oil	20 percent opacity.		

(*) Emission limitations in lbs/hr are 30-day rolling averages, except for NO_X, which is limited in ppmvd (at 15% oxygen) and complied with on a 24-hour block average via CEMS. Pollutant emission rates may vary depending on ambient conditions and the CT characteristics. ~~Manufacturer's curves for the emission rate correction to other temperatures at different loads shall be provided to DEP for review 120 days after the Siting Board approval of the site certification.~~ Subject to approval by the Department, the manufacturer's curves may be used to establish pollutant emission rates over a range of temperatures for the purpose of compliance determination.

~~(**) The emission limit for NO_x is adjusted as follows for higher fuel-bound nitrogen contents up to a maximum of 0.030 percent by weight:~~

~~FUEL-BOUND NITROGEN (% by weight)~~	~~NO_x EMISSION LEVELS (ppmvd @ 15% 0_2)~~
~~0.015 or less~~	~~42~~
~~0.020~~	~~44~~
~~0.025~~	~~46~~
~~0.030~~	~~48~~

~~using the formula STD = 0.0042 + F where:~~

~~STD = allowable NO_x emissions (% by volume at 15% 0_2 and on a dry basis).~~

~~F = NOx emission allowance for FBN defined by the following table:~~

~~FUEL BOUND NITROGEN (% by weight)~~	~~F (NOx % by volume)~~
~~0 < N < 0.015~~	~~0~~
~~015 < N < 0.03~~	~~0.04 (N-0.015)~~

~~N = nitrogen content of the fuel (% by weight).~~

~~NOx emissions are preliminary for the fuel oil specified in Condition XIII.C. The Permittee shall submit fuel bound nitrogen content data for the low sulfur fuel oil prior to commercial operation to the Bureau of Air Regulation in Tallahassee, and on each occasion that fuel oil is transferred to the storage tanks from any other source to the Southwest District office in Tampa. The percent FBN (Z) following each delivery of fuel shall be determined by the following equation:~~

~~x(Y) + m(n) = (x+m) (Z)~~
~~where x = amount fuel in storage tank~~
~~y = % FBN in storage tank~~
~~m = amount fuel added~~
~~n = % FBN of fuel added~~
~~Z = % FBN of composite~~

(***) Ammonia slip emission limitations of 5 ppmvd at SCR exit apply.

5. After the demonstration period and prior to the commissioning of the SCR unit, permittee shall operate the combustion turbine to achieve the lowest possible NO_X emission limit but shall not exceed 25 ppmvd corrected to 15 percent oxygen and ISO conditions. In the event that the SCR is required to be temporarily removed from service, it shall comply with the availability requirements specified in Specific Condition H.8. During this period of time, NO_X emissions from EU-001 shall be limited to 25 ppmvd (syngas) and 42 ppmvd (oil).

8. The installation of an SCR is required within 18 months of the date of issuance of this permit modification. It shall be designed and installed in order to ensure that EU-001 complies with all emission limits specified herein. The availability of the SCR shall be at least 98% as measured on a 12 month rolling average. Availability shall be computed each calendar month based upon the hours of operation during which EU-001 is complying with the specified NO_X emission limits (identified in Table H.1. as 5 ppmvd while firing syngas and 9 ppmvd while firing oil), divided by the hours of operation during which EU-001 is combusting any fuel. Each monthly calculation shall be averaged with the same calculation, which was determined during the prior eleven calendar months of operation. Periods where EU-001 combusts no fuel shall be excluded within the 12 month rolling average. Up to 2 hours in any 24-hour period may be excluded from this average for initial CT firing (i.e. firings of the CT while the steam turbine is off line) as required for startup of the combined cycle unit and placement of the SCR in service.

J. Performance Testing

1. l. The owner or operator shall determine compliance with the ammonia slip limit (of 5 ppmvd) using CTM-027, while simultaneously demonstrating annual compliance with the NO_X emission limit as per Specific Condition J.1.e. The ammonia test and analyses shall be conducted so that the minimum detection limit is 1 ppmvd (I, A)

M. Notification, Reporting, and Recordkeeping

To determine compliance with the syngas and fuel oil firing heat input limitation, the permittee shall maintain daily records of syngas and fuel oil consumption for the turbine and heating value for each fuel. All records shall be maintained for a minimum of five years after the date of each record and shall be made available to representatives of the Department upon request.

Daily records of all hourly NO_X emissions shall be maintained for a minimum of five years. These records may be maintained electronically in a manner, which shall be approved by the Department. Each monthly calculation of the SCR 12-month rolling average availability shall be submitted to the Department annually with the submittal of the AOR, in addition to being available on site at the Department's request.

Documentation verifying that the coal/petroleum coke blends input to the solid fuel gasification system have not exceeded the 60.0 percent (1,395 tons per day) maximum petroleum coke by weight limit and the blended fuel sulfur content of 3.5 percent by weight limit specified by Specific Condition F, shall be maintained and submitted to the Department's Southwest District Office with each annual report.

The permittee shall maintain and submit to the Department, on an annual basis for a period of five years from the date the unit begin firing syngas produced from blends of petroleum coke and coal, data demonstrating that the operational change associated with the use of petroleum coke did not result in a significant emission increase pursuant to 62-210.200(12)(d), F.A.C.

APPENDIX BD - 2001

BEST AVAILABLE CONTROL TECHNOLOGY DETERMINATION (BACT) FOR NO_X

Tampa Electric Company
Polk Power Station
PSD-FL-194 and PA92-32
Polk County, Florida

BACKGROUND

The applicant, Tampa Electric Company (TEC) is responsible for the operation of an existing facility known as the Polk Power Station. This facility is located at 9995 State Route 37 South, Mulberry, Polk County; UTM Coordinates: Zone 17, 402.45 km East and 3067.35 km North; Latitude: 27° 43' 43" North and Longitude: 81° 59' 23" West. The regulated emissions units at the coal gasification facility include a 260 megawatt (electric) combined cycle combustion turbine which fires syngas or No. 2 fuel oil; an auxiliary boiler which fires No. 2 fuel oil; a sulfuric acid plant; a solid fuel handling system; and a solid fuel gasification system.

As per the original PSD permit, (as well as the Site Certification and Title V permit) the combined cycle combustion turbine is now required to undergo a BACT analysis for NO_X only. Specific Condition **H.7.** of the Site Certification document reads as follows: "*One month after the test period ends (estimated to be by June 1, 2001), the Permittee will submit to the Department a NO_X recommended BACT Determination as if it were a new source using the data gathered on this facility, other similar facilities and the manufacturer's research. The Department will make a determination on the BACT for NO_X only and adjust the NO_X emission limits accordingly.*" Based upon existing permit conditions, the test period ended during November 2000.

BACT ANALYSIS:

A BACT analysis was prepared by the applicant's consultant, Environmental Consulting & Technology, Inc. (ECT) and received by the Department on November 27, 2000. The proposal is summarized below:

POLLUTANT	CONTROL TECHNOLOGY	BACT PROPOSAL
NO_X	Syngas firing - N_2 diluent	25 ppmvd @ 15% O_2
	Distillate oil firing – water injection	42 ppmvd @ 15% O_2

This proposal would allow the current (temporary) emission limit to become the BACT determined limit, i.e. would require no major change to the facility configuration.

BACT DETERMINATION PROCEDURE:

In accordance with Chapter 62-212, F.A.C., this BACT determination is based on the maximum degree of reduction of each pollutant emitted which the Department of Environmental Protection (Department), on a case by case basis, taking into account energy, environmental and economic impacts, and other costs, determines is achievable through application of production processes and available methods, systems, and techniques. In addition, the regulations state that, in making the BACT determination, the Department shall give consideration to:

- Any Environmental Protection Agency determination of BACT pursuant to Section 169, and any emission limitation contained in 40 CFR Part 60 - Standards of Performance for New Stationary Sources or 40 CFR Part 61 - National Emission Standards for Hazardous Air Pollutants.

- All scientific, engineering, and technical material and other information available to the Department.
- The emission limiting standards or BACT determination of any other state.
- The social and economic impact of the application of such technology.

The EPA currently stresses that BACT should be determined using the "top-down" approach. The first step in this approach is to determine, for the emission unit in question, the most stringent control available for a similar or identical emission unit or emission unit category. If it is shown that this level of control is technically or economically unfeasible for the emission unit in question, then the next most stringent level of control is determined and similarly evaluated. This process continues until the BACT level under consideration cannot be eliminated by any substantial or unique technical, environmental, or economic objections. Since SIP approval has not been given (by the EPA) to Florida for power plants which are subject to the Power Plant Siting Act (PPSA), the Florida Department of Environmental Protection (FDEP) is acting on behalf of the EPA.

STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES:

The minimum basis for a BACT determination is 40 CFR 60, Subpart GG, Standards of Performance for Stationary Gas Turbines (NSPS). The Department adopted subpart GG by reference in Rule 62-204.800, F.A.C. The key emission limits required by Subpart GG are 75 ppmvd NO_X @ 15% O_2. (assuming 25 percent efficiency) and 150 ppmvd SO_2 @ 15% O_2 (or <0.8% sulfur in fuel). Although this BACT determination is required for NO_X only, the applicant's proposal is consistent with the NSPS, which allows NO_X emissions in the range of 110 ppmvd for the unit.

