TAMPA ELECTRIC

RECEIVED

MAY 11 2001

BUREAU OF AIR REGULATION

May 10, 2001

Mr. Michael Halpin, P.E.
New Source Review Section
Florida Department of Environmental Protection
111 South Magnolia Avenue, Suite 4
Tallahassee, Florida 32301

Via Fed Ex
Airbill No. 7900 4812 1562

Re: Polk Power Station Unit 1
Syngas Fired Combustion Turbine NO_x BACT Determination

Dear Mr. Halpin:

Tampa Electric Company (TEC) would like to take this opportunity to submit additional information regarding the Best Available Control Technology (BACT) determination for Polk Power Station Unit 1. This information is submitted as a follow up to our meeting of April 3, 2001, and subsequent communications via telephone. This submittal is comprised of three main elements, an overview of the original BACT evaluation, a refined BACT cost analysis, and information regarding a recently permitted syngas fired Combustion Turbine (CT) installation. Furthermore, if deemed acceptable, TEC would like to work with the Florida Department of Environmental Protection (FDEP) in developing a continuous improvement program (CIP) to reduce NO_x emissions from Polk Unit 1 through the use of process optimization and equipment upgrades.

The Original BACT Evaluation

In the course of developing the original BACT evaluation, TEC was required to consider "data gathered on this facility, other similar facilities, and manufacturer's research." In taking this approach, TEC determined that a NO_x limit of 25 ppmvd @15% O_2 was appropriate as an emission limit. This would allow TEC to continue firing its present array of fuels while generating safe and reliable electricity to serve its customers.

In subsequent discussions with FDEP, TEC has come to understand that the Department may be considering the application of a selective catalytic reduction (SCR) system to Polk Unit 1 as BACT. In the original BACT submittal, TEC outlined several technical concerns with the application of this technology to an Integrated Gasification Combined Cycle (IGCC) facility, and, based on discussions with several catalyst vendors, these overriding technical concerns remain. The most significant of these concerns is the formation of ammonium sulfate and ammonium bisulfate compounds. These compounds, when formed in the Heat Recovery Steam Generator (HRSG) will cause significant plugging and fouling of heat transfer equipment, which could require several additional outages per year to allow for the cleaning of this equipment.

Since the manufacturer of the combustion turbine, General Electric, believes that SCR is not applicable to this unit, no other IGCC in the United States currently employs SCR technology, and the testing performed at the Polk facility demonstrated that 25 ppmvd @15% O_2 is a reasonable limit, TEC feels that based on the criteria established by the Department for this evaluation, a SCR system can clearly be eliminated as a BACT recommended technology for Polk Unit 1.

Refined BACT Cost Analysis

Due to the fact that the original submittal was required within 30 days of the completion of the test program, TEC based the original SCR cost analysis on vendor quotes for other facilities that did not fire syngas as a primary fuel. Since that time, TEC has solicited additional input from four SCR equipment vendors to refine the cost analysis presented in the initial submittal. Of the four vendors contacted, two vendors submitted no-bid responses, one of whom was Englehard. This point is important as the original submittal was based on an Englehard quote for a facility that was not an IGCC. The SCR quote that is used in this current analysis was provided by Deltak. The quote is enclosed as Attachment 1 to this letter and serves as a basis for the cost analysis performed in this submittal.

The Deltak quote specifies an outlet NO_x concentration from the SCR of 5 ppmvd corrected to 15% oxygen. Because this quote is based on this exit concentration, the 5 ppmvd value is used as the controlled NO_x value when estimating cost effectiveness, and the baseline for NO_x emissions remains at 25 ppmvd. The baseline emissions from oil firing (i.e., back up fuel firing) is 42 ppmvd, and the SCR system is expected to have the same 80% control for the NO_x emissions when firing oil as when controlling syngas firing. Therefore, the associated controlled NO_x emission rate during oil firing would be 10.5 ppmvd. Although oil is only fired for a maximum of 10% of the total allowable operation, the emissions reductions from the oil case represent approximately 21% of the total emissions reductions. Thus, because the maximum allowable back up fuel firing load is used in the estimation of cost effectiveness, the cost effectiveness calculations tend to be conservative in nature (i.e., will tend to under estimate the cost per ton of pollutant removed because back up fuel is typically fired in considerably less quantities than the allowable limit).

The Deltak quote includes the following statement on the first page regarding concerns with ammonia sulfate and ammonia bisulfate deposition and plugging. The fact that two vendors elected not to bid on this project coupled with the placement of this concern on the cover page of the Deltak quote lends credence to the overall priority that equipment vendors place on this concern.

> *I would like to note one potential problem with retrofitting SCR into the subject HRSG. There is a rather high SO_2 loading in the exhaust gas stream due to the combustion of syn-gas in the combustion turbine. Approximately 5% of the SO_2 in the gas stream will oxidize to SO_3 across the catalyst. This additional SO_3 along with the unspecified level of SO_3 in the combustion turbine exhaust will combine with the injected ammonia (NH_3) to form ammonium salts (primarily ammonium bisulfate) that are likely to adhere to the tubing in the cooler HRSG sections causing both a thermal insulation effect and/or an increase in turbine back pressure. With the fuel that is being burned, and the potential for Fuel Oil back-up fuel, the potential for ammonium salt fouling will be quite significant.*

Based on this concern, TEC estimates that the HRSG and down stream exhaust ductwork will need to be cleaned three times per year, at a minimum. The cost estimate includes two entries to account for these costs. The first entry is the annualized costs of HRSG maintenance that is expected to occur with increased degradation and corrosion of the heat transfer media. These estimates were prepared by plant personnel, taking into account the anticipated increased tube replacement costs that will be incurred starting in the third year after the installation of the SCR unit. These costs were estimated through ten years, then converted to an annualized recurring cost using engineering economic accounting methods.

In addition to the HRSG maintenance costs, contract labor costs are included for performing the anticipated cleanings. One cleaning will be performed during a scheduled outage, and two cleanings will be performed during unscheduled outages. The contract labor costs involved with the cleaning will be incurred by TEC during each of the outages. The estimated cleaning cost is $60,000 per occurrence.

During the scheduled outage, there are no additional costs that are incurred by TEC. However, during the unscheduled outages that are performed solely to address the plugging, TEC will incur costs associated with the loss of generating capacity. During these unscheduled outages, TEC will need to replace the electricity that would otherwise be generated by the Polk facility (i.e., 315 MW). The basis for estimating the incremental replacement cost of $20 per MW-hour is presented on page 6-22 of the November 2000 submittal.

TEC believes the incremental costs to replace the electrical power that would otherwise be generated by the Polk facility to be a real and valid cost that is associated with an unscheduled outage. During the meeting between FDEP and TEC, the Department had indicated that additional supporting information for the use of this cost estimate is warranted, especially as it related to United States Environmental Protection Agency (USEPA) guidance on accounting for lost power generation capacity during plant outages. TEC understands USEPA guidance to state that during scheduled outages, or those events that can reasonably take place during scheduled outages, it is not appropriate to account for the lost generation capacity. As such, costs for events such as catalyst replacement and one cleaning of the catalyst per year are estimated without the additional costs of replacing the power that would otherwise be generated by the facility.

However, because the Polk facility is a base load unit on TEC's system and has a current overall availability commitment of 86.5%, any unscheduled outages will incur considerable costs to TEC, especially if these unscheduled outages will affect the ability of the Polk facility to meet this availability commitment. TEC believes the estimated incremental cost for electrical generation or purchase to be a real cost that would be incurred by the facility during any unscheduled outage, regardless of the reason for the outage. This cost is one of the reasons that unscheduled outages get prompt attention of engineering and maintenance staff, including subcontractors, to return the facility to normal operational mode.

TEC believes that the cost of replacing the power generation capacity lost during an unscheduled outage is a real and justifiable cost that must be included in the performance of the economic analysis of control options. To provide a complete analysis to FDEP, TEC has provided the information on cost effectiveness analysis for both cases, with and without the incremental cost for power replacement Attachment 2.

The revised cost effectiveness estimate for the SCR control of NO_x is $5,737 per ton of NO_x removed, as summarized in Table 1. This cost takes into account the incremental cost of replacing power during two unscheduled outages per year. Table 2 presents the cost effectiveness of $3,499 per ton, which does not take into account the incremental cost for replacing power during the outage. Tables 3 through 5 contain supporting information regarding costs estimates used for this analysis. This analysis follows the same approach that was used in the November 2000 submittal, hence is not described in further detail.

The incremental cost of replacing the lost power generating capacity is approximately 40% of the total cost associated with the SCR. TEC has serious concerns regarding the fouling, plugging and corrosion of components downstream of the SCR in the high sulfur environment, and believes these cost estimates to be conservatively low. Because there is a shortage of practical experience of CT SCR performance in high sulfur environments, these estimates are based on expected performance, not actual data. TEC is aware of predictions by equipment vendors (e.g., General Electric) that account for considerably more difficulties and associated costs that TEC is taking into account in this cost analysis.

Recent Syngas Fired CT BACT Determination

The Kentucky Pioneer Energy LLC facility proposed for Trapp, Kentucky is currently undergoing the public review of its draft Prevention of Significant Deterioration (PSD) permit. This permit proposes NO_x BACT of 15 ppmvd for syngas firing, and 25 ppmvd for back up fuel (i.e., natural gas) firing. The NO_x control technology selected for this facility is steam injection. The subject equipment includes two CTs which are GE 7FA CTs, each rated at 197 MW without the associated HRSG.

Discussions with Mr. Donald Newell, the Commonwealth of Kentucky permit engineer, indicate that no questions were raised to date by the public regarding the proposed BACT emissions limit. The questions raised by the public concerned other items, such as the placement of lights at the facility to minimize light pollution, the need to keep the public informed of what is happening at the facility, mercury emissions and the impacts of burning municipal solid waste on rainwater.

The USEPA has questioned certain aspects of the BACT determination for the facility, but has not determined that add-on controls (e.g., an SCR) are cost effective or technically feasible. The questions from the USEPA are included as Attachment 3. The questions raised in this letter regard specific aspects of the BACT determination for the facility, and ask for supporting information to validate the concerns regarding the implementation of SCR on an IGCC CT. For example, regarding validation of the plugging concerns, the USEPA states:

> *We would be more persuaded if the applicant were to provide information directly from one or more HRSG vendors discussing why ammonium bisulfate salts pose a greater problem for combined cycle combustion turbine HRSG's than for coal-fired boilers.*

Additional concerns raised by the USEPA address other aspects of the BACT determination, such as cost data and the survey of other similar facilities conducted to support the permit application. Mr. Newell indicated that he is in the process of collecting additional information to support his determination of steam injection meeting BACT, and will be responding to USEPA comments. Mr. Newell expressed concerns with reliability and clogging of equipment as a result of using an SCR system.

Until a final determination of the BACT is made for this Kentucky facility, TEC feels it is inappropriate to use the fact that questions are being raised by USEPA as a justification for requiring SCR as BACT for the Polk facility. First, the BACT process is interactive in nature, allowing for all concerned parties (e.g., citizen groups, USEPA, and affected Class I area managers) to provide their input and comments. The final BACT determination takes into account these comments, as well as other factors that are reviewed by the permitting agency. Additionally, many of the questions raised by the USEPA regarding the Kentucky BACT determination either do not apply to the Polk facility, or already were addressed by TEC in prior submittals.

Additionally, the CT at the Polk facility, although similar to the CTs proposed for the Kentucky facility, is approximately two generations in technological advances behind the CTs that will be installed in Kentucky. This point is further discussed in the November 2000 submittal. Thus, because the CT at the Kentucky facility is expected to achieve 15 ppmvd NO_x emissions, it is not appropriate to expect the Polk CT to achieve the same level of emissions.

Conclusions

Through the use of a CIP, TEC is willing to work with the Department to reduce NO_x emissions from the Polk facility. This program would investigate the use of process optimization and the addition of hardware where applicable to minimize the formation of NO_x rather than remove it from the flue gas stream. This is a prudent approach to the minimization of NO_x emissions from Unit 1, and does not carry with it the significant technical concerns associated with the addition of a post combustion control technology such as SCR.

TEC has considerable technical concerns with the use of an SCR system at this facility because of the high sulfur content of the exhaust gas, and these concerns are shared by several SCR vendors. Although TEC has tried to incorporate the costs associated with these concerns into the cost effectiveness analysis, the costs are based on estimated difficulties, not on data from similar facilities because there are no similar IGCC facilities that operate an SCR unit. Since the control cost effectiveness evaluation was conservative in nature, TEC believes the cost effectiveness value of $5,737 per ton of NO_x removed to be a lower bound of the cost, and actual costs of an SCR may be substantially higher. Based on this analysis, TEC believes the SCR control option to be both technically and economically infeasible.

Thank you in advance for your consideration of this matter. If you have any questions regarding the information contained in this submittal, please feel free to telephone Shannon Todd or me at (813) 641-5125.

Sincerely,

Laura R. Crouch for

Gregory M. Nelson, P.E.
Director
Environmental Affairs

EA/gm/SKT253

Attachments

c: Mr. A.A. Linero – FDEP
Mr. Jerry Kissel - FDEP SW
M. Halpin
G. Worley, EPA

ATTACHMENT 1

DELTAK

April 19, 2001

Mr. Stirling Robertson
Environmental Consulting & Technology, Inc.
1901 S. Harbor City Blvd., Suite 600
Melbourne, FL 32901

FAX: 321-733-1303
E-Mail: srobertson@ectinc.com

Ref: **Request for SCR Quote**
Deltak Ref: Budgetary Proposal B22707

Dear Mr. Robertson,

The purpose of this letter is to respond to your request for quotation fo the retrofit of an SCR system into an existing HRSG.

The information supplied in your Request for Quote was not sufficient for me to go through the actual design process of an SCR retrofit. However, I am able to offer you some rough information based upon past SCR retrofit projects that have been completed by Deltak. This information, including rough budgetary pricing is included below. This budgetary proposal assumes that there is an existing spool duct in the HRSG for the addition of SCR catalyst.

I would like to note one potential problem with retrofitting SCR into the subject HRSG. There is a rather high SO_2 loading in the exhaust gas stream due to the combustion of syn-gas in the combustion turbine. Approximately 5% of the SO_2 in the gas stream will oxidize to SO_3 across the catalyst. This additional SO_3 along with the unspecified level of SO_3 in the combustion turbine exhaust will combine with the injected ammonia (NH_3) to form ammonium salts (primarily ammonium bisulfate) that are likely to adhere to the tubing in the cooler HRSG sections causing both a thermal insulation effect and/or an increase in combustion turbine back pressure. With the fuel that is being burned, and the potential for Fuel Oil back-up fuel, the potential for ammonium salt fouling will be quite significant.

Page 2 of your Request for Quotation outlined the specific information that you wished Deltak to provide. Below is a repeat of your required information outline with information provided.

1. Equipment Included

The following equipment and services have been assumed to be required, and are included in this budgetary proposal:

1. SCR Spool Duct Modifications:

a) Add bolted access hatches to duct roof for catalyst access.
b) Remove existing liner and insulation, as needed, for installation of catalyst frame components to duct casing walls.
c) Structural steel engineering and floor modifications/reinforcement to support the catalyst system.
d) Add insulation and liner necessary to transition between the catalyst frame and the existing liner and insulation.
e) Add 12 test ports (3 upstream, 3 downstream of the catalyst on each side wall). Each port to be a 2.5" minimum pipe penetrating the HRSG casing, insulation and liner with flange and blind on the outside.

2. Catalyst Frame:
   a) Frame designed to support catalyst modules from Catalyst vendor
   b) Frame designed to fit inside existing SCR spool duct.
   c) The frame components will be lowered inside the duct and attached to the duct floor, sidewalls and structural steel as required for proper support.
   d) The frame will include space for expansion of the catalyst bed depth by no less than 50%.

3. Catalyst Modules:
   a) Multiple catalyst modules will be supplied by the selected Catalyst supplier. Each module will be supplied so they can be lowered inside the catalyst frames.
   b) The modules can be lifted out of the catalyst frame when fresh modules are required.

4. Ammonia Injection Grid (AIG) Lances
   a) AIG Location: The grid will be designed for installation into an existing HRSG access lane.
   b) Ammonia Injection Lances. Each lance will span the width of the HRSG, and be supported by the sidewalls. The lance material will be SS304.
   c) The appropriate number of lances, nozzles and nozzle sizes will be provided to assure uniform distribution of ammonia in the exhaust stream. Ammonia will be fed into the HRSG from one sidewall.
   d) Lance Casing Penetration Sleeves & Guides. Each lance will be supplied with a flanged casing penetration on one sidewall, and a support guide penetrating the opposite wall.
   e) AIG Lance Liner: 10ga. carbon steel liner and insulation to fit around AIG lance penetrations.

5. AIG Distribution Piping
   a) Distribution piping between the ammonia "distribution header" and the AIG lances. Each distribution pipe will supply vaporized ammonia to four AIG lances.
   b) Pipe supports.
   c) Insulation and lagging. (Insulation and lagging to be 2" mineral wool with .020 aluminum with vapor barrier.)

6. AIG Distribution Manifold Header
    a) Header assembly to distribute vaporized ammonia to the distribution pipes. The 12" SA106B header will be located adjacent to one sidewall of the SCR spool duct.
    b) Distribution pipe flow adjustment trim: Each of the manifold's distribution pipe stubs will include the following shop installed trim: flow element, pressure differential gauge with sensing lines, manual butterfly valve.
    c) Manifold header pressure tap and gage.
    d) Insulation and lagging. (Insulation and lagging to be 2" mineral wool with .020 aluminum with vapor barrier.)

7. Aqueous Ammonia Dilution Skid: This shop fabricated and prewired skid will include the following:
    a) Dilution Air Fans: Two (2) fans, 100% capacity each. (≈ 15 Hp, 460VAC/60Hz/3ph)
    b) Dilution Air Heater (Approximate Rating = 180 kW)
    c) Deltak assumes that existing "spare cabinets" in a motor control center would be used to house the new buckets required for the skid motors and heater.
    d) Aqueous Ammonia Vaporizer Tank
    e) Shop installed interconnecting piping and wiring which will be brought to connection points at the skid boundary, ready for instrument air, ammonia supply piping, and wiring connections.
    f) Panel mounted system controls for vaporizer (on/off/temp indicator/reset), fans (on/off/flow indicators), system pressure indicators, air/ammonia flow indicator and controller, main power disconnect switch.
    g) Skid mounted PLC controller.

8. Aqueous Ammonia Storage Tank and Unloading Station
    a) 15,000 gallon capacity, horizontal storage tank 10 feet OD x 24 feet, 25 psig internal pressure (no vacuum rating) with 18" manway, constructed in accordance with ASME Section VIII, Division 1.
    b) Liquid fill and vapor return lines.
    c) Tank Trim: liquid level gauging device, pressure and vacuum relief valve, four ammonia leak detectors mounted on posts and one ammonia sensor mounted on a panel.
    d) Aqueous Ammonia Injection Pumps: Two (2) 100% capacity skid mounted NH_3 injection pumps to deliver ammonia from the storage tank to the dilution skid. Skid to be located inside storage tank containment basin. (Pump Size: ≈ 1 hp, 120 VAC)
    e) Truck unloading pump not included and assumed to be provided on delivery truck, which is typical.

f) Containment Dike: concrete containment consisting of floor & sidewalls for containment of ammonia storage tank leak/spill containment. The dike will be capable of holding at least the tank capacity volume plus 10%.

g) Sump well and electric pump for draining containment dike. Pump discharge piping to be supplied to top of containment wall. Piping from containment wall to collection point by others. (Pump Size: 1 hp, 120 VAC).

9. Aqueous & Vaporized Ammonia Piping Between Tank and AIG Manifold
   a) Storage tank to Injection pumps (2" SA106B - aqueous).
   b) Injection pumps to Ammonia dilution skid (3/4" SA106B - aqueous).
   c) Dilution skid to the Ammonia distribution manifold (8" SA106B - vaporized).
   d) Pipe supports.
   e) Insulation & lagging for vaporized flows. (Insulation and lagging to be 2" mineral wool with .020 aluminum with vapor barrier.)

10. Civil Engineering:
    a) Design: Ammonia vaporizer skid pad & foundations; Ammonia injection pump skid pad & foundations; Aqueous ammonia storage tank foundations and containment basin;
    b) General: Stamped Drawings

11. Electrical Engineering and Equipment:
    a) Power wiring between the Skid Mounted Equipment, MCC's and existing power supplies.
    b) Control wiring between the Skid Mounted Equipment, MCC's and existing power supplies.
    c) MCC's for the two injection pumps, one trolley hoist, and the vaporization heater.
    d) Electrical Classification Plan (NEC Code)

12. Controls Engineering:
    a) Develop and supply the necessary control logic diagram and information for the SCR system. The information and diagrams will be sufficient to permit the controls integration into the existing plant DCS.

13. Deltak Documentation:
    a) Operations & Maintenance Manuals: Five (5) copies will be provided.
    b) Arrangement drawings of the system.

14. Installation Services:
    a) Equipment, materials and labor to install all Deltak supplied equipment.

2. Equipment Excluded

The following equipment and/or services are excluded from the proposed scope of supply:

1. Catalyst loading monorail and electric hoist.
2. Performance test procedures, test equipment, test personnel or test results analysis.
3. Stack Continuous Emissions Monitor System (CEMS), or NOx analyzers.
4. NOx sample probe, sampling lines and analyzers for detecting NOx.
5. Stack modifications for NOx sampling.
6. Safety eye wash station and/or shower.
7. Fire protection system modifications.
8. Engineering and/or evaluation to update existing plant procedures and policies.
9. Modification of existing foundation.
10. Shipping of equipment to the, as yet, unknown plant site.

3. Mechanical Warranty

Typically the mechanical warranty statement for a catalyst system would be as follows:

> The sole, and exclusive, remedies for breach of these warranties shall be that Deltak will repair or replace defective or nonconforming equipment or parts thereof free of charge, F.O.B. point of shipment; provided the defect or nonconformance is due to its fault and is not the result of abuse, misuse, accident, or other event outside Deltak's control and provided that the user of the equipment gives written notice of any defect or nonconformance within ten days of discovery thereof. In no event shall Seller have any responsibility for the cost of creating adequate access to the equipment for the purpose of repair or replacement thereof. Deltak's obligation hereunder, shall cease, in the case of equipment manufactured by it 18 months from date of shipment or 12 months from date of start-up, whichever occurs first. Thereafter, Deltak shall have no further obligation.
>
> With respect to auxiliaries and accessories furnished by Deltak, but manufactured by others, the warranties shall be limited in all respects, including duration and available remedies, to the warranty of the respective equipment manufacturer. Deltak shall not have any liability with respect to such equipment not manufactured by it except only to the assignment of whatever rights Deltak has against the manufacturer of such equipment and such rights are hereby assigned.
>
> The user agrees that the above conditions precedent are reasonable limitations, and waives any right of recovery if it fails to comply with them or the defect or failure of performance does not occur within the stated time.

4. Performance Guarantee

The subject Request for Quote did not specify a required NOx reduction, or NH_3 slip requirements. This budgetary proposal is based upon the following assumption:

Inlet NOx – 25 ppmvd @ 15% O_2 Max.
Outlet NOx – 5 ppmvd @ 15% O_2 (80% NOx reduction)
NH_3 Slip – 5 ppmvd @ 15% O_2

Outlet NOx and NH_3 slip would be guaranteed for a period of three years from first introduction of combustion turbine exhaust gas into the catalyst.

5. Expected Catalyst Life

A. Guarantee Life – Typically an SCR catalyst is guaranteed for a three (3) year life. A three (3) year life has been assumed in this budgetary proposal.

B. Typical Lifetime – Actual catalyst life depends upon the service environment and the care that is taken to not subject the catalyst to poisons and large amounts of water. In Deltak's experience, SCR catalyst life is typically in the five (5) to eight (8) year range.

6. Budget Pricing

Budgetary pricing for this inquiry is based upon the scope of supply and assumptions outlined in this proposal. The budgetary price for the supply and installation of the proposed SCR catalyst is $3,110,000.00.

7. NH_3 Slip (ppm)

The budgetary design for the proposed SCR system assumes a maximum NH_3 slip of 5 ppmvd @ 15% O_2.

8. Express any concerns you have about catalyst poisoning and ammonia bisulfate deposition.

Catalyst Poisoning: The following contaminants and compounds are known catalyst deactivators and contribute to shortened catalyst life:

Heavy and Base Metals: Antimony, Arsenic, Chrome, Copper, Lead, Mercury, Nickel, Tin, Zinc
Alkali Metals: Cesium, Francium, Lithium, Potassium, Rubidium and Sodium, Alkaline Earth Metals: Calcium, Magnesium, Barium, Strontium, Silica Compounds: Silicone and Siloxane
Phosphorous: Particularly from oil or turbine cleaning detergents.

It is the responsibility of Owner to notify Deltak if the catalyst will be exposed to these poisons. Deltak is not responsible for the shortening of catalyst life due to poisons, unless properly advised of the potential poisons before the catalyst is designed. The catalyst will accommodate exposure to combustion turbine oil firing exhaust with the ammonia injection system off. The catalyst suitability with the ammonia injection system on is yet to be determined because the turbine exhaust analysis is unknown.

Ammonia Salts Deposition

The referenced specification did not state the expected SO_3 levels in the exhaust gas stream. However, considering the levels of SO_2 in the exhaust gas, it is assumed that SO_3 levels are significant. Additionally, approximately 5% of the SO_2 will be oxidized to SO_3 across the catalyst. Ammonia salts are formed by the reaction of SO_3 and NH_3 in the exhaust stream. The salts once formed, deposit on cool HRSG surfaces. It should be assumed significant ammonia salt fouling of the cool end of the subject HRSG will occur.

I trust that this information is satisfactory for your needs at this time. If you require additional information, I can be reached at 763-557-7457, or by E-Mail at **rmeyer@dletak.com**.

Sincerely,

Ronald J. Meyer, PE
Aftermarket Product Manager

c: Em Mohammed – RME Associates, Inc.

ATTACHMENT 2

Table 1. Cost-Effectiveness Summary, 25 to 5 ppm, Including Electrical Costs of Unscheduled Outages

CT No.	Scenario No.	No. of CTs	Annual Operation (hrs/yr)	NO_x Emission Rates								Economic Impacts	
				Baseline			Outlet - SCR Control System				Decrease	Annualized Cost	Cost-Effectiveness Over Baseline
				(ppmvd)	(lb/hr)	(tpy)	(Eff. - %)	(ppmvd)	(lb/hr)	(tpy)	(tpy)	($)	($/ton)
Unit 1	Natural Gas	1	7,884	25.0	222.5	877.1	80.0	5.0	44.5	175.4	701.7		
Unit 1	Oil	1	876	42.0	311.0	136.2	80.0	8.4	62.2	27.2	109.0		
		Totals	8,760	N/A	N/A	1,013.3	N/A	N/A	N/A	202.7	810.7	4,650,600	5,737

Table 2. Cost-Effectiveness Summary, 25 to 5 ppm, Excluding Electrical Costs of Unscheduled Outages

CT No.	Scenario No.	No. of CTs	Annual Operation (hrs/yr)	NO_x Emission Rates Baseline (ppmvd)	Baseline (lb/hr)	Baseline (tpy)	Outlet - SCR Control System (Eff. - %)	Outlet (ppmvd)	Outlet (lb/hr)	Outlet (tpy)	Decrease (tpy)	Economic Impacts Annualized Cost ($)	Cost-Effectiveness Over Baseline ($/ton)
Unit 1	Natural Gas	1	7,884	25.0	222.5	877.1	80.0	5.0	44.5	175.4	701.7		
Unit 1	Oil	1	876	42.0	311.0	136.2	80.0	8.4	62.2	27.2	109.0		
		Totals	8,760	N/A	N/A	1,013.3	N/A	N/A	N/A	202.7	810.7	2,836,200	3,499

Table 3. Capital Cost Summary (Both Cases)

Direct Costs	($)	OAQPS Factor
Purchased Equipment (PE)		
SCR Control System	3,110,000	Deltak Quote 4/19/01
Aqueous Ammonia Storage Tank	0	Included with SCR System
Purchased Equipment Total	3,110,000	A
Instrumentation	311,000	0.10 * A
Sales Tax	186,600	0.06 * A
Freight	155,500	0.05 * A
HRSG Modifications	300,000	Engineering Estimate, allows for cleaning
Total Purchased Equipment	4,063,100	B
Installation		
Foundations & Supports	325,000	0.08 * B
Handling & Erection	568,800	0.14 * B
Electrical	162,500	0.04 * B
Piping	81,300	0.02 * B
Insulation For Ductwork	40,600	0.01 * B
Painting	40,600	0.01 * B
Total Installation Cost	1,218,800	
Total Direct Cost	5,281,900	TDC
Indirect Costs	**($)**	**OAQPS Factor**
Engineering	406,300	0.10 * B
Construction & Field Expenses	203,200	0.05 * B
Contractor Fees	406,300	0.10 * B
Start-up	81,300	0.02 * B
Performance Test	40,600	0.01 * B
Contingency	121,900	0.03 * B
Total Indirect Cost	1,259,600	TIC
Total Capital Investment	**6,541,500**	TCI

Source: ECT, 2001.

Table 4. Operating Cost Summary, Including Electrical Costs of Unscheduled Outages

Direct Costs	($)	OAQPS Factor
Labor & Material Costs		
Operator	12,000	A
Supervisor	1,800	0.15 * A
Maintenance		
Labor	12,000	B
Material	12,000	1.0 * B
Total Labor & Material Costs	37,800	C
Catalyst Costs		
Replacement (materials)	823,600	
Replacement (labor)	20,000	
Disposal	138,600	
Total Catalyst Cost	982,200	
Annualized Catalyst Cost	239,500	
Aqueous Ammonia	285,300	113/ton
Electricity Costs	78,500	
Scheduled Outage	60,000	
Unscheduled Outage	1,934,400	
HRSG Maintenance	129,600	
Energy Penalties		
Turbine Backpressure - control system	403,700	0.50%
Turbine Backpressure - plugging	403,700	
Total Energy Penalties	807,400	
Total Direct Cost	3,572,500	TDC
Indirect Costs	**($)**	**OAQPS Factor**
Overhead	22,700	0.60 * C
Administrative Charges	130,800	0.02 * TCI
Property Taxes	65,400	0.01 * TCI
Insurance	65,400	0.01 * TCI
Capital Recovery	814,100	
Total Indirect Cost	1,098,400	
Emission Fee Credit	(20,300)	$25/ton
Total Annual Cost	**4,650,600**	

Source: ECT, 2000.

Table 5. Operating Cost Summary, Excluding Electrical Costs of Unscheduled Outages

Direct Costs	($)	OAQPS Factor
Labor & Material Costs		
Operator	12,000	A
Supervisor	1,800	0.15 * A
Maintenance		
Labor	12,000	B
Material	12,000	1.0 * B
Total Labor & Material Costs	37,800	C
Catalyst Costs		
Replacement (materials)	823,600	
Replacement (labor)	20,000	
Disposal	138,600	
Total Catalyst Cost	982,200	
Annualized Catalyst Cost	239,500	
Aqueous Ammonia	285,300	113/ton
Electricity Costs	78,500	
Scheduled Outage	60,000	
Unscheduled Outage	120,000	
HRSG Maintenance	129,600	
Energy Penalties		
Turbine Backpressure - control system	403,700	0.50%
Turbine Backpressure - plugging	403,700	
Total Energy Penalties	807,400	
Total Direct Cost	1,758,100	TDC
Indirect Costs	**($)**	**OAQPS Factor**
Overhead	22,700	0.60 * C
Administrative Charges	130,800	0.02 * TCI
Property Taxes	65,400	0.01 * TCI
Insurance	65,400	0.01 * TCI
Capital Recovery	814,100	
Total Indirect Cost	1,098,400	
Emission Fee Credit	(20,300)	$25/ton
Total Annual Cost	**2,836,200**	

Source: ECT, 2001.

ATTTACHMENT 3

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 4
ATLANTA FEDERAL CENTER
61 FORSYTH STREET
ATLANTA, GEORGIA 30303-8960

May 1, 2001

4APT-ARB

John E. Hornback, Director
Division for Air Quality
Department for Environmental Protection
Natural Resources and Environmental
Protection Cabinet
803 Schenkel Lane
Frankfort, Kentucky 40601-1403

Dear Mr. Hornback:

Thank you for sending the draft PSD/Title V permit and preliminary determination and statement of basis for the proposed Kentucky Pioneer Energy facility in Clark County, Kentucky (Permit No. V-00-049). The project operator will be Kentucky Pioneer Energy LLC, a subsidiary of Global Energy USA. The project will consist of an integrated gasification combined cycle (IGCC) combustion turbine electric power generating station with two combustion turbines. The primary fuel for the combustion turbines will be a synthetic gas (syngas) generated on site by gasification of coal and municipal waste. Based on the applicant's emission estimates, the facility will be a major source under prevention of significant deterioration (PSD) and title V permitting regulations. Also based on the applicant's estimates, the facility is subject to PSD review for the following pollutants: nitrogen oxides (NO_x), sulfur dioxide (SO_2), carbon monoxide (CO), particulate matter (PM and PM_{10}), volatile organic compounds (VOC), beryllium, municipal solid waste metals, and municipal solid waste acid gases.

This letter provides Region 4's comments on the PSD components of the draft permit and on federal new source performance standards (NSPS) applicable to municipal waste combustors and stationary gas turbines. We will send a separate letter commenting on the title V components. Our PSD and NSPS comments are as follows:

1. 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 applicant's proposed NO_x BACT, which as of this time has been accepted by the Kentucky Department for Air Quality (KDAQ), is a combination of combustor design plus use of diluent water/steam to minimize NO_x formation, without use of a post-combustion NO_x control method such as selective catalytic reduction (SCR) or

SCONOx™. Our concerns regarding this approach are discussed in the following items.

a. 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.

b. The applicant's (and KDAQ's) primary concern about use of SCR as a NO_x control method appears to be the potential for reaction of residual ammonia downstream of the SCR device with syngas sulfur to form ammonium bisulfate salts. These salts could in turn "cause serious plugging, loss of heat transfer and corrosion in the downstream portions of the heat recovery steam generator." [Quote from applicant's revised NO_x BACT analysis dated August 2, 2000.] Our response to this concern is as follows:

    - 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. The applicant addresses this consideration by saying that formation and deposition of ammonium bisulfate salts within coal-fired boiler air preheaters is a less serious concern because air preheaters can be cleaned more easily than the surfaces within a heat recovery steam generator (HRSG) and because such deposition has a lesser effect on heat transfer in coal-fired boilers. We would be more persuaded if the applicant were to provide information directly from one or more HRSG vendors discussing why ammonium bisulfate salts pose a greater problem for combined cycle combustion turbine HRSG's than for coal-fired boilers.

    - 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. We recognize that fuel oil is generally proposed only as a backup fuel for combined cycle combustion turbine projects and not as the primary fuel. Accordingly, intermittent combustion of fuel oil may not pose the same potential for HRSG contamination as continuous combustion of syngas. Nevertheless, we would be interested in the applicant's explanation of why SCR can be used with fuel oil combustion in combined cycle combustion turbines but not with syngas combustion.

- We are aware of at least one SCR vendor (Huntington Environmental Systems) that also provides a component for residual ammonia scavenging to minimize plugging and corrosion of equipment downstream of the SCR device. 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.

c. Although acknowledging the technical feasibility concerns of SCR, KDAQ's preliminary determination also includes a cost effectiveness evaluation for SCR as a technically feasible option. The comparison point for this cost evaluation is an uncontrolled baseline emission rate. Table A-5 (page 29) in the preliminary determination (and information in the original permit application on which Table A-5 is based) lists a NO_x emissions rate of 15 ppmvd as the "uncontrolled" emissions rate. We have two concerns about this baseline rate. (1) Using an emission rate of 15 ppmvd as the uncontrolled level overlooks the contribution of natural gas combustion at an emission rate of 25 ppmvd. By the terms of the draft permit, natural gas combustion can equal approximately 12 percent of the total heat input to the combustion turbines after the first two years of operation (during which natural gas use can be even higher). We recognize that the applicant's revised NO_x BACT evaluation dated August 2, 2000, contains a weighted average "uncontrolled" NO_x emission rate of 16.6 ppmvd to adjust for natural gas use. (2) We question whether 15 ppmvd (or 16.6 ppmvd) is truly the uncontrolled baseline rate. This rate represents the level achieved with use of diluent water/steam injection. Unless the turbines can not be run without diluent water/steam injection, then the emission rate without diluent injection should be estimated and used as the uncontrolled baseline. Use of a higher baseline emission rate would result in a lower cost effectiveness value (lower dollars per ton removed).

d. 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 Englehard 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, as follows. (1) The EPA document is generic in nature and may not be appropriate for every project. More importantly, it does not reflect the substantial improvements and cost reductions in SCR technology for large combined cycle combustion turbines that have occurred since the time that the EPA document was written in the early 1990's. (2) 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. A possible justification for this high cost is that more than half of the equipment cost is due to the estimated additional cost for HRSG improvements. However, we did not find any information directly from a HRSG vendor in the draft permit package that would support this additional cost. (3) A revised BACT analysis from the applicant dated August 2, 2000, contains another SCR vendor quote, this one from Cormetech. The equipment cost in the Cormetech quote is \$1,394,000 for two units, or approximately \$700,000 for each combustion turbine. The quote also contains a statement that "Based on discussions with an HRSG company, Cormetech estimates that the balance of the SCR equipment would cost an additional \$500,000 to \$600,000." If this "additional" amount is not accounted for in the Cormetech quote of \$1,394,000 for two units, adding it to the quote would boost the total equipment cost to about \$1,000,000 per turbine. This is much lower than the equipment cost based on the Engelhard quote. (4) The cost effectiveness analysis for SCR based on the Englehard quote (page 34 of the preliminary determination) contains a "Maintenance labor and materials" cost of \$518,300 per year for both turbines combined. This cost appears excessive compared to cost estimates for the same item in other recent combustion turbine permit applications. The cost estimate for this item appears to be based on a procedure in the 1993 EPA document cited above, a document that we have indicated is out of date. (5) 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.

e. Appendix C of the draft permit/preliminary determination package contains a list of selected simple cycle combustion turbine NO_x BACT determinations from 1995 to present. We are not exactly sure why a list of simple cycle projects is included since the combustion turbine projects at the Kentucky Pioneer Energy facility will be combined cycle combustion turbines. Assuming this list has some relevance, we offer the following observations. (1) The list does not impart the reality that essentially all recently permitted simple cycle combustion turbine projects have NO_x BACT levels in the 9 ppmvd to 15 ppmvd range when firing natural gas, much lower than the 25 ppmvd proposed for the Kentucky Pioneer Energy facility when firing natural gas. (2) The list includes the Enron Calvert City project in Kentucky that was eventually canceled and that had a proposed NO_x BACT level of 25 ppmvd (for natural gas combustion) with which we strongly disagreed.

f. In the preliminary determination, KDAQ states that the SCONOx™ technology for control of NO_x emissions from combined cycle combustion turbines "is not yet commercialized for combustion turbines larger than 100 MW." Our understanding is that SCONOx™ is commercially available for large combustion turbines from ALSTOM Power, and, in fact, that ALSTOM Power is the sole licensee of the technology for turbines of this size. This is not to say that SCONOx™ should be required as BACT for the Kentucky Pioneer Energy facility, but we request that your final BACT determination take into account the presumption that SCONOX™ is commercially available.

g. Table A-1 (page 19-20) in the preliminary determination contains a "snapshot" of projects that for the most part are pre-1996 projects that do not necessarily reflect current technology.

h. Page 25 of the preliminary determination is a copy of a letter from General Electric (GE) stating in essence that GE's Dry Low NO_x (DLN) product line is not available for combustion turbines firing syngas fuels. This letter is dated October 19, 1999. We request that KDAQ check with GE to confirm that the position stated in this letter is still valid.

i. On page 22 of the preliminary determination, KDAQ refers to Tampa Electric Company's (TECO's) IGCC facility (Polk Power Station), and cites the NO_x limit of 25 ppmvd for this facility. Please note that this was an interim limit to be confirmed or replaced pending a final BACT determination to be made at a later date. In fact, the Florida Department of Environmental Protection is currently assessing the appropriate BACT for the TECO facility. Therefore, KDAQ should not assume that 25 ppmvd has been accepted as BACT for the TECO facility.