DETERMINATIONS BY EPA AND STATES:

The following table is a sample of information on some recent determinations by states for combined cycle stationary gas turbine projects. This particular review has been limited to gas turbines in the United States which are permitted to combust coal or pet-coke produced syngas. The application of an SCR with a 3.5 ppmvd emission limit represents the typical BACT determination for pipeline natural gas fired combined cycle CT's. Additionally, the application of SCR with an emission limit of 0.125 lb/MMBtu has been determined to represent BACT for a (conventional) Florida coal-fired unit. The applicant's proposed BACT is included for reference.

TABLE 1

RECENT LIMITS FOR NITROGEN OXIDES FOR LARGE STATIONARY GAS TURBINE COMBINED CYCLE PROJECTS WHICH COMBUST SYNGAS

Project Location	Power Output Megawatts	NO_X Emission Rate	Gasification Technology	Comments
Pinon Pine; Sierra Pacific, NV	100	0.07 lb/MMBtu	KRW air-blown pressurized fluidized bed	95% SO_2 removal
Wabash River; Terre Haute, IN	262	0.096 lb/MMBtu	Destec two-stage pressurized oxygen-blown entrained flow	
Kentucky Pioneer **(proposed)**	580	0.07 lb/MMBtu	British Gas / Lurgi slagging fixed bed	99% SO_2 removal
Motiva; Delaware City, DE	240	16 ppmvd	Texaco pressurized oxygen-blown entrained-flow	
TECO POLK; Polk County FL)	260	25 ppmvd (equiv. 0.126 lb/MMBtu)	Texaco pressurized oxygen-blown entrained-flow	96% SO_2 removal

IGCC PLANT INFORMATION:

Many portions of this discussion are extracted from a paper prepared by Jürgen Karg and Günther Haupt, representing Siemens AG Power Generation. The main Features of an Oxygen-Blown Integrated-Gasification Combined Cycle (IGCC) plant are:

1) a gasification plant including preparation of the feedstock
2) raw gas heat recovery systems
3) a gas purification system with sulfur recovery
4) an air separation unit (only for oxygen-blown gasification)
5) a gas turbine-generator with heat-recovery steam generator
6) a steam turbine-generator

The gasifier feedstock is more or less completely gasified to so-called synthesis gas (syngas) with the addition of steam and either enriched oxygen or air. The known fixed-bed, fluidized-bed and entrained-flow gasifiers for coal are basically suited to integration in the combined cycle, as well as the well-proven entrained-flow systems for refinery residues. The selection of a specific gasifier type to achieve the best cost, efficiency and emission levels depends on the type of fuel and the particular application and must be investigated on a case-by-case basis.

In most gasifier systems applied to coal, the sensible heat of the hot raw gas is used in a syngas cooler to generate steam for the steam turbine. In some cases, considerable amounts of steam are generated in this way. This also cools the gas sufficiently that it can be led directly to the gas purification system. An alternative, primarily applied to the gasification of residues, is direct water quench for cooling the produced hot raw gas.

Dust, soot and heavy metal removal are key issues of the initial raw gas purification downstream of syngas cooler and quench system, respectively. Subsequently, chemical pollutants such as H_2S, COS, HCl, HF, NH_3 and HCN are removed, along with the remaining dust. The separated H_2S-rich gas stream, known as acid gas, is processed to recover saleable elemental sulfur. Downstream of the gas purification system, the clean gas is reheated, saturated with water if necessary (NO_X reduction) and supplied to the gas turbine combustion chamber. In this way, low-level heat can be used and gas turbine mass flow is increased. The air separation unit (ASU) generates the more or less enriched oxygen supply necessary for the gasification process. The inevitably (co-produced) nitrogen from the ASU is preferably used in the gas turbine cycle (e.g. diluent injection), and, in case of coal, smaller amounts for transportation of the solid fuels to the gasifier and for inerting purposes.

In addition to air for the combustion chambers, the compressor of the gas turbine-generator also supplies all or part of the air for the ASU. Nitrogen from the air separation unit is mixed with the purified gas to prevent temperature peaks in the low-NOx burners, and to increase the mass flow rate (including MW output) in the gas turbine. In the case of air-blown gasification, the extracted air is supplied directly to the gasifier following additional compression.

The hot exhaust gases from the gas turbine generate steam for the steam turbine in an unfired heat-recovery steam generator before they are discharged via the stack. The steam turbine is supplied with steam from the gas turbine heat-recovery steam generator (HRSG).

TEXACO GASIFIER INFORMATION:

Much of this information was obtained from a paper presented by William Preston of Texaco in October, 2000. The Texaco Gasification Process (TGP) is utilized for the conversion of heavy oils, petroleum coke, and other heavy petroleum streams, to valuable products. According to Texaco, in the year 2000, the commercial acceptance of the technology for the production of power, hydrogen, ammonia, and other chemicals reached a record number of startups and capacity additions. In all, twelve new commercial TGP plants were or will be started up in six countries. The feedstocks for these plants include coal, petroleum coke, natural gas, and a wide variety of low-valued heavy oil streams. The total syngas production capacity from these new projects totals 1375 million standard cubic feet per day, increasing the total operating capacity of the TGP around the world by more than fifty percent.

As noted, in the calendar year 2000, twelve projects using the TGP will (or did) startup. These break down geographically as follows: In Asia, two projects are in China, and two are in Singapore. In Europe, three projects are in Italy, and one is in Germany. Three projects are in the U. S., and the twelfth project is in Australia. Eight of the projects are fed by some type of heavy oil, three by coal or petroleum coke, and one by natural gas. Power and steam are the main products of five of the projects. Three of the projects mainly produce ammonia, two produce syngas for sale to a merchant chemicals market, one produces methanol and one produces hydrogen. In all, 1375 million standard cubic feet per day (MMscfd) of new syngas capacity will be added to the previously operating 2100 MMscfd capacity of TGP generated syngas worldwide. The eight new oil fed projects generate 1083 MMscfd, or 79%, of this syngas. Solid feeds such as coal or petroleum coke generate 262 MMscfd, or 19%. The remaining 2% is generated by a natural gas fed TGP unit.

The twelve TGP projects scheduled for year 2000 startups are listed below with pertinent information:

NAME	COUNTRY	OUTPUT	THRU-PUT	FEEDSTOCK
ISAB	Italy	500 MW	3174 sTPD	Deasphalter bottoms from the ISAB Sicily refinery in Priolo Gargallo, Siracusa
API	Italy	250 MW	1470 sTPD	Visbreaker residue from the API refinery in Falconara
Saras (Sarlux)	Italy	250 MW	3771 sTPD	Visbreaker residue from the Saras refinery in Sarroch, Cagliari.
DEA	Germany	methanol	600 sTPD	Heavy oil from the DEA refinery in Wesseling, Germany
Huainan	P.R. China	ammonia	990 sTPD	Coal
Nanjing	P.R. China	ammonia	850 sTPD	Heavy Oil
SSPL	Singapore	syngas	630 sTPD	Heavy Oil from local Caltex refinery
Exxon	Singapore	160 MW	1019 sTPD	Steam cracker tar
BOC	Australia	hydrogen	15 MMscfd	Natural gas
Baytown	USA (La.)	syngas	1213 sTPD	Deasphalter bottoms from the adjacent Exxon Mobil refinery
Farmland	USA (Kan.)	ammonia	1084 sTPD	Petcoke from Coffeyville refinery
Motiva	USA (Del.)	180	2300 sTPD	Petcoke from adjacent refinery

In addition to the above, Repsol and Iberdrola are planning to construct an IGCC facility in Spain, which will be based upon the Texaco gasifier with vacuum column residue feedstock. The planned 2004 startup of the 1654 MW (thermal) facility will represent the largest single generating facility based upon the TGP.

COMBUSTION TURBINE INFORMATION:

The combustion turbine utilized at the Polk Power Station is a General Electric 107FA. As a result, the Department has elected to incorporate pertinent portions of GE published information relative to their combustion turbine experience in the area of gasified fuels.

As of June 1998, General Electric had 10 units in operation on synthesis gas from the gasification of coal, petroleum coke and other low-grade fuels. According to GE, an additional twelve units for gasification applications were on order, or already shipped, with startup dates ranging from 1999 through 2001. These turbines include the full range of the GE products: one PGTIOB, one Frame 7E, two Frame 7FA's, five Frame 6B's six Frame 6FA's, six Frame 9E's, and one 9FA.

The IGCC projects include various levels of integration with the gasification plant, ranging from steamside integration only on many projects, to nitrogen return (Tampa, Motiva), and full steam and air integration including both air extraction and nitrogen return (El Dorado, Pinon Pine). GE turbines are in operation on syngas from gasifier technologies by Texaco (solid fuels and oil), Destec (coal), GSP (coal and waste), Shell (oil), and operation with the Lurgi gasifier (biomass) is scheduled for operation in 2001.

In addition to synthesis gas applications, GE also has numerous turbines in operation on other special fuel gases, including refinery gases containing hydrogen, butane, propane, ethane, and blends of various process gases. These units include six Frame 3's, seventeen Frame 5's, 19 Frame 6's, and 15 Frame 7EA's.

The table below summarizes these applications, and is followed by a brief description of each project.

TABLE 2 - THE FOLLOWING IGCC POWER PLANTS ARE OPERATING, UNDER CONSTRUCTION OR ON ORDER:

Project	Location	COD	MW	Power Block	Fuel
Cool Water IGCC	Barstow, California	1984	120	107E	Coal
PSI Wabash River	Terre Haute, Indiana	1996	262	7FA	Coal
Tampa Electric	Polk, Florida	1996	250	107FA	Coal
Pinon Pine	Sparks, Nevada	1996	100	106FA	Coal
Texaco El Dorado	El Dorado, Kansas	1996	40	6B	Pet Coke
ILVA ISE	Taranto, Italy	1996	520	3xI09E	BFG/COG
SvZ	Schwarze Pumpe, Germany	1996	40	6B	Coal/Waste
Shell Pernis	Pemis, Netherlands	1997	120	206B	Oil
Fife Energy	Fife, Scotland	1999	109	106FA	Coal/Waste
Motiva Enterprises	Delaware City, Delaware	1999	180	2-6FA	Pet Coke
Sarlux	Sarroch, Italy	2000	550	3x109E	Oil
Fife Electric	Fife, Scotland	2000	350	109FA	Coal/Waste
Exxon Singapore	Jurong Island, Singapore	2000	173	2-6FA	Oil
IBIL Sanghai	Gujarat, India	2001	53	106B	Coal
Bioelettrica TEF	Cascina, Italy	2001	12	PGT10B/CC	Wood/Waste

Cool Water
The Cool Water Coal Gasification Program was the first commercial demonstration of integrated coal gasification combined cycle power generation. The gasification island included a 1200-ton per day, oxygen-blown Texaco gasifier with full heat recovery using both radiant and convective syngas coolers.
Wabash River (PSI)
The Wabash River Coal Gasification Repowering Project is a joint project between the U.S. Department of Energy and a Joint Venture formed in 1990 between Destec Energy Inc. and Public Service of Indiana (PSI). The gasification island includes a Destec two-stage, oxygen blown gasifier including full heat recovery steam integration with the power island.
Tampa Electric
The Tampa Electric Co. Polk Power coal gasification project is partially funded by the U.S. Department of Energy, and includes a Texaco oxygen blown gasifier with full heat recovery using both radiant and convective syngas coolers. Process syngas, steam, and nitrogen are integrated with the GE STAG-107FA power block.
Pinon Pine
The Pinon Pine Power Project - Undertaken by Sierra Pacific Power Company at its Tracy station in Sparks, Nevada, with support from the U.S. Department of Energy, includes a KRW air-blown fluidized bed gasifier with hot gas cleanup. Air extraction from the GE 6FA gas turbine is integrated with the process island to produce high temperature low Btu syngas for the 100 MW combined cycle power block.
Texaco El Dorado
The El Dorado gasification facility, developed by Texaco Alternative Energy Inc., is fully commercial without government subsidies. The project incorporates a Texaco oxygen blown quench type gasifier fired on a mixture of petroleum coke (approx. 166 tpd), and about 15 tpd of waste streams provided from the Texaco refinery site in El Dorado, Kansas. A 35 MW GE MS6001B gas turbine is co-fired with syngas and natural gas to meet the refinery's total internal power needs.
ILVA- ISE
The ILVA Sistemi Energia (ISE) cogeneration project is located at the ILVA steelworks in Taranto, Italy. Three GE 109E combined cycle units operate on a variable mixture of compressed steel mill recovery gases (coke oven gas, blast furnace gas, and LD furnace gas), which normally combine to an equivalent low heating value fuel (140 Btu/scf-LHV). The combined facility output is 520 MW, with 150 tons/hr of steam feed to the steel mill. Each gas turbine generator unit is directly coupled to a centrifugal fuel gas compressor in a single shaft lineup with a separate steam turbine generator unit.
Schwarze Pumpe
The Sekundarrohstoff-Verwertungszentrum Schwarze Pumpe GmbH (SVZ) is a waste utilization facility, established and privatized in 1995. The facility contains seven fixed bed gasifiers, which gasify a mixture of waste combustibles with the help of oxygen and hydrogen. The synthesis gases from these facilities are used for methanol production and to fuel a combined cycle plant built around a MS6001B gas turbine provided by Thomassen under GE license. The turbine also combusts purge gas from the methanol plant and operates on distillate as backup and startup fuel.
Shell Pernis
The PER+ project is an upgrade of the existing Shell Pernis refinery. A new hydrocracker unit was added for the conversion of heavy, high-sulfur crudes into light low-sulfur fuels. Hydrogen required for the conversion process is supplied by the Shell Gasification Hydrogen Process plant, which gasifies heavy residues with oxygen and water to yield syngas. Most of the hydrogen is then removed to feed the hydrocracker, and the depleted syngas is then used as fuel in a combined cycle cogeneration facility. The syngas is blended with LPG and/or natural gas when the heating value in combination with the amount of

the syngas is insufficient for the desired load of the turbines. The turbines can also fire 100% natural gas, which is used for startup and as backup fuel.

Fife Energy

Global Energy Inc., as owner of the Westfield Development Center in Fife, Scotland is developing a new Advanced Fuel Technology (AFT)-IGCC power project (Fife Energy), at an existing gasification test facility. The 109 MW GE 106FA combined cycle power block is fueled by syngas produced from the oxygen-blown British Gas/Lurgi staging gasifier and natural gas. A wide variety of organic waste feedstocks including MSW and MSP, which can be mixed with petroleum coke or coal, are compressed into briquettes that are gasified under pressure to produce a medium Btu syngas.

Motiva Enterprises

The Motiva IGCC project is a cogeneration project located at the Star refinery at Delaware City, Delaware. This gasification system incorporates the Texaco oxygen-blown high-pressure quench process design, using petroleum coke from the refinery as feedstock. The 180 MW net power block output is produced from two GE 6FA gas turbine units operating on syngas, with nitrogen return for NO_X control. Power production services the internal IGCC loads, with surplus power being sold into the Delmarva utility system.

Sarlux

The Sarlux IGCC project company will own and operate a 550 MW cogeneration project to be sited at the Saras oil refinery located in Sarroch Italy, on the island of Sardinia. Three Texaco oxygen blown low-pressure quench gasifiers are used to produce a dry medium Btu syngas from vacuum visbroken residue (tar) feedstock, for the co-production of power and hydrogen. Three GE 109E single-shaft combined cycle units each gross 186 MW of power on moisturized syngas at 77F, and provide 285-tons/hr total process steam to the refinery.

Fife Electric

Global Energy Inc., is expanding their Environmental Energy Park at the Westfield site to include another Advanced Fuel Technology-IGCC project called Fife Electric, which will provide an additional 350 MW to the facility. Power block will be fueled by a mixture of natural gas and syngas produced from additional new oxygen-blown British Gas/Lurgi slagging gasifiers. The combined cycle plant co-fires a mixture of dry syngas, nitrogen, and natural gas, and uses steam injection for NO_X control.

Exxon Singapore

The Exxon Singapore IGCC project uses the Texaco oil-gasification process as part of a major expansion program for the existing refinery, to produces syngas feeding two GE 6FA gas turbines coupled with single-pressure supplementary-fired HRSGs. When natural gas becomes available at the site, the units will be converted to use natural gas for startup, co-firing, and backup fuel operation. The gas turbines will normally be fired on a combination of the backup fuel and syngas, and the amount of syngas will vary depending on the hydrogen demand of the refinery.

IBIL Sanghi

The project is based on the air blown pressurized fluidized bed gasification of lignite, with hot gas cleanup, and a GE 106B combined cycle system. Air supply to the gasifier is first extracted from the gas turbine and increased in pressure using a boost compressor. Raw product gas is cooled after the cyclone separator by a fire tube heat recovery boiler producing high-pressure steam for use in the steam turbine.

Bioelettrica (TEF)

This is a biomass IGCC project initiated by the European Commission in 1994. This net 12.1 MW project incorporates a Lurgi atmospheric, air blown circulating, fluidized-bed (CFB) gasifier, integrated with a Nuovo Pignone PGTIOB single-shaft, heavy-duty gas turbine. Fuel supply to the gasifier is a combination of short rotation forestry (SRF) wood, and agricultural and forestry residues.

OTHER INFORMATION AVAILABLE TO THE DEPARTMENT:

Besides the initial information submitted by the applicant, the summary above, and the references at the end of this document, some of the key information reviewed by the Department includes:

- Noell SCR Training Manual for OUC Stanton Energy Center Unit 2
- "Improved SCR Control to Reduce Ammonia Slip", K. Zammit (EPRI), A. Engelmeyer (OUC) 2000
- Letters from EPA Region IV dated February 2, and November 8, 1999 regarding KUA Cane Island 3
- Polk Power Station reports to DOE (various)
- Pinon Pine reports to DOE (various)
- Wabash River reports to DOE (various)
- E & A Associates report on the application of zinc titanium pellets for coal gasifiers
- Technical reports (several) concerning coal gasification, prepared by Dr. H. Christopher Frey, Associate Professor, North Carolina State University
- Study reviewing a Texaco based IGCC power plant (published in U.K.)
- "Repowering Conventional Coal Plants with Texaco Gasification", Cynthia Caputo, Paul Wallace and Leslie Bazzoon
- Review of Claus process prepared for the USEPA
- "Status of IGCC" Adapted from a paper presented by Lowe, Benyon, and O'Neill, dated January 1998
- 1999 EPRI Gasification Technologies Conference
- "A Membrane Reactor for H_2S Decomposition", D. Edlund
- "Phillips Sorbent Development for Tampa Electric...", Phillips Petroleum Company
- "Development of Disposable Sorbents for Chloride Removal from High Temperature Coal-Derived Gases"; SRI, Research Triangle and GE
- "Wabash River Coal Gasification Repowering Project", E.J. Troxclair and Jack Stultz
- "Clean Coal Technology Evaluation Guide – Final Report", December 1999, DOE
- "Microbial Sweetening of Low Quality Sour natural Gas", Charanjit Rai, Texas A & M University
- "Technical Guidance – Oil and Gas Processes", published by U.K. Environment Agency
- BACT proposal prepared for Kentucky Pioneer Energy
- Mitsubishi Documentation on SCR applications
- Alternative Control Techniques Document - NO_X Emissions from Stationary Gas Turbines
- General Electric 39th Turbine State-of-the-Art Technology Seminar Proceedings
- GE Guarantee for Jacksonville Electric Authority Kennedy Plant Project
- "Oil & Gas Journal", several issues.
- TNRCC NOx Rule Log No. 2000-011H-117

BEST AVAILABLE CONTROL TECHNOLOGY DETERMINATION (BACT) FOR NO_X

REVIEW OF NITROGEN OXIDES CONTROL TECHNOLOGIES:

Some of the discussion in this section is based on a 1993 EPA document on Alternative Control Techniques for NO_X Emissions from Stationary Gas Turbines. Project-specific information is included where applicable.