2. We are confused concerning whether the NO_x emissions listed in KDAQ's preliminary determination and draft permit are consistent with the most recent emissions estimates provided by the applicant. The annual NO_x emission rate listed on page 9 of the preliminary determination for the entire project is 1060.1 tons per year (tpy), whereas the annual NO_x emissions rate listed in the applicant's revised emissions estimates dated August 3, 2000, for the two combustion turbines alone range from 1,337 tpy for the first year of operation to 1,187 tpy for operation after the first two years of operation. More importantly, the combustion turbine NO_x emissions limit in the draft permit for synthetic fuel combustion is 0.072 pounds per million Btu (lb/MMBtu), but the estimate in the applicant's August 3, 2000, application revision is 0.0735 lb/MMBtu. We request that KDAQ review the preliminary determination and draft permit to confirm that they are based on the most recent information for the project.

3. The applicant and KDAQ have identified two options for minimization of SO_2 emissions from the combustion turbines, as summarized on pages 40 to 42 of the preliminary determination. The top two control methods are identified as amine-based acid gas cleanup (which is the applicant's choice) and flue gas desulfurization (FGD). Another option that would provide an even greater level of control than either of these methods individually is a combination of the two, that is, amine-based acid gas cleanup to remove sulfur prior to combustion and FGD to remove SO_2 after combustion. Although this combination might be prohibitively expensive, we request that KDAQ consider acid gas cleanup combined with FGD as the "top" technically feasible option when arriving at a final BACT determination.

4. Section B.4. of the draft permit excludes startup and shutdown periods from compliance with emissions limits. We consider periods of startup and shutdown to be part of normal source operation, and we recommend that KDAQ consider including more specific BACT requirements for startup and shutdown in the final PSD permit. Startup and shutdown control options that could be considered include (but are not limited to) the following: limitations on the number of startups and shutdowns in any 12-month period; limitations on the number of hours allowed in any 24-hour period for excess NO_x and CO emissions due to startup and shutdown conditions; mass emission limits for NO_x and CO emissions during any 24-hour period to include emissions during startup and shutdown; and future establishment of startup and shutdown BACT emission limits for NO_x derived from test results during the first few months of commercial operation. At a minimum, the final permit should include a definition of the words startup and shutdown in terms of the observable operating conditions that indicate a period of startup and a period of shutdown.

5. We direct your attention to a possible discrepancy in the averaging period to be used for assessment of compliance with SO_2 emissions limits. Section B.2.c) of the draft permit states that the SO_2 emissions limit is based on "any rolling three-hour average period." Section B.4.h) states that "... if any 24-hour rolling average sulfur dioxide value exceeds ...." We request that you review these two permit conditions and make revisions if needed.

6. In terms of the air quality impact assessment, our review comments on the PSD permit application and KDAQ preliminary determination are provided below. Because the modeling computer files were not available, they were not included in our review.

    a. Alternate Operational Scenarios - Only one operational scenario was modeled in the application. To ensure the worst-case ambient impact is considered in the modeling, other possible operational scenarios (e.g., independent partial load for each of the two combined-cycle turbines) should be considered, or each combustion turbine should be limited to nearly full load operation.

b. Modeling Receptor Grid - The receptor grid spacing of 1.0 km is not sufficient to identify the maximum concentration close to the facility (e.g., within 5 km of the facility). Confirmation is needed that the refined 100-m grids were of sufficient size to ensure adequate coverage of the area between coarse grid points. To ensure identification of maximum concentrations for 100-m grid modeling, smaller grid spacings (e.g., 200-500 meters) are needed within the first few kilometers of the site boundary.

c. Site Boundary - A figure in the permit application indicates the site boundary as the rail loop about the facility. The application indicates a 100-m interval receptor grid was placed about the fenceline. Confirmation is needed that the modeled site boundary is an actual fence containing property owned or controlled by Kentucky Pioneer Energy. If this is different from the rail loop about the site, the fenceline should be identified.

d. Class I Area Analysis - The PSD class I area analysis provided in the application does not follow the modeling guidance provided by EPA and the class I area federal land managers (FLMs): (1) the ISCST3 model is not appropriate beyond 50 km; (2) improper class I PSD significant impact levels were used; and (3) the visibility assessments beyond 50 km from the facility should be for regional haze. The preliminary determination indicates the federal land manager of the nearest class I area (National Park Service) has performed a CALPUFF screening assessment for all air quality related values and found no significant adverse impacts. The maximum CALPUFF ambient concentrations in the Class I area should be provided to confirm that they are less than the appropriate PSD Class I significant impact levels.

e. Air Toxics Impact Assessment - The procedure used to assess the ambient impacts of non-criteria toxic emissions was reviewed by the Kentucky Division of Environmental Services. Their comments, provided in a memo dated September 29, 2000, need to be resolved.

7. We have the following comments related to NSPS for municipal waste combustor (MWC) units in 40 C.F.R. part 60, subpart Eb and for stationary gas turbines in 40 C.F.R. part 60, subpart GG:

<u>Section B, Part 1, Operating Limitations</u>

In Condition #1g, line 5, change to read - "...of this section, **a fully certified shift supervisor, or a provisionally certified shift supervisor who is scheduled to take the full certification exam according to the schedule specified in paragraph (b) of this section**." [reference §60.54b(c)]

In Condition #1g, add the requirements of §60.54b(c)(2) - "**If one of the persons listed**

in paragraph (c) of this section must leave the affected facility during their operating shift, a provisionally certified control room operator, who is onsite at the affected facility may fulfill the requirement in paragraph (c) in this section."

In Condition #1h, the second sentence should be changed to include all of the elements outlined in §60.54b(e)(1) through (e)(11).

In Condition #1h, add the requirements of §60.54b(g) - "**The operating manual required by paragraph (e) of this section shall be kept in a readily accessible location for all persons required to undergo training under paragraph (f) of this section. The operating manual and records of training shall be available for inspection by the EPA or Kentucky DAQ.**"

In Condition #1i, change the condition to read - "Pursuant to **40 C.F.R. 60.57b(a) and (b), a preliminary and draft final materials separation plan and a siting analysis plan shall be prepared for the facility.**" These applicable NSPS requirements are listed in the draft permit, however, compliance with the requirements for preparation of the preliminary and draft final materials separation plan and the siting analysis plan must be completed before the final construction permit can be issued. Information to fulfill the requirements of §60.57b(b)(1) and (b)(2) for preparing the siting analysis plan can be taken from the PSD permit application. Preparation of the materials separation plan for the facility and its service area must include the information required by §60.57b(a)(2)(iii)(A) through (H) and may not be available in the PSD permit application. A public meeting to accept comments on the preliminary draft materials separation plan and siting analysis must be conducted as outlined in §60.57b(a) and (b).

<u>Section B, Part 2, Emission Limitations</u>

In Condition #2c, line 2, the emission limitation for sulfur dioxide is listed as 0.032 lb/MMBtu with no corresponding parts per million (ppm) basis. Condition #2c should also list the §60.52b(b)(1) limit for sulfur dioxide of "**30 ppm by volume or 20 percent of the potential sulfur dioxide emission concentration (80 percent reduction by weight or volume), corrected to 7% oxygen (dry basis), whichever is less stringent.**"

In Condition #2j, line 2, change to read - "...shall not exceed 0.080 milligrams per dry standard cubic meter **or 15 percent of the potential mercury emission concentration (85 percent reduction by weight), corrected to 7% oxygen, whichever is less stringent.**"

In Condition #2k, verify that the hydrogen chloride limit is correctly stated as "0.2 ppm, corrected to 15% oxygen." The limit from §60.52b(b)(2) is "25 ppm by volume or 5 percent of the potential hydrogen chloride emission concentration (85 percent reduction by weight or volume), corrected to 7% oxygen (dry basis), whichever is less stringent."

In Condition #21, verify that the dioxin/furan limit of "0.01 nanograms per dry standard cubic meter, corrected to 7% oxygen," is measured as toxic equivalency or total mass and annotate that measure in the permit condition. The dioxin/furan total mass emissions limit from §60.52b(c)(2) is "13 nanograms per dry standard cubic (total mass), corrected to 7% oxygen."

<u>Section B, Part 3, Testing Requirements</u>

In Condition #3a, line 3, change "40 C.F.R. 60.335" to "**40 C.F.R. 60.335(f)**."

Add Condition #3b as a new condition and, after other revisions, renumber after b, to read as follows - "**Pursuant to Regulation 40 C.F.R. 60.58b, in conducting performance tests required by 40 C.F.R. 60.8, the owner or operator shall use as reference methods and procedures the test methods in Appendix A of Part 60, except as provided for in 40 C.F.R. 60.8(b).**" This will ensure that alternatives to test methods are approved by the appropriate EPA Region 4 authority or KDAQ authority, depending on the minor, intermediate, or major change to a test method under consideration as an alternative.

In Condition #3b, change to read - "Pursuant to Regulation 401 KAR 50:045 **and 40 C.F.R. 60.58b,** ...." [reference §60.58b(h)]

In Condition #3c, change to read - "Pursuant to Regulation 401 KAR 50:045 **and 40 C.F.R. 60.58b,** ...." [reference §60.58b(e)]

In Condition #3d, line 2, change to read - "...carbon monoxide, in accordance with General Condition G(d)(5)."

In Condition #3e, line 2, change to read - "...particulate matter, in accordance with General Condition G(d)(5)."

Condition #3h should be deleted, since it is repeated verbatim in the General Conditions as G(d)(6).

In Condition #3i, line 2, change to read - "...cadmium, lead and mercury using EPA Reference Method 29, in accordance with General Condition G(d)(5)."

In Condition #3j, line 2, change to read - "...hydrogen chloride using EPA Reference Method 26 or 26A, in accordance with General Condition G(d)(5)."

In Condition #3k, line 2, change to read - "...dioxins and furans using EPA Reference

Method 23, in accordance with General Condition G(d)(5)."

Section B, Part 5, Specific Recordkeeping Requirements

Add Condition #5g as a new condition, to read as follows - "**Pursuant to Regulation 40 C.F.R. 60.59b, the permittee shall maintain records of the information specified in paragraphs (d)(1) through (d)(15) of this section, as applicable, for this facility for a period of at least 5 years.**" [reference §60.59b(d)]

Section B, Part 6, Specific Reporting Requirements

In Condition #6p, line 3, change to read - "...fuels planned for use **in the unit,** the unit capacity...

Add Condition #6q as a new condition, to read as follows - "**Pursuant to Regulation 40 C.F.R. 60.59b, the owner or operator shall submit to the Division's Frankfort Regional Office the preliminary and final draft materials separation plan information specified in paragraphs (a)(1) through (a)(4) of this section.**" [reference §60.59b(a)]

Section B, Emissions Unit: 05 (05) - Vitrified Frit Handling Operations

In Testing Requirements, first sentence, change to read - "Pursuant to Regulation 40 C.F.R. 60.55b **and 60.58b**, the owner or operator shall conduct initial and annual performance tests for fugitive particulate emissions using EPA Reference Method 22, in accordance with General Condition G(d)(5)." [reference §60.58b(k)] See comment regarding new Condition #3b for additional information.

Section D, Source Emission Limitations and Testing Requirements

Renumber Condition #3 to #2.

If you have any questions concerning the comments in this letter, please contact Jim Little of the EPA Region 4 staff at (404) 562-9118.

Sincerely,

/s/

R. Douglas Neeley
Chief
Air and Radiation Technology Branch
Air, Pesticides, and Toxics

From: Shannon Todd [sktodd@tecoenergy.com]
Sent: Thursday, May 10, 2001 4:18 PM
To: Halpin, Mike
Cc: Laura Crouch
Subject: Polk NOx BACT

halpin1_.doc

Mike,

Attached is the letter with additional information on the Polk NOx BACT Determination for your consideration. This letter will be sent today via FedEx and should arrive tomorrow. If you have any questions, feel free to call me at (813) 641-5125.

-Shannon

May 10, 2001

Mr. Michael Halpin, P.E.
New Source Review Section
Florida Department of Environmental Protection
111 South Magnolia Avenue, Suite 4
Tallahassee, Florida 32301

Via Fed Ex
Airbill No. 7900 4812 1562

Re: Polk Power Station Unit 1
Syngas Fired Combustion Turbine NO_x BACT Determination

Dear Mr. Halpin:

Tampa Electric Company (TEC) would like to take this opportunity to submit additional information regarding the Best Available Control Technology (BACT) determination for Polk Power Station Unit 1. This information is submitted as a follow up to our meeting of April 3, 2001, and subsequent communications via telephone. This submittal is comprised of three main elements, an overview of the original BACT evaluation, a refined BACT cost analysis, and information regarding a recently permitted syngas fired Combustion Turbine (CT) installation. Furthermore, if deemed acceptable, TEC would like to work with the Florida Department of Environmental Protection (FDEP) in developing a continuous improvement program (CIP) to reduce NO_x emissions from Polk Unit 1 through the use of process optimization and equipment upgrades.

The Original BACT Evaluation

In the course of developing the original BACT evaluation, TEC was required to consider "data gathered on this facility, other similar facilities, and manufacturer's research." In taking this approach, TEC determined that a NO_x limit of 25 ppmvd @15% O_2 was appropriate as an emission limit. This would allow TEC to continue firing its present array of fuels while generating safe and reliable electricity to serve its customers.

In subsequent discussions with FDEP, TEC has come to understand that the Department may be considering the application of a selective catalytic reduction (SCR) system to Polk Unit 1 as BACT. In the original BACT submittal, TEC outlined several technical concerns with the application of this technology to an Integrated Gasification Combined Cycle (IGCC) facility, and, based on discussions with several catalyst vendors, these overriding technical concerns remain. The most significant of these concerns is the formation of ammonium sulfate and ammonium bisulfate compounds. These compounds, when formed in the Heat Recovery Steam Generator (HRSG) will cause significant plugging and fouling of heat transfer equipment, which could require several additional outages per year to allow for the cleaning of this equipment.

Since the manufacturer of the combustion turbine, General Electric, believes that SCR is not applicable to this unit, no other IGCC in the United States currently employs SCR technology, and the testing performed at the Polk facility demonstrated that 25 ppmvd @15% O_2 is a reasonable limit, TEC feels that based on the criteria established by the Department for this evaluation, a SCR system can clearly be eliminated as a BACT recommended technology for Polk Unit 1.

Refined BACT Cost Analysis

Due to the fact that the original submittal was required within 30 days of the completion of the test program, TEC based the original SCR cost analysis on vendor quotes for other facilities that did not fire syngas as a primary fuel. Since that time, TEC has solicited additional input from four SCR equipment vendors to refine the cost analysis presented in the initial submittal. Of the four vendors contacted, two vendors submitted no-bid responses, one of whom was Englehard. This point is important as the original submittal was based on an Englehard quote for a facility that was not an IGCC. The SCR quote that is used in this current analysis was provided by Deltak. The quote is enclosed as Attachment 1 to this letter and serves as a basis for the cost analysis performed in this submittal.

The Deltak quote specifies an outlet NO_x concentration from the SCR of 5 ppmvd corrected to 15% oxygen. Because this quote is based on this exit concentration, the 5 ppmvd value is used as the controlled NO_x value when estimating cost effectiveness, and the baseline for NO_x emissions remains at 25 ppmvd. The baseline emissions from oil firing (i.e., back up fuel firing) is 42 ppmvd, and the SCR system is expected to have the same 80% control for the NO_x emissions when firing oil as when controlling syngas firing. Therefore, the associated controlled NO_x emission rate during oil firing would be 10.5 ppmvd. Although oil is only fired for a maximum of 10% of the total allowable operation, the emissions reductions from the oil case represent approximately 21% of the total emissions reductions. Thus, because the maximum allowable back up fuel firing load is used in the estimation of cost effectiveness, the cost effectiveness calculations tend to be conservative in nature (i.e., will tend to under estimate the cost per ton of pollutant removed because back up fuel is typically fired in considerably less quantities than the allowable limit).

The Deltak quote includes the following statement on the first page regarding concerns with ammonia sulfate and ammonia bisulfate deposition and plugging. The fact that two vendors elected not to bid on this project coupled with the placement of this concern on the cover page of the Deltak quote lends credence to the overall priority that equipment vendors place on this concern.

> *I would like to note one potential problem with retrofitting SCR into the subject HRSG. There is a rather high SO_2 loading in the exhaust gas stream due to the combustion of syn-gas in the combustion turbine. Approximately 5% of the SO_2 in the gas stream will oxidize to SO_3 across the catalyst. This additional SO_3 along with the unspecified level of SO_3 in the combustion turbine exhaust will combine with the injected ammonia (NH_3) to form ammonium salts (primarily ammonium bisulfate) that are likely to adhere to the tubing in the cooler HRSG sections causing both a thermal insulation effect and/or an increase in turbine back pressure. With the fuel that is being burned, and the potential for Fuel Oil back-up fuel, the potential for ammonium salt fouling will be quite significant.*

Based on this concern, TEC estimates that the HRSG and down stream exhaust ductwork will need to be cleaned three times per year, at a minimum. The cost estimate includes two entries to account for these costs. The first entry is the annualized costs of HRSG maintenance that is expected to occur with increased degradation and corrosion of the heat transfer media. These estimates were prepared by plant personnel, taking into account the anticipated increased tube replacement costs that will be incurred starting in the third year after the installation of the SCR unit. These costs were estimated through ten years, then converted to an annualized recurring cost using engineering economic accounting methods.

In addition to the HRSG maintenance costs, contract labor costs are included for performing the anticipated cleanings. One cleaning will be performed during a scheduled outage, and two cleanings will be performed during unscheduled outages. The contract labor costs involved with the cleaning will be incurred by TEC during each of the outages. The estimated cleaning cost is $60,000 per occurrence.

During the scheduled outage, there are no additional costs that are incurred by TEC. However, during the unscheduled outages that are performed solely to address the plugging, TEC will incur costs associated with the loss of generating capacity. During these unscheduled outages, TEC will need to replace the electricity that would otherwise be generated by the Polk facility (i.e., 315 MW). The basis for estimating the incremental replacement cost of $20 per MW-hour is presented on page 6-22 of the November 2000 submittal.

TEC believes the incremental costs to replace the electrical power that would otherwise be generated by the Polk facility to be a real and valid cost that is associated with an unscheduled outage. During the meeting between FDEP and TEC, the Department had indicated that additional supporting information for the use of this cost estimate is warranted, especially as it related to United States Environmental Protection Agency (USEPA) guidance on accounting for lost power generation capacity during plant outages. TEC understands USEPA guidance to state that during scheduled outages, or those events that can reasonably take place during scheduled outages, it is not appropriate to account for the lost generation capacity. As such, costs for events such as catalyst replacement and one cleaning of the catalyst per year are estimated without the additional costs of replacing the power that would otherwise be generated by the facility.

However, because the Polk facility is a base load unit on TEC's system and has a current overall availability commitment of 86.5%, any unscheduled outages will incur considerable costs to TEC, especially if these unscheduled outages will affect the ability of the Polk facility to meet this availability commitment. TEC believes the estimated incremental cost for electrical generation or purchase to be a real cost that would be incurred by the facility during any unscheduled outage, regardless of the reason for the outage. This cost is one of the reasons that unscheduled outages get prompt attention of engineering and maintenance staff, including subcontractors, to return the facility to normal operational mode.

TEC believes that the cost of replacing the power generation capacity lost during an unscheduled outage is a real and justifiable cost that must be included in the performance of the economic analysis of control options. To provide a complete analysis to FDEP, TEC has provided the information on cost effectiveness analysis for both cases, with and without the incremental cost for power replacement Attachment 2.

The revised cost effectiveness estimate for the SCR control of NO_x is $5,737 per ton of NO_x removed, as summarized in Table 1. This cost takes into account the incremental cost of replacing power during two unscheduled outages per year. Table 2 presents the cost effectiveness of $3,499 per ton, which does not take into account the incremental cost for replacing power during the outage. Tables 3 through 5 contain supporting information regarding costs estimates used for this analysis. This analysis follows the same approach that was used in the November 2000 submittal, hence is not described in further detail.

The incremental cost of replacing the lost power generating capacity is approximately 40% of the total cost associated with the SCR. TEC has serious concerns regarding the fouling, plugging and corrosion of components downstream of the SCR in the high sulfur environment, and believes these cost estimates to be conservatively low. Because there is a shortage of practical experience of CT SCR performance in high sulfur environments, these estimates are based on expected performance, not actual data. TEC is aware of predictions by equipment vendors (e.g., General Electric) that account for considerably more difficulties and associated costs that TEC is taking into account in this cost analysis.

Recent Syngas Fired CT BACT Determination

The Kentucky Pioneer Energy LLC facility proposed for Trapp, Kentucky is currently undergoing the public review of its draft Prevention of Significant Deterioration (PSD) permit. This permit proposes NO_x BACT of 15 ppmvd for syngas firing, and 25 ppmvd for back up fuel (i.e., natural gas) firing. The NO_x control technology selected for this facility is steam injection. The subject equipment includes two CTs which are GE 7FA CTs, each rated at 197 MW without the associated HRSG.

Discussions with Mr. Donald Newell, the Commonwealth of Kentucky permit engineer, indicate that no questions were raised to date by the public regarding the proposed BACT emissions limit. The questions raised by the public concerned other items, such as the placement of lights at the facility to minimize light pollution, the need to keep the public informed of what is happening at the facility, mercury emissions and the impacts of burning municipal solid waste on rainwater.

The USEPA has questioned certain aspects of the BACT determination for the facility, but has not determined that add-on controls (e.g., an SCR) are cost effective or technically feasible. The questions from the USEPA are included as Attachment 3. The questions raised in this letter regard specific aspects of the BACT determination for the facility, and ask for supporting information to validate the concerns regarding the implementation of SCR on an IGCC CT. For example, regarding validation of the plugging concerns, the USEPA states:

> *We would be more persuaded if the applicant were to provide information directly from one or more HRSG vendors discussing why ammonium bisulfate salts pose a greater problem for combined cycle combustion turbine HRSG=s than for coal-fired boilers.*

Additional concerns raised by the USEPA address other aspects of the BACT determination, such as cost data and the survey of other similar facilities conducted to support the permit application. Mr. Newell indicated that he is in the process of collecting additional information to support his determination of steam injection meeting BACT, and will be responding to USEPA comments. Mr. Newell expressed concerns with reliability and clogging of equipment as a result of using an SCR system.

Until a final determination of the BACT is made for this Kentucky facility, TEC feels it is inappropriate to use the fact that questions are being raised by USEPA as a justification for requiring SCR as BACT for the Polk facility. First, the BACT process is interactive in nature, allowing for all concerned parties (e.g., citizen groups, USEPA, and affected Class I area managers) to provide their input and comments. The final BACT determination takes into account these comments, as well as other factors that are reviewed by the permitting agency. Additionally, many of the questions raised by the USEPA regarding the Kentucky BACT determination either do not apply to the Polk facility, or already were addressed by TEC in prior submittals.

Additionally, the CT at the Polk facility, although similar to the CTs proposed for the Kentucky facility, is approximately two generations in technological advances behind the CTs that will be installed in Kentucky. This point is further discussed in the November 2000 submittal. Thus, because the CT at the Kentucky facility is expected to achieve 15 ppmvd NO_x emissions, it is not appropriate to expect the Polk CT to achieve the same level of emissions.

Conclusions

Through the use of a CIP, TEC is willing to work with the Department to reduce NO_x emissions from the Polk facility. This program would investigate the use of process optimization and the addition of hardware where applicable to minimize the formation of NO_x rather than remove it from the flue gas stream. This is a prudent approach to the minimization of NO_x emissions from Unit 1, and does not carry with it the significant technical concerns associated with the addition of a post combustion control technology such as SCR.

TEC has considerable technical concerns with the use of an SCR system at this facility because of the high sulfur content of the exhaust gas, and these concerns are shared by several SCR vendors. Although TEC has tried to incorporate the costs associated with these concerns into the cost effectiveness analysis, the costs are based on estimated difficulties, not on data from similar facilities because there are no similar IGCC facilities that operate an SCR unit. Since the control cost effectiveness evaluation was conservative in nature, TEC believes the cost effectiveness value of $5,737 per ton of NO_x removed to be a lower bound of the cost, and actual costs of an SCR may be substantially higher. Based on this analysis, TEC believes the SCR control option to be both technically and economically infeasible.

Thank you in advance for your consideration of this matter. If you have any questions regarding the information contained in this submittal, please feel free to telephone Shannon Todd or me at (813) 641-5125.

Sincerely,

Gregory M. Nelson, P.E.
Director
Environmental Affairs

EA/gm/SKT253

Attachments

c: Mr. A.A. Linero – FDEP
Mr. Jerry Kissel - FDEP SW

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

TAMPA ELECTRIC

RECEIVED

APR 09 2001

BUREAU OF AIR REGULATION

April 6, 2001

Mr. Clair Fancy
Florida Department of Environmental Protection
111 South Magnolia Drive, Suite 4
Tallahassee, Florida 32301

Via FedEx
Airbill No. 7915 2139 2472

Re: Tampa Electric Company (TEC) – Polk Power Station Title V Permit BACT Determination for Syngas Combustion Turbine – Test #7

Dear Mr. Fancy:

During the review of the Polk Power Station NO_x BACT Determination, it was discovered that the turbine summary data table titled "Polk Power Station Unit 1 BACT #7" found in Appendix B of the seventh test report contained data for October 18, 2000 rather than October 17, 2000; the actual test date. The enclosed table corrects this error and contains the turbine data for October 17, 2001. Please replace the original data table with the one enclosed.

If you have any questions, please feel free to contact me at (813) 641-5125.

Sincerely,

Shannon K. Todd
Engineer
Environmental Affairs

EP\gm\SKT247

Enclosures

c/enc: Mr. Al Linero – FDEP
Mr. Mike Halpin - FDEP
Mr. Jerry Kissel - FDEP SW

POLK POWER STATION UNIT 1 BACT #7

10/17/2000	1MIN	Gas Flow lb/sec	Load Watts	Gen Watts	Heating Content, BTU/IB	N2 Flow	Inlet Temp, Deg,F	Bar, Press
10/17/2000	Date:Time	1TSYFI910	1PWRJI900	1GMLJI962	1TSYJYI910	NITFI920	1TMSTI922M	1TMSPI909
Polk 1	17-Oct-00 10:30:00	99.62400818	191.873138	192.6472	174.954071	111.581	73.12463379	29.857426
	17-Oct-00 10:31:00	100.0039673	191.578033	192.66579	174.954071	111.295	73.71014404	29.857327
	17-Oct-00 10:32:00	100.1067505	192.141251	192.68437	174.954071	110.502	74.47385406	29.857227
	17-Oct-00 10:33:00	99.42021179	192.040085	192.70297	174.954071	111.324	74.69023895	29.857128
	17-Oct-00 10:34:00	99.86873627	192.213745	192.72156	174.954071	112.134	73.8343811	29.857031
	17-Oct-00 10:35:00	99.87377167	191.852097	192.67868	174.954071	111.283	73.22729492	29.856932
	17-Oct-00 10:36:00	99.87773895	191.811249	192.582	174.954071	111.173	73.63794708	29.856833
	17-Oct-00 10:37:00	99.96877289	191.794754	192.48532	174.954071	111.363	74.54411316	29.856733
	17-Oct-00 10:38:00	99.90661621	191.866409	192.45126	174.954071	111.745	74.72731781	29.856636
	17-Oct-00 10:39:00	99.9093399	191.938065	192.472	174.954071	112.344	74.78911591	29.856537
	17-Oct-00 10:40:00	99.75204468	191.739304	192.49275	174.954071	112.059	74.85092163	29.856438
	17-Oct-00 10:41:00	99.80929565	192.039337	192.51349	174.954071	111.492	74.91271973	29.856339
	17-Oct-00 10:42:00	99.88878632	191.749359	192.53423	174.954071	111.791	74.97451782	29.856239
	17-Oct-00 10:43:00	100.1504593	191.787338	192.55498	174.954071	111.418	74.65851593	29.856142
	17-Oct-00 10:44:00	100.1126938	191.634247	192.57571	174.954071	111.704	74.59712219	29.856043
	17-Oct-00 10:45:00	99.96179199	191.491318	192.59645	174.954071	110.625	74.53572845	29.855944
	17-Oct-00 10:46:00	100.0699005	191.643158	192.6172	174.954071	111.106	74.47432709	29.855844
	17-Oct-00 10:47:00	99.92645264	191.795013	192.63794	174.954071	110.913	74.41293335	29.855747
	17-Oct-00 10:48:00	99.94142914	192.319717	192.65868	174.954071	111.501	74.6337738	29.855648
	17-Oct-00 10:49:00	99.75979614	191.563446	192.67943	174.954071	112.142	74.94226074	29.855549
	17-Oct-00 10:50:00	99.77153015	191.728546	192.70016	174.954071	111.781	74.78952026	29.85545
	17-Oct-00 10:51:00	99.8414917	191.893646	192.7209	174.954071	111.994	74.79803467	29.855352
	17-Oct-00 10:52:00	99.59534454	191.69278	192.69728	174.954071	111.104	74.88529968	29.855253
	17-Oct-00 10:53:00	99.85980988	191.886398	192.63736	174.954071	111.562	75.31647491	29.855154
	17-Oct-00 10:54:00	99.79956818	191.517166	192.60939	174.954071	111.434	75.31647491	29.855055
	17-Oct-00 10:55:00	100.1811523	191.375793	192.60939	174.954071	111.489	75.08163452	29.854958
	17-Oct-00 10:56:00	100.09552	191.565598	192.60939	174.954071	111.89	74.37712097	29.854858
	17-Oct-00 10:57:00	100.0772095	191.639496	192.60939	174.954071	112.093	74.4938736	29.854759
	17-Oct-00 10:58:00	99.88398743	191.650452	192.60939	174.954071	111.643	74.89753723	29.85466
	17-Oct-00 10:59:00	99.83202362	191.766586	192.60939	174.954071	111.939	75.88339996	29.854561
	17-Oct-00 11:00:00	99.80254364	191.718292	192.60939	174.954071	111.063	75.57968903	29.854464
	17-Oct-00 11:01:00	99.75766754	191.610229	192.60939	174.954071	111.757	75.35697174	29.854364

POLK POWER STATION UNIT 1 BACT #7

17-Oct-00 11:02:00	100.0191498	191.827911	192.60939	174.954071	110.915	75.66068268	29.854265
17-Oct-00 11:03:00	99.92171478	192.185211	192.60939	174.954071	111.039	75.92369843	29.854166
17-Oct-00 11:04:00	99.95223999	191.905579	192.60939	174.954071	111.428	75.82047272	29.854069
17-Oct-00 11:05:00	100.074707	191.936096	192.60939	174.954071	111.808	75.71723938	29.85397
17-Oct-00 11:06:00	99.90463257	191.804001	192.60939	174.954071	112.538	75.57902527	29.85387
17-Oct-00 11:07:00	99.79013824	191.979248	192.60939	174.954071	111.731	75.00335693	29.853771
17-Oct-00 11:08:00	99.91147614	191.809082	192.60939	174.954071	111.808	75.06539917	29.853674
17-Oct-00 11:09:00	100.0402908	191.638916	192.60939	174.954071	112.102	75.91377258	29.853575
17-Oct-00 11:10:00	100.0140076	191.605927	192.60939	174.954071	111.723	75.61006165	29.853476
17-Oct-00 11:11:00	99.63607788	191.692978	192.60939	174.954071	111.88	75.32629395	29.853376
17-Oct-00 11:12:00	99.78009796	191.780029	192.60939	174.954071	111.118	75.62089539	29.853277
17-Oct-00 11:13:00	99.80437469	191.805222	192.60939	174.954071	111.166	75.31647491	29.85318
17-Oct-00 11:14:00	99.89753723	191.835388	192.60939	174.954071	111.573	75.62089539	29.853081
17-Oct-00 11:15:00	99.90746307	191.552734	192.60939	174.954071	111.804	75.75574493	29.852982
17-Oct-00 11:16:00	99.97499847	191.937271	192.60939	174.954071	111.239	76.20246887	29.852882
17-Oct-00 11:17:00	99.96238708	191.804886	192.60939	174.954071	111.572	76.15524292	29.852785
17-Oct-00 11:18:00	100.1427994	191.813492	192.60939	174.954071	111.752	76.05313873	29.852686
17-Oct-00 11:19:00	99.96963501	191.770065	192.80276	174.954071	113.338	75.95103455	29.852587
17-Oct-00 11:20:00	99.76781464	191.943146	192.81082	174.954071	111.931	75.84893036	29.852488
17-Oct-00 11:21:00	100.0164413	191.532928	192.50868	174.954071	112.311	75.74682617	29.85239
17-Oct-00 11:22:00	99.73769379	191.735291	192.36769	174.954071	112.062	75.64472198	29.852291
17-Oct-00 11:23:00	99.95539856	191.903488	192.36769	174.954071	110.75	76.10101318	29.852192
17-Oct-00 11:24:00	99.88525391	191.887787	192.36769	174.954071	112.379	76.36519623	29.852093
17-Oct-00 11:25:00	100.056427	191.872101	192.36769	174.954071	111.563	76.51919556	29.851994
17-Oct-00 11:26:00	100.3948059	191.8564	192.36769	174.954071	111.766	77.01197052	29.851896
17-Oct-00 11:27:00	100.019989	191.869263	192.36769	174.954071	111.025	76.65778351	29.851797
17-Oct-00 11:28:00	99.92891693	191.685837	192.36769	174.954071	112.376	76.66635132	29.851698
17-Oct-00 11:29:00	99.93255615	191.915604	192.36769	174.954071	111.736	76.82161713	29.851599
17-Oct-00 11:30:00	99.95391083	191.787125	192.36769	174.954071	112.824	76.76044464	29.851501
17-Oct-00 11:31:00	99.97364807	191.705383	192.36769	174.954071	112.546	77.66661835	29.851402
17-Oct-00 11:32:00	99.64261627	192.077011	192.36769	174.954071	111.33	77.55012512	29.851303
17-Oct-00 11:33:00	100.0031281	191.625717	192.36769	174.954071	111.726	77.05303955	29.851204
17-Oct-00 11:34:00	99.7379303	191.66832	192.46437	174.954071	111.416	77.01197052	29.851107
17-Oct-00 11:35:00	100.0520325	191.710922	192.64565	174.954071	110.732	76.85250092	29.851007
17-Oct-00 11:36:00	100.031662	191.753525	192.69586	174.954071	112.143	76.87337494	29.850908

POLK POWER STATION UNIT 1 BACT #7

17-Oct-00 11:37:00	99.70114899	191.796127	192.63141	174.954071	111.815	76.56025696	29.850809
17-Oct-00 11:38:00	100.0153732	191.647079	192.56696	174.954071	111.523	76.69371796	29.850712
17-Oct-00 11:39:00	99.89013672	191.522415	192.51883	174.954071	110.644	77.11463928	29.850613
17-Oct-00 11:40:00	99.81169891	192.193176	192.485	174.954071	111.905	76.96063995	29.850513
17-Oct-00 11:41:00	99.697258	191.49585	192.45116	174.954071	112.06	77.14324951	29.850414
17-Oct-00 11:42:00	99.88671112	191.905273	192.41731	174.954071	111.96	77.0394516	29.850315
17-Oct-00 11:43:00	99.67871857	191.859985	192.38348	174.954071	111.716	76.93565369	29.850218
17-Oct-00 11:44:00	99.98565674	192.206696	192.40636	174.954071	112.086	76.78611755	29.850119
17-Oct-00 11:45:00	99.81109619	191.96814	192.47887	174.954071	112.549	77.0769043	29.850019
17-Oct-00 11:46:00	99.76637268	191.507462	192.55138	174.954071	112.009	76.98117065	29.84992
17-Oct-00 11:47:00	99.84021759	191.636978	192.62389	174.954071	111.889	77.1708374	29.849823
17-Oct-00 11:48:00	99.82670593	191.449631	192.65451	174.954071	111.2	77.94404602	29.849724
17-Oct-00 11:49:00	99.95635986	191.914795	192.64847	174.954071	111.115	77.58311462	29.849625
17-Oct-00 11:50:00	99.81594086	191.600235	192.64243	174.954071	112.195	77.73060608	29.849525
17-Oct-00 11:51:00	100.0169144	191.594833	192.63638	174.954071	111.145	77.42262268	29.849428
17-Oct-00 11:52:00	99.97146606	191.771896	192.63034	174.954071	112.814	77.32791138	29.849329
17-Oct-00 11:53:00	99.31424713	192.0159	192.6243	174.954071	114.825	77.81273651	29.84923
17-Oct-00 11:54:00	99.7056427	191.711731	192.61826	174.954071	116.004	77.81273651	29.849131
17-Oct-00 11:55:00	99.55458832	191.897949	192.61221	174.954071	116.37	77.70836639	29.849031
17-Oct-00 11:56:00	99.9710083	192.011719	192.60939	174.954071	116.905	77.21195984	29.848934
17-Oct-00 11:57:00	99.35849762	191.930664	192.60939	174.954071	116.397	77.36470032	29.848835
17-Oct-00 11:58:00	99.55181122	191.849609	192.60939	174.954071	116.74	77.5714798	29.848736
17-Oct-00 11:59:00	99.53305054	191.76857	192.60939	174.954071	116.77	78.110466	29.848637
17-Oct-00 12:00:00	99.34428406	191.565506	192.60939	174.954071	117.88	77.95646667	29.848539
17-Oct-00 12:01:00	99.4318924	191.889099	192.60939	174.954071	117.453	77.5304184	29.84844
17-Oct-00 12:02:00	99.50956726	191.618942	192.60939	174.954071	115.947	77.81273651	29.848341
17-Oct-00 12:03:00	99.42259216	191.735855	192.60939	174.954071	116.628	77.81273651	29.848242
17-Oct-00 12:04:00	99.89511108	192.096283	192.60939	174.954071	117.241	77.81273651	29.848145
17-Oct-00 12:05:00	99.7309494	191.932083	192.60939	174.954071	117.978	77.48934937	29.848045
17-Oct-00 12:06:00	99.52472687	191.767883	192.60939	174.954071	118.168	77.19693756	29.847946
17-Oct-00 12:07:00	99.46226501	191.824249	192.60939	174.954071	119.315	77.79186249	29.847847
17-Oct-00 12:08:00	99.57975769	191.967331	192.60939	174.954071	118.954	77.21730042	29.847748
17-Oct-00 12:09:00	99.88806152	191.717636	192.60939	174.954071	119.358	77.91201782	29.847651
17-Oct-00 12:10:00	99.26657104	191.661865	192.60939	174.954071	119.131	78.67572784	29.847551
17-Oct-00 12:11:00	99.4341507	191.700668	192.60939	174.954071	118.566	78.19772339	29.847452

POLK POWER STATION UNIT 1 BACT #7

17-Oct-00 12:12:00	99.55519104	191.555527	192.60939	174.954071	119.552	77.00074768	29.847353
17-Oct-00 12:13:00	99.60112	191.646469	192.60939	174.954071	119.131	77.98213196	29.847256
17-Oct-00 12:14:00	99.51071167	191.322662	192.60939	174.954071	118.398	78.34807587	29.847157
17-Oct-00 12:15:00	99.63084412	191.997406	192.62233	174.954071	118.374	78.4389801	29.847057
17-Oct-00 12:16:00	99.22039032	191.725571	192.64658	174.954071	119.054	77.681427	29.846958
17-Oct-00 12:17:00	99.57975769	191.694046	192.67082	174.954071	118.637	77.74600983	29.846861
17-Oct-00 12:18:00	99.36605835	191.493164	192.69508	174.954071	118.397	78.05400085	29.846762
17-Oct-00 12:19:00	99.53359985	191.452423	192.71933	174.954071	118.617	77.88973236	29.846663
17-Oct-00 12:20:00	99.06906128	192.06601	192.70815	174.954071	118.45	78.04373169	29.846563
17-Oct-00 12:21:00	99.08981323	191.874542	192.66797	174.954071	118.476	77.82801056	29.846464
17-Oct-00 12:22:00	99.24888611	192.026733	192.62781	174.954071	118.647	78.28623962	29.846367
17-Oct-00 12:23:00	99.31063843	191.957993	192.58763	174.954071	118.238	78.23023224	29.846268
17-Oct-00 12:24:00	99.60352325	191.822906	192.54745	174.954071	118.58	78.53650665	29.846169
17-Oct-00 12:25:00	99.55939484	191.68782	192.50729	174.954071	119.071	78.61790466	29.846069
17-Oct-00 12:26:00	99.50401306	191.905624	192.4944	174.954071	118.907	78.41145325	29.845972
17-Oct-00 12:27:00	99.47111511	191.852036	192.50539	174.954071	118.683	78.20500183	29.845873
17-Oct-00 12:28:00	99.43632507	191.798447	192.51637	174.954071	118.841	78.34915161	29.845774
17-Oct-00 12:29:00	99.59399414	192.07663	192.52736	174.954071	119.04	78.19515228	29.845675
17-Oct-00 12:30:00	99.59777069	191.921814	192.53835	174.954071	119.24	78.04116058	29.845577
17-Oct-00 12:31:00	99.51114655	191.965073	192.54933	174.954071	119.022	77.88716888	29.845478
17-Oct-00 12:32:00	99.47102356	191.996841	192.56032	174.954071	118.931	78.0873642	29.845379
17-Oct-00 12:33:00	99.50498962	191.859421	192.5713	174.954071	119.398	78.01036835	29.84528
17-Oct-00 12:34:00	99.52383423	191.991486	192.58229	174.954071	119.081	77.93336487	29.845182
17-Oct-00 12:35:00	99.6908493	191.968643	192.59328	174.954071	118.764	77.85636902	29.845083
17-Oct-00 12:36:00	99.3259201	191.621567	192.60426	174.954071	118.7	77.88002014	29.844984
17-Oct-00 12:37:00	99.04317474	191.759155	192.63087	174.954071	118.199	78.03528595	29.844885
17-Oct-00 12:38:00	99.22940826	191.522873	192.67116	174.954071	119.056	78.37837982	29.844786
17-Oct-00 12:39:00	99.23970795	191.994537	192.71144	174.954071	118.807	78.75209808	29.844688
17-Oct-00 12:40:00	99.92614746	192.043213	192.6817	174.954071	118.241	78.75209808	29.844589
17-Oct-00 12:41:00	99.32321167	192.134766	192.59068	174.954071	119.461	78.42871094	29.84449
17-Oct-00 12:42:00	99.24910736	191.990891	192.49966	174.954071	118.737	77.96800232	29.844391
17-Oct-00 12:43:00	99.38737488	191.781921	192.40865	174.954071	119.284	78.43379974	29.844294
17-Oct-00 12:44:00	99.61485291	191.572937	192.37244	174.954071	118.601	78.65294647	29.844194
17-Oct-00 12:45:00	99.55984497	191.655701	192.38107	174.954071	119.043	78.33982086	29.844095
17-Oct-00 12:46:00	99.47626495	191.343414	192.38971	174.954071	119.164	78.02670288	29.843996

POLK POWER STATION UNIT 1 BACT #7

17-Oct-00 12:47:00	99.62333679	191.528	192.39833	174.954071	119.065	78.18403625	29.843899
17-Oct-00 12:48:00	99.83000946	192.019272	192.40697	174.954071	119.415	78.38935852	29.8438
17-Oct-00 12:49:00	99.5973053	191.932068	192.4156	174.954071	119.257	78.59468079	29.8437
17-Oct-00 12:50:00	99.02432251	191.784882	192.42422	174.954071	118	78.53998566	29.843601
17-Oct-00 12:51:00	99.60913086	191.794037	192.43286	174.954071	119.374	77.96672821	29.843502
17-Oct-00 12:52:00	99.51480103	191.531799	192.4415	174.954071	118.934	78.73670197	29.843405
17-Oct-00 12:53:00	99.39767456	191.607727	192.45013	174.954071	118.76	79.32615662	29.843306
17-Oct-00 12:54:00	99.65354919	191.539566	192.45876	174.954071	118.847	78.65970612	29.843206
17-Oct-00 12:55:00	99.68502808	191.482193	192.46739	174.954071	119.043	78.24707031	29.843107
17-Oct-00 12:56:00	99.68205261	191.583359	192.47603	174.954071	118.61	79.06521606	29.84301
17-Oct-00 12:57:00	99.534935	191.840897	192.48465	174.954071	118.675	78.79059601	29.842911
17-Oct-00 12:58:00	99.55369568	191.600281	192.49329	174.954071	119.325	79.25257874	29.842812
17-Oct-00 12:59:00	99.450737	191.821213	192.50192	174.954071	118.943	79.66065979	29.842712
17-Oct-00 13:00:00	99.47309875	191.770172	192.51056	174.954071	118.416	79.06521606	29.842615
17-Oct-00 13:01:00	99.46032715	191.719131	192.51918	174.954071	118.616	79.06521606	29.842516
17-Oct-00 13:02:00	99.70298004	191.718735	192.52782	174.954071	118.864	78.44924927	29.842417
17-Oct-00 13:03:00	99.63597107	191.799789	192.53645	174.954071	118.311	78.4389801	29.842318
17-Oct-00 13:04:00	99.71877289	191.880844	192.54507	174.954071	119.299	78.4389801	29.842218
17-Oct-00 13:05:00	99.63614655	191.563156	192.55371	174.954071	118.487	78.98822021	29.842121
17-Oct-00 13:06:00	99.5535202	191.507034	192.56235	174.954071	118.053	78.78289795	29.842022
17-Oct-00 13:07:00	99.80727386	191.709671	192.57098	174.954071	119.214	79.3157196	29.841923
17-Oct-00 13:08:00	99.9223938	191.85376	192.57961	174.954071	119.574	79.46798706	29.841824
17-Oct-00 13:09:00	99.67345428	191.822235	192.58824	174.954071	119.367	79.29011536	29.841726
17-Oct-00 13:10:00	99.3509903	191.747635	192.59688	174.954071	119.125	79.18631744	29.841627
17-Oct-00 13:11:00	99.72815704	191.618927	192.6055	174.954071	119.352	79.08251953	29.841528
17-Oct-00 13:12:00	99.35170746	191.571121	192.60464	174.954071	119.126	79.37834167	29.841429
17-Oct-00 13:13:00	99.63479614	191.640915	192.59601	174.954071	118.914	78.97180176	29.841331
17-Oct-00 13:14:00	99.62123871	191.710709	192.58737	174.954071	120.061	78.45281982	29.841232
17-Oct-00 13:15:00	99.59638977	191.780502	192.57875	174.954071	117.805	77.93383026	29.841133
17-Oct-00 13:16:00	99.69275665	191.853958	192.57011	174.954071	119.157	78.89350891	29.841034
17-Oct-00 13:17:00	99.73628235	191.480301	192.56148	174.954071	117.961	79.94197845	29.840937
17-Oct-00 13:18:00	99.18778992	192.198013	192.55286	174.954071	119.487	79.8693924	29.840837
17-Oct-00 13:19:00	99.91943359	191.577805	192.54422	174.954071	119.026	79.46833801	29.840738
17-Oct-00 13:20:00	99.62593079	191.709473	192.53558	174.954071	118.764	78.69631958	29.840639
17-Oct-00 13:21:00	99.62033081	191.841125	192.52695	174.954071	119.435	78.71274567	29.84054

POLK POWER STATION UNIT 1 BACT #7

17-Oct-00 13:22:00	99.50823975	191.745911	192.51833	174.954071	119.291	79.12339783	29.840443
17-Oct-00 13:23:00	99.41762543	191.646851	192.50969	174.954071	119.615	79.53404236	29.840343
17-Oct-00 13:24:00	99.63353729	191.637543	192.50105	174.954071	119.892	79.37834167	29.840244
17-Oct-00 13:25:00	99.8739624	191.646851	192.49243	174.954071	119.505	78.8393631	29.840145
17-Oct-00 13:26:00	99.73725891	191.408203	192.55501	174.954071	118.724	78.56934357	29.840048
17-Oct-00 13:27:00	99.72750092	191.526459	192.67586	174.954071	118.728	78.79938507	29.839949
17-Oct-00 13:28:00	99.69020081	191.699615	192.72285	174.954071	118.492	79.0294342	29.839849
17-Oct-00 13:29:00	99.5293808	191.872772	192.70943	174.954071	118.903	79.25948334	29.83975
17-Oct-00 13:30:00	99.63673401	191.633636	192.696	174.954071	119.238	79.23069	29.839653
17-Oct-00 13:31:00	99.81790924	191.989807	192.68257	174.954071	118.173	78.92520905	29.839554
17-Oct-00 13:32:00	99.4289093	191.928467	192.66914	174.954071	119.073	79.0147171	29.839455
17-Oct-00 13:33:00	99.50244141	191.57251	192.65572	174.954071	118.776	79.2530899	29.839355
17-Oct-00 13:34:00	99.41557312	191.50441	192.64229	174.954071	118.917	79.31160736	29.839256
17-Oct-00 13:35:00	99.69541931	191.834457	192.62886	174.954071	119.367	79.34090424	29.839159
17-Oct-00 13:36:00	99.21149445	191.573303	192.61543	174.954071	118.812	79.23880005	29.83906
17-Oct-00 13:37:00	99.54718018	191.792435	192.5695	174.954071	118.77	79.13668823	29.838961
17-Oct-00 13:38:00	99.41918945	191.674316	192.49699	174.954071	118.332	79.20365906	29.838861
17-Oct-00 13:39:00	99.62574005	191.752365	192.42448	174.954071	118.628	79.66514587	29.838764
17-Oct-00 13:40:00	99.70195007	191.830414	192.35197	174.954071	119.32	79.82377625	29.838665
17-Oct-00 13:41:00	99.71320343	191.591019	192.27945	174.954071	119.082	79.40557098	29.838566
17-Oct-00 13:42:00	99.76226044	191.64505	192.29648	174.954071	118.835	79.50767517	29.838467
17-Oct-00 13:43:00	99.81785583	192.009949	192.38673	174.954071	118.94	79.60977936	29.838369
17-Oct-00 13:44:00	99.53131104	191.673187	192.47701	174.954071	119.045	79.50666809	29.83827
17-Oct-00 13:45:00	99.75554657	191.857803	192.56726	174.954071	119.15	78.8374939	29.838171
17-Oct-00 13:46:00	99.41793823	191.66156	192.63087	174.954071	119.433	79.30329132	29.838072
17-Oct-00 13:47:00	99.17041016	191.787491	192.67116	174.954071	119.153	79.46798706	29.837973
17-Oct-00 13:48:00	99.53403473	191.948273	192.71144	174.954071	118.956	79.9603653	29.837875
17-Oct-00 13:49:00	99.67631531	191.961197	192.68703	174.954071	119.112	79.46840668	29.837776
17-Oct-00 13:50:00	99.75676727	191.752365	192.60602	174.954071	118.123	80.29864502	29.837677
17-Oct-00 13:51:00	99.58639526	191.672791	192.52499	174.954071	119.25	80.14337921	29.837578
17-Oct-00 13:52:00	99.41191101	191.801163	192.48439	174.954071	118.739	80.288414	29.837481
17-Oct-00 13:53:00	99.45313263	191.92955	192.47685	174.954071	118.97	79.69817352	29.837381
17-Oct-00 13:54:00	99.4974823	191.908905	192.4693	174.954071	118.856	79.89954376	29.837282
17-Oct-00 13:55:00	99.25626373	191.681824	192.46176	174.954071	118.373	80.100914	29.837183
17-Oct-00 13:56:00	99.60951233	191.723404	192.45421	174.954071	117.979	80.30228424	29.837086

POLK POWER STATION UNIT 1 BACT #7

17-Oct-00 13:57:00	99.57862091	191.764984	192.44667	174.954071	119.313	79.40936279	29.836987
17-Oct-00 13:58:00	99.67521667	191.752304	192.43912	174.954071	118.945	79.50003815	29.836887
17-Oct-00 13:59:00	99.44698334	191.543457	192.43158	174.954071	119.369	79.95774078	29.836788
17-Oct-00 14:00:00	99.51654816	191.8172	192.42403	174.954071	119.142	79.71682739	29.836691
17-Oct-00 14:01:00	99.64922333	191.924377	192.41649	174.954071	119.793	80.51704407	29.836592
17-Oct-00 14:02:00	99.5896759	191.95723	192.40894	174.954071	119.471	80.35005951	29.836493
17-Oct-00 14:03:00	99.80339813	191.557739	192.4014	174.954071	118.395	80.5716095	29.836393
17-Oct-00 14:04:00	99.6203537	191.542648	192.39384	174.954071	119.379	79.85928345	29.836294
17-Oct-00 14:05:00	99.62693787	191.527557	192.38631	174.954071	118.765	79.87759399	29.836197
17-Oct-00 14:06:00	99.44517517	192.048874	192.37875	174.954071	118.866	80.1055069	29.836098
17-Oct-00 14:07:00	99.52577972	191.584656	192.37122	174.954071	118.924	80.3334198	29.835999
17-Oct-00 14:08:00	99.56907654	191.7901	192.56105	174.954071	119.105	80.56134033	29.835899
17-Oct-00 14:09:00	99.87120819	191.995544	192.68727	174.954071	119.69	80.51100922	29.835802
17-Oct-00 14:10:00	99.7151947	191.692871	192.6067	174.954071	119.373	80.3595047	29.835703
17-Oct-00 14:11:00	99.44319153	191.381577	192.52614	174.954071	118.49	79.70857239	29.835604
17-Oct-00 14:12:00	99.31707001	192.08342	192.48854	174.954071	118.719	79.44371796	29.835505
17-Oct-00 14:13:00	99.50392914	191.806244	192.48854	174.954071	119.06	79.54694366	29.835407
17-Oct-00 14:14:00	99.39597321	191.482056	192.48854	174.954071	119.456	79.65016937	29.835308
17-Oct-00 14:15:00	99.36907959	191.992661	192.48854	174.954071	118.858	80.5348587	29.835209
17-Oct-00 14:16:00	99.40771484	191.862839	192.48854	174.954071	118.696	80.41166687	29.83511
17-Oct-00 14:17:00	99.46244049	191.549423	192.48854	174.954071	118.603	79.99588013	29.835011
17-Oct-00 14:18:00	99.42948914	191.843323	192.48854	174.954071	118.891	79.99588013	29.834913
17-Oct-00 14:19:00	99.68572998	191.843323	192.48854	174.954071	118.089	80.29889679	29.834814
17-Oct-00 14:20:00	99.66896057	191.843323	192.48854	174.954071	119.327	80.19493103	29.834715
17-Oct-00 14:21:00	99.64079285	191.843323	192.48854	174.954071	118.612	79.62158966	29.834616
17-Oct-00 14:22:00	99.45051575	191.802643	192.48854	174.954071	119.341	79.46632385	29.834518
17-Oct-00 14:23:00	99.06460571	191.787567	192.48854	174.954071	118.184	79.25437164	29.834419
17-Oct-00 14:24:00	99.65239716	191.649109	192.48854	174.954071	119.879	79.70835876	29.83432
17-Oct-00 14:25:00	99.63065338	191.629883	192.48854	174.954071	119.65	80.05188751	29.834221
17-Oct-00 14:26:00	99.34634399	191.665909	192.48854	174.954071	119.383	80.20462799	29.834124
17-Oct-00 14:27:00	99.8777771	191.70192	192.48854	174.954071	119.71	80.21147156	29.834024
17-Oct-00 14:28:00	99.78303528	191.552399	192.49365	174.954071	118.741	80.08981323	29.833925
17-Oct-00 14:29:00	99.41680908	191.94133	192.50294	174.954071	119.04	79.99588013	29.833826
17-Oct-00 14:30:00	99.32293701	191.815262	192.51225	174.954071	119.094	79.99588013	29.833727
17-Oct-00 14:31:00	99.21557617	191.638657	192.52155	174.954071	118.485	79.99588013	29.83363

POLK POWER STATION UNIT 1 BACT #7

17-Oct-00 14:32:00	99.64376831	191.548691	192.53084	174.954071	118.869	80.38085938	29.83353
17-Oct-00 14:33:00	99.47538757	191.411301	192.54013	174.954071	118.683	80.81204987	29.833431
17-Oct-00 14:34:00	99.39189911	191.549744	192.54942	174.954071	119.372	80.29027557	29.833332
17-Oct-00 14:35:00	99.44776917	191.601852	192.55873	174.954071	119.005	80.18817902	29.833235
17-Oct-00 14:36:00	99.15962219	191.835159	192.56802	174.954071	118.964	80.08607483	29.833136
17-Oct-00 14:37:00	99.27793121	191.778427	192.57732	174.954071	119.197	80.01384735	29.833036
17-Oct-00 14:38:00	99.40542603	191.72171	192.58661	174.954071	119.261	80.16783905	29.832937
17-Oct-00 14:39:00	99.39246368	191.942673	192.59592	174.954071	119.378	80.28333282	29.83284
17-Oct-00 14:40:00	99.30020905	191.801926	192.60521	174.954071	119.103	80.30389404	29.832741
17-Oct-00 14:41:00	99.74098969	191.589218	192.60497	174.954071	119.013	80.20178986	29.832642
17-Oct-00 14:42:00	99.80532074	191.876144	192.59691	174.954071	119.352	80.09968567	29.832542
17-Oct-00 14:43:00	99.30700684	191.782349	192.58885	174.954071	118.73	79.99758148	29.832443
17-Oct-00 14:44:00	99.45106506	191.726425	192.5808	174.954071	118.454	80.14730835	29.832346
17-Oct-00 14:45:00	99.55841827	191.766312	192.57274	174.954071	119.476	80.30130005	29.832247
17-Oct-00 14:46:00	99.53462982	191.757553	192.56468	174.954071	119.447	80.01641083	29.832148
17-Oct-00 14:47:00	99.56907654	191.572937	192.55663	174.954071	118.248	80.57078552	29.832048
17-Oct-00 14:48:00	99.42173767	191.563477	192.54857	174.954071	118.548	80.79291534	29.831951
17-Oct-00 14:49:00	99.48210144	192.144394	192.54051	174.954071	119.507	80.63764191	29.831852
17-Oct-00 14:50:00	99.76439667	192.139648	192.53246	174.954071	118.576	79.81154633	29.831753
17-Oct-00 14:51:00	99.64479828	192.246826	192.5244	174.954071	118.637	79.69145966	29.831654
17-Oct-00 14:52:00	99.54906464	192.293442	192.51634	174.954071	118.706	80.73134613	29.831556
17-Oct-00 14:53:00	99.49267578	191.555893	192.50829	174.954071	118.761	80.62211609	29.831457
17-Oct-00 14:54:00	99.61943054	192.016571	192.50023	174.954071	119.083	79.87759399	29.831358
17-Oct-00 14:55:00	99.45882416	191.995682	192.49217	174.954071	119.337	80.23593903	29.831259
17-Oct-00 14:56:00	99.54896545	191.974777	192.48412	174.954071	119.072	80.07668304	29.831161
17-Oct-00 14:57:00	99.43504333	191.953888	192.47606	174.954071	119.017	80.33466339	29.831062
17-Oct-00 14:58:00	99.53016663	191.430878	192.468	174.954071	119.217	80.79664612	29.830963
17-Oct-00 14:59:00	99.72592926	191.528931	192.45995	174.954071	118.992	80.40452576	29.830864
17-Oct-00 15:00:00	99.27587891	191.660583	192.45189	174.954071	119.01	80.57078552	29.830765
Averages	**99.65**	**191.77**	**192.55**	**174.95**	**116.61**	**78.12**	**29.84**

Suggested Agenda and Discussion Topics

Location: FDEP Offices Tallahassee, FL
Date: April 3, 2001
Time: 9:00 am
Subject: Polk Unit 1 NO_x BACT Determination

Tampa Electric Company requested this meeting to discuss any outstanding issues associated with the Polk Unit 1 NO_x BACT Determination. Below is a suggested list of discussion topics for this meeting.

1. Review of the last correspondence
   A. Additional questions
   B. Submittal completion status

2. Polk Power Station overview
   A. Coal plant
   B. Technology has not matured
   C. Process is variable by nature
   D. Clean Coal Demonstration Project

3. Review of BACT Submittal
   A. Existing operation
   B. Add on controls

FLORIDA

Department of
Environmental Protection

Jeb Bush
Governor

Marjory Stoneman Douglas Building
3900 Commonwealth Boulevard
Tallahassee, Florida 32399-3000

David B. Struhs
Secretary

February 23, 2000 2001

Mr. Gregg Worley, Chief
Air, Radiation Technology Branch
Preconstruction/HAP Section
U.S. EPA – Region IV
61 Forsyth Street
Atlanta, Georgia 30303

Re: Tampa Electric Company, Polk Power Station

Dear Mr. Worley:

We have supplied, under separate cover, a submittal from Tampa Electric Company (TEC) concerning their Polk Power Station. That facility incorporates an IGCC electrical generating unit (GE 7FA), which combusts synthetic gas. As a result of the original permitting which was done, the BACT Determination for NO_X (only) was to be executed after the facility was operating for a period of time, such that test data was available. We are now commencing our review of this project.

The applicant's recently submitted BACT Review concluded that the initial (temporary) permit limit (25 ppmvd @ 15% O_2) is appropriate for use in the future. This review rejected the use of SCR for multiple reasons, many of which can be seen from the attached 3 pages, representing a portion of TEC's responses to our questions of that BACT Review.

We would appreciate your review and comments on TEC's responses, and your specific comments regarding the application of SCR to this emissions unit. If necessary, additional information can be provided to assist in your review. Your comments can be forwarded to my attention at the letterhead address or faxed to me at (850) 922-6979. Please be aware that our review time of 30 days expires on March 21, provided that we have no further questions of TEC. If you have any questions, please contact Mike Halpin at (850) 921-9519.

Sincerely,

A. A. Linero

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

AAL/mph

w/ enclosures

FDEP Comment 3

In a November 8, 1999 letter, EPA Region IV established that BACT for combined cycle turbines is 3.5 ppm NO_x. (Note: EPA wrote the letter after the Florida Department of Environmental Protection proposed a 6 ppm NO_X limit for a GE combined cycle Frame 7 turbine with SCR). Recently (on November 17, 2000) the Department issued a draft permit and BACT Determination 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. This determination was made under the assumption that cost of NO_X control by SCR might be as high as $6,000 per ton (with ammonia emissions held to 5 ppmvd), which represents a NO_X control cost significantly higher than that offered in TECO's submittal.

a) Accordingly, this will 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.

b) The Department notes (in reviewing the records for this project), that although the final BACT Determination for NO_X (while firing syngas) was set at 25 ppmvd through the test period, that the initial draft (1993) of the BACT evaluation had concluded that a NO_X emission limit of 12.5 ppmvd was appropriate, even if the application of an SCR was required.

TEC Response

Although the November 8, 1999 letter from EPA Region IV established BACT for combined cycle combustion turbines as 3.5 ppm, this letter addressed natural gas fired combustion turbines, not syngas fired combustion turbines. In addition, subsequent draft guidance from John S. Seitz, director of the Office of Air Quality Planning and Standards dated August 4, 2000 (see enclosed) 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.

UARG also supports the draft guidance in a September 18, 2000 letter (enclosed) to Ms. Ellen Brown of the USEPA and states, in part, "The Clean Air Act as well as EPA's regulations make it abundantly clear that a BACT determination must be based upon a case-by-case, site-specific balancing of energy, environmental, and economic impacts and other costs, and mandate that this balancing be done by the appropriate State permitting authority." This supports the position that BACT is determined on a case by case basis, and is not a limit to be applied to all units at all times. As such, TEC believes that fuel and associated technical differences must be considered when evaluating BACT and other similar facilities. The fact that SCR was deemed to be BACT for NO_x at the CPV Gulf Coast natural gas fired facility does not necessarily mean that SCR is BACT for the Polk Unit 1 syngas fired IGCC facility.

Additionally, 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 (enclosed), these compounds are responsible for plugging in the HRSG, tube fouling, and increased emissions of particulate matter.

Furthermore, it should be noted that the Specific Condition A.50 of the Polk Power Station Title V Permit directs Tampa Electric Company to conduct a BACT evaluation for NO_x based on "data gathered on this facility, <u>other similar facilities</u>, and the manufacturer's research." (Underline emphasis added) In the Department's letter dated December 4, 2000, references are made to BACT determinations for NO_x on other <u>natural gas fired</u> combined cycle facilities. Since Polk Unit 1 fires syngas, it is TEC's position that this Unit is similar to a natural gas fired facility only in that it fires a gaseous fuel. In fact, during the recent EPA Mercury Information Collection Request, Unit 1 was classified as a coal fired facility. Syngas is a sulfur containing fuel and, to date, there is no evidence of a successful SCR installation on a combined cycle combustion turbine that fires a sulfur containing fuel. To compare Unit 1 to a truly similar facility, one must look to the PSI Destec Wabash River Station in Vigo County, Indiana. This facility operates a syngas fired combustion turbine of similar design and vintage as the Unit found at Polk Power Station and does not operate an SCR for NO_x control. In addition, the somewhat similar and recently permitted Star Delaware IGCC facility is required to meet a NO_x limit of 15 ppmvd @ 15% O_2 using through the use of advanced combustors as a result of a LAER determination. As described in the original BACT Analysis, this facility was not required to install an SCR system. This is significant, because a LAER determination does not consider cost effectiveness in the analysis. This facility utilizes advanced burner technology that cannot be effectively applied to the Polk facility due to limited nitrogen diluent production at Polk Power Station.

In the December 4, 2000 comment letter, FDEP indicated that the CPV Gulf Coast facility was required to install an SCR for NO_x control although the cost of control might be as high at \$6,000 per ton of NO_x removed. Since TEC submitted a NO_x control cost lower than \$6,000 the application of SCR on Polk Unit 1 would be deemed economically feasible and, therefore, determined to be BACT. According to 40 CFR 52.21(b)(12), BACT is defined as:

*"An emissions limitation (including a visible emission standard) based on the maximum degree of reduction for each pollutant subject to regulation under Act which would be emitted from any proposed major stationary source or major modification which the Administrator, **on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs**, determines is achievable for such source or modification through application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of such pollutant. In no event shall application of best available control technology result in emissions of any pollutant which would exceed the emissions allowed by any applicable standard under 40 CFR parts 60 and 61. **If the Administrator determines that technological or economic limitations on the application of measurement methodology to a particular emissions unit would make the imposition of an emissions standard infeasible, a design, equipment, work practice, operational standard, or combination thereof, may be***

prescribed instead to satisfy the requirement for the application of best available control technology. Such standard shall, to the degree possible, set forth the emissions reduction achievable by implementation of such design, equipment, work practice or operation, and shall provide for compliance by means which achieve equivalent results." (bold emphasis added)

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 <u>might</u> 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.

Finally, 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. In fact, recent research developed by GE suggests that the cost to control NO_x emissions from a combined cycle combustion turbine that fires a sulfur bearing fuel may be much higher than originally anticipated. (see enclosed)

Based on the above discussion, TEC believes that it would be presumptuous for FDEP to consider the application of SCR to Polk Unit 1 as BACT without considering the severe technical consequences of installing such a control to an IGCC facility. As mentioned above, it appears that FDEP has concluded that SCR is applicable to Polk Unit 1 based on the operating experience of natural gas fired combined cycle facilities as well as recent BACT determinations for such facilities. In fact, an IGCC facility is considerably different than a natural gas fired combined cycle facility, and any BACT determination for such a facility should consider the energy, environmental, economic, and other costs as mandated by 40 CFR 52.21(b)(12). Furthermore, in this special case, the BACT analysis must consider the data gathered during the bimonthly stack tests, other similar facilities, and manufacturer's research. As such, the initial draft of the BACT evaluation performed in 1993 that concluded that a NO_x emission limit of 12.5 ppm was appropriate must not be considered in this determination. This was a preliminary limit and was subsequently rejected based on further analysis.

TEC has provided the Department with all of the above information and believes that a NO_x emission limit of 25 ppm @15% O_2 continues to be appropriate for this facility. This is consistent with the Wabash River Station, the statistical results of the individual stack tests performed in support of this analysis, and the research of GE, the original equipment manufacturer.

TAMPA ELECTRIC

RECEIVED

FEB 15 2001

BUREAU OF AIR REGULATION

February 14, 2001

Mr. A.A. Linero, P.E.
Administrator - New Source Review Section
Florida Department of Environmental Protection
111 South Magnolia Avenue, Suite 4
Tallahassee, Florida 32301

Via FedEx
Airbill No. 7926 5766 4183

Re: Polk Power Station Unit 1
Syngas Fired Combustion Turbine NO_x BACT Determination

Dear Mr. Linero:

TEC has received your letter dated December 4, 2000 regarding the NO_x BACT Determination for Unit 1 at the Polk Power Station and offers the following responses to the issues raised by FDEP.

FDEP Comment 1

Please provide 30 day rolling average NO_X emissions data for calendar months October 1999 through November 2000. This submittal should include actual NO_X emissions (tons) for each calendar month, as well as the following related data:

a) **each calendar month summary should include each daily average NO_X emission value in lb/hr (and ppm corrected to 15% O_2), as well as the total daily heat input by fuel type (e.g. synfuel, natural gas or oil), heating value and daily hours of operation on each fuel; the average daily MW output (from the CT) and average daily SO_2 emission (CEM) rates should also be shown**

b) **provide the ultimate analysis of the "as-fired" coal for each calendar month listed above where synfuel was fired in the combustion turbine**

c) **if available, provide data on gasifier H_2S and COS removal, as compared to the coal feedstock used**

TEC Response

Other than NO_x emissions corrected to 15% O_2, the data requested above are enclosed. Due to the varying nature of the fuels gasified at Polk Power Station, the heat content of the syngas fired in the combustion turbine fluctuates and is generally between 250 and 275 Btu/SCF (HHV). The heat content of the distillate oil fired in the combustion turbine is typically about 138,000 Btu/gallon of oil fired.

Currently, Polk Power Station demonstrates compliance with the limit of 25 ppm @ 15% O_2 by monitoring NO_x emissions on a lb/hr basis.

TAMPA ELECTRIC COMPANY
P. O. BOX 111 TAMPA, FL 33601-0111
(813) 228-4111

AN EQUAL OPPORTUNITY COMPANY
HTTP://WWW.TECOENERGY.COM

CUSTOMER SERVICE:
HILLSBOROUGH COUNTY (813) 223-0800
OUTSIDE HILLSBOROUGH COUNTY 1 (888) 223-0800

For clarity, it is important to emphasize that although the request in paragraph a) calls for a total daily heat input when firing natural gas, this unit has never fired natural gas, nor is it capable of doing so. Unit 1 is designed to accommodate syngas as the primary fuel and distillate oil as the backup fuel. Paragraph c) requests the gasifier H_2S and COS removal, but these data are not monitored or limited by a permit condition and are, therefore, not available. However, based on plant operating experience, between 60% and 90% of the incoming COS is removed in the process. This removal efficiency is highly dependent on several process parameters such as ambient temperature and feed stock. Hence the removal efficiency is variable. The facility monitors SO_2 emissions to assure environmental compliance.

FDEP Comment 2

Please provide the average nitrogen diluent flow delivered to the CT during each of the seven NO_X BACT tests identified on page 4-1 of the submitted BACT analysis.

TEC Response

The requested data are presented below. 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.

The table below summarizes the ratio of nitrogen diluent flow to syngas flow during each test as compared to the NO_x emissions. As the data in the table demonstrates, although the nitrogen flow and the syngas flow vary from test to test, the ratio is reasonably consistent.

Test Date	Average Nitrogen Diluent Flow (lb/sec)	Average Syngas flow rate (lb/sec)	Average Nitrogen Diluent/Syngas Ratio	Average NOx Emissions Result (ppmvd, 15% O2, ISO)
October 14, 1999	118.0	102.8	1.1	16.7
December 7, 1999	124.1	103.8	1.2	14.6
February 7, 2000	117.3	102.7	1.1	19.0
April 17, 2000	126.8	102.1	1.2	17.0
June 14, 2000	118.0	101.0	1.2	18.1
August 15, 2000	124.7	100.2	1.2	16.6
October 17, 2000	116.6	99.7	1.2	22.5

These data, presented graphically in the enclosed Figure 1, show no strong correlation between diluent/syngas flow rate and NOx emissions rate. A linear regression analysis demonstrated a large error in fitting the data, with a regression coefficient of 0.14 thus, it may be concluded that factors other than the diluent/syngas flow ratio considerably affect the emissions performance of the combustion turbine.

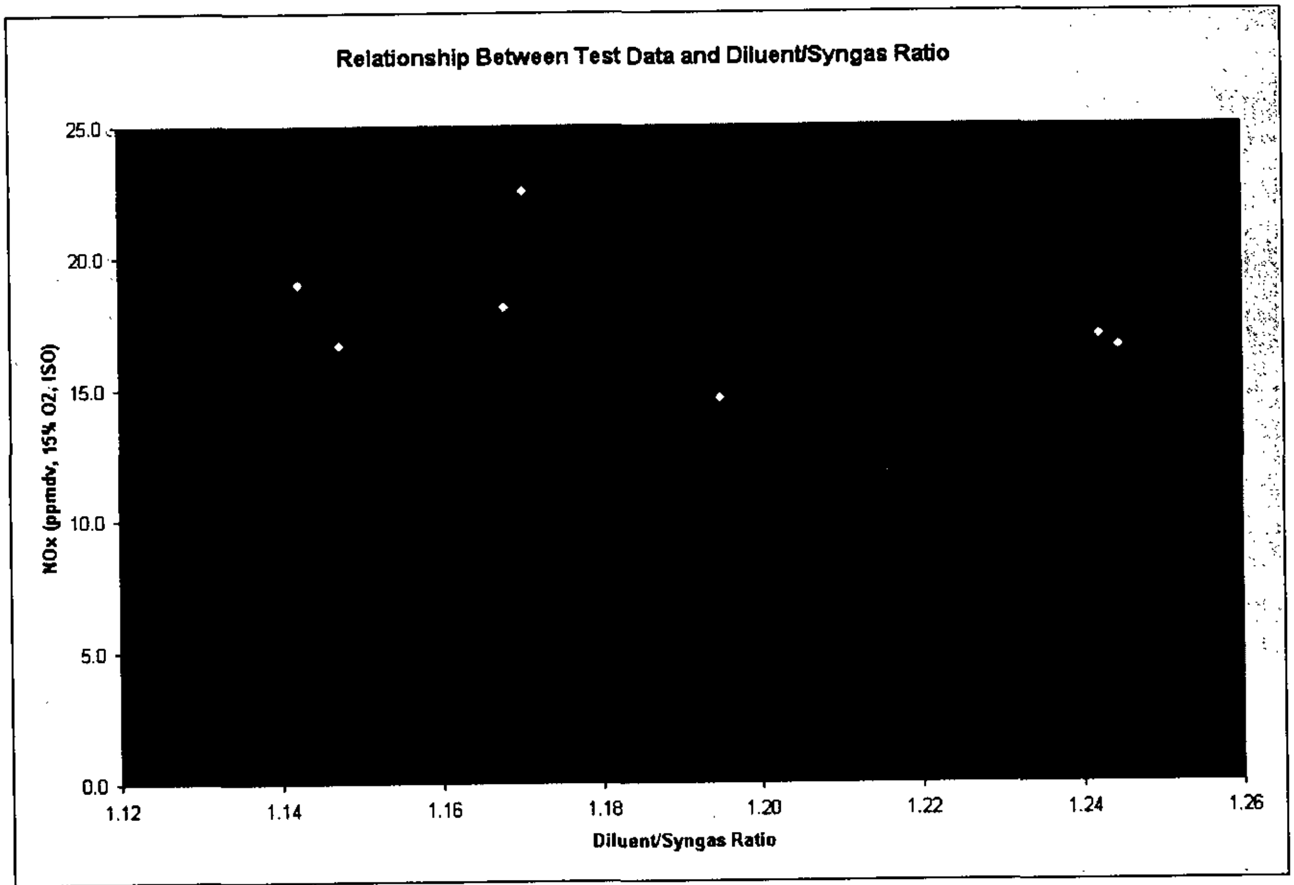


Figure 1

FDEP Comment 3

In a November 8, 1999 letter, EPA Region IV established that BACT for combined cycle turbines is 3.5 ppm NO_x. (Note: EPA wrote the letter after the Florida Department of Environmental Protection proposed a 6 ppm NO_X limit for a GE combined cycle Frame 7 turbine with SCR). Recently (on November 17, 2000) the Department issued a draft permit and BACT Determination 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. This determination was made under the assumption that cost of NO_X control by SCR might be as high as $6,000 per ton (with ammonia emissions held to 5 ppmvd), which represents a NO_X control cost significantly higher than that offered in TECO's submittal.

a) **Accordingly, this will 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.**

b) The Department notes (in reviewing the records for this project), that although the final BACT Determination for NO_X (while firing syngas) was set at 25 ppmvd through the test period, that the initial draft (1993) of the BACT evaluation had concluded that a NO_X emission limit of 12.5 ppmvd was appropriate, even if the application of an SCR was required.