Nitrogen Oxides Formation

Nitrogen oxides form in the gas turbine combustion process as a result of the dissociation of molecular nitrogen and oxygen to their atomic forms and subsequent recombination into seven different oxides of nitrogen. Thermal NO_X forms in the high temperature area of the gas turbine combustor. Thermal NO_X increases exponentially with increases in flame temperature and linearly with increases in residence time. Flame temperature is dependent upon the ratio of fuel burned in a flame to the amount of fuel that consumes all of the available oxygen.

By maintaining a low fuel ratio (lean combustion), the flame temperature will be lower, thus reducing the potential for NO_X formation. Prompt NO_X is formed in the proximity of the flame front as intermediate combustion products. The contribution of Prompt to overall NO_X is relatively small in near-stoichiometric combustors and increases for leaner fuel mixtures. This provides a practical limit for NO_X control by lean combustion. Fuel NO_X is formed when fuels containing bound nitrogen are burned.

Uncontrolled emissions range from about 100 to over 600 parts per million by volume, dry, corrected to 15 percent oxygen (ppmvd @15% O_2). The Department estimates uncontrolled emissions as high as 200 ppmvd @15% O_2 for the subject TEC combustion turbine. The proposed NO_X control (diluent injection) reduces these emissions significantly.

NO_X Control Techniques

Diluent Injection

Water, steam (or in this case nitrogen) is injected into the primary combustion zone to reduce the flame temperature, resulting in lower NO_X emissions. Water injected into this zone acts as a heat sink by absorbing heat necessary to vaporize the water and raise the temperature of the vaporized water to the temperature of the exhaust gas stream. Nitrogen and steam injection use the same principle, excluding the heat required to vaporize the water. Therefore, much more diluent is required (on a mass basis) than water to achieve the same level of NO_X control (e.g. approximately 6000 TPD at this facility). However, there is a physical limit to the amount of any diluent that may be injected before flame instability or cold spots in the combustion zone would cause adverse operating conditions for the combustion turbine. Advanced combustor designs with injection can achieve NO_X emissions of 25/42 ppmvd for gas/oil firing, resulting in 60% to 80% control efficiencies. This is the technology recommended by the applicant.

Combustion Controls

The U.S. Department of Energy has provided millions of dollars of funding to a number of combustion turbine manufacturers to develop inherently lower pollutant-emitting units. Efforts over the last ten years have focused on reducing the peak flame temperature for natural gas fired units by staging combustors and premixing fuel with air prior to combustion in the primary zone. Typically, this occurs in four distinct modes: primary, lean-lean, secondary, and premix. In the primary mode, fuel is supplied only to the primary nozzles to ignite, accelerate, and operate the unit over a range of low- to mid-loads and up to a set combustion reference temperature. Once the first combustion reference temperature is reached, operation in the lean-lean mode begins when fuel is also introduced to the secondary nozzles to achieve the second combustion reference temperature. After the second combustion reference temperature is reached, operation in the secondary mode begins by shutting off fuel to the primary nozzle and extinguishing the flame in the primary zone. Finally, in the premix mode, fuel is reintroduced to the primary zone for premixing fuel and air. Although fuel is supplied to both the primary and secondary nozzles in the premix mode, there is only flame in the secondary stage. The premix mode of operation occurs at loads between 50% and 100% of base load and provides the lowest NO_X emissions. Due to the intricate air and fuel staging necessary for dry low-NO_X combustor technology, the gas turbine control system becomes a very important component of the overall system. DLN systems result in control efficiencies of 80% to 95%.

Selective Catalytic Reduction

Selective catalytic reduction (SCR) is an add-on NO_X control technology that is employed in the exhaust stream following the gas turbine. SCR reduces NO_X emissions by injecting ammonia into the flue gas in the presence of a catalyst. Ammonia reacts with NO_X in the presence of a catalyst and excess oxygen yielding molecular nitrogen and water. The catalysts used in combined cycle, low temperature applications (conventional SCR), are usually vanadium or titanium oxide and account for almost all installations. For high temperature applications (Hot SCR up to 1100 °F), such as simple cycle turbines, zeolite catalysts are available but used in few applications to-date outside of California. SCR units are typically used in combination with diluent injection or DLN combustion controls.

In the past, sulfur was found to poison the catalyst material. Sulfur-resistant catalyst materials are now becoming commonplace and have recently been specified for CPV Gulf Coast (PSD-FL-300). In that review, the Department determined that SCR was cost effective for reducing NO_X emissions from 9 ppmvd to 3.5 ppmvd on a General Electric 7FA unit burning natural gas in combined cycle mode. This review additionally concluded that the unit would be capable of combusting 0.05%S diesel fuel oil for up to 30 days per year while emitting 10 ppmvd of NO_X. Catalyst formulation improvements have proven effective in resisting sulfur-induced performance degradation with fuel oil in Europe and Japan. These newer catalysts (versus the older alumina-based catalysts) are resistant to sulfur fouling at temperatures below 770°F (EPRI). In fact, Mitsubishi reports that as of 1998, SCR's were installed on 61 boilers which combust residual oil (40 of which are utility boilers) and another 70 industrial boilers, which fire diesel oil. Likewise, B & W reports satisfactory results with the installation of SCR to several large Taiwan Power Company utility boilers, which fire a wide range of coals, as well as heavy fuel oil with sulfur contents up to 2.0% and 50 ppm vanadium. Catalyst life in excess of 4 to 6 years has been achieved, while 8 to 10 years catalyst life has been reported with natural gas.

As of early 1992, over 100 gas turbine installations already used SCR in the United States. Only one combustion turbine project in Florida (FPC Hines Power Block 1) currently employs SCR. The equipment was installed on a temporary basis because Westinghouse had not yet demonstrated emissions as low as 12 ppmvd by DLN technology at the time the units were to start up in 1998. Seminole Electric will install SCR on a previously permitted 501F unit at the Hardee Unit 3 project and Kissimmee Utility Authority will install SCR on newly permitted Cane Island Unit 3. New combined cycle combustion turbine projects in Florida are normally considered to be prime candidates for SCR and today are routinely permitted as such (as noted on page 2).

Figure B is a photograph of FPC Hines Energy Complex. The magnitude of the installation can be appreciated from the relative size compared with nearby individuals and vehicles. Figure C below is a diagram of a HRSG including an SCR reactor with honeycomb catalyst and the ammonia injection grid. The SCR system lies between low and high-pressure steam systems, where the temperature requirements for conventional SCR can be met.

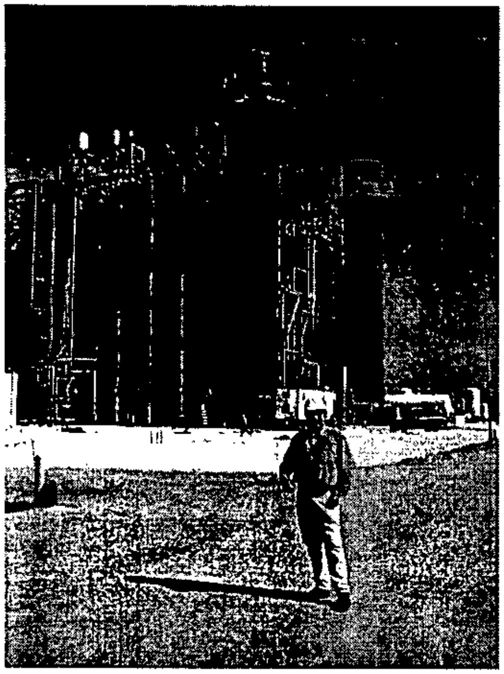


Figure B

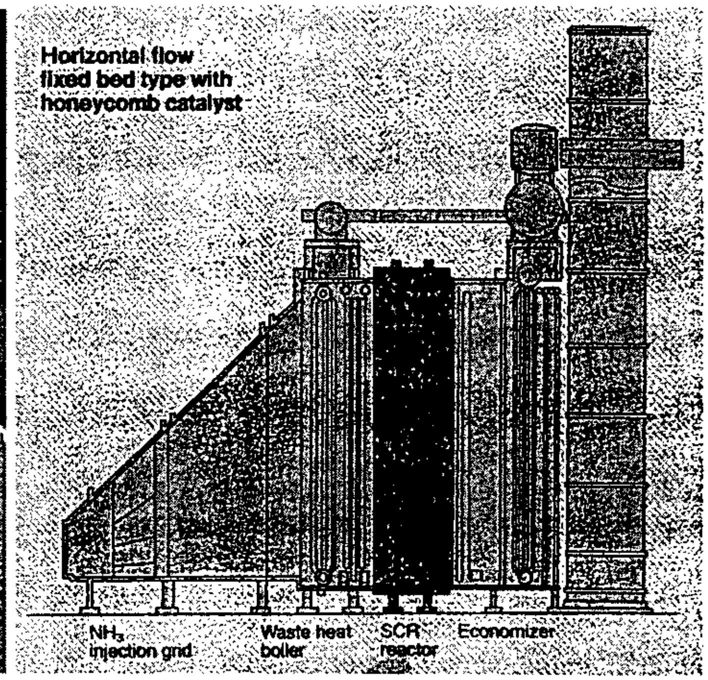


Figure C

Permit limits as low as 2 to 3.5 ppmvd NO_X have been specified using SCR on combined cycle F Class projects throughout the country. Permit BACT limits of 3.5 ppmvd NO_X are being routinely specified using SCR for F Class projects (with large in-line duct burners) in the Southeast and even lower limits in the southwest. This technology will be further reviewed for this specific application.