TEC Response

Although the November 8, 1999 letter from EPA Region IV established BACT for combined cycle combustion turbines as 3.5 ppm, this letter addressed natural gas fired combustion turbines, not syngas fired combustion turbines. In addition, subsequent draft guidance from John S. Seitz, director of the Office of Air Quality Planning and Standards dated August 4, 2000 (see enclosed) 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.

UARG also supports the draft guidance in a September 18, 2000 letter (enclosed) to Ms. Ellen Brown of the USEPA and states, in part, "The Clean Air Act as well as EPA's regulations make it abundantly clear that a BACT determination must be based upon a case-by-case, site-specific *balancing of energy, environmental, and economic impacts and other costs, and mandate that this balancing be done by the appropriate State permitting authority." This supports the position that BACT is determined on a case by case basis, and is not a limit to be applied to all units at all times. As such, TEC believes that fuel and associated technical differences must be considered when evaluating BACT and other similar facilities. The fact that SCR was deemed to be BACT for NO_x at the CPV Gulf Coast natural gas fired facility does not necessarily mean that SCR is BACT for the Polk Unit 1 syngas fired IGCC facility.*

Additionally, 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 (enclosed), these compounds are responsible for plugging in the HRSG, tube fouling, and increased emissions of particulate matter.

Furthermore, it should be noted that the Specific Condition A.50 of the Polk Power Station Title V Permit directs Tampa Electric Company to conduct a BACT evaluation for NO_x based on "data gathered on this facility, <u>other similar facilities</u>, and the manufacturer's research." (Underline emphasis added) In the Department's letter dated December 4, 2000, references are made to BACT determinations for NO_x on other <u>natural gas fired</u> combined cycle facilities. Since Polk Unit 1 fires syngas, it is TEC's position that this Unit is similar to a natural gas fired facility only in that it fires a gaseous fuel. In fact, during the recent EPA Mercury Information Collection Request, Unit 1 was classified as a coal fired facility. Syngas is a sulfur containing fuel and, to date, there is no evidence of a successful SCR installation on a combined cycle combustion turbine that fires a sulfur containing fuel. To compare Unit 1 to a truly similar facility, one must look to the PSI Destec Wabash River Station in Vigo County, Indiana. This facility operates a syngas fired combustion turbine of similar design and vintage as the Unit found at Polk Power Station and does not operate an SCR for NO_x control. In addition, the somewhat similar and recently permitted Star Delaware IGCC facility is required to meet a NO_x limit of 15 ppmvd @ 15% O_2 using through the use of advanced combustors as a result of a LAER determination. As described in the original BACT Analysis, this facility was not required to install an SCR system. This is significant, because a LAER determination does not consider cost effectiveness in the analysis. This facility utilizes advanced burner technology that cannot be effectively applied to the Polk facility due to limited nitrogen diluent production at Polk Power Station.

In the December 4, 2000 comment letter, FDEP indicated that the CPV Gulf Coast facility was required to install an SCR for NO_x control although the cost of control might be as high at \$6,000 per ton of NO_x removed. Since TEC submitted a NO_x control cost lower than \$6,000 the *application of SCR on Polk Unit 1 would be deemed economically feasible and, therefore, determined to be BACT. According to 40 CFR 52.21(b)(12), BACT is defined as:*

> *" An emissions limitation (including a visible emission standard) based on the maximum degree of reduction for each pollutant subject to regulation under Act which would be emitted from any proposed major stationary source or major modification which the Administrator,* ***on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs,*** *determines is achievable for such source or modification through application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of such pollutant. In no event shall application of best available control technology result in emissions of any pollutant which would exceed the emissions allowed by any applicable standard under 40 CFR parts 60 and 61.* ***If the Administrator determines that technological or economic limitations on the application of measurement methodology to a particular emissions unit would make the imposition of an emissions standard infeasible, a design, equipment, work practice, operational standard, or combination thereof, may be prescribed instead to satisfy the requirement for the application of best available control technology.*** *Such standard shall, to the degree possible, set forth the emissions reduction achievable by implementation of such design, equipment, work practice or operation, and shall provide for compliance by means which achieve equivalent results." (bold emphasis added)*

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 <u>*might*</u> *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.*

Finally, 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. In fact, recent research developed by GE suggests that the cost to control NO_x emissions from a combined cycle combustion turbine that fires a sulfur bearing fuel may be much higher than originally anticipated. (see enclosed)

Based on the above discussion, TEC believes that it would be presumptuous for FDEP to consider the application of SCR to Polk Unit 1 as BACT without considering the severe technical consequences of installing such a control to an IGCC facility. As mentioned above, it appears that FDEP has concluded that SCR is applicable to Polk Unit 1 based on the operating experience of natural gas fired combined cycle facilities as well as recent BACT determinations for such facilities. In fact, an IGCC facility is considerably different than a natural gas fired combined cycle facility, and any BACT determination for such a facility should consider the energy, environmental, economic, and other costs as mandated by 40 CFR 52.21(b)(12). Furthermore, in *this special case, the BACT analysis must consider the data gathered during the bimonthly stack tests, other similar facilities, and manufacturer's research. As such, the initial draft of the BACT evaluation performed in 1993 that concluded that a NO_x emission limit of 12.5 ppm was appropriate must not be considered in this determination. This was a preliminary limit and was subsequently rejected based on further analysis.*

TEC has provided the Department with all of the above information and believes that a NO_x emission limit of 25 ppm @15% O_2 continues to be appropriate for this facility. This is consistent with the Wabash River Station, the statistical results of the individual stack tests performed in support of this analysis, and the research of GE, the original equipment manufacturer.

FDEP Comment 4

Please estimate schedule requirements, which would be necessary to procure and install an SCR for the subject unit. Additionally, please confirm that Engelhard Corporation expects the catalyst life to be 5 to 7 years and will guarantee same for 3 years of operation.

TEC Response

Below are the schedule requirements necessary to procure and install an SCR system, if required.

Step	Description	Time Required (weeks)
1	Develop specification package	6
2	Solicit bids	4
3	Review bids/select vendor	2
4	Contract negotiations	4
5	Design/build/delivery	40
6	Site Prep and Installation	8
7	Startup/debug	6
	Total	**70 weeks**

According to Englehard Corporation, catalyst life is expected to be 5-7 years with a 3 year guarantee.

TEC appreciates the opportunity to respond to the Department's comments and looks forward to working with FDEP to ensure that a reasonable BACT determination for NO_x on Polk Unit 1 is arrived at. TEC is confident that this determination will benefit the environment while encouraging the development of future NO_x reduction technologies as well as the advancement of clean coal technologies.

If you have any questions, please feel free to telephone Shannon Todd or me at (813) 641-5125.

Sincerely,

Mark J Hornick

Mark J. Hornick
General Manager/Responsible Official
Polk Power Station

EP\gm\SKT233

Enclosure

c/enc: Mr. Michael Halpin – FDEP
Mr. Syed Arif - FDEP
Mr. Jerry Kissel - FDEP SW
G. Little, EPA
B. Worley, EPA
J. Bunyak, NPS

Comment 1 Enclosures

OCTOBER 1999	30-Day Rolling Average NO_X Emissions		Average NO_X Emissions	Daily Hours of Operation		Total Daily Heat Input		Daily Average MW Output	30-Day Rolling Average SO_2 Emission	
	Synfuel	Oil		Synfuel	Oil	Synfuel	Oil		Synfuel	Oil
	(lbs / hr)		(lb / hr)	(hr)		(MMBTU / day)		(MW)	(lbs)	
1	174.8	201.3	212.3	24:00	0:00	48,638.2	0.0	191.00	146.4	26.7
2	176.2	201.3	207.1	24:00	0:00	47,571.9	0.0	184.96	153.7	26.7
3	175.8	205.2	173.0	21:00	3:00	37,180.9	5,311.6	154.46	156.4	27.3
4	175.8	204.9	7.1	0:00	0:15	0.0	0.0	0.00	156.4	26.7
5	175.8	201.4	2.7	0:00	1:30	0.0	0.1	0.13	156.4	26
6	175.8	207.6	9.9	0:00	1:15	0.0	1.0	1.04	156.4	26.6
7	175.8	210.9	237.2	0:00	16:45	0.0	76.1	76.13	156.4	26.4
8	0.0	0.0	0.0	0:00	0:00	0.0	0.0	0.00	0.0	0.0
9	0.0	0.0	0.0	0:00	0:00	0.0	0.0	0.00	0.0	0.0
10	180.3	229.1	355.8	7:00	8:30	9,753.6	11,843.6	71.83	153.3	25.5
11	180.3	229.1	183.3	24:00	0:00	48,099.3	0.0	188.29	152.5	25.5
12	180.8	229.1	186.0	24:00	0:00	47,755.1	0.0	188.96	155.1	25.5
13	181.5	229.1	183.3	24:00	0:00	48,036.5	0.0	190.83	161.8	25.5
14	182.1	229.1	182.7	24:00	0:00	48,158.9	0.0	191.00	170.3	25.5
15	182.2	229.1	166.5	24:00	0:00	47,141.4	0.0	187.42	178.4	25.5
16	182.4	229.1	175.8	24:00	0:00	47,942.5	0.0	191.00	182.1	25.5
17	182.7	229.1	176.3	24:00	0:00	48,057.1	0.0	191.00	188.6	25.5
18	182.9	229.1	173.9	24:00	0:00	48,116.6	0.0	190.71	193.7	25.5
19	183.4	229.1	181.6	24:00	0:00	46,815.2	0.0	185.50	197.9	25.5
20	183.7	229.1	164.3	24:00	0:00	45,616.4	0.0	179.83	206.1	25.5
21	183.1	229.1	166.3	24:00	0:00	46,708.2	0.0	186.54	210.9	25.5
22	182.8	229.1	168.3	24:00	0:00	47,372.7	0.0	191.00	215.7	25.5
23	182.1	229.1	164.5	24:00	0:00	47,115.5	0.0	189.00	221	25.5
24	182	229.1	164.0	24:00	0:00	47,330.4	0.0	190.13	226.6	25.5
25	181.5	229.1	165.9	24:00	0:00	47,635.0	0.0	190.54	232.5	25.5
26	180.9	229.1	166.0	24:00	0:00	47,237.2	0.0	188.79	241	25.5
27	180.3	229.1	165.8	24:00	0:00	47,061.7	0.0	187.25	247.3	25.5
28	179.8	229.1	163.1	24:00	0:00	47,962.0	0.0	188.50	249.9	25.5
29	179.5	229.1	163.3	24:00	0:00	48,050.0	0.0	189.29	251	25.5
30	179.1	229.1	166.4	24:00	0:00	48,391.0	0.0	189.46	248.6	25.5
31	179.2	229.1	166.5	24:00	0:00	48,637.6	0.0	190.29	246.3	25.5

Total Actual NO_x Emissions for the month (tons) :	57.9

NOVEMBER 1999	30-Day Rolling Average NO_X Emissions Synfuel	Oil	Average NO_X Emissions	Daily Hours of Operation Synfuel	Oil	Total Daily Heat Input Synfuel	Oil	Daily Average MW Output	30-Day Rolling Average SO_2 Emission Synfuel	Oil
	(lbs)		(lb / hr)	(hr)		(MMBTU / day)		(MW)	(lbs)	
1	179.1	229.1	169.0	24:00	0:00	48,727.1	0.0	190.96	247.8	25.5
2	178.8	229.1	162.8	24:00	0:00	48,210.2	0.0	191.00	249.5	25.5
3	178.6	229.1	167.0	24:00	0:00	48,093.3	0.0	190.67	244.8	25.5
4	177.5	229.1	95.1	15:45	0:00	29,572.6	0.0	114.08	245.6	25.5
5	177.5	225.8	53.6	0:00	8:15	0.0	19.5	19.46	245.6	24.9
6	177.7	222.6	169.8	20:45	1:00	37,508.9	6.9	149.92	241.8	24.4
7	176.4	222.6	174.1	24:00	0:00	47,911.3	0.0	189.04	237.9	24.4
8	175.3	222.6	174.4	24:00	0:00	48,381.2	0.0	189.17	233.2	24.4
9	175.6	222.6	177.2	24:00	0:00	48,894.8	0.0	186.00	234.5	24.4
10	171.7	227.5	182.4	17:15	1:00	32,257.8	6.6	121.17	240.4	23.5
11	171.8	227.5	203.0	24:00	0:00	49,369.2	0.0	186.33	249.7	23.5
12	170.9	225.3	217.2	18:00	6:00	34,098.9	37.6	150.38	253.1	22.8
13	170.9	225.3	200.8	24:00	0:00	49,444.8	0.0	191.00	252.9	22.8
14	170.8	225.3	201.8	24:00	0:00	49,696.8	0.0	191.00	248.4	22.8
15	171.3	225.3	200.0	24:00	0:00	49,495.2	0.0	191.00	247.5	22.8
16	170.8	225.3	171.9	24:00	0:00	45,860.4	0.0	185.83	250.2	22.8
17	170.4	225.3	164.4	24:00	0:00	45,022.7	0.0	191.00	252.6	22.8
18	170	225.3	163.3	24:00	0:00	44,781.5	0.0	188.63	254.9	22.8
19	169.3	225.3	160.5	24:00	0:00	45,013.4	0.0	190.46	258.2	22.8
20	169.4	225.3	163.6	24:00	0:00	44,391.1	0.0	190.54	259.2	22.8
21	169.2	225.3	159.7	24:00	0:00	44,244.3	0.0	190.75	263.9	22.8
22	168.6	225.3	159.5	24:00	0:00	44,176.6	0.0	190.50	267.9	22.8
23	168.3	225.3	154.0	24:00	0:00	44,381.4	0.0	189.29	267	22.8
24	167.9	225.3	152.8	24:00	0:00	43,981.0	0.0	187.92	267.8	22.8
25	167.6	225.3	153.4	24:00	0:00	44,476.4	0.0	189.21	272.9	22.8
26	167.5	225.3	161.5	24:00	0:00	44,792.2	0.0	191.00	274.6	22.8
27	167.1	225.3	156.0	24:00	0:00	44,806.4	0.0	191.00	277	22.8
28	166.7	225.3	150.9	24:00	0:00	44,536.7	0.0	191.00	275.9	22.8
29	166.4	225.3	153.3	24:00	0:00	44,956.4	0.0	191.00	277.2	22.8
30	165.8	225	149.6	23:00	1:00	41,042.5	7.7	184.13	282.3	22.3

Total Actual NO_x Emissions for the month (tons) :	59.11

DECEMBER 1999	30-Day Rolling Average NO_X Emissions Synfuel	30-Day Rolling Average NO_X Emissions Oil	Average NO_X Emissions	Daily Hours of Operation Synfuel	Daily Hours of Operation Oil	Total Daily Heat Input Synfuel	Total Daily Heat Input Oil	Daily Average MW Output	30-Day Rolling Average SO_2 Emission Synfuel	30-Day Rolling Average SO_2 Emission Oil
	(lbs)		(lb / hr)	(hr)		(MMBTU / day)		(MW)	(lbs)	
1	165	222.9	148.5	19:00	5:00	29,763.7	7,832.6	159.13	293.1	23.2
2	164.8	222.9	163.9	24:00	0:00	43,798.6	0.0	191.00	295	23.2
3	164.7	222.9	156.8	24:00	0:00	43,585.4	0.0	191.00	294.6	23.2
4	164.3	222.9	156.9	24:00	0:00	43,610.4	0.0	191.00	293.4	23.2
5	164.8	222.9	156.1	24:00	0:00	43,993.6	0.0	191.00	287.4	23.2
6	163.7	222.9	157.4	24:00	0:00	44,053.9	0.0	190.50	290.9	23.2
7	162.7	222.9	145.8	24:00	0:00	44,220.8	0.0	189.38	296.4	23.2
8	161.5	222.9	138.1	24:00	0:00	43,524.1	0.0	184.54	299.5	23.2
9	160.4	222.9	137.8	24:00	0:00	44,486.1	0.0	190.00	302.7	23.2
10	158.6	222.9	140.2	24:00	0:00	44,427.3	0.0	188.29	308.2	23.2
11	157.6	222.9	154.7	24:00	0:00	45,949.2	0.0	190.58	308.4	23.2
12	157.6	225	165.0	21:00	2:30	36,318.1	4,323.6	161.04	303.9	23.8
13	0.0	0.0	1.9	0:00	0:00	0.0	0.0	0.00	0.0	0.0
14	0.0	0.0	0.0	0:00	0:00	0.0	0.0	0.00	0.0	0.0
15	0.0	0.0	0.0	0:00	0:00	0.0	0.0	0.00	0.0	0.0
16	0.0	0.0	0.0	0:00	0:00	0.0	0.0	0.00	0.0	0.0
17	157.6	224.2	88.7	0:00	11:30	0.0	14,788.5	52.04	303.9	24.2
18	157.6	220.9	171.9	0:00	24:00	0.0	33,080.1	113.58	303.9	24
19	155.2	217.2	129.2	12:00	12:00	16,106.7	16,106.7	130.13	318.2	23.7
20	153	217.2	116.0	24:00	0:00	42,477.3	0.0	190.50	325.1	23.7
21	148.7	217.2	72.6	24:00	0:00	40,405.7	0.0	189.58	325	23.7
22	144.1	217.2	25.2	24:00	0:00	39,573.1	0.0	189.17	324.5	23.7
23	139.4	217.2	25.3	24:00	0:00	40,327.3	0.0	189.46	324.9	23.7
24	134.5	217.2	17.6	24:00	0:00	39,620.4	0.0	189.42	324	23.7
25	129.7	217.2	14.7	24:00	0:00	39,696.1	0.0	190.21	321.7	23.7
26	125.1	217.2	22.5	24:00	0:00	39,228.1	0.0	190.83	318	23.7
27	120.7	217.2	28.5	24:00	0:00	39,306.0	0.0	189.88	314.3	23.7
28	116	217.2	19.8	24:00	0:00	38,939.6	0.0	187.21	313.3	23.7
29	111.9	217.2	31.3	24:00	0:00	39,585.0	0.0	190.71	311.6	23.7
30	108.2	217.2	38.9	24:00	0:00	39,222.9	0.0	190.92	312.7	23.7
31	103.5	210.4	24.0	17:30	3:00	20,873.6	3,578.3	114.88	307.5	22.5

Total Actual NO_x Emissions for the month (tons) :	31.8

JANUARY 2000	30-Day Rolling Average NO_X Emissions Synfuel	Oil	Average NO_X Emissions	Daily Hours of Operation Synfuel	Oil	Total Daily Heat Input Synfuel	Oil	Daily Average MW Output	30-Day Rolling Average SO_2 Emission Synfuel	Oil
	(lbs)		(lb / hr)	(hr)		(MMBTU / day)		(MW)	(lbs)	
1	99.1	203.2	29.9	15:30	6:00	19,164.2	7,418.4	124.75	298.3	21.2
2	94.3	203.2	18.1	24:00	0:00	37,425.2	0.0	182.79	297.5	21.2
3	89.8	197.7	36.8	16:00	8:00	20,555.4	10,277.7	146.38	299.6	20.1
4	85.3	197.7	17.6	24:00	0:00	39,212.2	0.0	191.00	302.8	20.1
5	80.7	197.7	13.0	24:00	0:00	38,903.2	0.0	189.42	306.3	20.1
6	76.5	197.4	17.9	24:00	0:00	38,964.4	0.0	190.71	300.6	20.1
7	72	197.4	27.0	24:00	0:00	38,906.9	0.0	191.00	301.9	20.1
8	67.6	197.4	26.0	24:00	0:00	38,849.9	0.0	191.00	300.8	20.1
9	63.2	197.4	24.0	24:00	0:00	38,910.4	0.0	191.00	310.4	20.1
10	58.6	197.4	23.7	24:00	0:00	38,986.2	0.0	191.00	318.3	20.1
11	54.3	197.4	27.1	24:00	0:00	38,566.7	0.0	190.88	319.9	20.1
12	50.2	197.4	22.3	24:00	0:00	39,139.9	0.0	191.00	320.8	20.1
13	46.4	190.1	24.6	24:00	0:00	39,245.3	0.0	191.00	317.4	19.9
14	42.5	190.1	19.8	24:00	0:00	39,539.1	0.0	191.00	313.3	19.9
15	38.8	190.1	30.8	24:00	0:00	39,782.2	0.0	191.00	312.2	19.9
16	34.7	190.1	30.0	24:00	0:00	39,568.4	0.0	191.00	310	19.9
17	30.3	190.1	30.9	24:00	0:00	38,690.0	0.0	187.13	313.9	19.9
18	29.3	190.1	65.2	24:00	0:00	33,890.7	0.0	165.75	291.4	19.9
19	30.3	190.1	140.1	24:00	0:00	37,710.8	0.0	183.63	288.6	19.9
20	32.9	190.1	128.2	24:00	0:00	43,380.3	0.0	187.79	293.5	19.9
21	36.2	190.1	135.0	24:00	0:00	42,992.9	0.0	185.33	298	19.9
22	36.6	190.1	177.9	24:00	0:00	48,265.2	0.0	187.71	295.3	19.9
23	37.3	190.1	190.0	24:00	0:00	47,870.2	0.0	190.33	295.5	19.9
24	41.2	197.9	136.5	13:45	6:00	20,623.0	8,999.1	112.96	291.2	20.7
25	45.8	197.9	154.0	24:00	0:00	43,961.5	0.0	190.58	291.1	20.7
26	50.5	197.9	165.2	23:00	0:00	43,738.3	0.0	191.54	294.3	20.7
27	56.3	197.9	187.9	24:00	0:00	44,653.7	0.0	190.58	293.5	20.7
28	61.2	197.9	169.1	24:00	0:00	41,676.1	0.0	180.33	297	20.7
29	63.8	197.9	24.1	3:15	0:00	5,238.8	0.0	21.08	290.3	20.7
30	68.6	204.1	98.9	8:15	8:30	10,295.1	10,607.0	79.29	284	21.8
31	0.0	0.0	0.0	0:00	0:00	0.0	0.0	0.00	0.0	0.0

Total Actual NO_x Emissions for the month (tons) :	26.3

FEBRUARY 2000	30-Day Rolling Average NO_X Emissions Synfuel	Oil	Average NO_X Emissions	Daily Hours of Operation Synfuel	Oil	Total Daily Heat Input Synfuel	Oil	Daily Average MW Output	30-Day Rolling Average SO_2 Emission Synfuel	Oil
	(lbs)		(lb / hr)	(hr)		(MMBTU / day)		(MW)	(lbs)	
1	69.2	199.4	15.2	1:30	2:00	819.6	1,092.7	4.42	281.3	21.7
2	69.2	195.2	124.3	0:00	24:00	0.0	21,978.2	60.67	281.3	22
3	73.6	192.5	143.0	21:00	3:00	34,209.8	4,887.1	162.25	278.4	22
4	79.1	188.5	137.9	8:00	16:00	9,261.6	18,523.1	97.33	275.2	21.8
5	83	187.9	133.0	15:00	9:00	21,279.1	12,767.4	135.29	275.2	22.1
6	88.9	187.9	178.0	24:00	0:00	44,068.7	0.0	191.00	272.5	22.1
7	94.7	187.9	181.3	24:00	0:00	44,439.6	0.0	191.00	270.2	22.1
8	99.6	187.9	116.7	16:45	0:00	32,469.8	0.0	133.83	270.3	22.1
9			0.0	0:00	0:00	0.0	0.0	0.00		
10	99.6	181.4	13.4	0:00	3:15	0.0	1,904.8	3.67	270.3	21.4
11	102.6	171.7	128.4	10:00	14:00	12,656.3	17,718.8	108.42	272.2	21.1
12	106.8	171.7	139.4	24:00	0:00	43,140.0	0.0	179.75	268.5	21.1
13	110.8	170.3	132.6	17:00	7:00	24,403.4	10,048.5	134.92	261.6	21.4
14	115.4	170.3	156.0	24:00	0:00	42,396.0	0.0	178.13	259	21.4
15	120.4	170.3	161.2	24:00	0:00	43,981.3	0.0	182.50	256.5	21.4
16	126.5	170.3	195.2	24:00	0:00	45,067.0	0.0	189.71	254.9	21.4
17	132.6	171.6	178.2	18:00	6:00	28,125.6	9,375.2	151.50	251.4	21.9
18	138.3	171.6	189.9	24:00	0:00	45,563.9	0.0	191.00	245	21.9
19	143.9	171.6	190.6	24:00	0:00	46,241.8	0.0	191.00	238.3	21.9
20	149.4	171.6	184.6	24:00	0:00	45,188.4	0.0	191.00	231.6	21.9
21	152.8	171.6	176.5	24:00	0:00	44,897.5	0.0	191.00	233.2	21.9
22	154.2	171.6	183.7	24:00	0:00	45,008.1	0.0	191.00	225.3	21.9
23	155.1	171.6	158.3	24:00	0:00	46,015.0	0.0	190.54	216.3	21.9
24	156.7	171.6	170.5	24:00	0:00	44,912.0	0.0	191.00	207.4	21.9
25	157	171.6	167.1	24:00	0:00	43,157.9	0.0	182.46	206.5	21.9
26	157	165.4	12.2	0:00	1:00	0.0	440.8	0.42	206.5	20.6
27	0.0	0.0	0.0	0:00	0:00	0.0	0.0	0.00	0.0	0.0
28	0.0	0.0	0.0	0:00	0:00	0.0	0.0	0.00	0.0	0.0
29	0.0	0.0	0.0	0:00	0:00	0.0	0.0	0.00	0.0	0.0

Total Actual NO_x Emissions for the month (tons) :	42.76

MARCH 2000	30-Day Rolling Average NO_X Emissions Synfuel	Oil	Average NO_X Emissions	Daily Hours of Operation Synfuel	Oil	Total Daily Heat Input Synfuel	Oil	Daily Average MW Output	30-Day Rolling Average SO_2 Emission Synfuel	Oil
	(lbs)		(lb / hr)	(hr)		(MMBTU / day)		(MW)	(lbs)	
1	0.0	0.0	0.0	0:00	0:00	0.0	0.0	0.00	0.0	0.0
2	0.0	0.0	0.0	0:30	0:00	0.0	0.0	0.00	0.0	0.0
3	0.0	0.0	0.0	0:00	0:00	0.0	0.0	0.00	0.0	0.0
4	0.0	0.0	0.0	0:00	0:00	0.0	0.0	0.00	0.0	0.0
5	0.0	0.0	0.0	0:00	0:00	0.0	0.0	0.00	0.0	0.0
6	0.0	0.0	0.0	0:00	0:00	0.0	0.0	0.00	0.0	0.0
7	0.0	0.0	0.0	0:00	0:00	0.0	0.0	0.00	0.0	0.0
8	0.0	0.0	0.0	0:00	0:00	0.0	0.0	0.00	0.0	0.0
9	0.0	0.0	0.0	0:00	0:00	0.0	0.0	0.00	0.0	0.0
10	0.0	0.0	0.0	0:00	0:00	0.0	0.0	0.00	0.0	0.0
11	0.0	0.0	0.0	0:00	0:00	0.0	0.0	0.00	0.0	0.0
12	0.0	0.0	0.0	0:00	0:00	0.0	0.0	0.00	0.0	0.0
13	157	160.3	5.1	0:00	2:45	0.0	810.8	0.08	206.5	20.2
14	157	163.8	34.3	0:00	5:15	0.0	3,844.3	4.13	206.5	21.9
15	157	160.3	14.1	0:00	3:15	0.0	2,076.6	4.50	206.5	21.9
16	155.7	154.3	150.4	16:00	8:00	26,127.5	13,063.7	151.75	208.4	21.5
17	155.8	154.3	53.5	10:15	0:00	14,620.9	0.0	60.13	208.5	21.5
18	0.0	0.0	0.0	0:00	0:00	0.0	0.0	0.00	0.0	0.0
19	0.0	0.0	0.0	0:00	0:00	0.0	0.0	0.00	0.0	0.0
20	0.0	0.0	0.0	0:00	0:00	0.0	0.0	0.00	0.0	0.0
21	155.8	127.3	2.5	0:00	1:15	0.0	295.3	0.17	208.5	20.9
22	0.0	0.0	0.0	0:00	0:00	0.0	0.0	0.00	0.0	0.0
23	0.0	0.0	0.0	0:00	0:00	0.0	0.0	0.00	0.0	0.0
24	0.0	0.0	0.0	0:00	0:00	0.0	0.0	0.00	0.0	0.0
25	0.0	0.0	0.0	0:00	0:00	0.0	0.0	0.00	0.0	0.0
26	0.0	0.0	0.0	0:00	0:00	0.0	0.0	0.00	0.0	0.0
27	0.0	0.0	0.0	0:00	0:00	0.0	0.0	0.00	0.0	0.0
28	0.0	0.0	0.0	0:00	0:00	0.0	0.0	0.00	0.0	0.0
29	155.8	128.2	51.7	0:00	7:15	0.0	8,411.7	24.92	208.5	21.4
30	155.8	135.9	75.3	0:00	11:15	0.0	12,402.8	38.08	208.5	23.1
31	0.0	0.0	0.0	0:00	0:00	0.0	0.0	0.00	0.0	0.0

Total Actual NO_x Emissions for the month (tons) :	4.6

APRIL 2000	30-Day Rolling Average NO_X Emissions Synfuel	Oil	Average NO_X Emissions	Daily Hours of Operation Synfuel	Oil	Total Daily Heat Input Synfuel	Oil	Daily Average MW Output	30-Day Rolling Average SO_2 Emission Synfuel	Oil
	(lbs)		(lb / hr)	(hr)		(MMBTU / day)		(MW)	(lbs)	
1	155.8	134.8	27.2	0:00	4:45	0.0	3,495.1	8.79	208.5	23
2	155.8	135.8	45.7	0:00	6:15	0.0	5,684.2	16.54	208.5	23.1
3	155.2	136.9	138.4	20:00	4:00	30,445.8	6,089.2	159.29	213.2	23.4
4	154.7	136.9	153.9	24:00	0:00	41,216.1	0.0	181.63	213.3	23.4
5	153.9	136.9	151.7	24:00	0:00	39,131.2	0.0	179.54	213.5	23.4
6	153.8	136.9	134.1	19:45	0:00	32,621.6	0.0	144.38	214.8	23.4
7	0.0	0.0	0.0	0:00	0:00	0.0	0.0	0.00	0.0	0.0
8	0.0	0.0	0.0	0:00	0:00	0.0	0.0	0.00	0.0	0.0
9	0.0	0.0	0.0	0:00	0:00	0.0	0.0	0.00	0.0	0.0
10	0.0	0.0	0.0	0:00	0:00	0.0	0.0	0.00	0.0	0.0
11	0.0	0.0	0.0	0:00	0:00	0.0	0.0	0.00	0.0	0.0
12	0.0	0.0	0.0	0:00	0:00	0.0	0.0	0.00	0.0	0.0
13	0.0	0.0	0.0	0:00	0:00	0.0	0.0	0.00	0.0	0.0
14	153.8	129.9	29.7	0:00	5:00	0.0	3,519.0	8.96	214.8	129.9
15	154.9	130	154.9	20:00	4:00	31,708.4	6,341.7	162.25	222.2	130
16	155.1	130	166.0	24:00	0:00	48,653.2	0.0	191.00	229.8	130
17	159.4	130	170.8	23:45	0:00	46,949.8	0.0	191.00	237.1	130
18	160.4	130	168.6	23:45	0:00	45,575.8	0.0	190.88	234.5	130
19	160.7	130	171.8	24:00	0:00	45,248.8	0.0	191.00	232	130
20	161.8	130	155.2	24:00	0:00	39,721.4	0.0	169.13	226.8	130
21	161.3	130	5.1	6:00	0:00	1,920.4	0.0	0.17	223.6	130
22	160.5	127.1	142.0	18:00	2:00	29,469.7	3,274.4	124.00	221.1	127.1
23	160.3	127.1	207.3	24:00	0:00	44,478.9	0.0	186.08	216.1	127.1
24	162.3	127.1	189.9	24:00	0:00	45,362.3	0.0	191.00	212.1	127.1
25	163.3	127.1	163.8	24:00	0:00	45,146.6	0.0	190.58	208	127.1
26	164.7	127.1	163.4	24:00	0:00	44,308.5	0.0	191.00	210.1	127.1
27	165	127.1	169.0	24:00	0:00	44,667.3	0.0	190.54	209.7	127.1
28	165.2	127.1	172.9	24:00	0:00	45,266.1	0.0	190.50	206.7	127.1
29	163.7	127.1	161.9	24:00	0:00	45,290.3	0.0	189.96	209.5	127.1
30	162.2	127.1	162.3	24:00	0:00	45,002.7	0.0	189.96	214.7	127.1

Total Actual NO_x Emissions for the month (tons) :	38.5

MAY 2000	30-Day Rolling Average NO_X Emissions Synfuel	Oil	Average NO_X Emissions	Daily Hours of Operation Synfuel	Oil	Total Daily Heat Input Synfuel	Oil	Daily Average MW Output	30-Day Rolling Average SO_2 Emission Synfuel	Oil
	(lbs)		(lb / hr)	(hr)		(MMBTU / day)		(MW)	(lbs)	
1	160.7	127.1	157.5	24:00	0:00	45,289.8	0.0	189.58	216.9	21.7
2	159.1	127.1	154.7	24:00	0:00	45,218.4	0.0	187.33	221.5	21.7
3	157.9	127.1	155.5	24:00	0:00	43,918.4	0.0	188.83	228.7	21.7
4	156.7	127.1	159.9	24:00	0:00	43,404.6	0.0	191.00	233.6	21.7
5	154.2	127.1	143.9	23:30	0:00	41,436.9	0.0	182.08	236.1	21.7
6	154.3	127.1	158.6	24:00	0:00	42,215.9	0.0	191.00	234.1	21.7
7	153.8	127.1	157.2	24:00	0:00	41,827.6	0.0	188.33	237	21.7
8	153.5	127.1	157.3	24:00	0:00	40,640.9	0.0	187.67	240.2	21.7
9	155.7	127.1	152.8	24:00	0:00	41,715.4	0.0	186.92	235.4	21.7
10	157.2	127.1	151.8	24:00	0:00	41,203.5	0.0	183.33	238.6	21.7
11	158.7	127.1	162.3	24:00	0:00	41,909.8	0.0	186.29	231.4	21.7
12	160.2	127.1	172.3	24:00	0:00	40,902.9	0.0	185.00	223.8	21.7
13	161.3	127.1	174.4	24:00	0:00	41,297.4	0.0	185.71	223	21.7
14	161.7	127.1	175.3	24:00	0:00	41,145.2	0.0	183.63	221.6	21.7
15	162.9	127.1	167.2	24:00	0:00	40,314.6	0.0	180.54	219.3	21.7
16	163.2	127.1	159.1	24:00	0:00	39,809.2	0.0	179.46	220.2	21.7
17	162.1	127.1	153.2	24:00	0:00	39,240.8	0.0	177.54	218.1	21.7
18	161.3	127.1	154.0	24:00	0:00	38,945.8	0.0	175.92	219.4	21.7
19	160	127.1	152.8	24:00	0:00	38,837.2	0.0	174.83	219.7	21.7
20	158.6	127.1	136.7	24:00	0:00	38,090.6	0.0	168.50	220.9	21.7
21	161.4	127.1	216.2	24:00	0:00	40,569.5	0.0	187.08	212.9	21.7
22	162.5	127.1	184.0	24:00	0:00	41,836.3	0.0	191.00	208.9	21.7
23	163.2	127.1	176.6	24:00	0:00	41,811.0	0.0	191.00	204.4	21.7
24	163.4	127.1	164.7	24:00	0:00	40,812.5	0.0	190.46	201.8	21.7
25	163.7	127.1	173.4	24:00	0:00	42,118.9	0.0	191.00	209	21.7
26	163.7	127.1	158.2	24:00	0:00	40,921.8	0.0	190.33	230.6	21.7
27	163.6	127.1	160.6	24:00	0:00	40,896.8	0.0	186.17	237	21.7
28	162.2	127.1	128.1	24:00	0:00	39,455.5	0.0	173.79	234.6	21.7
29	161.7	127.1	148.9	24:00	0:00	39,782.8	0.0	177.08	232.1	21.7
30	161.7	127.1	159.9	24:00	0:00	40,603.7	0.0	182.21	229.2	21.7
31	161.9	127.1	166.9	24:00	0:00	41,481.7	0.0	185.88	228	21.7

Total Actual NO_x Emissions for the month (tons) :	60.0

JUNE 2000	30-Day Rolling Average NO_X Emissions Synfuel (lbs)	Oil	Average NO_X Emissions (lb / hr)	Daily Hours of Operation Synfuel (hr)	Oil	Total Daily Heat Input Synfuel (MMBTU / day)	Oil	Daily Average MW Output (MW)	30-Day Rolling Average SO_2 Emission Synfuel (lbs)	Oil
1	162	127.1	161.7	24:00	0:00	39,184.6	0.0	181.04	228.1	21.7
2	161.9	127.1	135.6	24:00	0:00	33,544.9	0.0	188.38	230.5	21.7
3	162.4	127.1	128.4	24:00	0:00	30,967.7	0.0	190.00	230.5	21.7
4	163.3	127.1	169.4	24:00	0:00	41,775.1	0.0	190.17	233.2	21.7
5	163.6	127.1	163.8	24:00	0:00	39,875.0	0.0	187.71	234.8	21.7
6	163.9	127.1	147.8	24:00	0:00	36,562.5	0.0	188.88	235.2	21.7
7	163.9	127.1	36.4	5:45	0:00	6,420.2	0.0	28.21	235.7	21.7
8	164.9	127.1	132.7	24:00	0:00	30,833.8	0.0	189.17	239.9	21.7
9	165.7	127.1	175.5	24:00	0:00	42,046.2	0.0	190.63	244.5	21.7
10	166.5	127.1	188.1	24:00	0:00	42,259.4	0.0	190.71	245.6	21.7
11	166.9	127.1	180.1	24:00	0:00	41,830.4	0.0	191.00	247.9	21.7
12	166.6	127.1	134.2	24:00	0:00	31,692.1	0.0	191.00	246.7	21.7
13	166.3	127.1	161.0	24:00	0:00	43,666.5	0.0	188.75	244.8	21.7
14	166.3	127.1	184.1	24:00	0:00	45,516.9	0.0	188.75	242	21.7
15	166.5	127.1	198.9	24:00	0:00	44,720.0	0.0	191.00	239.6	21.7
16	167	127.1	195.9	24:00	0:00	44,715.0	0.0	189.88	241.9	21.7
17	167.6	127.1	184.1	24:00	0:00	44,496.5	0.0	189.29	243.8	21.7
18	168.2	127.1	188.2	24:00	0:00	43,549.4	0.0	186.54	244.5	21.7
19	169.7	127.1	190.2	24:00	0:00	43,500.8	0.0	184.38	244.7	21.7
20	167.7	127.1	66.4	7:45	0:00	11,677.4	0.0	40.79	253	21.7
21	165.4	127.1	157.1	23:00	0:00	36,186.1	0.0	142.38	257.5	21.7
22	164	127.1	148.6	24:00	0:00	36,577.1	0.0	161.00	263.9	21.7
23	163.7	127.1	159.5	24:00	0:00	37,416.9	0.0	166.79	272.2	21.7
24	163.5	127.1	166.7	24:00	0:00	37,924.0	0.0	169.71	269.4	21.7
25	163.1	127.1	154.2	24:00	0:00	38,127.2	0.0	168.67	251.3	21.7
26	162.4	123.5	122.7	19:00	1:30	26,932.5	2,126.3	124.96	242.1	21.4
27	162.4	118.9	0.3	0:00	0:30	0.0	107.9	0.04	242.1	20.8
28	162.4	117.8	4.7	0:00	1:15	0.0	481.8	0.54	242.1	21.1
29	162.4	122	47.9	0:00	6:00	0.0	6,936.8	21.25	242.1	22.4
30	162.4	120.1	0.8	0:00	0:45	0.0	184.9	0.00	242.1	22.7