Selective Non-Catalytic Reduction

Selective non-catalytic reduction (SNCR) reduction works on the same principal as SCR. The differences are that it is applicable to hotter streams than conventional SCR, no catalyst is required, and urea can be used as a source of ammonia. Certain manufacturers, such as Engelhard, market an SNCR for NO_X control within the temperature ranges for which this project will operate (700 – 1400°F). The process also requires a low oxygen content in the exhaust stream in order to be effective. Although SNCR may be applicable for this project, a top-down review requires a further evaluation of more stringent technologies.

Emerging Technologies: SCONOx™ and XONON™

SCONOx™ is a catalytic technology that achieves NO_X control by oxidizing and then absorbing the pollutant onto a honeycomb structure coated with potassium carbonate. The pollutant is then released as harmless molecular nitrogen during a regeneration cycle that requires dilute hydrogen gas. The technology has been demonstrated on small units in California and has been purchased for a small source in Massachusetts. California regulators and industry sources have permitted the La Paloma Plant near Bakersfield for the installation of one 250 MW block with SCONOx ™. The overall project includes several more 250 MW blocks with SCR for control. According to industry sources, the installation has proceeded with a standard SCR due to schedule constraints. Recently, PG&E has been approved to install SCONOx™ on two F frame units at Otay Mesa, approximately 15 miles S.E. of San Diego, California. Additionally, USEPA has identified an "achieved in practice" BACT value of 2.0 ppmvd over a three-hour rolling average based upon the recent performance of a Vernon, California natural gas-fired 32 MW combined cycle turbine (without duct burners) equipped with the patented SCONOx™ system.

SCONOx™ technology (at 2.0 ppmvd) is considered to represent LAER in non-attainment areas where cost is not a factor in setting an emission limit. It competes with less-expensive SCR in those areas, but has the advantages that it does not cause ammonia emissions in exchange for NO_X reduction. Advantages of the SCONOx ™ process include (in addition to the reduction of NO_X) the elimination of ammonia and the control of VOC and CO emissions. SCONOx™ has not been applied on any major sources in ozone attainment areas, apparently only due to cost considerations. The Department is interested in seeing this technology implemented in Florida and intends to continue to work with applicants seeking an opportunity to demonstrate ammonia-free emissions on a large unit. The applicant estimates that the application of this control technology to the Polk Power Station results in cost-effectiveness of $10,820 per ton of NO_X removed. Although there are specific items within the applicant's analysis that the Department does not support, on balance the Department concurs with the conclusion that $SCONO_X$ is likely not cost-effective for this project. However, given the applicant's concerns for ammonia bisulfate formation (see pages that follow) the Department believes that it may very well be an appropriate control technology for this application and is not opposed to reconsidering the cost effectiveness, given the opportunity.

Catalytica Combustion Systems, Inc. develops, manufactures and markets the XONON™ Combustion System. XONON™, which works by partially burning fuel in a low temperature pre-combustor and completing the combustion in a catalytic combustor. The overall result is low temperature partial combustion (and thus lower NO_X combustion) followed by flameless catalytic combustion to further attenuate NO_X formation. The technology has been demonstrated on combustors on the same order of size as SCONOx™ has. XONON™ avoids the emissions of ammonia and the need to generate hydrogen. It is also extremely attractive from a mechanical point of view.

On February 8, 2001, Catalytica Energy Systems, Inc. announced that its XONON™ Cool Combustion system had successfully completed an evaluation process by the U.S. Environmental Protection Agency (EPA), which verified the ultra-low emissions performance of a XONON™-equipped gas turbine operating at Silicon Valley Power. The performance results gathered through the EPA's Environmental Technology Verification (ETV) Program provide high-quality, third party confirmation of XONON™ 's ability to deliver a near-zero emissions solution for gas turbine power production. The verification, which was conducted over a two-day period on a XONON™-equipped Kawasaki M1A-13A (1.4 MW) gas turbine operating at Silicon Valley Power, recorded nitrogen oxides (NO_X) emissions of less than 2.5 parts per million (ppm) and ultra-low emissions of carbon monoxide and unburned hydrocarbons.

The XONON™-equipped Kawasaki M1A-13A gas turbine has operated for over 7400 hours at Silicon Valley Power (SVP), a municipally owned utility, supplying essentially pollution-free power to the residents of the City of Santa Clara, California, with NO_X levels averaging under 2.5 ppm. Enron Energy Services North America, Kawasaki and Catalytica recently signed contracts for the installation of three XONON™-equipped 1.4MW Kawasaki GPB15X gas turbines in Massachusetts, at a healthcare facility of a U.S. Government agency. These turbines will enter service in late 2001.

In a definitive agreement signed on November 19, 1998, GE Power Systems and Catalytica agreed to cooperate in the design, application, and commercialization of XONON™ systems for both new and installed GE E and F-class turbines used in power generation and mechanical drive applications. This appears to be an up-and-coming technology, the development of which will be watched closely by the Department for future applications. However, the technology cannot (at this time) be recommended for the attendant project.

PLANT SPECIFIC ANALYSIS

Based upon the information presented thus far, an initial BACT determination for a new IGCC facility would likely result in either the application of an SCR or the imposition of a NO_X emission rate between 0.07 lb/MMBtu and 0.096 lb/MMBtu (approximately 14 ppmvd and 19 ppmvd respectively). Either of these outcomes is more stringent than what the applicant had proposed. The following arguments have been made by the applicant in support of its conclusion to reject the use of an SCR on this project.

Applicant Comment: Although EPA has established BACT for NO_X emissions on combined cycle combustion turbines as 3.5 ppmvd, Polk Unit 1 fires syngas. The fuel differences are adequately significant to consider Polk as a separate and unique facility.

Department Response: A review of the estimated differences for SCR inlet streams follows (based upon one 1760 MMBtu/hr turbine). Shaded areas represent those parameters where syngas emissions appear to be an area of possible concern for the application of an SCR when compared to other fuels:

Pollutant	Syngas [a]	Natural gas [b,c]	Refinery Gas [f]	#2 Fuel Oil [b,d]	Coal [e]
SO_2 – lb/MMBtu	0.032 – 0.146	0.0006	0.029 – 3.31	0.051	3.5
H_2S, SO_2 or SO_3	40 ppm SO_2	< 4 ppmvd H_2S	< 200 ppmvd H_2S		25 ppmvd SO_3 [g]
Trace metal	**10^6 lb/MMBtu**	**10^6 lb/MMBtu**	**10^6 lb/MMBtu**	**10^6 lb/MMBtu**	**10^6 lb/MMBtu**
Arsenic	6.0	0.20	0.85	11	16
Beryllium	0.60	0.012	0.257	0.31	0.81
Cadmium	5.0	1.1	0.99	4.8	2.0
Chromium	1.1	1.4	2.17	11	10
Cobalt	12	0.08	ND	ND	3.8
Lead	10	ND	4.89	14	16
Manganese	4.0	0.37	6.81	790	19
Mercury	0.70	0.25	0.18	1.2	3.2
Nickel	310	2.1	9.42	52	11
Selenium	1.4	0.024	0.012	ND	50

a Emission factors from Kentucky Pioneer PSD permit application; sulfur compounds obtained from TEC publications and Acid Rain website
b Emission factors from AP-42, Section 3.1
c Trace Metal emission factors from AP-42, Section 1.4
d Sulfur Factor was multiplied by sulfur wt% in fuel (0.05); Nickel emission factor from MEMORANDUM: HAP Emission Control Technology for New Stationary Combustion Turbines
e Factors from AP-42 Section 1.1: PC, dry-bottom, tangentially fired, sub-bituminous, pre-NSPS and from DOE Conference on SCR, May 1997
f Factors from CARB report dated August 14, 1998; SO_2 and H_2S factors from reports by the European Environment Agency;
g Obtained from OUC Stanton Energy Center; not a fuel quality, but represents SO_3 design-basis at SCR inlet

The Department finds that fuel differences do exist, yet predominantly in the area of nickel and (perhaps) cobalt. However, SCR has been applied to coal facilities (Indiantown Cogeneration and Orlando Utilities Stanton Energy Center) as well as to the combustion of refinery gas where BAAQMD has set SCR as BACT (re: Tosco Refining Co., Wilmington, CA; Mobil Oil refinery, Torrance, CA; Scanraff refinery, Lysekil Sweden, and at least 7 Japanese refineries). In fact, an IGCC facility with SCR is currently proposed at a Polish refinery (Gdansk) with a varied feedstock of oils and refinery resids. It is noteworthy that BP Amoco is sponsoring a project to investigate next generation LNB technology, as SCR is one of the few control technologies that can reduce refinery NO_X emissions to levels required in the Houston-Galveston area. This review suggests that the application of an SCR cannot be rejected purely on technical grounds. This has been confirmed (and reconfirmed at the Department's request) by the ability of TEC to obtain performance guarantees from at least one manufacturer (Engelhard).