Total Actual NO_x Emissions for the month (tons) :	49.0

JULY 2000	30-Day Rolling Average NO_X Emissions Synfuel (lbs)	30-Day Rolling Average NO_X Emissions Oil (lbs)	Average NO_X Emissions (lb / hr)	Daily Hours of Operation Synfuel (hr)	Daily Hours of Operation Oil (hr)	Total Daily Heat Input Synfuel (MMBTU / day)	Total Daily Heat Input Oil (MMBTU / day)	Daily Average MW Output (MW)	30-Day Rolling Average SO_2 Emission Synfuel (lbs)	30-Day Rolling Average SO_2 Emission Oil (lbs)
1	162.4	122	111.3	9:00	9:30	11,107.8	11,724.8	86.04	248.9	23
2	163.5	122.6	170.6	23:00	1:00	37,643.4	1,636.7	169.46	252	23.2
3	165.2	124	192.4	22:00	2:00	37,715.5	3,428.7	175.50	264.4	23.7
4	166.3	124	191.2	24:00	0:00	44,242.6	0.0	190.96	274.7	23.7
5	167.7	124	193.1	24:00	0:00	43,679.3	0.0	190.58	281.8	23.7
6	169.1	124	190.7	24:00	0:00	43,606.0	0.0	190.71	287.3	23.7
7	169.3	124	175.5	24:00	0:00	43,379.8	0.0	191.00	296.8	23.7
8	168.8	124	160.6	24:00	0:00	43,339.7	0.0	191.00	297.5	23.7
9	168.5	124	162.1	24:00	0:00	43,346.1	0.0	191.00	301.5	23.7
10	168.2	124	160.0	24:00	0:00	42,149.2	0.0	185.38	306.5	23.7
11	167.9	125.6	155.3	21:00	3:00	33,997.9	4,856.8	166.83	310.8	24.1
12	167.1	125.6	168.8	24:00	0:00	43,361.8	0.0	190.71	313	24.1
13	166.7	125.6	167.0	24:00	0:00	43,183.2	0.0	190.17	312.8	24.1
14	165.2	125.6	156.9	24:00	0:00	43,037.1	0.0	191.00	314.5	24.1
15	163.5	125.6	146.2	24:00	0:00	42,719.3	0.0	191.00	312.5	24.1
16	162.6	125.6	144.0	24:00	0:00	43,069.7	0.0	190.13	308.8	24.1
17	162.3	125.6	156.0	24:00	0:00	43,197.1	0.0	191.00	305.1	24.1
18	162.4	125.6	165.0	24:00	0:00	43,208.4	0.0	191.00	301.9	24.1
19	162.5	125.6	163.5	24:00	0:00	43,001.7	0.0	190.92	299.2	24.1
20	162.4	125.6	160.2	24:00	0:00	42,773.5	0.0	190.79	294.8	24.1
21	162.4	125.6	162.9	24:00	0:00	42,566.6	0.0	190.75	290.8	24.1
22	162.5	125.6	166.1	24:00	0:00	42,890.5	0.0	191.00	287.3	24.1
23	162.4	125.6	158.0	24:00	0:00	43,138.9	0.0	191.00	285.2	24.1
24	162	125.6	150.1	24:00	0:00	42,974.7	0.0	191.00	285.5	24.1
25	162	125.6	135.0	24:00	0:00	43,214.9	0.0	189.42	290.3	24.1
26	161.8	125.6	143.6	24:00	0:00	43,413.4	0.0	190.83	291.1	24.1
27	161.2	125.6	140.6	24:00	0:00	43,463.6	0.0	190.67	291.2	24.1
28	160.7	125.6	153.7	24:00	0:00	42,839.4	0.0	189.33	287.1	24.1
29	160.9	125.6	157.6	24:00	0:00	42,997.3	0.0	191.00	285.6	24.1
30	161	125.6	150.6	24:00	0:00	42,954.1	0.0	191.00	289.6	24.1
31	161.7	125.6	150.6	24:00	0:00	43,156.2	0.0	191.00	291.2	24.1

Total Actual NO_x Emissions for the month (tons) :	59.6

AUGUST 2000	30-Day Rolling Average NO_x Emissions Synfuel (lbs)	30-Day Rolling Average NO_x Emissions Oil (lbs)	Average NO_x Emissions (lb / hr)	Daily Hours of Operation Synfuel (hr)	Daily Hours of Operation Oil (hr)	Total Daily Heat Input Synfuel (MMBTU / day)	Total Daily Heat Input Oil (MMBTU / day)	Daily Average MW Output (MW)	30-Day Rolling Average SO_2 Emission Synfuel (lbs)	30-Day Rolling Average SO_2 Emission Oil (lbs)
1	160.4	125.6	133.3	24:00	0:00	42,603.6	0.0	187.63	293.7	24.1
2	158.5	125.6	137.9	24:00	0:00	42,883.1	0.0	189.29	289.5	24.1
3	157.1	125.6	148.2	24:00	0:00	42,631.5	0.0	189.04	282.8	24.1
4	155.6	125.6	149.9	24:00	0:00	43,466.0	0.0	191.00	279.4	24.1
5	154.4	125.6	153.1	24:00	0:00	43,304.1	0.0	190.50	275.3	24.1
6	153.6	125.6	151.8	24:00	0:00	43,467.1	0.0	191.00	274.2	24.1
7	153.4	125.6	153.0	24:00	0:00	42,404.5	0.0	187.25	276.4	24.1
8	153.1	125.6	155.3	24:00	0:00	42,863.9	0.0	189.83	276.8	24.1
9	153.2	125.6	160.9	24:00	0:00	42,672.7	0.0	190.92	275.4	24.1
10	153.2	125.6	153.9	24:00	0:00	42,775.2	0.0	190.67	274.2	24.1
11	152.9	125.6	160.2	24:00	0:00	42,929.6	0.0	190.96	270.8	24.1
12	152.6	125.6	158.7	24:00	0:00	42,510.0	0.0	191.00	267.9	24.1
13	153.2	125.6	172.2	24:00	0:00	42,662.3	0.0	191.00	264.7	24.1
14	153.9	125.6	167.8	24:00	0:00	42,653.9	0.0	191.00	264	24.1
15	154.4	125.6	158.6	24:00	0:00	42,852.5	0.0	191.00	265.5	24.1
16	154.6	125.6	163.2	24:00	0:00	42,774.7	0.0	191.00	268	24.1
17	154.6	125.6	165.2	24:00	0:00	42,551.9	0.0	191.00	269.3	24.1
18	154.5	125.6	159.2	24:00	0:00	42,674.1	0.0	190.21	271.7	24.1
19	154.1	125.6	148.6	24:00	0:00	42,896.2	0.0	188.54	277	24.1
20	153.8	125.6	154.4	24:00	0:00	42,601.1	0.0	188.79	280.9	24.1
21	153.6	125.6	159.6	24:00	0:00	42,846.8	0.0	190.13	284.8	24.1
22	153.5	125.6	155.1	24:00	0:00	43,243.2	0.0	191.00	287.8	24.1
23	153.7	125.6	157.6	24:00	0:00	43,226.8	0.0	191.00	289.6	24.1
24	154.5	125.6	157.3	24:00	0:00	43,176.3	0.0	191.00	289.5	24.1
25	154.9	125.6	155.4	24:00	0:00	43,023.7	0.0	190.58	293.4	24.1
26	155.4	125.6	155.3	24:00	0:00	42,737.6	0.0	190.21	293	24.1
27	155.3	125.6	152.4	24:00	0:00	43,044.1	0.0	190.21	298.2	24.1
28	154.3	124.9	53.2	8:30	0:15	9,942.9	292.4	42.67	294.5	24
29	0.0	0.0	0.0	0:00	0:00	0.0	0.0	0.00	0.0	0.0
30	149.4	124.9	0.1	0:30	0:00	24.2	0.0	0.00	283.9	24
31	146.5	133.6	120.8	1:45	8:00	1,491.9	6,820.0	25.25	272.2	24.8

Total Actual NO_x Emissions for the month (tons) :	52.5

SEPTEMBER 2000	30-Day Rolling Average NO_x Emissions Synfuel (lbs)	30-Day Rolling Average NO_x Emissions Oil (lbs)	Average NO_x Emissions (lb / hr)	Daily Hours of Operation Synfuel (hr)	Daily Hours of Operation Oil (hr)	Total Daily Heat Input Synfuel (MMBTU / day)	Total Daily Heat Input Oil (MMBTU / day)	Daily Average MW Output (MW)	30-Day Rolling Average SO_2 Emission Synfuel (lbs)	30-Day Rolling Average SO_2 Emission Oil (lbs)
1	146.5	138.1	265.1	0:00	24:00	0.0	37,913.4	133.29	272.2	26.1
2	147.8	142.7	201.3	9:00	15:00	12,215.1	20,358.4	127.88	267.2	27.2
3	148.3	146.7	186.7	16:00	8:00	24,679.8	12,339.9	155.38	266	28.1
4	150.1	147.7	191.1	17:00	7:00	27,531.1	11,336.4	167.00	267.3	29.1
5	151.8	147.7	202.7	24:00	0:00	42,478.4	0.0	188.83	269.3	29.1
6	152.6	151.6	182.2	22:00	2:00	35,050.6	3,186.4	168.25	265.3	30.2
7	153.8	154	187.5	19:00	5:00	30,149.6	7,934.1	161.63	261.4	31.1
8	155	154	189.3	24:00	0:00	42,891.6	0.0	190.88	262.2	31.1
9	155.9	154	183.0	24:00	0:00	42,931.2	0.0	190.88	263.7	31.1
10	157	154	193.5	24:00	0:00	43,088.3	0.0	190.83	263.2	31.1
11	158.1	154	184.8	24:00	0:00	43,354.5	0.0	191.00	262.3	31.1
12	158.8	154	182.9	24:00	0:00	43,391.9	0.0	191.00	263.4	31.1
13	159.5	154	180.5	24:00	0:00	43,203.3	0.0	191.00	264	31.1
14	160.3	154	196.2	24:00	0:00	42,860.8	0.0	191.00	265.1	31.1
15	161.1	154	189.8	24:00	0:00	42,438.4	0.0	191.00	266.9	31.1
16	161.3	154	165.9	24:00	0:00	42,302.4	0.0	191.00	266.2	31.1
17	161.4	154	167.2	24:00	0:00	42,206.9	0.0	191.00	263.2	31.1
18	161.6	154	169.0	24:00	0:00	42,244.8	0.0	191.00	261	31.1
19	161.6	154	161.9	24:00	0:00	42,357.6	0.0	191.00	256.4	31.1
20	161.6	158.6	136.5	13:30	7:00	18,921.9	9,811.4	121.42	249.9	32.7
21	163.1	158.6	198.9	24:00	0:00	43,002.9	0.0	190.42	249	32.7
22	163.1	158.6	160.8	24:00	0:00	42,680.2	0.0	191.00	248.3	32.7
23	163.3	158.6	160.9	24:00	0:00	42,922.8	0.0	191.00	245.4	32.7
24	163.3	158.6	157.4	24:00	0:00	41,987.0	0.0	189.54	243.9	32.7
25	162.6	158.6	136.4	24:00	0:00	42,682.7	0.0	191.00	246.3	32.7
26	161.7	158.6	130.9	24:00	0:00	42,554.8	0.0	191.00	246.7	32.7
27	161.1	158.6	134.9	24:00	0:00	42,500.0	0.0	191.00	245.4	32.7
28	160.5	161.6	170.9	6:30	15:00	10,532.5	24,305.9	132.21	240.7	33
29	160.1	164.7	161.9	5:00	19:00	6,490.3	24,663.1	112.50	239.3	34.1
30	164.7	164.7	140.6	24:00	0:00	42,871.9	0.0	190.96	245.6	34.1

Total Actual NO_x Emissions for the month (tons) :	63.2

OCTOBER 2000	30-Day Average NO_X Emissions Synfuel	30-Day Average NO_X Emissions Oil	NO_X Emissions	Daily Hours of Operation Synfuel	Daily Hours of Operation Oil	Total Daily Heat Input Synfuel	Total Daily Heat Input Oil	Daily Average MW Output	30-Day Rolling Average SO_2 Emission Synfuel	30-Day Rolling Average SO_2 Emission Oil
	(lbs)		(lb / hr)	(hr)		(MMBTU / day)		(MW)	(lbs)	
1	167.5	164.7	145.4	24:00	0:00	42,681.6	0.0	191.00	256.9	34.1
2	166.5	164.7	142.9	24:00	0:00	42,118.6	0.0	191.00	264.3	34.1
3	165.7	164.7	131.0	24:00	0:00	42,513.8	0.0	191.00	266.5	34.1
4	163.3	164.7	130.6	24:00	0:00	42,808.0	0.0	191.00	269.1	34.1
5	161	164.7	132.6	24:00	0:00	43,124.3	0.0	191.00	269.1	34.1
6	159.5	164.7	129.7	24:00	0:00	43,164.4	0.0	191.00	275.3	34.1
7	157.6	164.7	133.2	24:00	0:00	42,825.4	0.0	191.00	280.1	34.1
8	155.7	164.7	131.1	24:00	0:00	43,110.7	0.0	191.00	280.4	34.1
9	154.3	164.7	142.1	24:00	0:00	42,516.0	0.0	191.00	278	34.1
10	153.5	164.7	166.5	24:00	0:00	42,894.5	0.0	191.00	277.2	34.1
11	153.2	164.7	176.1	24:00	0:00	43,185.7	0.0	191.00	278.7	34.1
12	152.7	164.7	167.4	24:00	0:00	43,281.7	0.0	191.00	277.9	34.1
13	152	164.7	160.2	24:00	0:00	42,955.8	0.0	187.75	274.6	34.1
14	151.3	164.7	177.7	24:00	0:00	43,325.8	0.0	191.00	270.3	34.1
15	151.5	164.7	193.0	24:00	0:00	42,955.0	0.0	191.00	265.3	34.1
16	152.6	164.7	199.3	24:00	0:00	42,939.7	0.0	191.00	265.9	34.1
17	153.3	164.7	189.2	24:00	0:00	42,798.1	0.0	191.00	270.2	34.1
18	153.7	164.7	179.8	24:00	0:00	43,194.3	0.0	191.00	275.3	34.1
19	154.7	164.7	181.1	24:00	0:00	43,303.0	0.0	191.00	280.5	34.1
20	156.4	164.7	194.2	24:00	0:00	43,179.4	0.0	191.00	284.9	34.1
21	155.7	164.7	177.7	24:00	0:00	43,077.5	0.0	191.00	284.5	34.1
22	156.4	164.7	182.0	24:00	0:00	43,198.0	0.0	191.00	283.5	34.1
23	157.1	164.7	180.5	24:00	0:00	43,131.6	0.0	191.00	284	34.1
24	157.3	166.9	220.4	7:00	17:00	12,088.7	29,358.4	161.96	280.7	35.3
25	157.3	173.4	229.2	0:00	24:00	0.0	37,062.2	133.17	280.7	37.1
26	160.1	174	161.9	8:45	10:15	11,887.2	13,925.1	101.71	269.7	37.4
27	163.1	174	222.7	24:00	0:00	43,023.7	0.0	191.00	262.7	37.4
28	165.1	174	196.3	24:00	0:00	43,014.8	0.0	191.00	261.1	37.4
29	167.2	174	197.1	24:00	0:00	43,192.7	0.0	191.00	262.3	37.4
30	169.7	174	190.3	24:00	0:00	42,998.6	0.0	191.00	271.5	37.8
31	171.5	174	197.0	24:00	0:00	42,829.8	0.0	191.00	273.8	37.8

Total Actual NO_x Emissions for the month (tons) :	64.4

NOVEMBER 2000	30-Day Average NO_X Emissions Synfuel (lbs)	Oil	NO_X Emissions (lb / hr)	Daily Hours of Operation Synfuel (hr)	Oil	Total Daily Heat Input Synfuel (MMBTU / day)	Oil	Daily Average MW Output (MW)	30-Day Rolling Average SO_2 Emission Synfuel (lbs)	Oil
1	173.1	174	191.2	24:00	0:00	42,972.8	0.0	191.00	270.1	37.8
2	174.9	174	197.4	24:00	0:00	42,621.5	0.0	191.00	267.6	37.8
3	176.6	174	180.7	24:00	0:00	40,822.8	0.0	183.29	266.8	37.8
4	178.1	173.2	174.3	22:00	2:00	35,440.6	3,221.9	169.42	266.5	40.6
5	179.5	173.2	175.8	24:00	0:00	42,462.6	0.0	191.00	266.2	40.6
6	180.8	173.2	169.3	24:00	0:00	42,687.4	0.0	191.00	264.3	40.6
7	182	173.2	168.4	24:00	0:00	42,892.1	0.0	191.00	261.8	40.6
8	183.5	173.2	175.9	24:00	0:00	42,727.5	0.0	191.00	259.7	40.6
9	184.7	173.2	176.8	24:00	0:00	42,552.6	0.0	191.00	261.3	40.6
10	184.4	173.2	159.1	24:00	0:00	41,129.1	0.0	183.21	257.3	40.6
11	183.9	173.2	163.1	24:00	0:00	38,954.0	0.0	174.88	248.6	40.6
12	183.9	173.2	167.5	24:00	0:00	38,899.0	0.0	174.79	241.6	40.6
13	183.8	173.2	156.6	24:00	0:00	39,057.9	0.0	174.83	240.7	40.6
14	183	173.2	153.1	24:00	0:00	38,890.4	0.0	174.71	244.3	40.6
15	182.1	173.2	165.3	24:00	0:00	38,938.1	0.0	174.75	250.4	40.6
16	180.3	174.2	149.2	23:00	1:00	34,465.5	1,498.5	157.67	252.4	42
17	178.9	174.2	145.7	24:00	0:00	39,534.5	0.0	174.83	250.8	42
18	177.6	174.2	141.9	24:00	0:00	39,614.2	0.0	174.88	249	42
19	175.9	174.2	139.1	24:00	0:00	39,616.0	0.0	174.83	247.8	42
20	174.2	174.2	148.7	24:00	0:00	39,587.2	0.0	174.71	249.3	42
21	173.9	174.2	167.2	24:00	0:00	39,708.5	0.0	174.92	245.7	42
22	174	174.2	183.2	24:00	0:00	40,356.9	0.0	178.42	243.1	42
23	173.7	174.2	174.3	24:00	0:00	39,487.3	0.0	174.88	239.3	42
24	173.7	174.2	164.6	24:00	0:00	39,554.4	0.0	174.92	238	42
25	171.4	174.2	148.1	24:00	0:00	39,718.7	0.0	174.88	242.1	42
26	169.1	174.2	152.3	24:00	0:00	39,527.6	0.0	174.83	245.9	42
27	167.9	174.2	161.9	24:00	0:00	39,663.3	0.0	174.79	247.9	42
28	167.3	174.2	178.3	24:00	0:00	39,538.0	0.0	174.83	247.4	42
29	166.2	175.5	166.2	19:00	5:00	28,636.6	7,536.0	152.75	244.8	43.1
30	164.9	175.5	157.5	24:00	0:00	37,662.2	0.0	164.92	242.3	43.1

Total Actual NO_x Emissions for the month (tons) :	59.5

October 1999

Mine: Ohio #11 **Coal Blend: 54%**

Coal Analysis - As Received	Result	Units
Ash, as Received	6.81	%
BTU, as Received	11841	BTU/Lb
Sulfur, as Received	2.88	%
Volatiles, as Received	37.49	%
Fixed Carbon, as Received	44.30	%
Carbon, as Received	65.27	%
Hydrogen, as Received	4.48	%
Nitrogen as Received	1.34	%
Oxygen, as Received	7.72	%

Mine: Camp **Coal Blend: 46%**

Coal Analysis - As Received	Result	Units
Ash, as Received	9.22	%
BTU, as Received	11664	BTU/Lb
Sulfur, as Received	2.93	%
Volatiles, as Received	35.51	%
Fixed Carbon, as Received	44.77	%
Carbon, as Received	65.25	%
Hydrogen, as Received	4.47	%
Nitrogen as Received	1.38	%
Oxygen, as Received	6.17	%

November 1999

Mine: Camp **Coal Blend: 100%**

Coal Analysis - As Received	Result	Units
Ash, as Received	9.22	%
BTU, as Received	11664	BTU/Lb
Sulfur, as Received	2.93	%
Volatiles, as Received	35.51	%
Fixed Carbon, as Received	44.77	%
Carbon, as Received	65.25	%
Hydrogen, as Received	4.47	%
Nitrogen as Received	1.38	%
Oxygen, as Received	6.17	%

December 1999

Mine: Camp

Coal Blend: 100%

Coal Analysis - As Received	Result	Units
Ash, as Received	9.12	%
BTU, as Received	11629	BTU/Lb
Sulfur, as Received	2.89	%
Volatiles, as Received	35.61	%
Fixed Carbon, as Received	44.67	%
Carbon, as Received	64.91	%
Hydrogen, as Received	4.55	%
Nitrogen as Received	1.38	%
Oxygen, as Received	6.43	%

January 2000

Mine: Camp **Coal Blend: 100%**

Coal Analysis - As Received	Result	Units
Ash, as Received	9.21	%
BTU, as Received	11456	BTU/Lb
Sulfur, as Received	2.92	%
Volatiles, as Received	35.04	%
Fixed Carbon, as Received	44.35	%
Carbon, as Received	63.71	%
Hydrogen, as Received	4.34	%
Nitrogen as Received	1.39	%
Oxygen, as Received	6.94	%

February 2000

Mine: Camp **Coal Blend: 47%**

Coal Analysis - As Received	Result	Units
Ash, as Received	9.26	%
BTU, as Received	11501	BTU/Lb
Sulfur, as Received	2.95	%
Volatiles, as Received	35.19	%
Fixed Carbon, as Received	44.55	%
Carbon, as Received	64.12	%
Hydrogen, as Received	4.72	%
Nitrogen as Received	1.44	%
Oxygen, as Received	6.41	%

Mine: Petcoke **Coal Blend: 21%**

Coal Analysis - As Received	Result	Units
Ash, as Received	0.403	%
BTU, as Received	14558	BTU/Lb
Sulfur, as Received	5.00	%
Volatiles, as Received	11.44	%
Fixed Carbon, as Received	83.72	%
Carbon, as Received	84.28	%
Hydrogen, as Received	3.62	%
Nitrogen as Received	1.67	%
Oxygen, as Received	0.557	%

Mine: Pitt **Coal Blend: 33%**

Coal Analysis - As Received	Result	Units
Ash, as Received	7.11	%
BTU, as Received	13290	BTU/Lb
Sulfur, as Received	1.50	%
Volatiles, as Received	35.18	%
Fixed Carbon, as Received	52.57	%
Carbon, as Received	74.75	%
Hydrogen, as Received	4.89	%
Nitrogen as Received	1.50	%
Oxygen, as Received	4.97	%

March 2000

Mine: Camp **Coal Blend: 100%**

Coal Analysis - As Received	Result	Units
Ash, as Received	8.74	%
BTU, as Received	11499	BTU/Lb
Sulfur, as Received	2.61	%
Volatiles, as Received	34.93	%
Fixed Carbon, as Received	44.93	%
Carbon, as Received	64.08	%
Hydrogen, as Received	4.39	%
Nitrogen as Received	1.43	%
Oxygen, as Received	7.22	%

April 2000

Mine: **Camp** **Coal Blend:** **62%**

Coal Analysis - As Received	Result	Units
Ash, as Received	9.26	%
BTU, as Received	11510	BTU/Lb
Sulfur, as Received	2.94	%
Volatiles, as Received	34.99	%
Fixed Carbon, as Received	44.75	%
Carbon, as Received	64.26	%
Hydrogen, as Received	4.49	%
Nitrogen as Received	1.42	%
Oxygen, as Received	6.53	%

Mine: **Petcoke** **Coal Blend:** **22%**

Coal Analysis - As Received	Result	Units
Ash, as Received	0.402	%
BTU, as Received	14072	BTU/Lb
Sulfur, as Received	5.64	%
Volatiles, as Received	9.174	%
Fixed Carbon, as Received	83.27	%
Carbon, as Received	81.67	%
Hydrogen, as Received	3.48	%
Nitrogen as Received	1.54	%
Oxygen, as Received	0.058	%

Mine: **Pitt** **Coal Blend:** **16%**

Coal Analysis - As Received	Result	Units
Ash, as Received	7.29	%
BTU, as Received	13276	BTU/Lb
Sulfur, as Received	1.46	%
Volatiles, as Received	35.27	%
Fixed Carbon, as Received	52.34	%
Carbon, as Received	74.29	%
Hydrogen, as Received	4.87	%
Nitrogen as Received	1.51	%
Oxygen, as Received	5.36	%

May 2000

Mine: Camp **Coal Blend: 69%**

Coal Analysis - As Received	Result	Units
Ash, as Received	9.26	%
BTU, as Received	11510	BTU/Lb
Sulfur, as Received	2.94	%
Volatiles, as Received	34.99	%
Fixed Carbon, as Received	44.75	%
Carbon, as Received	64.26	%
Hydrogen, as Received	4.49	%
Nitrogen as Received	1.42	%
Oxygen, as Received	6.53	%

Mine: Petcoke **Coal Blend: 3%**

Coal Analysis - As Received	Result	Units
Ash, as Received	0.486	%
BTU, as Received	13743	BTU/Lb
Sulfur, as Received	4.15	%
Volatiles, as Received	10.69	%
Fixed Carbon, as Received	78.82	%
Carbon, as Received	79.80	%
Hydrogen, as Received	2.94	%
Nitrogen as Received	2.02	%
Oxygen, as Received	0.564	%

Mine: Pitt **Coal Blend: 28%**

Coal Analysis - As Received	Result	Units
Ash, as Received	7.29	%
BTU, as Received	13276	BTU/Lb
Sulfur, as Received	1.46	%
Volatiles, as Received	35.27	%
Fixed Carbon, as Received	52.34	%
Carbon, as Received	74.29	%
Hydrogen, as Received	4.87	%
Nitrogen as Received	1.51	%
Oxygen, as Received	5.36	%

June 2000

Mine: Camp **Coal Blend: 100%**

Coal Analysis - As Received	Result	Units
Ash, as Received	9.26	%
BTU, as Received	11510	BTU/Lb
Sulfur, as Received	2.94	%
Volatiles, as Received	34.99	%
Fixed Carbon, as Received	44.75	%
Carbon, as Received	64.26	%
Hydrogen, as Received	4.49	%
Nitrogen as Received	1.42	%
Oxygen, as Received	6.53	%

July 2000

Mine: Camp **Coal Blend: 100%**

Coal Analysis - As Received	Result	Units
Ash, as Received	9.26	%
BTU, as Received	11510	BTU/Lb
Sulfur, as Received	2.94	%
Volatiles, as Received	34.99	%
Fixed Carbon, as Received	44.75	%
Carbon, as Received	64.26	%
Hydrogen, as Received	4.49	%
Nitrogen as Received	1.42	%
Oxygen, as Received	6.53	%

August 2000

Mine: Camp **Coal Blend: 100%**

Coal Analysis - As Received	Result	Units
Ash, as Received	9.26	%
BTU, as Received	11510	BTU/Lb
Sulfur, as Received	2.94	%
Volatiles, as Received	34.99	%
Fixed Carbon, as Received	44.75	%
Carbon, as Received	64.26	%
Hydrogen, as Received	4.49	%
Nitrogen as Received	1.42	%
Oxygen, as Received	6.53	%

September 2000

Mine: Camp **Coal Blend: 48%**

Coal Analysis - As Received	Result	Units
Ash, as Received	9.26	%
BTU, as Received	11510	BTU/Lb
Sulfur, as Received	2.94	%
Volatiles, as Received	34.99	%
Fixed Carbon, as Received	44.75	%
Carbon, as Received	64.26	%
Hydrogen, as Received	4.49	%
Nitrogen as Received	1.42	%
Oxygen, as Received	6.53	%

Mine: Pitt **Coal Blend: 52%**

Coal Analysis - As Received	Result	Units
Ash, as Received	7.70	%
BTU, as Received	13103	BTU/Lb
Sulfur, as Received	2.52	%
Volatiles, as Received	36.53	%
Fixed Carbon, as Received	49.62	%
Carbon, as Received	73.32	%
Hydrogen, as Received	4.90	%
Nitrogen as Received	1.46	%
Oxygen, as Received	3.87	%

October 2000

Mine: **Pitt** **Coal Blend:** **100%**

Coal Analysis - As Received	Result	Units
Ash, as Received	7.84	%
BTU, as Received	13090	BTU/Lb
Sulfur, as Received	2.33	%
Volatiles, as Received	36.43	%
Fixed Carbon, as Received	49.73	%
Carbon, as Received	72.77	%
Hydrogen, as Received	4.79	%
Nitrogen as Received	1.45	%
Oxygen, as Received	4.74	%

October 2000

Mine: **Pitt**

Coal Blend: **100%**

Coal Analysis - As Received	Result	Units
Ash, as Received	7.62	%
BTU, as Received	13251	BTU/Lb
Sulfur, as Received	2.66	%
Volatiles, as Received	37.06	%
Fixed Carbon, as Received	49.96	%
Carbon, as Received	73.68	%
Hydrogen, as Received	4.88	%
Nitrogen as Received	1.45	%
Oxygen, as Received	4.27	%

Comment 3 Enclosures

GE Power Generation

Gas Turbine NOx Emissions Approaching Zero – Is it Worth the Price?

Marvin M. Schorr, Consulting Engineer
Joel Chalfin, Manager, Environmental Engineering
General Electric Power Systems
Schenectady, New York

GAS TURBINE NOx EMISSIONS APPROACHING ZERO - IS IT WORTH THE PRICE?

Marvin M. Schorr, Consulting Engineer
Joel Chalfin, Manager, Environmental Engineering
General Electric Power Systems
Schenectady, New York

ABSTRACT

The requirement for gas turbines to meet ever lower NOx emission levels results from a regulatory approach developed before combustion systems existed that are capable of achieving single digit NOx. Dry low NOx (DLN) combustors for GE Frame 7FAs, 7EAs and 6Bs are now demonstrating 9 ppm NOx. This paper compares the energy, environmental and economic impacts of requiring add-on emission controls to achieve a lower level of NOx, with a gas turbine combustion system that is already capable of achieving single digit NOx. The conclusion reached is that ratcheting NOx down to lower and lower levels through the use of add-on emission controls reaches the point of diminishing return when the gas turbine combustion system is capable of achieving single digit NOx. The cost of add-on emission controls to achieve a lower NOx level becomes excessive, the heat rate increases and the overall environmental impacts are actually worsened. The recommendation is made for the U.S. EPA to amend the regulatory process to allow permit authorities to consider conflicting environmental, energy and economic impacts in nonattainment areas, as they now can in attainment areas, in cases where add-on emission controls will result in only a small reduction in emissions.

INTRODUCTION

The current regulatory process for permitting gas turbines is the product of a regulatory approach that does not seem to have anticipated gas turbine combustion systems capable of achieving single digit NOx without add-on controls (such as selective catalytic reduction, SCR). The technology forcing approach of the Clean Air Act New Source Review process has been especially successful with respect to gas turbine combustion system emissions through the use of Best Available Control Technology (BACT) and Lowest Achievable Emission Rate (LAER) requirements. Allowable NOx emissions have been ratcheted down from an New Source Performance Standards (NSPS) level of 75 ppm (plus heat rate correction) to less than 10 ppm (when firing natural gas) in about 12 years. However, the point of diminishing returns appears to have been reached, at least for GE gas turbine combustion systems that are now achieving single digit NOx without the use of post combustion, add-on emission controls. The response of gas turbine manufacturers to the technology forcing programs of the Clean Air Act has been truly impressive.

Dry low NOx (DLN) combustors for GE Frame 7FAs, 7EAs and 6Bs are now operating at 9 ppm NOx and even lower levels are likely to be achieved in the next few years. The cost of add-on emission controls to achieve a NOx level below 9 ppm becomes excessive and the overall environmental impacts may actually be worsened when the gas turbine combustion system is capable of achieving single digit NOx. The recommendation is made for the U.S. EPA to amend the regulatory process to allow permit authorities to consider conflicting environmental, energy and economic impacts in nonattainment areas, as they now can in attainment areas, in cases where add-on emission controls will result in only a marginal reduction in emissions.

REGULATORY BACKGROUND

The decade of the 1980s was one of rapid change for both gas turbine emission control regulations and the technologies used to meet those regulations. The primary pollutant of concern from gas turbines has been, and continues to be, oxides of nitrogen. The Gas Turbine New Source Performance Standards (NSPS), issued in 1979, did not regulate the emissions of carbon monoxide or unburned hydrocarbons from gas turbines because the levels are very low at base load. However, in December 1987, EPA's "top-down approach" for determining the Best Available Control Technology (BACT) became a requirement. This ratcheted allowable gas turbine NOx emission levels down to levels significantly lower than the NSPS. As the allowable NOx levels decreased, with steam or water injection the primary technology used for NOx control, carbon monoxide emissions started to become more of a concern. Increases in CO levels resulted from massive amounts of steam or water being injected to control NOx to the lower levels and part load operation in cogeneration applications. As a result, advances in dry low NOx combustion technology and new add-on emission controls allowed gas turbine operators to achieve very low levels of NOx without injection. The Clean Air Act Amendments of 1990 have resulted in new emission control requirements, not only for NOx, but also for CO and VOCs in ozone non-attainment areas.

GAS TURBINE EMISSIONS

Potential pollutant emissions from gas turbines include oxides of nitrogen (NO and NO2, collectively referred to as NOx), carbon monoxide (CO), unburned hydrocarbons (UHC, usually expressed as equivalent methane), oxides of sulfur (SO2 and SO3) and particulate matter (PM). Unburned hydrocarbons are made up of volatile organic compounds (VOCs), which contribute to the formation of ground level atmospheric ozone, and compounds such as methane and ethane, that do not contribute to ozone formation. SO2, UHC and PM are generally considered negligible when burning natural gas. Thus, NOx and possibly CO are the only emissions of significance when combusting natural gas in combustion turbines.

The NOx production rate falls sharply as either the combustion temperature decreases, or as the fuel-air ratio decreases, due to an exponential temperature effect. Therefore, the introduction of a small amount of any diluent into the combustion zone will decrease the rate of thermal NOx production. This is the physics behind the injection of water or steam and of lean combustors. Because the diluent effect is a thermal one, the higher specific heat of steam means that less steam needs to be introduced than air and less water than steam to achieve the equivalent NOx reduction. However, the introduction of steam or water to the gas turbine combustor is a thermodynamic loss, whereas redistributing combustor airflow splits (combustion vs. dilution/cooling) has no impact on the cycle efficiency. As a result, the use of very lean combustors to achieve the lower NOx levels is more desirable than steam/water injection.

NO$_X$ CONTROL TECHNOLOGIES

The "front-end" technologies that are available for the control of NOx emissions from gas turbines include: (1) injection of water or steam into the combustion zone, a control technology that lowers flame temperature, (2) dry low NOx combustion (DLN), a technology that uses staged combustion and lean-premixed fuel-air mixtures, and (3) catalytic combustion, a new technology that holds the promise of achieving extremely low emission levels. "Back-end" exhaust gas clean-up systems include (4) selective catalytic reduction (SCR) and (5) SCONOXTM, a new catalytic technology.

Water/Steam Injection

Most of the experience base with gas turbine NOx emission control prior to 1990 was with diluent injection into the combustion zone. The injected diluent provides a heat sink that lowers the combustion zone temperature, which is the primary parameter affecting NOx formation. As the combustion zone temperature decreases, NOx production decreases exponentially.

Manufacturers continue to develop machines having higher firing temperatures as a way to increase the overall thermodynamic efficiency. However, higher firing temperatures mean higher combustion temperatures, which produce more NOx, resulting in the need for more diluent injection to achieve the same emission levels of NOx. There has also been a reduction of allowable NOx emissions and lower NOx levels require even more injection. The increased injection rate lowers the thermodynamic efficiency, seen as an increase in heat rate (fuel use), due to taking some of the energy from combustion gases to heat the water or steam. Furthermore, as injection increases, dynamic pressure oscillation activity (i.e., noise) in the combustor also increases, resulting in increased wear of internal parts. Carbon monoxide, which may be viewed as a measure of the inefficiency of the combustion process, also increases as the injection rate increases. Basically, as more and more water or steam is injected into the combustor to lower the combustion temperature, flame stability is affected until, if it were increased sufficiently, the water would literally put out the flame. Thus, a design dichotomy exists whereby increasing firing temperature to increase the efficiency of the combustion process, unfortunately produces more NOx, requiring more injection, which lowers the thermodynamic efficiency, producing more CO and also decreasing parts life. Increased injection to meet lower NOx emission limits simply exacerbates the problems associated with increased injection. The lowest practical NOx levels achieved with injection are generally 25 ppm when firing natural gas and 42 ppm when firing oil.

Selective Catalytic Reduction, SCR

In the SCR process, ammonia (NH) injected into the gas turbine exhaust gas stream as it passes through the heat recovery steam generator (HRSG), reacts with nitrogen oxides (NOx) in the presence of a catalyst to form molecular nitrogen and water. Based on experience, SCR works best in base loaded combined cycle gas turbine applications where the fuel is natural gas. The reasons for that relate to the temperature dependency of the catalytic NOx-ammonia reaction and the catalyst life, and to major problems associated with the use of sulfur bearing (liquid) fuels. The reaction takes place over a limited temperature range, 600-750°F, and above approximately 850°F the catalyst is damaged irreversibly. In addition, because of the temperature dependency of the chemical reaction and catalyst life, SCR cannot be used in simple cycle configurations, except possibly in lower exhaust temperature systems. Other issues associated with SCR include exhaust emissions of ammonia (known as ammonia slip); concerns about accidental release of stored ammonia to the atmosphere, environmental concerns and costs of disposal of spent catalyst.

Ammonia Release

The use of ammonia in the SCR chemical process for NOx control presents several problems. Ammonia is on EPA's list of Extremely Hazardous Substances under Title III, Section 302 of the Superfund Amendments and Reauthorization Act of 1986 (SARA). Releases of ammonia to the atmosphere may occur due to unreacted ammonia going out the stack (known as ammonia "slip"), or it can be accidentally released during transport, transfer, or storage. In addition, ammonia is a PM-10 precursor emission (particulate matter smaller in diameter than 10 microns).

Some ammonia slip is unavoidable with SCR due to the non-uniform distribution of the reacting gases. Thus, some ammonia and unreacted NOx will pass through the catalyst and in fact some catalyst manufacturers recommend operating with excess ammonia to compensate for imperfect distribution. An ammonia slip of 10-20 ppm is generally permitted in a new system (although higher slip has been noted) and will increase with catalyst age. In the past, ammonia slip was not considered to be a problem by regulatory agencies because they felt that by releasing it from an elevated stack, the ground level concentration would be low. However, it has never appeared to be good environmental policy to allow ammonia to be released to the atmosphere in place of NOx and ammonia emissions are now of concern because of PM–2.5 considerations.

The Use of Sulfur-Bearing Fuels

The Problem – Distillate oil contains sulfur. There is no successful operating experience when SCR is used for NOx control while firing a gas turbine with sulfur bearing oil. However, some regulatory agencies require the use of SCR, even when distillate oil is used as a backup fuel. In most cases regulators have simply pointed to the many combined cycle plants with SCR permitted with oil as the backup fuel, ignoring the fact that most of those plants actually operate almost exclusively on gas and use little or no oil fuel. Those that have used oil have experienced significant problems.

The problems associated with the use of sulfur bearing fuels are due to the formation of the ammonium salts ammonium bisulfate, NH_4HSO_4, and ammonium sulfate, $(NH_4)SO_4$. These compounds are formed by the chemical reaction between the sulfur oxides in the exhaust gas and the ammonia injected for NOx control. Ammonium bisulfate causes rapid corrosion of boiler tube materials; and both ammonium compounds cause fouling and plugging of the boiler and an increase of PM–10 emissions.

Ammonium bisulfate forms in the lower temperature section of the HRSG where it deposits on the walls and heat transfer surfaces. These surface deposits can lead to rapid corrosion in the HRSG economizer and downstream metal surfaces resulting in increased pressure drop and reduced heat transfer (lower power output and cycle efficiency). While ammonium sulfate is not corrosive, its formation also contributes to plugging and fouling of the heat transfer surfaces (leading to reduced heat transfer efficiency) and higher particulate emissions. The increase in emissions of particulates due to the ammonium salts can be as high as a factor of five due to conversion of SO_2 to SO_3. Some of the SO_2 formed from the fuel sulfur is converted to SO_3 and it is the SO_3 that reacts with water and ammonia to form ammonium bisulfate and ammonium sulfate. The increase is a function of the amount of sulfur in the fuel, the ammonia slip (ammonia that does not react with NOx) and the temperature. It can also be increased by supplementary firing of the HRSG and by the use of a CO oxidizing catalyst (which significantly increases the conversion of SO_2 to SO_3).

The only effective way to inhibit the formation of ammonium 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. Pipeline quality natural gas usually has a sulfur content low enough that ammonium salt formation, while it is present, has not yet been a significant problem with natural gas-fired units. However, the sulfur content of even very low sulfur distillate oil (e.g., 0.05 percent) or liquid aviation fuel (Jet–A) may not be low enough to prevent enough formation of ammonium bisulfate to avoid the problems discussed above (ambient sulfates may also contribute). This potential is usually handled by a requirement to limit the operating time on the low sulfur distillate oil to a relatively few hundred hours between shutdowns and then clean the HRSG internals (although disposal of the deposits may be a problem due to the presence of hazardous materials). Lowering the ammonia slip or the sulfur concentration could lengthen the time between cleanings. Limiting the ammonia that is available to react with the sulfur oxides to negligible levels does not appear practical at NOx removal efficiencies above 80 percent because higher excess ammonia levels are required to achieve the higher NOx removal efficiencies. Limiting the excess ammonia may work at lower NOx removal efficiencies because the lower NH_3/NOx ratios required ensure that all the ammonia is consumed. However, when oil is to be used as the primary fuel, the experience would indicate that SCR should not be used, as there appears to be significant risk of equipment damage or failure, performance degradation and increased emissions of fine PM.

Disposal of Spent Catalyst

SCR materials typically contain heavy metal oxides such as vanadium and/or titanium, thus creating a human health and environmental risk related to the handling and disposal of spent catalyst. Vanadium pentoxide, the most commonly used SCR catalyst, is on the EPA's list of Extremely Hazardous Materials. The quantity of waste associated with SCR is quite large, although the actual amount of active material in the catalyst bed is relatively small.

SCONOX

SCONOX is a post-combustion catalytic system that removes both NOx and CO from the gas turbine exhaust, but without ammonia injection. The catalyst is platinum and the active NOx removal reagent is potassium carbonate. At present, the only operating SCONOX system is being used with an LM2500 injected with steam to 25 ppm NOx at a facility in Vernon, CA. Stack NOx is maintained at 2 ppm or less and CO at less then 1 ppm.

How SCONOX Works

The exhaust gases from a gas turbine flow into the reactor and react with potassium carbonate which is coated on the platinum catalyst surface. The CO is oxidized to CO_2 by the platinum catalyst and the CO_2 is exhausted up the stack. NO is oxidized to NO_2 and then reacts with the potassium carbonate absorber coating on the catalyst to form potassium nitrites and nitrates at the surface of the catalyst. When the carbonate becomes saturated with NOx it must be regenerated. The effective operating temperature range is 280 to 750°F, with 500 to 700°F the optimum range for NOx removal. The optimum temperature range is approximately the same as that of SCR.

Regeneration is accomplished by passing a dilute hydrogen reducing gas (diluted to less than 4 percent hydrogen using steam) across the surface of the catalyst in the absence of oxygen. The sections of reactor catalyst undergoing regeneration are isolated from exhaust gases using sets of louvers on the upstream and downstream side of each reactor box. The Vernon LM2500 facility has 12 vertically stacked catalyst reactor boxes, nine of which are in the oxidation/absorption cycle at any given time, while three are in the regeneration cycle. When regen is completed in the three reactor boxes, the louvers open on those reactors and the louvers on three other reactors close and those reactors go into the regeneration cycle. Motor drives outside each box drive the shaft that opens and closes the louvers on each side of the box (inlet and outlet sides).

SCONOX Issues

There are several issues associated with the use of SCONOX. First, it is very sensitive to sulfur, even the small amount in pipeline natural gas. Second, the initial capital cost is about three times the cost of SCR, although this may come down once there are more in operation. Third, it has moving parts reliability and performance degradation due to leakage may be significant issues, especially on scale-up to bigger gas turbines (a 7FA would require 20 modules of 4 reactor boxes each vs. LM2500 using 3 modules of 4 reactor boxes). Last, use of any exhaust gas treatment technology (SCR or SCONOX) results in a pressure drop that reduces gas turbine efficiency. Thus, by adding a back-end cleanup system, more fuel must be burned to reduce NOx and SCONOX produces about twice the pressure drop of SCR.

The GE Dry Low NOx Combustor

GE began development of a dry low NOx combustor in 1973, primarily in response to increasingly stringent emission control requirements in California. The initial goal was a NOx level of 75 ppmvd at 15 percent oxygen, the NSPS requirement for utility gas turbines. An oil-fired combustor designed for a Frame 7 gas turbine achieved this goal in the laboratory in 1978. Field testing of the prototype dry low NOx combustor design demonstrated that the combustor was capable of meeting the NSPS. The design, tested at Houston Lighting and Power (HL and P) in 1980, has evolved into a system that is achieving a NOx level of 9 ppmvd at 15 percent oxygen in GE Frame 7EA, FA, and 6B gas turbines fired on natural gas.

DISCUSSION

Cost in $/ton of NOx Removed/Energy Output Reduction

The annual cost of reducing NOx using SCR from 9 ppm to 3.5 ppm for a GE Frame 7FA, 170 MW class gas turbine operating 8,000 hr/year is $8,000 to $12,000 per ton of NOx removed when a non sulfur bearing fuel is used and $15,000 to $30,000 if a sulfur bearing fuel is used. The cost will be the same or more than that with SCONOX, which in addition, cannot be used with sulfur bearing fuels without additional cost for sulfur removal. (The SCR cost effectiveness estimate with a sulfur bearing fuel is based on six year replacement of catalyst, 20 percent fixed charge rate and a vendor quote of 25 percent increase in HRSG cost for a redesigned economizer section to allow for cleaning of ammonium bisulfate. If a redesigned HRSG is not acceptable, the cost of periodic replacement of LP economizer tubes should be used in the BACT analysis.) Most gas turbine combined cycle or cogeneration systems today operate with natural gas as the primary fuel and fuel oil as the backup fuel. SCR operating and maintenance costs include continuous ammonia injection, periodic catalyst replacement, and the cost associated with a small decrease in power output (more than 650 kW for a 7FA). The output drop is due to power for auxiliaries associated with ammonia injection, catalyst pressure drop in the new and clean condition, which increases as ammonia-sulfur salts build up, and decrease in heat transfer as the salt buildup increases over time. This cost is considered too high for BACT in ozone attainment areas by most states. The decrease in output efficiency results in an increase in CO_2 emissions due to the need to burn more fuel to make up for the output reduction.

It is often argued that economics should not be considered at all in LAER determinations. There is, however, an implicit "reasonableness test" in all LAER determinations. Thus, no regulator has required that trains of multiple SCR be utilized to reduce NOx to zero (although this is technically possible) because the cost would be so high that we would conclude that it would not be "reasonable". This same rationale should apply to adding any emission control if the cost is unreasonably high, as is the case for adding SCR or SCONOX to a combustion system achieving 9 ppm NOx in a combined cycle.

Ammonia Slip/Ammonium-Sulfur Salts

The impact of slip on the environment may be at least as detrimental as if NOx were to be released. Where an ammonia emission limit is imposed, and there is often no such emission limit, slip is generally targeted at 10-20 ppm, although there are units operating with ammonia slip well below and well above that level. Most recent SCRs operate with 5 ppm slip or less, but slip is expected to be on the high side when the NOx level entering the catalyst bed is already very low. Unless there is perfect mixing, the ammonia molecules must "find" the fewer NOx molecules in order to react and this will require adding more excess ammonia. Thus, 20 ppm or more ammonia slip would be released in place of the reduction in NOx in going from 9 to 3.5 ppm. Table 1 shows that for a Frame 7FA with 20 ppm ammonia slip (base load, 8,000 hr/yr, 45°F ambient, natural gas) there are 24 tons per year (TPY) more ammonia emitted than NOx reduction by lowering NOx from 9 to 3.5 ppm with SCR. There also is an increase of 5 TPY in particulate matter emitted, or 36 TPY if a CO catalyst is also used. Note also that as the catalyst ages, ammonia slip increases as the efficiency of conversion decreases, until at the end of catalyst life the ammonia slip may be much higher than a new and clean catalyst. In fact that is one way that catalyst replacement is indicated. Some ammonia released to the atmosphere will be converted to NOx and ultimately to ozone. Finally, ammonia is on the SARA (Superfund) list of Extremely Hazardous Materials. Accident studies of transport and on-site storage of ammonia for use with SCR, performed for the Massachusetts DEP and California's South Coast AQMD, resulted in a change from anhydrous ammonia to aqueous ammonia. Aqueous ammonia has a lower ammonia concentration and lower storage pressure (resulting in a slower release rate) than anhydrous. Anhydrous ammonia was used until these studies revealed the potential public hazard in the event of catastrophic release. The hazard was reduced, but not eliminated.

GE Power Systems analysis of measurements of ammonia emissions on six plants with SCR showed a great deal of inconsistency (<1 ppm to 30 ppm). All of the tests were performed using different ammonia sampling methodologies. EPA Method 206 for ammonia was recently published for applicability to coal-fired plants. There is no specific method for gas turbine plants. The conclusion drawn from this study is that the ammonia slip on plants with SCR is not actually known with any accuracy.

Spent Catalyst

From a policy standpoint, the disposal of spent catalyst as hazardous waste, simply transfers an air problem (NOx) into a long-term solid waste disposal problem. This is not a good environmental tradeoff.

Use of Sulfur Bearing Fuels

It has been GE Power System's position for some time that SCR should not be used in gas turbine applications where a sulfur bearing fuel, such as distillate oil, is used. With the recent concern expressed by EPA through the promulgation of the National Ambient Air Quality Standards for fine particulate matter (PM 2.5), GE Power Systems feels even more strongly that the use of SCR should be avoided when such fuels are used. Unreacted ammonia from the SCR, and sulfur from the fuel react to form ammonium salts that are released as particulate matter, as previously discussed. EPA is very concerned with PM–2.5 (very fine, inhalable particulates) which would increase significantly. The example in Table 1 for a Frame 7FA shows an 8 TPY increase in PM with SCR and almost 50 TPY if a CO catalyst is also used, with only 400 hours per year of oil firing. Aside from the important health risks that EPA has indicated are posed by PM 2.5, the impact of the increase in fine particulates on regional haze should also be considered. A CO oxidizing catalyst, supplementary firing and noble metal catalysts will all result in much higher SO_2 to SO_2 conversion and greater sulfur salt formation. Note that particulate emission controls have never been used on gas turbines.

Although there are many gas turbine combined cycle plants using SCR that are permitted to use distillate oil as the backup fuel, GE Power Systems is not aware of ANY successful operation with this combination. Actual operating experience indicates that ammonium-sulfur salt formation and boiler damage occur without exception, when ANY sulfur bearing fuel is fired in the gas turbine and SCR is used for NOx control. This is not usually accounted for in BACT determinations, but adds significant cost and should be considered. Beside the down time associated with periodic cleaning, the added cost includes periodic replacement of the low pressure tube sections of the HRSG damaged by ammonium bisulfate corrosion, or the cost of an alternative design HRSG (which was used for the estimated cost in Section V.1). Reference 1 documents the damage done to the HRSGs on several representative plants.

State Example

The New York State Department of Environmental Conservation (DEC) Gas Turbine NOx Policy (93–AIR–39), allows a BACT NOx limit higher than normal when firing oil as a backup fuel, to either avoid the use of SCR, or to minimize ammonia slip. This is specifically stated to be in recognition of the increased particulate and ammonium bisulfate problems and concerns related to ammonia emissions. The NOx policy also states that the DEC "has determined that 6 ppmv (dry, corrected to 15 percent O) was the lowest emission limit for NOx which can be accurately measured in the stack, based on current monitoring/testing technology." This is the same finding as the ASME B133 Committee on emission measurements from gas turbines, Reference 2. Several other states also allow higher NOx levels if the use of SCR can be avoided to eliminate ammonia emissions. New Jersey has considered low sulfur kerosene for the backup fuel (rather than distillate oil) as BACT, when SCR is used for NOx control.

Measurement and Control of NOx

Recent regulatory agency actions in some states has resulted in excessively low NOx levels being required for gas turbines. Based on the performance of SCONOX at the single facility in California, NOx permit levels as low as 2 ppm are being required in some states. Even if such a level of NOx can be achieved, the question of how low a NOx level can be monitored and controlled has apparently not been addressed. Can we monitor and control on 2 ppm NOx? 40CFRPart 75 requires that a majority of readings be between 20 and 8 percent of the measurement range. A 10 ppm range is the lowest certified for a process NOx analyzer. With a 2 ppm NOx limit, the +/-10 percent of standard criterion is 0.2 ppm so that a CEMS would need to report no greater than 1.8 ppm NOx minus margin to insure not exceeding 2 ppm. The ASME B133 Committee study (Reference 2) concluded that if the reading is outside the 20 to 80 percent of scale range the error could be as high as 25%. Since the plant must actually operate below 2 ppm with a 2 ppm limit, EPA's Part 75 regulations are violated. Further, to insure not exceeding 2 ppm, a 7FA gas turbine would need to operate at:

- 1.5 ppm max to compensate for instrument error (25% of 2 ppm reading error)
- ~1.0 ppm max to compensate for combustion system operating variability
- Below 1.0 ppm (0 to 1 ppm) to compensate for ambient variability effects

The conclusion is that 2 ppm NOx is not a practical emission limit for gas turbines.

Environmental Impact of a Deregulated Electricity Market

The advent of electricity market deregulation is bringing in a new factor to consider for new power plants called "displacement". This process has been observed in the United Kingdom where deregulation is generally the furthest along among the mature industrialized nations. Parts of the USA are already seeing the development of new "merchant" power plants that will compete with traditional utility plants and non-utility power plants. The concept is that new combined cycle merchant plants will be added until the market price of electricity from the new merchant plants is at parity with the composite market price, including less environmentally friendly older plants. This in turn will force either reduced operation or shut down of the less competitive of these older plants, with a resultant net emissions reduction. However, if the cost of a new, cleaner plant is increased (by adding SCR) it becomes more difficult to compete with older plants and less displacement occurs. Figure 1 shows the environmental benefits of displacing a coal or oil-fired power plant meeting the 1979 NSPS with a new gas-fired combined cycle plant of the same MW output. Also shown is the impact of the incremental premium that must be paid for SCR on the ability of a plant to bid its power under the market clearing price (the highest price the market will pay for power). Figure 2 shows the relative costs for various control technologies, first as a function of the initial capital cost of the power plant and then as a life cycle cost, both as functions of the NOx emission level. DLN at 9 ppm NOx is a clear winner over SCR in this competitive market environment, where the cleanest total solution is one where the economics of reducing the usage of the older plants is a significant consideration.

Regulatory Policy Consistency and Fairness

The EPA promulgated a new NOx NSPS for utility and industrial steam generators in October 1998. The revised Utility and Industrial Boiler NSPS for NOx is:

Applicability	NOx Emission Limit	Fuels
New Utility Units	1.6 LB per MW-Hr of output	Fuel Neutral
Modified/Reconstructed Existing Utility Units	0.15 LB per MMBtu fuel input	Fuel Neutral
New & Existing Industrial Units	0.20 LB per MMBtu fuel input	Fuel Neutral

Note the change from pounds of NOx per unit of heat input to pounds of NOx per unit of electrical output for utility units. There is no percent reduction required and it is fuel neutral.

For a Frame 7FA, 9 ppm NOx is less than 1/8 of the newly revised utility boiler NSPS and for 8,760 hours per year of operation will total less than the 250 tons per year PSD threshold for simple cycle gas turbines.

- Utility Boiler NSPS, NOx limit = 1.6 # NOx/MW-hr
- 7FA STAG, 9 ppm NOx = 0.19 # NOx/MW-hr

A 7FA at 3 ppm NOx emits less than one-twenty fourth of the utility boiler NSPS. For 8,760 hours per year of operation NOx will total less than the 100 TPY PSD threshold for steam electric power plants (EPA has ruled that combined cycle power plants are steam electric power plants).

The new 22-state eastern ozone transport region created by EPA's NOx SIP Call requires that an average NOx limit of 0.15 lb of NOx per million Btu of heat input be achieved. For a gas turbine this is equivalent to about 37 ppm NOx at 15 percent O.

When the boiler NSPS and the SIP call NOx requirements are compared with the extremely stringent gas turbine NOx emission requirements it is obvious that there is neither consistency nor fairness in the NOx emission requirements for gas turbines.

QUESTIONS REGULATORY POLICY MAKERS SHOULD ADDRESS

If a gas turbine can achieve an uncontrolled NOx level of 9 ppm, must the permit require less than that at any cost? The cost effectiveness of reducing NOx from 9 ppm to 3.5 ppm with SCR is approximately $15,000 to $30,000/ton of NOx as previously discussed. Is this reasonable for a BACT or LAER determination? If the cost effectiveness of an add-on control is $100,000/ton should it be required, even as LAER in nonattainment areas? $1,000,000/ton?

While a state agency can impose more stringent requirements than EPA, should a state agency that requires the use of the top-down approach for the determination of BACT, ignore cost effectiveness or impose an arbitrary effectiveness threshold that is much higher for some gas turbines than for other emission sources. Should agencies arbitrarily take a one-number fits all gas turbines approach to BACT, recognizing that BACT, by its very definition, is supposed to be site/project specific?

As previously discussed, some gas turbines can currently achieve an uncontrolled NOx emission level of 9 ppm. Some environmental agencies require the use of add-on controls for those gas turbines to reduce the NOx to 2 or 3 ppm in attainment and nonattainment areas, simply because it can be done, ignoring all other factors. If an uncontrolled NOx Level of 5 ppm is eventually achieved, should add-on controls still be required in attainment or nonattainment areas to reduce NOx to 3 ppm? To 2 ppm? In the extreme case, if an uncontrolled NOx level of 3 ppm is achieved by a gas turbine manufacturer, should such gas turbines be required to use add-on NOx control to reduce NOx to 2.5 ppm if that level were achievable, no matter what the cost? Did the Clean Air Act anticipate this kind of situation?

Many regulators state that economics cannot be considered in determining LAER. Should the negative environmental impacts resulting from emission controls that are required to reduce emissions of a nonattainment pollutant, also be ignored in determining LAER?

Is it a good environmental trade-off to emit ammonia in place of NOx? If the reduction in atmospheric loading (TPY) of NOx is of the same order of magnitude as the ammonia emitted in its place? Is it good environmental policy?

Does it make economic sense to require the use of any technology to control NOx emissions to extremely low levels when it is not clear that control at such low levels can be practically achieved? Is a 2 ppm NOx emission control level achievable even if it can be measured? 3 ppm? While these levels can probably be measured, has anyone considered the ability to control a gas turbine at such low levels under all operating conditions? The one unit operating with SCONOX that appears to be achieving the 2 ppm level operates only at full load with no load following.

10 ppm is the lowest scale certified for a process NOx analyzer. Can the plant to be controlled below 20 percent of scale? Part 75 requires that a majority of readings must be between 20 and 80 percent of measurement range. The reason for that requirement is accuracy!

CONCLUSIONS/ RECOMMENDATIONS

In view of current gas turbine combustion system emission control achievements and the previous discussion, it is recommended that EPA re-examine its nonattainment requirements and amend the regulatory process. First, competing environmental impacts resulting from the use of add-on emission controls should be considered in both attainment and nonattainment areas, when the use of add-on emission controls will result in only a small reduction in nonattainment pollutant emissions. Second, cost effectiveness should be considered in determining LAER when the cost is clearly not "reasonable".

In the case of gas turbine combustion systems, the technology has forged ahead of the regulations for NOx emission control. It makes no economic sense, nor does it provide any real environmental benefit, to require add-on emission controls when combustion systems produce single digit pollutant emissions. Furthermore, gas turbine manufacturers will continue to develop lower NOx combustion systems only as long as economic incentives exist. If it is apparent that add-on controls such as SCR will be required no matter how low the uncontrolled NOx level achieved, the development of lower NOx combustion systems will be discouraged. Contrary to EPA policy, pollution prevention as a concept becomes meaningless for such systems and the inconsistency with that and other government programs and policy, such as the DOE advanced turbine system (ATS) with its 9 ppm NOx goal, becomes all to apparent. While this might not be considered important in combined cycles because SCR could be required, it could be very important for the many simple cycle machines that will be sold in coming years. No SCR currently exists that can be used with simple cycle, high firing temperature, F-technology gas turbines, or the next generation of even higher firing temperature, H-class machines from the ATS program.

VIII. REFERENCES

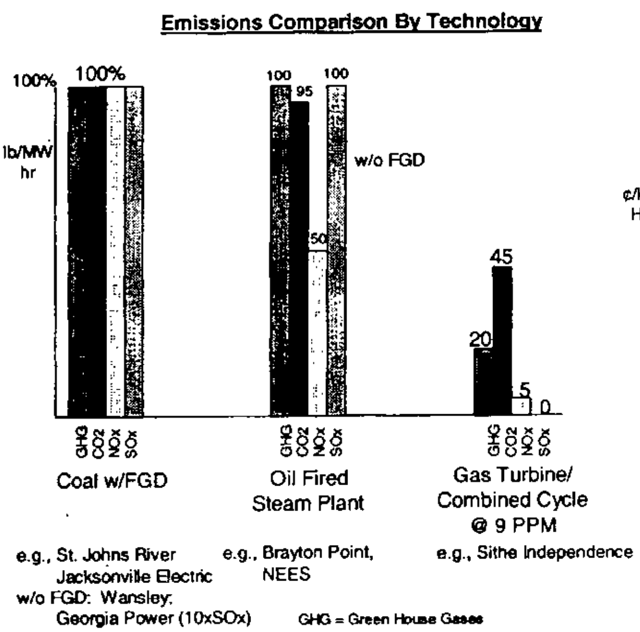
1. Schorr, M.M.; "NOx Emission Control for Gas Turbines: A 1995 Update on Regulations and Technology," CIBO NOx Control Conference, March 1995.

2. ASME Codes and Standards Committee B133, Subcommittee 2, Environmental Standards for Gas Turbines, Report 9855-3, *Low NOx Measurement: Gas Turbine Plants*, Dec. 4, 1998.

Table 1
Estimated Tons/Year Change in Emissions for STAG 207FA* With SCR & COC (Base Load, 8000 hr/yr, 20 ppm NH Slip, 45 oF Ambient)

	9 ppm NOx w/o SCR	3.5 ppm NOx w/SCR	TPY	3.5 ppm NOx w/SCR & COC	TPY
Natural Gas Only					
NOx	240	92	-148	92	–148
PM	36	41.6	+5.6	69.6	+33.6
NH	0	172	+172	164	+164
SO	40	39	–1	25	–15
Gas+400 hr/yr Oil					
NOx	294	116	–178	116	–178
PM	37.6	45.8	+8.2	86	+48.4
NH	0	172	+172	161	+161
SO	57	56	–1	36	-21

* DLN 2.6 combustor; emissions are per unit
SCR – Selective Catalytic Reduction
COC – CO oxidizing catalyst



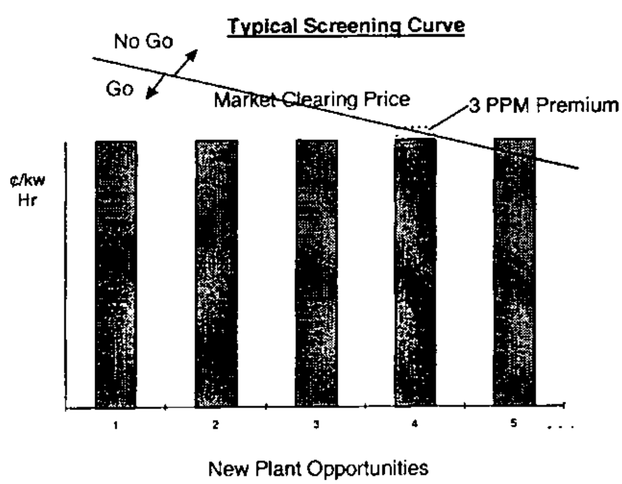
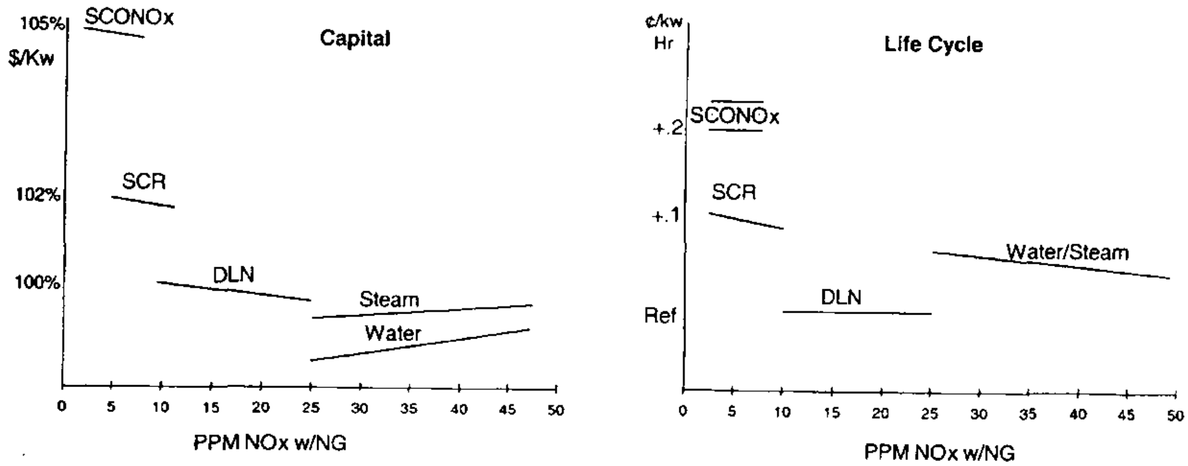


Figure 1. Optimizing Emissions in a Deregulated Electricity Market



- DLN Provides Significant Benefits Added Cost
- Emissions Trading Markets Continue Push Technologies
- Environmental and Safety Hazards Ammonia and Heavy Metal Catalysts Need to be
- Need to Consider Market Impacts

Figure 2. Economic Break Points for Gas Turbine Combined Cycle Plants

For further information, contact your GE Field Representative or write to GE Communication Programs

GE Power Systems

General Electric Company
One River Road
Schenectady, NY 12345

DRAFT

September 18, 2000 FILE NO: 31531.020001

BY HAND

Ms. Ellen Brown
Information Transfer and Program
Integration Division (MD-12)
Environmental Protection Agency
Office of Air Quality Planning and Standards
Research Triangle Park North Carolina 27711

Re: Comments on Draft Guidance for NOx Control at Combined Cycle Units

Dear Ms. Brown:

These comments are filed on behalf of the Utility Air Regulatory Group (UARG) in response to EPA's request for comments in 65 Fed. Reg. 50202 (August 17, 2000) concerning the Agency's draft best available control technology (BACT) guidance for NOx Control at Combined Cycle Units. UARG is a voluntary, nonprofit, ad hoc group of over 55 electric utilities, the Edison Electric Institute, the National Rural Electric Cooperative Association and the American Public Power Association (Enclosure 1). UARG participates on behalf of its members collectively in federal Clean Air Act rulemakings, guidance, and related litigation concerning issues of general interest to the electric utility industry.

In general, UARG supports EPA's draft guidance. We believe that several related policy issues should be clarified, and provide additional information and support in the attached technical paper by J.E. Cichanowicz and L. A. Angello (Enclosure 2). We believe that state permit writers should have a great deal of flexibility in determining BACT. The Clean Air Act as well as EPA's regulations make it abundantly clear that a BACT determination must be based upon a case-by-case, site-specific balancing of energy, environmental, and economic impacts and other costs, and mandate that this balancing be done by the appropriate State permitting authority.

I. The Clean Air Act

In the 1977 Amendments to the Act, Congress enacted a program for the prevention of significant deterioration of air quality. The Act's general scheme requires EPA to adopt nationally applicable air quality standards and other regulations which the States have "the primary responsibility" to implement. 42 U.S.C. §§7401(a)(3), 7407(a); see also 42 U.S.C. § 7410. In keeping with this scheme, Congress instructed EPA to develop and promulgate nationally applicable PSD regulations defining the requirements that a State must meet if that State chooses to adopt and get EPA approval of a PSD program. 42 U.S.C. §§7410(a)(2)(D), 7471. Congress intended these "measures" to allow States to play a major role in devising the PSD requirements that would work best within their boundaries. *See*, e.g., A Legislative History of the Clean Air Act Amendments of 1977 (hereinafter "1977 Legis. Hist.") at 531-33.

Among the PSD requirements that Congress imposed was that the State require any proposed major emitting facility subject to the PSD program to apply BACT for each pollutant subject to regulation under the Act that the source emits in a significant amount. 42 U.S.C. §7475(a)(4). The Act mandates that BACT limits are to be determined on a case-by-case basis after taking into account energy, environmental, and economic impacts and other costs. 42 U.S.C. §7479(3).[1] As Congress explained, in making this "key decision . . . the State is to take into account energy, environmental, and economic impacts and other costs of the application of best available control technology. The weight assigned to such factors is to be determined by the State." 1977 Legis. Hist. at

[1] The only constraint Congress placed on the balancing test is that the final decision not yield an emission limit less stringent than any applicable new source performance standard. Id.

1405 (emphasis added).[2] In other words, under the Act, the State can assign whatever weight to these "consideration" factors that the State deems appropriate. Thus, the BACT standard envisaged by Congress is consistent with the general intent of the Act that the States have primary responsibility to determine the content of emission limitations needed to meet "minimal" federal requirements.

Nowhere in the Act is there any suggestion that certain of the BACT criteria – energy, environmental and economic impacts and other costs – should be emphasized over others. Nowhere in the Act is there any indication that BACT limits must be the lowest emission limits that are technically and economically feasible for a similar source or source category.[3] And, nowhere in the Act is there any presumption that some technology is BACT simply because it has been determined to be BACT for a given type of emission source in another location. Congress recognized that the balancing test is mandatory simply because site- specific considerations will warrant emphasis on different considerations.[4]

Federal courts have consistently endorsed the statutory requirement that BACT be determined through a flexible, balancing process. The United States Court of Appeals for the District of Columbia Circuit pointed out, for example, that "BACT is defined, in general, as a level of control technology appropriate to the facts and circumstances of the

---

[2] See also 1977 Legis. Hist. at 729 (emphasis added) ("One objection which has been raised to requiring the use of the best available control technology is that a technology demonstrated to be applicable in one area of the country is not applicable at a new facility in another area because of difference[s] in feedstock material, plant configuration or other reasons. For this and other reasons, *the committee voted to permit emission limits based on best available technology on a case-by-case judgment at the State level.*").

[3] Indeed, such an interpretation of the Act would essentially make BACT limits equivalent to "lowest achievable emission rate" limits which Congress has imposed only on sources locating in nonattainment areas. See 42 U.S.C. §7501(3).

[4] 1977 Legis. Hist. at 729.

particular applicant." *Alabama Power v. Costle*, 606 F.2d 1068, 1085 (D.C. Cir. 1979) (emphasis added). The United States Court of Appeals for the Ninth Circuit observed that "the BACT determination is . . . source specific." *Northern Plains Resource Council v. EPA*, 645 F.2d 1349, 1359 (9th Cir. 1981) (emphasis added). Thus, the court concluded while a particular control technology may be BACT for one plant, the permitting authority "might decide that for [another] . . . facility . . . [that technology is] inappropriate for economic *or* energy *or* environmental reasons." Id. (emphasis added).

Court decisions, therefore, confirm what the language of the Act makes plain: a BACT determination must be made on a case-by-case basis by the State after taking into account energy, environmental, and economic impacts and other costs. Uniformity is not mandated by the BACT provisions; flexibility is.

II. EPA's PSD Regulations and Guidance

EPA promulgated a regulatory BACT definition in 1978 that, in all respects relevant here, is identical to the statutory definition. 43 Fed. Reg. 26,388, 26,404 (June 19, 1978).[5] The regulatory definition of BACT, like the statute, establishes that the BACT analysis must include a balancing of the relevant statutory factors. And, like the Act, the regulations limit consideration of technology to control technologies that are deemed "available" to that specific source. Indeed the regulations make it abundantly clear that the statutory criteria, including economic costs and energy, must be answered before a technology used in other types of sources impacts can be transferred to the new source. *See* 43 Fed. Reg. 26,380, 26,397 (1978).

---

[5] In response to a legal challenge EPA amended its PSD regulations in 1980. 45 Fed. Reg. 52,676 (1980).{ TA \l "45 Fed. Reg. 52,676 (1980)." \s "45 Fed. Reg. 52,676 (1980)." \c 2 } The current definition of BACT, like the one promulgated in 1978, closely tracks the statutory definition found in 42 U.S.C. §7479(3). See 40 C.F.R. §§52.21(b)(12){ TA \l "). See 40 C.F.R. §§52.21(b)(12)" \s "). See 40 C.F.R. §§52.21(b)(12)" \c 2 }.

Shortly after promulgating its PSD regulations, EPA released Guidelines for Determining Best Available Control Technology which explained that a BACT determination is based upon the standard of flexibility. EPA, OAQPS, Guidelines for Determining Best Available Control Technology (Dec. 1978). Specifically, the permitting authority (in this case, the States) must

> consider a number of local factors (for example the size of the plant, the amount of air quality increment that would be consumed, and desired economic growth in the area) in deciding on a weighting scheme. *State judgment . . . [is one of] the foundations for the BACT determination.*

Id. at 4 (emphasis added). Among the type of "economic impacts" that should be assessed, according to the 1978 Guidelines, are the cost per unit of pollution removed (for example, dollars/ton) and cost versus additional portion of remaining PSD increment preserved for future growth. Id. at 14.

EPA's view of the BACT standard was reinforced in its 1980 PSD Workshop Manual wherein EPA recognized that the reviewer's primary responsibility is to determine the best emissions strategy to balance the environmental benefits gained from applying pollution control technology with the prudent use of energy and justifiable industrial expenditures. EPA, PSD Workshop Manual at II-B-2 (Oct. 1980).

In the mid-1980s, EPA's then-Assistant Administrator for Air and Radiation, J. Craig Potter, became concerned that PSD applicants were not adequately analyzing the full range of alternative control strategies in BACT review." Potter, J. Craig, Memorandum on Improving New Source Review (NSR) Implementation, to all Regional Administrators at 3 (Dec. 1, 1987). To ensure that alternative control strategy analyses were comprehensive, Mr. Potter directed his staff to develop guidance on the use of a "top-down" approach to BACT which required the PSD permit applicant and the permitting agency to evaluate all technologies that were more stringent than the NSPS to determine BACT. The Potter memorandum caused considerable confusion in the regulated community because some permitting agencies (including some EPA Regions) read the memorandum to establish a BACT determination process fundamentally different than the process established by EPA in its PSD rules, in its earlier guidance, and even potentially at odds with the criteria embodied in the statutory BACT definition. To settle a legal challenge to the Potter memorandum, EPA agreed to propose and make available for comment any change to the PSD regulation if it wished to make the top-down approach, in the inflexible manner in which some agencies had interpreted it, mandatory.

In July 1996, EPA issued a proposal to revise the PSD rules. 61 Fed. Reg. 38,250 (1996). In the proposal, EPA explained that the Act establishes two core criteria to be satisfied in making a BACT determination. First, all available control systems for the source, including the most stringent, must be considered. Second, the selection of a particular control system as BACT must be justified in terms of the statutory criteria – energy, environmental and economic impacts and other costs – and be supported by the record, and include an explanation for the rejection of any more stringent control systems. Id. at 38,272. Notably, EPA's proposed revisions to the BACT regulations recognize and endorse the statutory case-by-case approach to making BACT determinations by State permitting authorities.

III. EPA's Proposed BACT Guidance

We endorse EPA's guidance because it assures state permit writers that they have the authority to implement the statutory and regulatory criteria – energy, environmental and economic impacts and other costs – in making BACT determinations. Moreover, state permit writers are free to determine the weights that are to be assigned to these factors. While evident from the Act and EPA's implementing regulations, the guidance should clarify that state permit writers have authority to consider the incremental costs and benefits of requiring selective catalytic reduction technology to further reduce NOx emissions. We agree with EPA that those "energy, environmental and economic impacts and other costs" include the effect of ammonia slip on the formation of fine particles and visibility, the effect of acidifying deposition on soils and water bodies, the possibility of nitrogen deposition causing eutrophication of water bodies, issues related to ammonia safety, and the costs and environmental problems associated with the disposal of spent catalyst materials. We also believe that these criteria allow state permit writers to consider other relevant factors that EPA did not discuss in its draft document. such as efficiency penalties.