Applicant Comment: Other collateral environmental impacts should be considered for this installation when performing a BACT evaluation. Draft guidance from John S. Seitz, director of the Office of Air Quality Planning and Standards dated August 4, 2000 allows for the consideration of collateral environmental impacts associated with the use of SCR on dry low NO_X natural gas fired combined cycle combustion turbines. Although Polk Unit 1 is a syngas fired combined cycle combustion turbine utilizing multinozzle quiet combustors, TEC feels that collateral environmental impacts should also be considered for this installation when performing a BACT evaluation. Several parties have commented on this draft guidance including the Department of Energy (DOE) and the Utility Air Regulatory Group (UARG). In an enclosed written opinion, DOE supports the draft guidance noting that, among other things, the establishment of the use of SCR as BACT for natural gas fired combined cycle facilities will:

1) Slow research and development of efficiency and performance improvement in advanced combustion turbines;
2) Slow the development of other non-ammonia based NO_X control technologies; and
3) Create a situation in which the units containing SCR become more expensive to operate, thus lowering their position in a system dispatch order and allowing dirtier plants to operate higher in the dispatch order. This will have the effect of increasing overall emissions despite the use of SCR on an already relatively clean unit.

Integrated Gasification Combined Cycle (IGCC) Technology is still in the early stages of development and provides a mechanism for the combustion of coal while minimizing air emissions. In fact, Polk Unit 1 was constructed as part of the Department of Energy's Clean Coal Technology program. If SCR is established as BACT for Polk Unit 1, it could impact the further development of this technology. Furthermore, if SCR becomes BACT for this type of installation, it could slow the development of further advances in combustion technology for clean coal facilities such as Polk Unit 1 by increasing the cost of an already high cost technology. In addition, although SCR has never been applied to a domestic IGCC facility, there is no evidence or operating experience that indicates that the application of SCR to an IGCC facility can be successfully accomplished as described in Section 8 of the BACT Analysis. If this occurs, Tampa Electric Company could be forced to operate other coal fired units in lieu of Polk Unit 1, resulting in an actual overall increase in NO_X emissions in the Tampa Bay area.

Department Response: Concerning the draft guidance and related comments, the Department offers no review within this BACT determination. However, in response to those issues raised in the final paragraph (which are specific to Polk), the Department has the following responses.

(1) Under the presumption that the application of SCR to the Polk Station offers no technical issues beyond those encountered at other facilities, added cost would have the most likely potential to impact the development of IGCC technology. To evaluate the cost impacts that would result from the installation of SCR as BACT, the Department will utilize TEC's estimated costs minus the "annual electrical loss penalty", which the Department believes is inappropriate.
Capital Cost impact: Approximately 1.5% ($4.5M as compared to $303M)
Production Cost impact: < 3.0% (4.58 cents/kWh as compared to 4.46 cents/kWh)
Although these are not insignificant, the Department believes that the increases are not likely to represent a major impediment in the further deployment of the technology.

(2) TEC suggests that the application of an SCR may result in it being forced to operate other coal-fired units in lieu of Polk 1, causing an overall increase in NO_X emissions in the Tampa Bay area. Although the Department's analysis does not support this conclusion, the most likely cause of this occurrence would seem to be SCR-induced, unscheduled shutdowns. In order to accommodate TEC's concern, the permit conditions will be structured to allow for this type of unexpected problem.

Applicant Comment: It is extremely important to draw the distinction between a natural gas fired combustion turbine and a syngas fired combustion turbine when applying the EPA determination; as the fuels are completely different. While natural gas is mainly composed of methane and almost completely free of sulfur and sulfur containing compounds, syngas is mostly composed of hydrogen and carbon monoxide, and also contains some carbonyl sulfide as well as hydrogen sulfide. Upon combustion, these sulfur-containing compounds are oxidized to form SO_2, and upon passage through an SCR system, most of the SO_2 is further oxidized to SO_3. When combined with water and the excess ammonia required by the SCR system for optimal NO_X removal, the sulfur oxides in the exhaust gas form ammonium bisulfate and ammonium sulfate. According to a paper authored by General Electric (within the TEC submittal), these compounds are responsible for plugging in the HRSG, tube fouling, and increased emissions of PM.

Department Response: Although these concerns are understandable, they are the similar in nature to past concerns related to coal firing. During the mid-1990's, DOE sponsored testing such as "Demonstration of SCR Technology for the Control of NO_X Emissions from High-Sulfur Coal-fired Utility Boilers" for the combustion of coals with sulfur contents ranging from 2.5 – 3.0%. Currently, the actual field use of SCR's for high-sulfur coal has been able to show that with a careful examination of catalyst characteristics suited to the specific application, the technology may be properly applied. In fact, with respect to catalyst SO_2 oxidation, W.S. Hinton & Associates have concluded that in practice, all SCR suppliers would likely be able to meet a customer's specific SO_2 oxidation requirements.

Given that an SCR supplier has proposed guarantees for this project, there is little reason for the Department to question the ability of the equipment to reduce NO_X to a limit of 3.5 ppmvd at the Polk Power Station. Of remaining concern is the applicant's contention (supported by a paper from General Electric) that the use of sulfur bearing fuels in conjunction with SCR may lead to fouling of downstream components such as the back passes (lower temperature regions) of the HRSG (walls and associated heat transfer surfaces). According to the GE paper, the cause of this is due to ammonium bisulfate formation, which is supported by the aforementioned DOE work as well as actual practice.

In order for ammonium bisulfate to form, excess ammonia (referred to as slip) must be present in conjunction with sulfur compounds. Minimization of NH_3 slip is also a major operational and design concern in the application of SCR to coal-fired boilers, as U.S. high-sulfur coal may form much more SO_3 in the boiler. The condensation of NH_4HSO_4 is a sticky, corrosive material that can cause corrosion problems. Factors that contribute to NH_4HSO_4 formation are the temperature, catalyst composition and the concentration of NH_3 and NO_X in the flue gas. The influence of temperature and catalyst composition is interdependent. The amount of SO_3 present is due to two factors: the amount formed in the boiler itself and the amount that formed by the catalytic oxidation of SO_2 to SO_3 in the SCR unit. Higher flue gas SO_2 content will likely cause more SO_2 to be converted to SO_3 in the SCR reactor, thereby aggravating the NH_4HSO_4 formation problems. Of course, if there is no ammonia slip, the compound may not form. According to the GE paper cited by TEC, "The only effective way to limit the formation ammonia salts appears to be to limit the sulfur content of the fuel to very low levels (or switch to a sulfur free fuel such as butane) and/or limit the excess ammonia available to react with the sulfur oxides." The paper additionally suggests that "Limiting the ammonia that is available to react with the sulfur oxides to negligible levels does not appear practical at NO_X removal efficiencies above 80%...(but) may work at lower NO_X removal efficiencies". Since Mitsubishi reports that SCR's are in use on 40 utility boilers firing residual oil (with average sulfur content > 1%), the latter GE recommendation appears more logical for Polk Power Station. In consideration of these concerns, the Department will restrict the ammonia slip to < 5ppm, and set the NO_X emission limit at 80% removal (5 ppmvd syngas and 9 ppmvd oil).

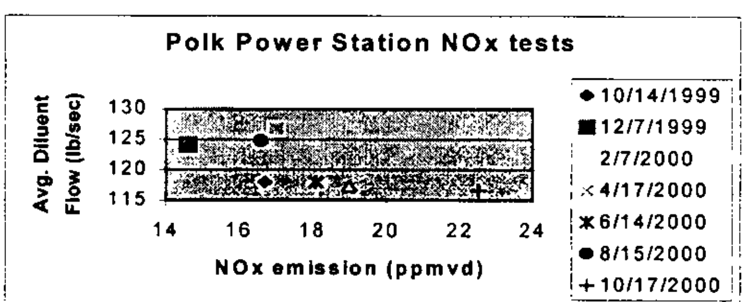
Applicant Comment: The cost to control NO_X emissions through the use of an SCR system on Polk Unit 1 presented in the analysis submitted to FDEP was based on a limited number of estimated costs. Since SCR has not been required for any IGCC installation in the United States, it is not possible to compare the cost of installing an SCR at the Polk facility to the cost of installing an SCR at another IGCC facility. The conclusion that SCR must be applied to Polk Unit 1 simply because the cost of NO_X control is lower than what the cost of NO_X control might be at the CPV Gulf Coast facility does not seem to take into account environmental, energy, and other costs as prescribed in the definition of BACT. In addition, this conclusion does not seem to consider the operation of 'other similar facilities' or 'manufacturer's research' as called for in Specific Condition A.50 of the Polk Power Station Title V Permit.

Department Response: It does not seem unreasonable to review the cost of applying an SCR to TEC's Polk Unit 1 (an IGCC unit) as it compares to the cost of applying an SCR to a gas/oil fired combined cycle unit. In fact, such a review leads to an initial conclusion that there is little difference in these costs.