Many of these issues are discussed and, to the extent practicable, quantified in the Cichanowicz and Angello report. For example, a state permit writer is authorized to conclude in a case-by-case analysis that BACT for a dry low NO_x combustor would not require SCR where the SCR would provide an incremental reduction of 159 tons of NO_x while releasing 100 tons of ammonia into the atmosphere and producing an addition 500 tons of CO_2. The state permit writer is entitled to weight the statutory factors in a manner that is appropriate for the particular case that is being analyzed.

The draft guidance should clarify that there is nothing "magic" in the Act or EPA's regulations about a 9 ppm emission rate at a dry low NOx combustor. For example, many combined cycle units include supplemental firing (e.g., duct burners) that will have a slightly higher – perhaps 10-12 ppm – emission rate. There is no reason that this analysis would not apply to such units, and the guidance should clarify this point. Moreover, the same analysis would apply to combustors with higher NOx rates. The results of any analysis must be case-by-case, and neither the Clean Air Act nor EPA's rules allow EPA to dictate in the abstract the results of such an analysis.

UARG appreciates the opportunity to comment on EPA's draft guidance. If you have further questions please call Craig S. Harrison (202-778-2240).

Sincerely,

F. William Brownell

Craig S. Harrison

Enclosures

Doc #: 172039

Attachment

DOE Staff Comments on EPA BACT Guidance for Natural Gas Combined Cycle Power Systems

Background

EPA has offered for public comment its August 4, 2000, draft guidance on BACT for NOx control for combined cycle turbines (65FR50202; August 17, 2000). The draft guidance recognizes the multiple benefits of deploying new combined cycle natural gas power systems, and is intended to assist State permitting authorities in setting an appropriate level for ABest Available Control Technology,@ or BACT, when issuing a construction permit to a new powerplant of this type seeking to site in a Aclean area.@ In particular, the guidance discusses the relevant factors in determining whether or not a new class of inherently low NOx natural gas power systems should universally be required to install Selective Catalytic Reduction (SCR) control systems to reduce NOx emissions further. The draft guidance states:

In most cases best available control technology (BACT) for controlling NOx emissions from combined cycle natural gas turbines used to generate electricity is a concentration that is achieved by selective catalytic reduction (SCR). This is true at all combined cycle natural gas plants including those that use a variant of the technology called dry low NOx (DLN) turbines that can achieve less than 10 parts per million NOx emissions without add on controls. In some situations, however, the collateral environmental impacts associated with the use of ammonia with SCR may justify not requiring SCR on DLN turbines. ... It is the permit applicant=s obligation to present information on any impacts, specific to the installation of SCR on the unit being permitted, that he wishes to be considered in the BACT determination.

The draft guidance presents a set of environmental impacts from NOx, or from ammonia emissions associated with SCR systems, including:

Tropospheric Ozone
Fine Particles
Acidifying Deposition
Nitrogen Deposition and Eutrofication

Global Warming and Stratospheric Ozone Depletion
Ammonia Safety
Waste Issues

A subsequent discussion addresses the impact of requiring SCR, in the context of the overall electric power system, as modeled by EPA for its Clean Air Power Initiative (the ACAPI@ program). This discussion concludes that requiring SCR on all combined cycle combustion turbines has the counter-intuitive result of increasing NOx emissions.

Discussion

This paper does not address in detail the generally excellent technical discussion presented in the draft EPA guidance document. However, certain points merit elaboration, as discussed below.

Lower Systems Emissions

The 1999 CAPI modeling assumed that traditional gas turbines either had SCR, or did not. The assumption projects the deployment of traditional turbines, not inherently low NOx turbines. These low NOx turbines reduce NOx emissions by roughly 65% on a heat input basis, and by even more on an electrical output basis due to their higher efficiency, compared to traditional units without SCR. Thus, the CAPI results presented by EPA in the draft guidance document in Exhibit 2 and accompanying text overstate NOx emissions in the case where SCR is not required for gas turbines. Nevertheless, EPA=s analysis strongly supports the point that the cost of producing electricity does matter, and that A... if these turbines must use SCR, more electricity will be produced by dirtier plants and therefore total NOx emissions would increase, not decrease.@

The difference in emissions between a 9 ppmv combined cycle natural gas system and even a very clean coal system (0.15 #NOx/mmBtu) is substantial. Based on information provided us by GE, its newly commercialized AH-frame@ turbine technology emits 85% less NOx than levels budgeted under the EPA NOx SIP call for coal units.

In the same sense, other emissions from these dirtier plants, including particulate matter, mercury and other trace metals, and sulfur dioxide, will also be greater if SCR is universally required on all combined cycle combustion turbines.

Chilling R&D in Technology Advancement

DOE is continuing its proven partnership with the private sector to develop even more improved levels of efficiency and environmental performance in advanced turbines. We have been told by our private sector partners that their limited R&D resources will not be committed to further NOx reduction advancements if the expected result is that even cleaner systems will be required to apply post-combustion cleanup.

Global Implications for Technology Deployment

Besides the obvious benefits cited by EPA regarding pollution prevention versus pollution control, the Agency should consider the global implications of encouraging inherently cleaner energy systems. While many other nations may lack the financial resources to acquire expensive add-on technologies, most would deploy technologies which are both more efficient and are inherently lower emitting. And while these same countries lack resources to develop such technology themselves, they will purchase it from United States companies if it is available. A strong Federal signal to continue development of inherently cleaner power systems will result in lower global emissions of several pollutants.

Other technologies

The draft guidance suggests that other non-ammonia based systems may be available for add-on NOx control for combustion turbines. While such technologies have been under development for some time, they have not been applied to any system comparable in size or operating conditions to today=s new large combined cycle powerplants. In addition, they are projected to cost four times as much as, and have much greater parasitic power requirements than, SCR. Thus, even if deployed, the cost issue for this technology suggests that total system emissions could actually increase as the units drop in the dispatching order or are not deployed.

Recommendations for improvements in the Draft Guideance

The key issue in the draft guidance is not its technical shortcomings, which are relatively minor, but rather its administrative shortcomings. EPA=s approach imposes a significant and unnecessary burden upon permit applicants to prove, case-by-case, the points the Agency has demonstrated generically in the guidance. Rather than face protracted negotiations with a State permitting authority, with the additional uncertainty of EPA=s retained authority to Asecond-guess,@ project proponents are more likely either to include SCR in the plant design, or not propose a new plant at all. If SCR is required, then the tradeoff for a marginally reduced NOx emission rate from the turbine would be a higher cost system which could be lower in the dispatching order, with the associated higher emissions from dirtier generation from other plants. If the turbine is not built at all, an opportunity for cleaner generation is lost, and power would come from dirtier generating units. Either scenario is undesirable.

A two part solution would resolve this dilemma. The first part is for EPA to exercise its clear authority to recognize the bifurcated nature of turbine technology by establishing two categories of combined cycle combustion turbines: first, newer designs which are more efficient and emit below 10 ppmv; and second, the older designs which are relatively less efficient and emit, without add-on controls, about 25 ppmv.

Once these two categories are identified, then the guidance document could identify minimum BACT requirements for each, much as it did at the beginning of the draft document. The difference is that the guidance would not create a rebuttable presumption that SCR is BACT for the inherently cleaner class of combined cycle combustion turbines. For those systems, the guidance would provide that the minimum level of BACT is proper operation and maintenance of the low NOx combustion system.

EPA=s current mechanisms for conveying information on technology improvements to permitting authorities would continue to communicate advances in the performance of inherently low emission combustion turbines. Hence the bifurcated categories (traditional turbines and inherently low NOx turbines) would proceed on separate but parallel paths toward continued reductions in allowable emissions over time.

This two-step approach retains State permitting agency ability to require more stringent controls on the cleaner category of turbines where local conditions warrant, as the Clean Air Act clearly contemplates, while clearly indicating that EPA will accept effective operation of the built-in NOx control system as BACT. In most situations, this approach would relieve the permit applicant from the responsibility of proving the points already demonstrated by EPA, thus expediting permitting of new generation needed to insure electricity reliability. These revisions would also make the guidance flexible enough to accommodate additional technologies in the future.

Department of Environmental Protection

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

Jeb Bush
Governor

David B. Struhs
Secretary

December 5, 2000

Mr. John Bunyak, Chief
Policy, Planning & Permit Review Branch
NPS – Air Quality Division
Post Office Box 25287
Denver, Colorado 80225

RE: Tampa Electric Company, Polk Power Station
BACT Determination for Syngas Combustion Turbine
PSD-FL-194, Project No. 1050233-007

Dear Mr. Bunyak:

Enclosed for your review and comment is the final report for the above referenced project. Your comments may be forwarded to my attention at the letterhead address or faxed to the Bureau of Air Regulation at 850/922-6979. If you have any questions, please contact the review engineer, Mike Halpin, at 850/921-9530.

Sincerely,

Patty Adams

for Al Linero, P.E.
Administrator
New Source Review Section

AAL/pa

Enclosure

Cc: M. Halpin

Department of Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

December 5, 2000

Mr. Gregg Worley, Chief
Air, Radiation Technology Branch
Preconstruction/HAP Section
U.S. EPA, Region 4
61 Forsyth Street
Atlanta, Georgia 30303

RE: Tampa Electric Company, Polk Power Station
BACT Determination for Syngas Combustion Turbine
PSD-FL-194, Project No. 1050233-007

Dear Mr. Worley:

Enclosed for your review and comment is the final report for the above referenced project. Your comments may be forwarded to my attention at the letterhead address or faxed to the Bureau of Air Regulation at 850/922-6979. If you have any questions, please contact the review engineer, Mike Halpin, at 850/921-9530.

Sincerely,

Patty Adams
for Al Linero, P.E.
Administrator
New Source Review Section

AAL/pa

Enclosure

Cc: M. Halpin

Department of
Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

December 4, 2000

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

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

Re: NO_x BACT Determination
Polk Power Station

Dear Mr. Hornick:

The Department is in receipt of the seventh NO_x BACT Determination test as well as the NO_X BACT Analysis called for in Specific Conditions 6 and 7 of permit PSD-FL-194 for the combined cycle unit at the above referenced facility. The Department finds that the analysis and submittals are incomplete. In order to continue processing your application, the Department will need the additional information below, specific to the combustion turbine emissions. Should your response to any of these items require new calculations, please submit the new calculations, assumptions, reference material and appropriate revised pages of the application form.

1. Please provide 30 day rolling average NO_X emissions data for calendar months October 1999 through November 2000. This submittal should include actual NO_X emissions (tons) for each calendar month, as well as the following related data:

   a) each calendar month summary should include each daily average NO_X emission value in lb/hr (and ppm corrected to 15% O_2), as well as the total daily heat input by fuel type (e.g. synfuel, natural gas or oil), heating value and daily hours of operation on each fuel; the average daily MW output (from the CT) and average daily SO_2 emission (CEM) rates should also be shown

   b) provide the ultimate analysis of the "as-fired" coal for each calendar month listed above where synfuel was fired in the combustion turbine

   c) if available, provide data on gasifier H_2S and COS removal, as compared to the coal feedstock used

2. Please provide the average nitrogen diluent flow delivered to the CT during each of the seven NO_X BACT tests identified on page 4-1 of the submitted BACT analysis.

3. In a November 8, 1999 letter, EPA Region IV established that BACT for combined cycle turbines is 3.5 ppm NO_x. (Note: EPA wrote the letter after the Florida Department of Environmental Protection proposed a 6 ppm NO_X limit for a GE combined cycle Frame 7 turbine with SCR). Recently (on November 17, 2000) the Department issued a draft permit and BACT Determination 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 10ppmvd of NO_X. This determination was made under the assumption that cost of NO_X control by SCR might be as high as $6,000 per ton (with ammonia emissions held to 5 ppmvd), which represents a NO_X control cost significantly higher than that offered in TECO's submittal.

a) Accordingly, this will 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.

b) The Department notes (in reviewing the records for this project), that although the final BACT Determination for NO_X (while firing syngas) was set at 25 ppmvd through the test period, that the initial draft (1993) of the BACT evaluation had concluded that a NO_X emission limit of 12.5 ppmvd was appropriate, even if the application of an SCR was required.

4. Please estimate schedule requirements, which would be necessary to procure and install an SCR for the subject unit. Additionally, please confirm that Engelhard Corporation expects the catalyst life to be 5 to 7 years and will guarantee same for 3 years of operation.

We are awaiting comments from the EPA and the National Park Service. We will forward them to you when received and they will comprise part of this completeness review.

Rule 62-4.050(3), F.A.C. requires that all applications for a Department permit must be certified by a professional engineer registered in the State of Florida. This requirement also applies to responses to Department requests for additional information of an engineering nature. Please note that per Rule 62-4.055(1): *"The applicant shall have ninety days after the Department mails a timely request for additional information to submit that information to the Department."*

If you have any questions, please call me or Michael P. Halpin, P.E. at 850/921-9530.

Sincerely,

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

AAL/mph

cc: Jerry Kissel, DEP-SWD
Jerry Campbell, HCEPC
Tom Davis, ECT

Is your RETURN ADDRESS completed on the reverse side?

SENDER:
- Complete items 1 and/or 2 for additional services.
- Complete items 3, 4a, and 4b.
- Print your name and address on the reverse of this form so that we can return this card to you.
- Attach this form to the front of the mailpiece, or on the back if space does not permit.
- Write "*Return Receipt Requested*" on the mailpiece below the article number.
- The Return Receipt will show to whom the article was delivered and the date delivered.

I also wish to receive the following services (for an extra fee):

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

Consult postmaster for fee.

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

4a. Article Number
7099 3400 0000 1453 3310

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

7. Date of Delivery
12/8/00

5. Received By: *(Print Name)*

6. Signature: *(Addressee or Agent)*
X

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

PS Form **3811**, December 1994 102595-98-B-0229 Domestic Return Receipt

Thank you for using Return Receipt Service.

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

7099 3400 0000 1453 3310

Article Sent To:

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

Postmark Here

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

PS Form 3800, July 1999 See Reverse for Instructions

TECO

TAMPA ELECTRIC

November 16, 2000

Mr. Clair Fancy
Florida Department of Environmental Protection
111 South Magnolia Drive, Suite 4
Tallahassee, Florida 32301

Via FedEx
Airbill No. 7904 0065 0249

Re: Tampa Electric Company (TEC) – Polk Power Station Title V Permit BACT Determination for Syngas Combustion Turbine – Test #7

1050233-007-AC

Dear Mr. Fancy:

As per Specific Condition A.49 of the Polk Power Station Title V Permit, Tampa Electric has completed the seventh and final NO_x BACT Determination Test on the combustion turbine while operating on syngas. Accordingly, the final report is enclosed for your review. In addition, the BACT Analysis called for in Specific Condition A.50 of the Title V Permit is enclosed for your review.

If you have any questions, please feel free to contact Shannon Todd or me at (813) 641-5125.

Sincerely,

Mark J. Hornick

Mark J. Hornick
General Manager/Responsible Official
Polk Power Station

EP\gm\SKT210

Enclosures

c/enc: Mr. Al Linero – FDEP
Mr. Syed Arif - FDEP
Mr. Jerry Kissel - FDEP SW

CERTIFICATION OF RESPONSIBLE OFFICIAL

Based on information and belief formed after reasonable inquiry, I certify that all statements made in these reports are true, accurate and complete.

Mark J. Hornick
(Signature of Responsible Official)

11/16/00
(Date)

Name: Mark J. Hornick
(Type or Print)

Title: General Manager, Polk Power Station
(Type or Print)

TAMPA ELECTRIC COMPANY
POLK POWER STATION
BEST AVAILABLE CONTROL TECHNOLOGY ANALYSIS

Prepared for:

TECO
TAMPA ELECTRIC
Tampa, Florida

Prepared by:

ECT
Environmental Consulting & Technology, Inc.
3701 Northwest 98th Street
Gainesville, Florida 32606

ECT No. 000656-0100

November 2000

TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

1.0 EXECUTIVE SUMMARY

As required by the Title V Operating Permit (1050233-001-AV) for the Polk Power Station (Polk or PPS) Integrated Gasification Combined Cycle (IGCC) Plant, an updated best available control technology (BACT) analysis is submitted for control of oxides of nitrogen (NO_x) emissions. This analysis was performed as if the combustion turbine (CT) were a new source using the data gathered at this facility, other similar facilities, and the manufacturer's research. Based on this analysis, Tampa Electric Company (TEC) requests that the current NO_x emissions limit of 25 parts per million by dry volume (ppmvd) be continued as the appropriate BACT emissions limit. The 25 ppmvd is based on a statistical analysis of the performance test data collected during the demonstration period for the facility and represents an emissions limit with which the facility can reasonably assure compliance.

Add-on control technologies were also evaluated; however, they were found to be unreasonable based on considerable technical concerns and cost considerations. An evaluation of other similar facilities was conducted, which indicated there was only one other facility regarded as similar based on the criteria used in the analysis. This similar facility has a NO_x emissions limit of 25 ppmvd, which is the same as the current limit for the Polk facility. Manufacturer's research indicated that technological advances have been made that are applicable to new IGCC installations; however, retrofitting these technologies to the Polk facility would require substantial capital investments and equipment downtime. As discussed in this report, an extensive retrofit was not further considered as a control option for this source because the emissions unit must be treated as a new source as specified in the Title V and Prevention of Significant Deterioration (PSD) permit conditions.

This report is divided into the following sections:

- Background.
- Regulatory requirement for BACT analysis.
- Demonstration Period Test Data summary.
- Consideration of appropriate emissions limit.
- Evaluation of available control technologies.
- Manufacturer's research.

2.0 BACKGROUND

TEC operates an IGCC process at the Polk facility. The power generation portion of this process consists of a 192-megawatt (MW) General Electric (GE) model 7FA turbine whose emissions pass through a heat recovery steam generator (HRSG). The resulting steam provides the energy necessary to generate approximately 125 MW from a steam turbine. The construction and operation of this facility was permitted on February 24, 1994, under permit numbers PSD-FL-194 and PA-92-32.

The original permit application included a BACT analysis. At the time of the permit issuance, the BACT for NO_x was determined to be diluent nitrogen injection coupled with a multinozzle quiet combustor (MNQC) for operation using the primary fuel, syngas. The associated NO_x emissions limit is 25 ppmvd at 15-percent oxygen (O_2). The NO_x BACT determination for the back-up fuel, distillate oil, was determined to be water injection with an associated NO_x emissions limit of 42 ppmvd at 15-percent oxygen. These emissions limits were based on the equipment supplier's (GE) guaranteed performance for this equipment installation.

At the same time, GE 7FA turbines configured for natural gas combustion could achieve somewhat lower NO_x emission rates, in the range of 9 to 15 ppmvd, by using air-premix type dry low NO_x (DLN) combustors. In contrast to natural gas, syngas contains over 35-percent hydrogen (H_2), which increases flame speed so much that the air premix type DLN combustor cannot be used for syngas fuel. This distinction is further discussed in Section 6 of this report. The original BACT determination and the issued PSD permit also addressed this difference between NO_x emissions rates for the different fuels.

At the time of the original BACT determination, this turbine was a unique equipment set that fires syngas using a revised MNQC design, which had not yet been in commercial service. Accordingly, the PSD and Title V permits each included a requirement for a testing period of 12 to 18 months, during which the NO_x emissions performance on syngas is tested bi-monthly. At the conclusion of testing period, TEC is to submit a revised

NO_x BACT determination to the Florida Department of Environmental Protection (FDEP). This document is being submitted to fulfill the submittal requirements of the BACT determination and air operation permits.

3.0 REGULATORY REQUIREMENT FOR BACT ANALYSIS

The BACT analysis is addressed in Specific Condition A.50. of the Title V permit, which states:

> "One month after the test period ends (estimated to be by February 2000), 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 emissions limits accordingly."

The provisions of this condition are analyzed in this section, preceding the NO_x BACT analysis.

The permit condition stipulates that the BACT determination should be performed as if the Polk IGCC facility were a new source as opposed to a candidate for replacement of a significant IGCC system or subsystem or major retrofit. This provision is an important element of the determination, as there have been options developed in IGCC technology in the past 10 years that may make some of today's CTs capable of achieving lower NO_x emission rates than the Polk facility. However, these options involve major deviations from Polk's IGCC hardware configuration such as using a different (less efficient) gasification system operating at much higher pressure, employing an entirely different approach to connecting/integrating the major plant subsystems (air separation, gasification, acid gas removal, and power generation), and using completely new turbine combustion hardware and controls.

In other words, even though these new plants are still IGCC facilities, using the same basic CT as Polk (GE's 7FA), they are so different that little, if any, of the IGCC plant's hardware is the same. Thus, in accordance with this permit condition, this analysis treats the Polk facility as a new source and does not analyze the options of replacing a major IGCC system or subsystem or attempting to retrofit Polk with this different technology configuration. For completeness, these differences in configuration are discussed in Section 9.0 of this report, *Manufacturer's Research*. Instead of major modifications to the

IGCC plant, the NO_x BACT analysis addresses two main areas, the establishment of a lower emissions limit for syngas firing within Polk's existing hardware constraints and the use of add-on controls.

When evaluating the performance of other similar facilities, it is important to limit the scope of the analysis. First, as contrasted with the more numerous electrical generating facilities fueled by natural gas, there are considerably fewer facilities fueled by syngas. Natural gas-fired facilities cannot be considered similar to Polk because of the significant differences in the fuel combustion characteristics. Second, the syngas production system is important in evaluating whether the facilities are similar. For example, less efficient gasification systems inherently have more CO_2 and N_2 available for use as diluents for NO_x abatement. Consequently, IGCC plants using either significantly more or less efficient gasification process than Polk's cannot be considered similar. Next, the manufacturer and vintage of the CT is an important element to consider when performing a survey of emissions data for what is considered a similar facility. Finally, the method of operation must be considered when evaluating other similar facilities. For example, other IGCC applications are co-fired with blends of syngas and natural gas or syngas and oil. The NO_x emissions performance data for the few facilities that may be considered similar to the Polk facility are discussed in Section 8 of this report, *Other Plant Experience*.

The manufacturer's research is explored to identify the advances that have been made in GE CT technology that allow the present line of CTs to have considerably better NO_x emissions performance than those from 10 years ago. Additionally, the emissions data and operating experience during the initial test period have been discussed with GE to explore potential operational improvements. These discussions are summarized in this report.

4.0 NO_X EMISSIONS TESTING PERIOD DATA SUMMARY

The NO_x emissions testing period lasted for 12 months and involved seven emissions tests. Appropriate emissions reports for each test have been submitted to FDEP in accordance with the permit requirements. Table 1 summarizes these test results. Each entry in the table represents the average of at least three individual test runs. Appendix B contains the results of the individual 1-hour test runs.

Table 1. TEC Polk Power Station NO_x Emissions Test Data Summary

Test Date	Average NO_x Emissions Result (ppmvd, 15% oxygen, ISO conditions)	Load (MW)
October 14, 1999	16.7	191
December 7, 1999	14.6	190
February 7, 2000	19.0	192
April 17, 2000	17.0	191
June 14, 2000	18.1	190
August 15, 2000	16.6	192
October 17, 2000	22.5	192

Source: ECT, 2000.

The first six tests used a syngas derived from the facility's base coal supply (i.e., Kentucky coal). However, due to mine closure, the facility will continue to gasify a variety of fuel supplies. The syngas burned in the seventh test had a greater heating value and adiabatic flame temperature than that produced from the supply used during the first six tests, leading to greater NO_x emissions, even with using an increased proportional diluent flow rate.

A preliminary analysis of these data indicates the CT has met the 25-ppmvd NO_x emissions limit contained in the permit. The next step in the analysis is to determine the statistical distribution of the emissions test data and to use this statistical analysis to ascertain the confidence level associated with meeting specific emissions levels. For this analysis, the raw data (i.e., each individual test run) are used instead of the average of the three tests runs. This difference in approach is to allow for a larger statistical sampling size, as estimating values such as standard deviation and confidence intervals are sample size dependent, especially for samples of less than 20 data points. Table 2 presents the governing statistical measures.

Table 2. Statistical Analysis of Emissions Test Data

Parameter	NO_x Emissions Result (ppmvd, 15% oxygen, ISO conditions)	Load (MW)
Sample size	21	21
Mean (average)	17.8	191.14
Low	14.0	190
Median	17	191
High	22.5	192
Range	8.5	2
Standard deviation (σ)	2.38	0.9
Mean plus 2 (σ) 90-percent confidence interval	22.55	N/A
Mean plus 3 (σ) 99.7-percent confidence interval	24.93	N/A

Note: N/A = not an appropriate statistical measure for load, maximum load is established as 192 MW.

Source: ECT, 2000.

The emissions test data are approximately normally distributed, with an overall average of 17.8 parts per million (ppm) and median of 17 ppm. The highest observed value is 22.5 ppm, and the lowest is 14.0 ppm. The standard deviation (σ or sigma) is 2.38 ppm.

Assuming a normal distribution of emissions data, a commonly used measure for statistical process control is the use of mean plus a certain number of standard deviations. For example, approximately 90 percent of the data will lie within plus/minus two standard deviations from the mean value, and 99.7 percent of the data will lie within three standard deviations from the mean. The three-sigma approach is commonly used in industrial statistical process control applications, and is also supplemented by a six-sigma approach for additional control.

Based on this analysis, the mean-plus-three-sigma value is 24.93 ppm. Based on the statistical analysis, only a small fraction (0.3 percent) of readings would be outside the mean-plus/minus three-sigma range, either higher or lower. Because the current emissions limit (expressed in pounds per hour) is based on a 30-day rolling average or the average of three test runs for an emissions test, it is not anticipated that this small percentage of values outside the mean-plus-three-sigma value would cause a compliance concern. However, because a considerable fraction (10 percent) of readings are outside the mean-plus/minus-two-sigma range, it could be that a limit based on this value would be difficult to meet. This analysis is used as a basis in the following section that addresses an alternate emissions limit.

5.0 CONSIDERATION OF APPROPRIATE EMISSIONS LIMIT

Originally, the facility was permitted with a NO_x emissions limit of 25 ppmvd based on the manufacturer's emissions guarantee. The statistical analysis of the demonstration test data was used to determine the emissions levels that are represented by the mean-plus-two-sigma (22.55 ppmvd) and the mean-plus-three-sigma (24.93 ppmvd) values. Based on the previous discussion (performed in Section 4.0) of the statistical distribution of the data, it is thought that the mean-plus-two-sigma limit is too stringent. However, the three-sigma limit is an appropriate limit as it provides for reasonably expected emissions variations that are associated with fluctuations in meteorological conditions, fuel supply, and other process parameters. Additionally, the data collected during this analysis are for a relatively new and clean CT. As the CT ages, it is reasonable to expect a degradation in both the combustion efficiency and emissions performance. Hence, this three-sigma limit will provide for reasonable variations and anticipated degradation with equipment aging.

As was discussed in Section 4, the performance test conducted on October 17, 2000, indicated a greater NO_x emissions rate than the previous tests. This difference is attributed to a change in coal supply and a resulting greater heat content and adiabatic flame temperature of the syngas. This variation in NO_x emissions with changes in fuel supply is an important factor to consider when establishing the appropriate BACT emissions limit for this facility. The proposed 25-ppm NO_x emissions limit is expected to allow TEC to burn a variety of syngas compositions that are derived from the entire fuel portfolio for the facility. Any NO_x emissions limit less than 25 ppm would unduly restrict the facility's ability to gasify the existing range of feed stock.

Thus, for the remainder of this analysis, it is assumed the current CT emission level of 25 ppmvd of NO_x for firing of coal-based syngas will be retained. This determination of a proposed emissions rate is important for the evaluation of cost effectiveness of add-on control technology.

6.0 EVALUATION OF AVAILABLE CONTROL TECHNOLOGIES

The initial BACT analysis evaluated several available control technologies. The use of a nitrogen diluent with an advanced combustor design was selected, and the appropriate control technology is installed and in use for this system. Despite this prior selection of controls, there have been recent advances in control technology that warrant a revisit of the control technologies, including cost estimates.

The original BACT analysis (1992) addressed the following six combustion process modifications as available control technologies. This evaluation will update the analysis presented in the original BACT analysis for these six combustion process modifications, and also addresses the additional option of catalytic combustion controls (e.g., XONON):

- Flue gas recirculation (FGR).
- Low excess air (LEA).
- Low-NO_x burners.
- Water/steam/diluent injection with standard combustor design.
- Water/steam/diluent injection with advanced combustor design (multinozzle quiet combustor).
- Dry low-NO_x combustor design.

The BACT analysis also addressed the following three postcombustion exhaust gas treatment systems:

- Selective noncatalytic reduction (SNCR).
- Nonselective catalytic reduction (NSCR).
- Selective catalytic reduction (SCR).

This BACT analysis will update the analysis for these three postcombustion exhaust gas treatment systems and also addresses the additional option of SCONO$_x$™, a catalytic adsorption and desorption/reaction control system.

6.1 COMBUSTION PROCESS MODIFICATIONS

The original analysis asserted that the first three combustion process modifications are applicable to boilers and, therefore, are not applicable to CTs. Thus, FGR, LEA, and low-NO_x burners (i.e., boiler-specific low-NO_x configuration) were not considered in the original analysis. There have been no changes in technology for these options that would make them applicable to the CTs today, thus these options are not considered further in this analysis.

Of the next two options, water/steam/diluent injection with standard combustor design and water/steam/diluent injection with advanced combustor design, the second option was chosen as BACT and is installed on the equipment. Since this selected option provides better NO_x emissions control than the first option, further discussion of these options is not warranted in this analysis. Recent advances in the selected option (water/steam/diluent injection with advanced combustor design) for NO_x control are discussed in Section 9.0 of this report, Manufacturer's Research.

The dry low-NO_x combustor design (i.e., premix combustion) technology was discussed in the original BACT analysis. This analysis stated that although this technology has shown considerable NO_x emissions reductions for natural gas combustion, it has not been developed for synthetic coal gas as a fuel. There are considerable differences between the two fuels, including British thermal unit (BTU) content and fuel burning characteristics, which preclude the direct application of the advances in dry low-NO_x design for natural gas to syngas combustion. As a result of these differences, no turbine manufacturer currently offers dry low-NO_x technology as a control option for syngas fuel.

One of the overriding technical concerns with the application of dry low-NO_x technology to syngas fuels is the presence of hydrogen in the syngas fuel. The hydrogen flame speed is considerably greater than that for natural gas. This higher flame speed can contribute to flash back, which can cause substantial damage to the dry low-NO_x combustor. Thus, the option of dry low-NO_x combustor design is not considered further in this analysis.

An emerging combustion technology potentially capable of reducing gas turbine NO_x emissions to 2 to 5 ppmvd is catalytic combustion. Catalytica, Inc., was the first to commercially develop catalytic combustion controls for certain (mostly smaller) turbines and markets this system under the name XONON™. Catalytic combustion technology is not yet commercially available for 190-MW, F-Class turbines. Additionally, no gas turbine manufacturer is currently developing this technology for syngas applications. Therefore, catalytic combustion does not represent an available control option for the Polk facility and is not further considered in this analysis.

6.2 POSTCOMBUSTION EXHAUST GAS TREATMENT

The four following postcombustion exhaust gas treatment systems are evaluated in this section:

- SNCR.
- NSCR.
- SCR.
- Catalytic adsorption and desorption/reaction control system ($SCONO_x$™).

6.2.1 SELECTIVE NONCATALYTIC REDUCTION

The SNCR process involves the gas phase reaction, in the absence of a catalyst, of NO_x in the exhaust gas stream with injected ammonia (NH_3) or urea to yield nitrogen and water vapor. Due to reaction temperature considerations, the SNCR injection system must be located at a point in the exhaust duct where temperatures are consistently between 1,600 and 2,000 degrees Fahrenheit (°F).

The maximum temperature of the CT exhaust gas stream is approximately 1,060°F; thus, this technology is not technically feasible. Therefore, SNCR does not represent an available control option for the Polk facility and is not further considered in this analysis.

6.2.2 NONSELECTIVE CATALYTIC REDUCTION

The NSCR process uses a platinum/rhodium catalyst to reduce NO_x to nitrogen and water vapor under fuel-rich (less than 3-percent oxygen) conditions. NSCR technology has been applied to automobiles and stationary reciprocating engines. Due to the high excess air rates used to fire the turbine, the oxygen content of CT exhaust gases is typically over 11 percent. Therefore, NSCR does not represent an available control option for the Polk facility and is not further considered in this analysis.

6.2.3 SELECTIVE CATALYTIC REDUCTION

SCR reduces NO_x emissions by reacting ammonia with exhaust gas NO_x to yield nitrogen and water vapor in the presence of a catalyst. Ammonia is injected upstream of the catalyst bed where the following primary reactions take place:

$$4NH_3 + 4NO + O_2 \rightarrow 4N_2 + 6H_2O \quad (1)$$

$$4NH_3 + 2NO_2 + O_2 \rightarrow 3N_2 + 6H_2O \quad (2)$$

The catalyst serves to lower the activation energy of these reactions, which allows the NO_x conversions to take place at a lower temperature (i.e., in the range of 600 to 750°F). Typical SCR catalysts include metal oxides (titanium oxide and vanadium), noble metals (combinations of platinum and rhodium), zeolite (alumino-silicates), and ceramics.

Factors affecting SCR performance include space velocity (volume per hour of flue gas divided by the cross-sectional area of the catalyst bed), ammonia/NO_x molar ratio, and catalyst bed temperature. Residence time is a function of catalyst bed depth. Increasing the residence time (increasing catalyst bed depth) will improve NO_x removal efficiency but will also cause an increase in catalyst bed pressure drop. The reaction of NO_x with ammonia theoretically requires a 1:1 molar ratio. Ammonia/NO_x molar ratios greater than 1:1 are necessary to achieve high-NO_x removal efficiencies due to imperfect mixing and other reaction limitations. However, ammonia/NO_x molar ratios are typically maintained at 1:1 or lower to prevent excessive unreacted ammonia (ammonia slip) emissions.

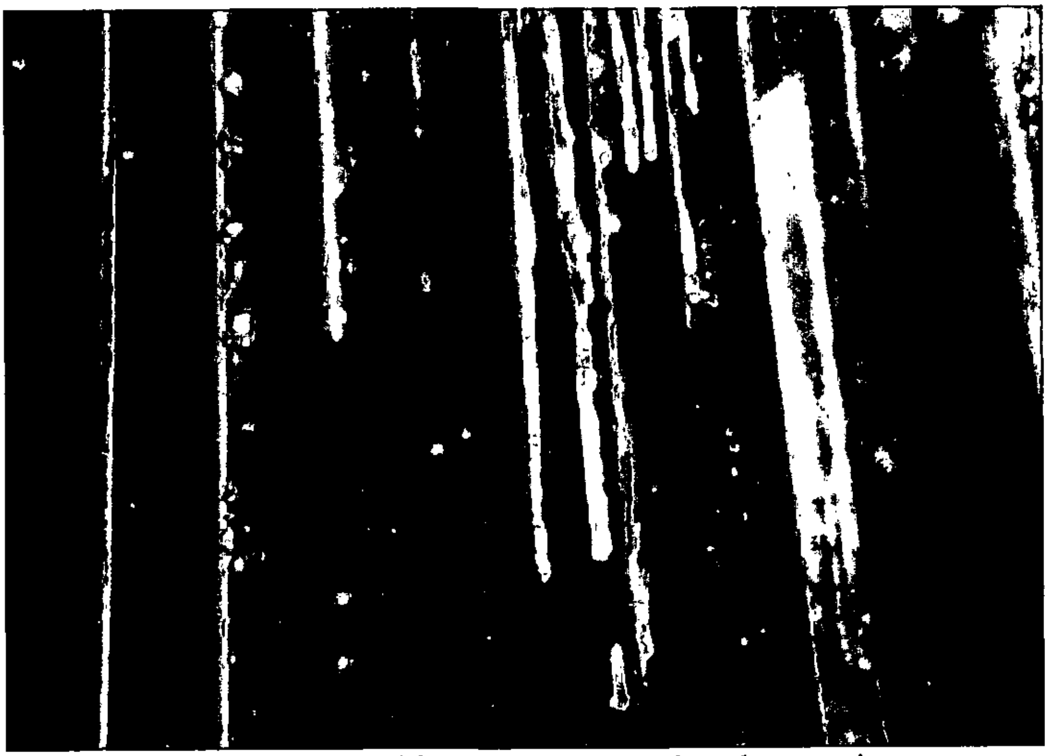
Reaction temperature is critical for proper SCR operation. The optimum temperature range for conventional SCR operation is 600 to 750°F. Below this temperature range, reduction reactions (1) and (2) will not proceed. At temperatures exceeding the optimal range, oxidation of ammonia will take place, resulting in an increase in NO_x emissions.

Specially formulated high temperature zeolite catalysts have been recently developed that function at exhaust stream temperatures up to a maximum of approximately 1,025°F. NO_x removal efficiencies for SCR systems typically range from 50 to 90 percent.

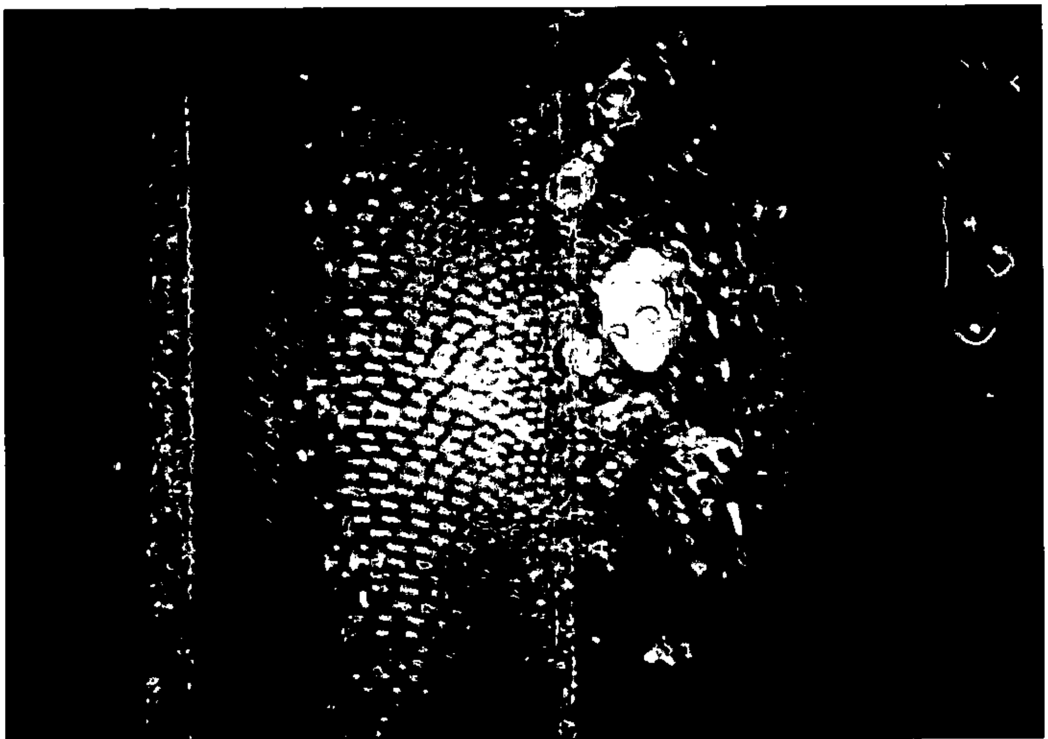
SCR catalyst is subject to deactivation by a number of mechanisms. Loss of catalyst activity can occur from thermal degradation if the catalyst is exposed to excessive temperatures over a prolonged period of time. Catalyst deactivation can also occur due to chemical poisoning. Principal poisons include arsenic, sulfur, mercury, potassium, sodium, and calcium. Due to the potential for chemical poisoning with fuels other than natural gas, application of SCR to CTs has been primarily limited to natural gas-fired units.