TEC has submitted an analysis concluding that the annualized cost of applying SCR to Polk Power Station is \$4,061,000. As mentioned earlier in this Determination of BACT, one line item within that analysis lists an annualized cost of \$1,934,400 for "Unscheduled Outages". According to the submittal, the majority of this figure (\$1,814,400) is attributable to replacement power costs of \$20/MWH for an assumed 12 days annually of unscheduled outages. Two similar line items exist (\$363,000 each) for lost power costs due to the pressure drop across the catalyst in a clean configuration and an additional cost for when the catalyst is assumed to be fouled. Although it is appropriate to calculate the costs of using additional natural gas to compensate for the power consumption resulting from pressure drops across the catalyst bed, lost revenue should not be included in the analysis and should be omitted. Since the basis of these costs was \$0.04/kwh, the Department presumes that each cost was developed based upon some measure of lost revenue and not increased natural gas costs. Accordingly, the Department will reject these line items, as inappropriate, which is consistent with EPA comments on previous analyses and in line with the Department's view in calculating cost effectiveness. The resulting annualized cost of applying SCR to Polk Unit 1 (\$1,520,600) yields a cost effectiveness of under \$2,000 per ton of NO_X removed. This is less than similar recent analyses submitted by other applicants for other projects (approximately \$2500/ton for OUC's Stanton new combined cycle unit and \$4,400/ton for JEA's Brandy Branch "repowering"). According to Polk Power Station's Title V permit (Specific Condition **A.50.**):

A.50. *One month after the test period ends (estimated to be by June 1, 2001), the permittee shall submit to the Department a NO_X recommended BACT Determination as if it were a new source, using the data gathered on this facility, other similar facilities and the manufacturer's research. The Department will make a determination of BACT for NO_X only and adjust the NO_X emission limits accordingly.*

Lastly then, an analysis of the data gathered from the facility is in order. Two sets of data exist: one which represents seven "full load tests" which were completed between October 1999 and October 2000, and the other is comprised of data from continuous emission monitoring systems (CEMS). Regarding the former, the data is represented on the chart below:



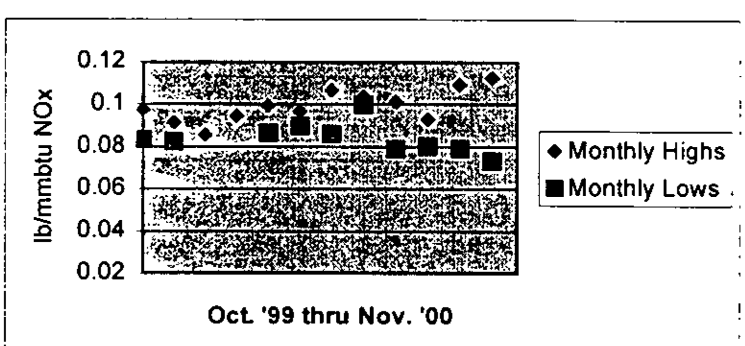
TEC has cautioned against an analysis of NO_X emissions as compared to diluent flow, noting that "*although the diluent flow is an important parameter for controlling NO_X emissions, a more appropriate measure is the ratio of diluent flow to syngas flow. On an overall basis, this ratio represents the proportional flows of NO_X controlling diluent and the syngas flow. Additional complicating factors that prevent a straightforward linear analysis of diluent flow rate or ratio and the NO_X emissions rate include the varying composition of the syngas, and the heating value of the fuel. Although these data are presented, TEC recommends against using these data to establish firm operating ranges due to the variability in other factors that significantly contribute to NO_X emissions from this combustion turbine.*" Since diluent flow will likely increase with generating load (up to some load point) and since syngas flow is directly proportional to unit load, it is likely that a measure of diluent flow to syngas flow (which the applicant purports is more appropriate) makes some sense, as in the case of reviewing the entire load range of a combustion turbine. However, the Department wishes to better understand the impact of diluent flow on NO_X emissions, given that the diluent is the control media for NO_X. Since the tests are at a similar load point, the syngas flow and its associated variability can be effectively ignored. This yields a chart similar to the one above, indicating some level of correlation (albeit with 7 data points) between the diluent flow and NO_X emissions. Given the very limited amount of tests, one initial conclusion which might be drawn is that NO_X emissions are likely to be less than 19 ppmvd if the diluent flow is held to 120 lb/sec or higher.

Regarding the latter set of data (from the CEMS), 14 months of data was reviewed, with the month of March 2000 ignored due to low operating time. In order to understand the range of data with respect to syngas NO_X emissions, only days where daily hours of operation firing syngas equaled 24 (all day) were analyzed. From this data set, the 5 highest and lowest daily average NO_X emission rates (in lb/MMBtu) were computed. This led to the chart below, with the lowest values during the months of December 1999 and January 2000 excluded due to calculated values around 0.01 lb/MMBtu. The following preliminary conclusions are drawn from this analysis:

1) There seems to be an increasing variability over the latter months, with highs increasing and lows decreasing.
2) The average of the monthly highs is just under 0.10 lb/MMBtu and the average of the monthly lows is just under 0.085 lb/MMBtu.
3) The facility should be able to easily comply with its current limit of 25 ppmvd (approximately 0.126 lb/MMBtu) and likely will operate closer to 0.09 lb/MMBtu (approximately 18 ppmvd) on a monthly average basis.

Each analysis of the facility data referred to herein suggests that a NO_X limit of 0.09 lb/MMBtu (approximately 18 ppmvd) via full load testing or monthly average would likely be reasonable (given that certain operational changes may be required), even if the Department had alternately concluded that more stringent controls should be rejected. Barring these operational changes, 25 ppmvd may be reasonable.

CEMS DATA



Additional SCR-related cost information received from the applicant after the application was complete:

As noted above, the application was received by the Department on November 27, 2000. Within the applicant's submittal was a cost analysis for the installation of an SCR, which included a vendor quote (Engelhard) dated October 25, 2000. The vendor quoted the SCR system cost at $1,738,000 with a three-year catalyst life guaranty, an expected life of 5-7 years and a 3.5 ppmvd NO_X output. TEC annualized the NO_X removal costs at $4660 per ton of NO_X removed, which is discussed in more detail above.

On December 4th, 2000 the Department requested additional information from TEC. Included within this request was a confirmation that Engelhard had provided a guarantee for the catalyst life at 3 years, and expected the catalyst life to be 5 to 7 years. Additionally, the Department stated that the application of an SCR (even with cost effectiveness costs as high as $6000 per ton) would "represent the Department's determination for this project, unless Tampa Electric Company can demonstrate to the Department's satisfaction (absent fuel quality issues) why this installation is significantly different". On February 15th, 2001 the Department received the requested information (which has been analyzed in the foregoing pages), including the requested Engelhard confirmation. The application was deemed complete that day.

On April 3rd, 2001 FDEP officials met with TEC officials at the request of the applicant. TEC indicated that the purpose of the meeting was to ensure that FDEP's questions were satisfactorily answered and to understand FDEP's intentions. At the prompting of TEC officials, FDEP indicated a *very preliminary* intention (pending the detailed review as required by a BACT Determination) to require SCR for the attendant project, although it may be at some control level above 3.5 ppmvd of NO_X. FDEP additionally noted that certain costs (such as replacement power) contained within the TEC cost analysis (see page 16 above) would likely be rejected, improving the cost effectiveness below the $4660/ ton value. At the meeting conclusion, TEC indicated a desire to provide additional submittals to the Department, and FDEP officials indicated that TEC was welcome to do so, however that no additional information was either requested or required by the Department in order to complete the BACT Determination. [Note: As can be seen herein, the Department had estimated that the annualized cost of an SCR was likely less than $2M].

On April 16th, 2001 FDEP received a voice-mail from the applicant indicating that TEC had contacted several catalyst vendors and expected responses by the week of April 23rd. TEC stated that they would be sending additional information to FDEP by the first week in May. No indication was provided as to the intent or the reasoning behind the forthcoming submittals. A follow-up phone call was received on April 24th at approximately 1:15 p.m., with the applicant indicating that the nature of the submittals was related to the applicant's concern over the formation of ammonia sulfates and that the information would be forthcoming soon. The applicant additionally inquired as to the Determination status, requesting to know whether the conclusion reached within the Department's BACT Determination (albeit unfinished) had changed in any way.

Although a draft BACT Determination would normally be issued well before day 74, the Department awaited the TEC submittal for several additional days. On May 2nd, 2001 (Day 76 on the DEP permit clock), the Department received a "Notice of Waiver of 90-Day Period" from TEC. This waiver was offered by the applicant as a means to allow more time for the additional information, which the applicant wished to submit. Inasmuch as this additional information was not requested by the Department in order to take action, the Department had no reason to accept TEC's waiver to be allowed until July 1st to submit the additional (unrequested) information.

EPA Comments regarding Kentucky Pioneer:

EPA commented adversely over Kentucky's Draft BACT Determination, which would authorize Kentucky Pioneer to emit NO_X at 15 ppmvd. TEC's submittal requests a BACT Determination at 25 ppmvd NO_X.

The best available control technology (BACT) question of most concern to us is BACT for the control of NO_x emissions from the combined cycle combustion turbines... The NO_x emission rates proposed as BACT for the combined cycle combustion turbines are an emission rate of 15 ppmvd (at 15% oxygen) when burning syngas and an emission rate of 25 ppmvd (at 15% oxygen) when burning natural gas (and a weighted average when burning both fuels simultaneously). All of the recent combined cycle combustion turbine projects throughout the U.S. that are known to us and that involve large natural gas-fired combustion turbines comparable in size to the Kentucky Pioneer Energy turbines have been permitted with a NO_x emission rate for natural gas combustion of 3.5 ppmvd or less to be achieved by a combination of combustor design and use of post-combustion controls. While we recognize that IGCC combustion turbines differ from standard natural gas-fired combined cycle combustion turbines, we are still concerned that the NO_x BACT levels proposed for Kentucky Pioneer Energy are four to seven times higher than the emission rates approved for all other recently permitted natural gas-fired combined cycle combustion turbines of comparable size.

EPA was not persuaded by Kentucky's argument that ammonia bisulfate salts would "cause serious plugging, loss of heat transfer and corrosion in the downstream portions of the heat recovery steam generator". What follows are selected EPA comments about this issue.

The sulfur content of syngas is much less than the sulfur content of post-combustion air streams in coal-fired boilers where SCR technology has been successfully applied despite initial concerns that the technology would not be feasible in the high-sulfur environment of such air streams

Most recent dual-fuel (natural gas and No. 2 fuel oil) combined cycle combustion turbine projects have been permitted to require use of SCR for NO_x control when burning fuel oil as well as when burning natural gas. The typical sulfur content of the fuel oil proposed for such projects is 0.05 percent by weight, which should yield exhaust gas sulfur compound concentrations comparable to those resulting from combustion of syngas.

Furthermore, in conventional SCR systems, proper operation of the ammonia feed system along with proper sizing and selection of the catalyst components can serve to minimize the amount of ammonia that slips through the SCR reaction zone. We recommend that the applicant or KDAQ investigate means of reducing residual ammonia before concluding that SCR is not a technically feasible option due to formation of ammonium bisulfate salts.

EPA did not accept the cost figures provided for the Kentucky project, which formed the basis of SCR being rejected at cost effectiveness values of $8516/ton or higher.

The preliminary determination and the original permit application contain two SCR cost evaluations, one based on a U.S. Environmental Protection Agency (EPA) publication (Alternative Control Techniques Document - NO_x Emissions from Stationary Gas Turbines, 1993) and one based on Engelhard vendor data with additional costs to allow for modifications of the HRSG to counteract the potential harmful effects of ammonium bisulfate salts. We have concerns about both evaluations.... The cost estimate ... appears to be based on a procedure in the 1993 EPA document cited above, a document that we have indicated is out of date.

The purchased equipment cost based on the Engelhard quote is a total of approximately $12,000,000 for both combustion turbines, or about $6,000,000 for each turbine. This cost is far higher than the typical equipment costs reported in other permit applications for F-class combustion turbines.

In summary, we have serious concerns about the cost evaluations for SCR. A further evaluation of costs coupled with use of a higher "uncontrolled" baseline emission rate is likely to show that the cost of SCR for the Kentucky Pioneer Energy combustion turbines is within the range of NO_x control costs considered acceptable for recent combined cycle combustion turbine projects involving combustion of conventional fuels.

It seems clear that EPA is not in agreement with the Draft BACT proposed by Kentucky. That Draft BACT rejects the application of an SCR for the proposed IGCC facility based upon costs. The excessive costs cited, find root in the applicant's concern that ammonia bisulfate formation will be a significant issue, which would affect the project. EPA does not accept the premise that ammonia bisulfate is a serious issue for the Kentucky project, nor do they accept the conclusion that SCR is not cost-effective, indicating a notion that the cost effectiveness is likely closer to that of a natural gas fired combined cycle unit.

Department analysis of related concerns as they may apply to TEC Polk:

A further review of concerns related to ammonia sulfate and ammonia bisulfate for this specific project follows. Much of the information presented is derived from published reports, which are itemized. From an October 1998 article in Pollution Engineering, written by Michael Sandell:

There is a concern about the use of SCR with high-sulfur fuels because sticky ammonium bisulfate can be deposited on the catalyst, air heater and other downstream surfaces. This compound is formed through the reaction of ammonia with SO_3, which in turn is formed primarily through the oxidation of SO_2 by the SCR catalyst. By minimizing ammonia slip and suppressing the oxidation of sulfur dioxide, the amount of ammonium bisulfate may be kept to a level that does not affect boiler operation. Ammonia slip, the emission of unreacted ammonia, is caused by the incomplete reaction of injected ammonia with NO_x present in the flue gas. A system designed to achieve good distribution and mixing of the injected ammonia with the flue gas, as well as proper catalyst sizing and selection, will ensure ammonia slip is controlled to levels low enough that effects on plant operation, ash properties and health will be insignificant.

From an article entitled "Properly Apply Selective Catalytic Reduction for NO_X Removal" authored by Dr. Soung M. Cho, January 1994 Chemical Engineering (note the specific references to industrial gas and low sulfur oil, which the author relates as being similar to natural gas):

...The other important reason for limiting the ammonia slip to a low value is to reduce the chances of forming ammonium sulfates in the presence of SO_3. Sulfur containing fuels produce SO_2 and a small quantity of SO_3. A small fraction of SO_2 is also converted to SO_3 by the SCR catalyst. When combined with excess ammonia and water vapor, SO_3 may form ammonium sulfates. Ammonium sulfate $(NH_4)_2SO_4$ is powdery and contributes to the quantity of particulates in the flue gas. Ammonium bisulfate NH_4HSO_4 is a sticky substance that can deposit in the catalyst layers and/or downstream equipment, causing flow blockage and equipment deterioration. Temperature is an extremely important factor in the formation of sulfates. The lower the temperature, the higher the probability of sulfate formation. When natural or industrial gas or low sulfur oil is used as the combustion fuel, the deteriorating effects discussed above are not likely to occur if the ammonia slip is limited to less than 10 ppm and the SO_3 concentration is less than 5 ppm (unless the gas temperature is very low).

From a March 1998 paper "Estimating Sulfuric Acid Aerosol Emissions from Coal-Fired Power Plants" authored by R. Hardman, R. Stacy (of Southern Company Services) and E. Dismukes (SRI):

...In the literature, varying and sometimes conflicting estimates exist regarding the conversion of SO_2 to SO_3. For example, in one publication the conversion rate is estimated to vary from 3 to 5 percent, from 1.25 to 5 percent, and from 1 to 4 percent, depending on the section of the book being read. In other reports, which focus on the performance of cold-side ESP's, the ratio of SO_2 to SO_3 at the air heater are presented. These ratios are lower since a portion of the SO_3 generated during the coal combustion process condenses onto the cold sections of the air heater baskets as the flue gas temperature drops. For example, in one evaluation average flue gas SO_3 concentrations dropped from 25 ppm to 11 ppm (56 percent) across a hot-side ESP and an air heater. Other reports (such as an EPA-documented SO_2 to SO_3 ratio of 0.4 percent) confirm these pilot scale results. The same EPA study reports that the SO_3 levels from six different power stations vary from undetectable levels to 0.67 percent of the SO_2 concentration. Other full-scale experimental results based on measurements during 16 field tests showed concentrations from 0.1 to 0.41 percent of the SO_2 levels. In both of these examples, the SO_3 concentrations when burning western coals were lower than the SO_3 concentrations when burning eastern coals. Laboratory results have confirmed the direct proportional relationship between the SO_2 to SO_3 conversion rate and the sulfur content of the fuel.

EPA's Acid Rain information system shows that typical flue gas SO_2 values for this emissions unit are less than 40 ppm. Therefore, according to the technical literature above, it is extremely likely that the amount of SO_3, which will be converted from the available SO_2, will be less than 2 ppm (5% of 40 ppm), and may very well be less than 1 ppm. This published information (referred to above) supports the conclusion that a well-designed ammonia injection system along with proper catalyst selection will minimize or eliminate concerns related to ammonia bisulfate formation, given a low ammonia slip level and low SO_3 values. It additionally supports EPA's comments on Kentucky: "*...proper operation of the ammonia feed system along with proper sizing and selection of the catalyst components can serve to minimize the amount of ammonia that slips through the SCR reaction zone. We recommend that the applicant or KDAQ investigate means of reducing residual ammonia before concluding that SCR is not a technically feasible option due to formation of ammonium bisulfate salts.*"

Accordingly, HRSG modifications and additional costs proposed for an IGCC project such as Polk are also deemed to be unwarranted costs and are rejected. The Department concludes that the cost effectiveness for installation of an SCR is less than $4,660 per ton and is within the range of reasonableness for prior natural gas combined cycle determinations. This value should be ample to ensure that the SCR will be designed with the proper catalyst sizing and selection, as well as to provide for an ammonia injection system capable of achieving good distribution and mixing of the injected ammonia, with a resulting low level of slip.

DEPARTMENT BACT DETERMINATION:

In summary, the application of SCR to the subject Polk generating unit *as if it were a new source* cannot be rejected based upon technical, economic, energy or environmental impacts. The determination that a control alternative is inappropriate involves a demonstration that unusual circumstances exist that distinguishes the source from other sources where the technology may have been required. The applicant has failed to meet this test. In this case, the Department has compensated for the shortage of IGCC specific data through a reasonable extrapolation of SCR and fuel data from utility units and refineries. Accordingly, SCR is deemed to be BACT. Following are the BACT limits determined for the Polk Power project for NO_X corrected to 15% O_2.

POLLUTANT	CONTROL TECHNOLOGY	BACT DETERMINATION
NO_X (syngas - all operating modes) NO_X (oil - all operating modes)	SCR	5.0 ppmvd (SCR) – 24 hour block average 9.0 ppmvd (SCR) – 24 hour block average 5 ppm ammonia slip at SCR outlet
POLLUTANT	**COMPLIANCE PROCEDURE**	
NO_X 24-hr block average	NO_X CEMS, O_2 or CO_2 diluent monitor, and flow device as needed	
NO_X (performance)	Annual Method 20 or 7E	
Ammonia Slip	CTM-027 initial and annual (The test and analyses shall be conducted so that the minimum detection limit is 1 ppmvd).	

DETAILS OF THE ANALYSIS MAY BE OBTAINED BY CONTACTING:

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