Of particular concern in this project is the use of the SCR catalyst on a sulfur-containing fuel. Yellow deposits composed of sulfur, and sulfur compounds have been noted from the high-pressure evaporator tubes to the low-pressure economizer. The temperature range associated with these deposits includes the normal operating temperature range of typical SCR catalysts. Several photographs were taken during a recent equipment shutdown that indicated the presence of sulfur compound deposition in the equipment, which is an overriding technical concern for fouling of the SCR control system. A sampling of these photographs is included in Figure 1 to support the assertion that the sulfur compounds in the exhaust stream present a technical obstacle to the use of an SCR emissions control system. Thus, there are significant amounts of sulfur and sulfur compounds in the exhaust stream that will adversely affect the performance of an SCR.

SCR catalyst will promote the oxidation of flue gas SO_2 to sulfur trioxide (SO_3), which will then combine with water vapor to form sulfuric acid (H_2SO_4). Accordingly, corrosion of downstream piping and heat transfer equipment (which would operate at temperatures below the H_2SO_4 dew-point) would be of concern when using SCR with sulfur-bearing fuels. Also, SO_3 will combine with unreacted ammonia to form ammonium bisulfate and ammonium sulfate. Ammonia bisulfate is a hygroscopic solid at approximately



Deposits in the HRSG, low-pressure section of economizer



Close-up of deposits in HRSG, low-pressure section of economizer.

FIGURE 1. (Page 1 of 2)

SITE PHOTOGRAPHS

Source: ECT, 2000.

ECT
Environmental Consulting & Technology, Inc.

Close-up of deposits in HRSG, low-pressure section of economizer.

Close-up of deposits in HRSG, low-pressure section of economizer.

FIGURE 1. (Page 2 of 2)

SITE PHOTOGRAPHS

Source: ECT, 2000.

ECT
Environmental Consulting & Technology, Inc.

380°F and will deposit on equipment surfaces below this temperature as a white solid. Both ammonium bisulfate and ammonium sulfate would be expected to deposit on HRSG heat transfer equipment where temperatures below 380°F will occur. Since ammonium bisulfate is hygroscopic, the material will absorb water, forming a sticky substance that can cause fouling of heat transfer equipment. Ammonium bisulfate cannot be easily removed due to its sticky nature; a unit shutdown would be required to clean fouled equipment. Formation of ammonium salts will also result in a significant increase in particulate matter (PM) emissions. Additionally, these deposits would be expected to increase the pressure drop across the equipment, adversely affecting overall CT efficiency.

The technical difficulties associated with SCR and sulfur-bearing fuels have been documented for fuels having relatively low sulfur contents. For example, the United Airlines cogeneration facility fires very low-sulfur (0.04 percent, 0.02 pound per million British thermal unit [lb/MMBtu]) Jet-A fuel as a back-up fuel[1]. Although this level is approximately half the sulfur level of the syngas fired at the Polk facility, the SCR catalyst was replaced three times during the first year of operation due to sulfur poisoning, and the back sections of the HRSG required washing to remove ammonium sulfate salt build-up.

Two examples of SCR applied to CTs firing sulfur-bearing fuels outside the United States were reported in the Lowest Achievable Emission Rate (LAER) analysis submitted for the Star Enterprise Delaware City Refinery permitted in 1998[2]. This analysis included two examples, one by the Japanese National Railway (JNR) and another in Linkoping, Sweden. The JNR facility had 50,000 hours of operating experience on a very low-sulfur fuel (0.007 weight percent, 0.004 lb/MMBtu); however, due to ammonium sulfate deposition, the unit is operated at approximately one-half of its design efficiency (40 percent actual versus 80 percent design NO_x reduction). By operating significantly below the

[1]General Electric Company, Industrial and Power Systems, Position Paper, The Use of SCR When Firing Gas Turbines with Distillate Oil, May 31, 1994.

[2] Air Quality Permit Application for the Star Enterprise Delaware City Refinery, Submitted to the State of Delaware Department of Natural Resources and Environmental Control, Division of Air and Waste Management, Permit Number APC-97/0503.

design ammonia/NO_x injection ratio, ammonia slip (and the associated formation of ammonium sulfate) is virtually eliminated.

The Linkoping installation had 16,000 hours of operation. The unit is designed to achieve greater than 90 percent NO_x removal with low ammonia slip. It is equipped with an HRSG, and it has steam-fired sootblowers operated at 725 pounds per square inch (psi). During the summer of 1995, while firing fuel oil with sulfur levels between 0.05 and 0.1 percent, some deposits were found in the economizer section of the HRSG. The catalyst had to be removed during cleaning to avoid wetting it; the cleaning process took 1 week. In the fall of 1996, the fuel oil sulfur content rose to approximately 0.13 percent (0.07 lb/MMBtu). This increased level resulted in further, increased deposits and a significant increase in the HRSG pressure drop, which forced a turbine shutdown due to excessive backpressure.

These reported experiences indicate the following overriding concerns with application of SCR to sulfur-containing fuel combustion processes:

- HRSG deposits will form even at low fuel sulfur levels.
- The large HRSG pressure drop increases that have been predicted in this service (large enough to shut down the turbine) are now confirmed in an actual oil-fired CT HRSG.
- Sootblowers do not seem to be effective in preventing deposition.

Although the fuels used at the Polk facility have relatively low sulfur contents (i.e., syngas and low sulfur distillate oil), the sulfur levels are more than sufficient to cause problems with operation of a SCR control system. The Title V Air Operating Permit for SO_2 emissions limits the sulfur content of the syngas to 0.1 lb/MMBtu (as elemental sulfur). Normal operating experience indicates typical syngas sulfur content of 0.07 lb/MMBtu. This sulfur content is substantially greater (up to 10 times greater) than demonstrated to cause the technical difficulties described in this section.

Recent advances in catalyst design allow for SCR catalysts that minimize the conversion of SO_2 to SO_3. However, these catalysts are specifically formulated for use in specific applications in the chemical process industry. Discussions with the catalyst manufacturer (Englehard 2000)[3] indicate that this special catalyst is not formulated for use in combustion turbine applications. Additionally, Englehard indicated that they do not have a catalyst available for combustion turbine applications that would lessen the rate of this side reaction that can cause subsequent deposition problems.

In contrast, natural gas has a sulfur content of approximately 0.02 to 0.27 grains of sulfur per 100 standard cubic feet (gr S/100 scf), or 2.72×10^{-5} to 3.67×10^{-4} lb/MMBtu. This sulfur level is considerably less than that which has been shown to cause the equipment fouling described in this report.

Problems associated with ammonium salt deposition can be ameliorated to some extent by reducing the ammonia/NO_x molar ratio when firing sulfur-containing fuels. However, all known successful applications of SCR for CTs are on natural gas-fired units. There are no applications of SCR to CTs fired with synthetic coal gas, including the LAER determination for the Star Enterprises Maryland facility. It should also be noted that the original equipment manufacturer[4] does not promote the application of a SCR to a syngas-fired unit.

For the purposes of providing a complete analysis of the SCR as an option for control, even with the overwhelming technical concerns, a cost-effective analysis of SCR control technology is presented in Section 6.3 and is summarized in Table 3. As demonstrated in this analysis, the expected cost effectiveness for SCR was determined to be $4,660 per ton of NO_x removed This economic analysis includes increased costs that would accrue due to downtime required for cleaning of fouled heat transfer equipment. Since Polk Unit 1 does not have a by-pass stack, the unit must be shut down completely during any

[3]Englehard, 2000. Telephone conversation, November 8, 2000, between Mr. Fred Booth, Englehard Corporation and Mr. John Shrock, ECT.

[4] General Electric Company, Industrial and Power Systems, Position Paper, The Use of SCR When Firing Gas Turbines with Distillate Oil, May 31, 1994.

outage caused by the SCR system. This cost control is greater than those previously considered to be reasonable for BACT NO_x determinations.

6.2.4 CATALYTIC ADSORPTION AND DESORPTION/REACTION CONTROL SYSTEM (SCONO$_X$™)

SCONO$_x$™ is a NO_x and CO catalytic absorption control system developed by Goal Line Environmental Technologies (GLET) and exclusively offered by Alstom Power. The SCONO$_x$™ system operates at a temperature range of 300 to 700°F. The SCONO$_x$™ process is further described in the information sheet included in Appendix C provided by the supplier of this technology.

The SCONO$_x$™ process addresses the sulfur poisoning issue by installing a SCOSO$_x$™ guard bed upstream of the SCONO$_x$™ catalyst bed. Even with the SCOSO$_x$™ guard bed, experience with natural gas-fired turbine exhausts indicates the first stage of the SCONO$_x$™ experiences sulfur poisoning. This first stage needs to be washed with an acid wash solution more frequently than the rest of the bed and also needs replacement on a more frequent basis. Thus, the SCOSO$_x$™ guard bed is not entirely effective at removing sulfur and sulfur compounds from the exhaust stream. Any effects noticed using the extremely low-sulfur natural gas fuel are expected to be amplified when using the higher sulfur content syngas or distillate oil fuel.

For the purposes of providing a complete analysis of the SCONO$_x$™ process as an option for control, even with the overwhelming technical concerns, a cost-effective analysis of SCONO$_x$™ control technology is presented in Section 6.3, and is summarized in Table 3. As demonstrated in this analysis, the expected cost effectiveness for SCONO$_x$™ was determined to be \$10,820 per ton of NO_x removed. This economic analysis includes the increased costs that would accrue due to downtime required for cleaning of fouled heat transfer equipment. This cost control is greater than those previously considered to be reasonable for BACT NO_x determinations.

6.3 COST-EFFECTIVENESS ANALYSIS

Economic analyses of the SCR and $SCONO_x$™ control technology alternatives were performed to compare the capital and annual costs in terms of the cost-effectiveness. The cost-effectiveness of a control technology is defined as the cost per ton of pollutant removed. As shown in Table 3, SCR is more cost-effective than $SCONO_x$™ (i.e., the cost per ton to control NO_x is approximately two times higher for $SCONO_x$™). However, neither $SCONO_x$™ nor SCR are considered to be a cost effective alternative for controlling NO_x at this installation. A discussion of the methodology used to perform the cost analysis follows in this section. Details of the costs associated with the SCR and $SCONO_x$™ systems are contained in Sections 6.3.1 and 6.3.2.

Table 3. BACT Analysis Summary of Cost-Effectiveness

	SCR Syngas Firing	SCR Oil Firing	SCONOx™ Syngas Firing	SCONOx™ Oil Firing
Baseline NO_x (ppmvd)	25.0	42.0	25.0	42.0
Baseline NO_x (lb/hr)	222.5	311.0	222.5	311.0
Baseline NO_x (tpy)	877.1	136.2	877.1	136.2
Controlled NO_x (ppmvd)*	3.5	5.9	2.0	3.4
Controlled NO_x (lb/hr)	31.2	43.5	17.8	24.9
Controlled NO_x (tpy)†	122.8	19.1	70.2	10.9
Emissions decrease (tpy)†	754.3 701.68	117.1	806.9	125.3
Unit 1 Total				
Emissions decrease (tpy)		871.4 818.78		932.2
Annualized cost ($)		$4,061,000		$10,086,500
Cost effectiveness ($/ton)		$4,660		$10,820

*SCR assumes an 86-percent control efficiency based on syngas firing inlet concentration of 25 ppm and outlet concentration of 3.5 ppm. This efficiency is assumed to apply to oil firing. The SCONOx™ assumes a 92-percent control efficiency based on syngas firing inlet concentration of 25 ppm and outlet concentration of 2 ppm. This efficiency is assumed to apply to oil firing.

†Annual emission estimates are based on maximum permitted heat input using oil firing for 876 hours per year (the permit limit) and 7884 hours per year on syngas.

Source: ECT, 2000.

Capital Costs

Capital costs include the initial cost of the components intrinsic to the complete control system, (e.g., SCR includes the catalyst bed, support frame, ammonia storage tanks, piping, rotating equipment, instrumentation, and monitoring equipment), and installation costs.

One additional initial capital cost associated with the SCR control option arises from the physical changes that are needed to accommodate the HRSG washing to remove anticipated ammonia sulfate deposits. These changes are required to allow for containment of the water used in washing which is estimated at approximately 20,000 gallons per occurrence. The changes involve installation of appropriate containment (i.e., both a sump and appropriate drainage system for the HRSG), pumps, and piping. Because the washing operation will be performed using scaffolding, appropriate brackets for the scaffolding will also need to be installed. The total capital cost for the HRSG modifications to allow for washing is estimated at $300,000, and is included in the capital costs for the SCR system.

Similar to the SCR control technology, the capital cost site upgrades to accommodate handling of wash water is also anticipated for the $SCONO_x$™ control technology due to the requirements for washing of the catalyst. Because the $SCONO_x$™ system is an ammonia free system, the difficulties with ammonia sulfate deposits and associated fouling are not anticipated. However, the $SCONO_x$™ control system is sensitive to the sulfur levels in the exhaust. Even with the low sulfur content of a natural gas fired combustion turbine exhaust stream, a $SCONO_x$™ guard bed is used to protect the $SCONO_x$™ main catalyst. Based on the higher sulfur content of the syngas CT exhaust, it is anticipated that similar semi-annual cleaning of the catalyst will be required.

Annual operating costs consist of the financial requirements to operate the control system on an annual basis and include overhead, maintenance, outages, labor, raw materials, and utilities. Table 4 summarizes specific factors used in estimating the capital and annual operating costs. Additional cost assumptions, such as the costs for electricity and steam, are contained in Table 5.

Table 4. Capital and Annual Operating Cost Factors

Cost Item	Factor
Direct Capital Costs	
Sales tax	0.06 × control system cost
Freight	0.05 × control system cost
Instrumentation	0.10 × control system cost
Foundations and supports	0.08 × purchased equipment cost
Handling and erection	0.14 × purchased equipment cost
Electrical	0.04 × purchased equipment cost
Piping	0.02 × purchased equipment cost
Insulation	0.01 × purchased equipment cost
Painting	0.01 × purchased equipment cost
Indirect Capital Costs	
Engineering	0.10 × purchased equipment cost
Construction and field expenses	0.05 × purchased equipment cost
Contractor fees	0.10 × purchased equipment cost
Start-up	0.02 × purchased equipment cost
Performance testing	0.01 × purchased equipment cost
Contingencies	0.03 × purchased equipment cost
Direct Annual Operating Costs	
Supervisor labor	0.15 × total operator labor cost
Maintenance materials	1.00 × total maintenance labor cost
Indirect Annual Operating Costs	
Overhead	0.60 × total of operating, supervisory, and maintenance labor and maintenance materials
Administrative charges	0.02 × total capital investment
Property taxes	0.01 × total capital investment
Insurance	0.01 × total capital investment

Sources: EPA, 1996.
ECT, 2000.

Table 5. Economic Cost Factors

Factor	Units	Value
Interest rate	%	7.0
Control system life	Years	10
SCR catalyst life	Years	5*
SCONOx™ catalyst life	Cost assumes leasing arrangement	
Aqueous ammonia cost	$/ton	113
Natural gas cost†	$/ft^3	0.00388
Steam cost**	$/lb	0.006
Electricity cost	$/kWh	0.04
Labor costs (base rates)	$/hour	
Operator		22.00
Maintenance		22.00

*The vendor's control system performance guarantee is for 3 years of operation or 3.5 years after catalyst delivery, whichever occurs first.
†Natural gas is used in the $SCONO_x$™ system for regenerating the catalyst, and not for firing the combustion turbine. Cost estimate from DOE, 1999.[5]
**Cost estimate from DOE, 1999.[5]

Sources: TECO, 2000.
ECT, 2000.

The capital cost estimating technique used in this analysis is based on the factored method of determining direct and indirect installation costs. This technique is a modified version of the "Lang Method," whereby installation costs are expressed as a function of known equipment costs. This method is consistent with the latest U.S. EPA guidance manual (OAQPS Control Cost Manual) on estimating control technology costs (EPA, 1996)[6]. The estimation factors used to calculate total capital costs are shown in Table 4.

Purchased equipment costs represent the delivered cost of the control equipment, auxiliary equipment, and instrumentation. Auxiliary equipment consists of all structural, mechanical, and electrical components required for efficient operation of the device. These may include such items as reagent storage, supply piping, and distributed controls. Aux-

[5]DOE, 1999. Cost Analysis of NO_x Control Alternatives for Stationary Gas Turbines. U.S. Department of Energy. Environmental Programs, Chicago Operations Office, 9800 South Cass Avenue, Chicago, IL 60439. November 5, 1999.

[6] EPA, 1996. U.S. Environmental Protection Agency (EPA). 1996. OAQPS Control Cost Manual, 5th Edition. EPA-453/B-96-001. Research Triangle Park, NC.

iliary equipment costs are taken as a straight percentage of the basic equipment cost, the percentage being based on the average requirements of typical systems and their auxiliary equipment (EPA, 1996). In this analysis, the basic equipment costs were based on recent quotes (i.e., 11/16/00 for $SCONO_x$™ and 11/25/00 for SCR) by qualified vendors for similar equipment (Appendix D). The costs were then scaled based on the differences in exhaust flowrate between the actual equipment and that for which the quote was prepared. In this case the cost estimates were based on the Siemens Westinghouse Model V84.3a2 with an exhaust flow rate of 3,515,508 lb/hr. The project unit, a General Electric 7FA, has an exhaust flow rate of 3,940,000 lb/hr. The resulting scaling factor of 1.12 was used to adjust the costs of the equipment and catalyst to the larger GE unit. Instrumentation, usually not included in the basic equipment cost, is estimated at 10 percent of the basic equipment cost.

Direct installation costs consist of the direct expenditures for materials and labor for site preparation, foundations, structural steel, erection, piping, electrical, painting, and facilities.

Indirect installation costs include engineering and supervision of contractors, construction and field expenses, construction fees, and contingencies. Direct installation costs are expressed as a function of the purchased equipment cost based on the average installation requirements of typical systems.

Indirect installation costs are designated as a percentage of the total direct cost (purchased equipment cost plus the direct installation cost) of the system. Other indirect costs include equipment startup and performance testing, working capital, and interest during construction.

Annualized Costs

Annualized costs are comprised of direct and indirect operating costs. Direct costs include labor, maintenance, replacement parts, raw materials, utilities, and waste disposal. Indirect operating costs include plant overhead, taxes, insurance, general administration, and capital charges. Annualized cost factors used to estimate total annualized cost are listed in Table 4. Annualized cost factors were obtained from the current EPA manual on estimating control technology costs (EPA, 1996).

Direct operating labor costs vary according to the system operating mode and operating time. Labor supervision is estimated as 15 percent of operating labor. Maintenance costs are calculated as 3 percent of total direct cost (TDC). Replacement part costs, such as the cost to replace aged catalyst, have been included where appropriate. Because the $SCONO_x$™ catalyst is leased, an annual lease cost is used instead of a replacement cost. Raw material and utility costs are based upon estimated annual consumption. The presence of a catalyst bed would increase turbine back-pressure resulting in efficiency losses to the system. This is reflected in the economic analysis as the value of lost power output based on turbine vendor estimates. With low inlet emission rates (i.e., 25 ppmvd), the catalyst is assumed to require replacement every five years due to aging, which is at a longer interval than the vendor's catalyst lifetime guarantee of three years. This extension of the lifetime of the catalyst serves to reduce the annual costs associated with catalyst replacement, which is based on the cost of replacement catalyst as provided by the catalyst vendor.

With the exception of overhead, indirect operating costs are calculated as a percentage of the total capital cost. The indirect capital costs are based on the capital recovery factor (CRF), defined by the following equation:

$$CRF = i(1+i)^n / [(1+i)^n - 1]$$

Where "i" is the annual interest rate and "n" is the equipment economic life in years. A control systems economic life is typically 10 to 20 years (EPA, 1996). In this analysis, a 10-year equipment economic life was assumed. The average interest rate is assumed to be 7.0 percent (EPA, 1996), although TEC currently incurs greater interest costs for this type of capital equipment. The CRF is therefore conservatively calculated to be 0.14238; however, this value would likely be higher for this facility because of the higher interest rates that would be expected for TEC.

Cost Effectiveness

The cost-effectiveness of an available control technology is based on the annualized cost of the available control technology and its annual pollutant emission reduction. Cost-effectiveness is calculated by dividing the annualized cost of the available control technology by the theoretical mass (tons) of pollutant removed by that control technology each year. The basis for determining the percent reduction of a given technology was based on information contained in U. S. EPA literature and from vendors of the control equipment.

6.3.1 SELECTIVE CATALYTIC REDUCTION

An assessment of economic impacts was performed by comparing control costs between the existing baseline case of advanced combustor technology and baseline technology with the addition of SCR controls. In the base case, the uncontrolled, annual NO_x emission rate is 1,013.3 tons per year (tpy) based on CT baseload operation for 8,760 hr/yr at 59°F and assuming oil firing for 10-percent of the year. No provisions (i.e., emission reductions) are included for the 432 hours of anticipated outages, since no operational constraints are being requested. This approach is conservative, as it will tends to overestimate emissions reductions resulting in lesser cost effectiveness values. The SCR controlled annual NO_x emission rate, based on 3.5 ppmvd effluent concentration on syngas (i.e., 86-percent control efficiency), is 122.8 tpy. Baseline technology is expected to achieve a NO_x exhaust concentration of 25 ppmvd at 15-percent O_2. SCR technology was premised to achieve NO_x concentrations of 3.5 ppmvd at 15-percent O_2. Base case and controlled NO_x emission rates are summarized in Table 3.

Average cost effectiveness for the application of SCR technology was determined to be \$4,660 per ton of NO_x removed. Based on recent Florida DEP BACT determinations, the control cost for SCR is not considered to be economically reasonable for this installation. Tables 6 and 7 summarize the results of the capital and annual operating costs associated with the SCR system.

Table 6. Capital Costs for SCR Catalyst System

Item	Dollars	OAQPS Factor
Direct Costs		
Purchased equipment*	2,047,900	A
Sales tax	122,900	0.06 × A
Instrumentation	204,800	0.10 × A
Freight	102,400	0.05 × A
HRSG Modification	300,000	
Subtotal Purchased Equipment	**2,778,000**	**B**
Installation		
Foundations and supports	222,200	0.08 × B
Handling and erection	388,900	0.14 × B
Electrical	111,100	0.04 × B
Piping	55,600	0.02 × B
Insulation for ductwork	27,800	0.01 × B
Painting	27,800	0.01 × B
Subtotal Installation Cost	**833,400**	
Subtotal Direct Costs	**3,611,400**	
Indirect Costs		
Engineering	277,800	0.10 × B
Construction and field expenses	138,900	0.05 × B
Contractor fees	277,800	0.10 × B
Startup	55,600	0.02 × B
Performance test	27,800	0.01 × B
Contingency	83,300	0.03 × B
Subtotal Indirect Costs	**861,200**	
TOTAL CAPITAL INVESTMENT	**4,472,600**	(TCI)

*Includes estimated $100,000 for ammonia storage tank.

Source: ECT, 2000.

Table 7. Annual Operating Costs for SCR Catalyst System

Item	Dollars	OAQPS Factor
<u>Direct Costs</u>		
Operator/supervisor Labor	13,800	
Maintenance Labor and Material	24,000	
Subtotal Labor and Maintenance Costs	**37,800**	C
Catalyst costs		
Replacement (materials, labor, disposal)	1,713,300	
Annualized Catalyst Costs	**417,900**	5 yr replacement
Aqueous ammonia costs	226,900	$113/ton
Electricity costs	62,800	NH_3 pump/vaporization
Scheduled Outages	60,000	labor and materials
Unscheduled Outages	1,934,400	labor, materials, and 6 days electrical loss
Energy Penalties		
Turbine backpressure-control system	363,000	0.54% penalty
Turbine backpressure-catalyst plugging	363,300	0.54% penalty
Subtotal Direct Costs	**3,466,400**	(TDC)
Indirect Costs		
Overhead	22,700	0.60 x C
Administrative charges	89,500	0.02 x TCI
Property taxes	44,700	0.01 x TCI
Insurance	44,700	0.01 x TCI
Capital recovery	414,800	10 yrs @ 7%
Subtotal Indirect Costs	**616,400**	
Emission fee credit	(21,800)	$25/ton
TOTAL ANNUAL COST	**4,061,000**	

Source: ECT, 2000.

The installation of SCR technology will cause an increase in back pressure on the CT due to the pressure drop across the catalyst bed. Additional energy would be needed for the pumping of aqueous NH_3 from storage to the injection nozzles and generation of steam for NH_3 vaporization. A SCR control system for the CT is projected to have a pressure drop across the catalyst bed of approximately 2.7 inches of water. This pressure drop will result in a 0.54 percent energy penalty due to reduced turbine output power. The reduction in turbine output power (lost power generation) will result in an energy penalty of 9,082,368 kilowatt hours (kwh) (30,990 MMBtu) per year at baseload (192 MW) operation for 8,760 hours per year. The lost power generation energy penalty, based on a power cost of $0.04/kwh, is $363,300 per year. This cost was included in the BACT analysis.

The fouling of the control equipment or the downstream equipment will also cause an increase in turbine backpressure. Thus, there are two energy penalties associated with each control technology. The first energy penalty is from the pressure drop across a clean configuration of the control system. The second energy penalty is from the pressure drop caused by fouling of the catalyst or the downstream exhaust equipment. It is assumed that the catalyst will be cleaned when the increased pressure drop from fouling is equal to twice the pressure drop associated with a clean system (i.e., when the total pressure drop is three times that of a clean system). For the SCR system, the nominal pressure drop is 2.7 inches of water. Thus, the catalyst will cleaned when the total pressure drop is at 8.1 inches of water. Because the catalyst condition will vary between clean and plugged, the increased pressure drop from fouling will approximately be equal to the nominal pressure drop. Hence, the annual costs associated with the pressure drop from plugging are estimated as the same costs as from the nominal pressure drop across the system.

The annual operating costs include costs for three outages per year. For the SCR system, these outages are for cleaning deposits in the HRSG and other portions of the exhaust system. The outages result from the high sulfur content of the exhaust gas. In preparing the cost estimates for this analysis, it is assumed that one of the two outages can coincide with a planned outage. However, the other outages would be unscheduled. This arrangement is appropriate as the combustion turbine has a designed availability of 95 percent.

There are two main costs that are associated with an outage. The first cost is the labor and materials costs that are associated with the cleaning activities. This cost is estimated by plant engineering staff as $60,000 per occurrence. This cost would apply to both scheduled and unscheduled outages.

The cost associated with unscheduled outages was also included in the analysis. It was estimated that two unscheduled outages per year, each lasting 6 days, would occur. This would result in lost energy production from the combined CT/HRSG system. At $20 per megawatt hour (the incremental cost of power generation), this outage would result in $151,200 per day for a total of $1,814,400 per year.

The incremental cost of power generation represents the differential cost to TEC of acquiring the power that would otherwise be generated by the Polk syngas fired turbine had a forced outage due to SCR failure not occurred. This differential cost is the cost of the replacement power less the cost of generating the power at the Polk facility. There are a variety of factors that contribute to the determination of the incremental cost, including the availability of other units in the TEC system, and the associated costs of generating additional electricity or the purchase of power from other sources comprising the power grid. Based on an internal review of historical and projected TEC generating capability and associated costs, including purchase from the power grid, if necessary, this incremental cost is estimated at $20 per megawatt hour.

If these costs were estimates as a lost factor, the total cost would be substantially higher, especially if an outage were to occur during peak demand periods. However, the costs are conservatively estimated as internal costs. These costs were assumed to be the same for both the SCR and $SCONO_x$™ systems.

6.3.2 SCONO$_X$™

The economic impact analysis for the SCONO$_x$™ system was conducted in the same manner as that described above for the SCR system. Assuming the same baseline conditions (i.e., 1,013.3 tpy emissions) the controlled annual NO_x emission rate, based on 92-percent control efficiency for the SCONO$_x$™, is 81.1 tpy (70.2 tpy on syngas). Baseline technology is expected to achieve a NO_x exhaust concentration of 25 ppmvd at 15-percent O_2. SCONO$_x$™ technology, which is generally higher performance than SCR, was premised to achieve NO_x concentrations of 2.0 ppmvd at 15-percent O_2. The base case and controlled NO_x emission rates are summarized in Table 3.

The specific capital and annual operating costs for the SCONO$_x$™ control system are contained in Tables 8 and 9. Average cost effectiveness for the application of SCONO$_x$™ technology to the CT was determined to be $10,820 per ton of NO_x removed. The control cost for SCONO$_x$™ is substantially higher than previously considered reasonable by the FDEP. One notable difference in the analysis for SCONO$_x$™ is that a catalyst maintenance agreement is assumed. Therefore, maintenance labor and catalyst replacement costs were replaced by a single $2,800,000 annual cost. Because of the high purchase cost of the SCONO$_x$™ catalyst, this annual maintenance agreement is considered to be the more economical option. The same internal cost that was assumed in the SCR analysis for unscheduled outages to correct catalyst fouling was used for the SCONO$_x$™ analysis.

In addition to the annual maintenance costs, several other items are unique to the SCONO$_x$™ system. For instance, natural gas is used for hydrogen reforming in the process to regenerate the catalyst. A significant amount of steam is required as the carrier for the gas. The cost estimates for the natural gas, steam, and electricity to run the process was based on information contained in a recent Department of Energy (DOE) cost analysis study of NO_x control alternatives (DOE,1999).

Table 8. Capital Costs for SCONO$_x$™ System

Item	Dollars	OAQPS Factor
Direct Costs		
Purchased equipment	7,845,200	A
Sales tax	470,700	0.06 x A
Instrumentation	784,500	0.01 x A
Freight	392,300	0.05 x A
HRSG Modifications	300,000	
Subtotal Purchased Equipment	**9,792,700**	**B**
Installation		
Foundations and supports	783,400	0.08 x B
Handling and erection	1,371,000	0.14 x B
Electrical	391,700	0.04 x B
Piping	195,900	0.02 x B
Insulation for ductwork	97,900	0.01 x B
Painting	97,900	0.01 x B
Subtotal Installation Cost	**2,937,800**	
Subtotal Direct Costs	**12,730,500**	
Indirect Costs		
Engineering	979,300	0.10 x B
Construction and field expenses	489,600	0.05 x B
Contractor fees	479,300	0.10 x B
Startup	195,900	0.02 x B
Performance test	97,900	0.01 x B
Contingency	293,800	0.03 x B
Subtotal Indirect Costs	**3,035,800**	
TOTAL CAPITAL INVESTMENT	**15,766,300**	(TCI)

Source: ECT, 2000.

Table 9. Annual Operating Costs for SCONO$_x$™ System

Item	Dollars	OAQPS Factor
Direct Costs		
Operator/supervisor Labor	13,800	
Maintenance Labor and Material	0	Maintenance agreement
Subtotal Labor and Maintenance Costs	**13,800**	C
System Maintenance and Catalyst Replacement (materials, labor, and disposal)	2,801,900	Maintenance agreement
Natural gas costs (H_2 reforming)*	91,400	14 ft^3/hr per MW capacity
Electricity costs*	40,400	0.6 kW per MW capacity
Steam costs (H_2 carrier)*	938,500	93 lb/hr per MW capacity
Scheduled Outages	60,000	labor and materials
Unscheduled Outages	1,934,400	labor, materials, and 6 days electrical loss
Energy Penalties		
Turbine backpressure-control system	672,800	1.0 % penalty
Turbine backpressure-catalyst plugging	672,800	0.2 % penalty
Subtotal Direct Costs	**7,226,000**	(TDC)
Indirect Costs		
Overhead	8,300	0.60 x C
Administrative charges	315,300	0.02 x TCI
Property taxes	157,700	0.01 x TCI
Insurance	157,700	0.01 x TCI
Capital recovery	2,244,800	10 yrs @ 7%
Subtotal Indirect Costs	**2,883,800**	
Emission fee credit	(23,300)	$25/ton
TOTAL ANNUAL COST	**10,086,500**	

*DOE, 1999

Source: ECT, 2000.

The annual operating costs include costs for three outages per year. For the $SCONO_x$™ system, these outages are for the cleaning of the catalyst. The outages result from the high sulfur content of the exhaust gas. In preparing the cost estimates for this analysis, it is assumed that one of the two outages can coincide with a planned outage. However, the other outages would be unscheduled. This arrangement is appropriate as the combustion turbine has a designed availability of 95 percent.

There are two main costs that are associated with an outage. The first cost is the labor and materials costs that are associated with the cleaning activities. This cost is estimated by plant engineering staff as $60,000 per occurrence. This cost would apply to both scheduled and unscheduled outages.

The cost associated with unscheduled outages was also included in the analysis. It was estimated that two unscheduled outages per year, each lasting 6 days, would occur. This would result in lost energy production from the combined CT/HRSG system. At $20 per megawatt hour (the incremental cost of power generation), this outage would result in $151,200 per day for a total of $1,814,400 per year.

The incremental cost of power generation represents the differential cost to TEC of acquiring the power that would otherwise be generated by the Polk syngas fired turbine had a forced outage due to $SCONO_x$™ failure not occurred. This differential cost is the cost of the replacement power less the cost of generating the power at the Polk facility. There are a variety of factors that contribute to the determination of the incremental cost, including the availability of other units in the TEC system, and the associated costs of generating additional electricity or the purchase of power from other sources comprising the power grid. Based on an internal review of historical and projected TEC generating capability and associated costs, including purchase from the power grid, if necessary, this incremental cost is estimated at $20 per megawatt hour.

If these costs were estimates as a lost revenue factor, the total cost would be substantially higher, especially if an outage were to occur during peak demand periods. However, the costs are conservatively estimated as internal costs. These costs were assumed to be the same for both the SCR and $SCONO_x$™ systems.

As with SCR, the installation of $SCONO_x$™ technology will also cause an increase in back pressure on the CT due to the pressure drop across the catalyst bed. A $SCONO_x$™ control system for the CT is projected to have a pressure drop across the catalyst bed of approximately 5.0 inches of water. This pressure drop will result in a 1.0 percent energy penalty due to reduced turbine output power. The reduction in turbine output power (lost power generation) will result in an energy penalty of 16,819,200 kwh (57,389 MMBtu) per year at baseload (192 MW) operation for 8,760 hr/yr. The lost power generation energy penalty, based on a power cost of $0.04/kwh, is $672,768 per year.

The fouling of the control equipment or the downstream equipment will also cause an increase in turbine backpressure. Thus, there are two energy penalties associated with each control technology. The first energy penalty is from the pressure drop across a clean configuration of the control system. The second energy penalty is from the pressure drop caused by fouling of the catalyst or the downstream exhaust equipment. It is assumed that the catalyst will be cleaned when the increased pressure drop from fouling is equal to twice the pressure drop associated with a clean system (i.e., when the total pressure drop is three times that of a clean system). For the SCONOx™ system, the nominal pressure drop is 5 inches of water. Thus, the catalyst will cleaned when the total pressure drop is at 15 inches of water. Because the catalyst condition will vary between clean and plugged, the increased pressure drop from fouling will approximately be equal to the nominal pressure drop. Hence, the annual costs associated with the pressure drop from plugging are estimated as the same costs as from the nominal pressure drop across the system.

7.0 GOOD COMBUSTION PRACTICES

Since facility start-up, including during the NO_x emissions testing period, the facility has been operating the CT in a manner that allows for reliable, stable, and reasonably economic performance of the entire IGCC facility. The facility's engineering staff have worked to identify several opportunities for reducing NO_x emissions and, as appropriate, have implemented these procedures. However, as reinforced by the nearly consistent NO_x emissions test results during the testing period[7], additional opportunities do not exist for combustion practice improvements that do not involve major capital expenditures. These expenditures/improvements represent a retrofit to the existing equipment and, as discussed previously, are not considered further in this analysis.

[7]Test of October 17, 2000, indicated increase NO_x emissions, which is attributed to higher heating value and adiabatic flame temperature of the fuel. This increase in NO_x emissions occurred even though diluent flow was increased during this testing

8.0 OTHER PLANT EXPERIENCE

One aspect of the required BACT analysis is to survey other similar facilities and their experience and abilities in achieving low-NO_x emissions rates. The term similar facilities is taken to mean large General Electric CTs of a comparable vintage and technology to what is installed at the Polk facility which are fueled by syngas produced in a gasification plant that is similar in efficiency and configuration to Polk. Based on our analysis, there is only one similar facility, the Cinergy/Global Energy Wabash River facility located in Indiana. The facility operates a 265-MW General Electric 7FA CT that combusts syngas created using Global Energy's E-Gas process, a two-stage entrained flow gasification system and is permitted with a NO_x emissions limit of 25 ppmvd. Fuel saturation and steam injection are used to suppress NO_x formation which is a departure from the configuration at Polk which uses nitrogen diluent. The Wabash River facility indicates that typical operations involve NO_x emissions rates ranging from 22 to 24 ppmvd at 15-percent oxygen. The NO_x emissions are maintained at less than the permitted emission rate by adjusting the steam injection rate[8].

There are several other IGCC plants containing syngas-fueled CTs, most of which were recently constructed. These facilities are different enough from Polk either in fuel plant configuration, in turbine manufacturer or vintage that they do not meet the definition of "similar facilities" as discussed in Section 3. Nevertheless, these IGCC facilities are included in this discussion because most have some relevant features. There are eight main facilities comprising this category that are discussed in this section.

The first facility that was somewhat similar to the Polk facility was the commercial-scale demonstration of a 120-MW power plant conducted adjacent to Southern California Edison's Cool Water Generating Station. This facility-fired syngas produced from low and high sulfur coals (approximately 0.35 and 3.1 weight percent sulfur) in a 65-MW CT. It operated between 1984 and 1989. Note that the CT is considerably smaller in capacity (a

[8] Conversation between Mr. John McDaniel, Tampa Electric Company, and Wabash River facility turbine operator, November 7, 2000.

GE 7E) than the one located at the Polk facility (a GE 7F). Water saturation of the fuel was used to reduce NO_x emissions, which typically averaged 22 ppmvd at 15-percent oxygen for various coals tested during the demonstration period. Based on the considerable difference in the specific turbine used at the Cool Water facility and the Polk facility, this operation is not considered a similar facility. However, it is appropriate to note that the proposed emissions limit for the Polk facility is based on an average NO_x emissions rate observed during the demonstration phase that was less than the average NO_x emissions rates observed for the Cool Water demonstration project.

The next facility is the Star Enterprises Delaware facility that was permitted in March 1998. The facility was permitted under a LAER limit of 15 ppmvd at 15-percent oxygen for a GE model PG6101FA turbine (90-MW nominal) without operation of the associated duct burner and 16 ppmvd with the operation of the associated duct burner. The basis for the LAER determination was not under the federal NSR provisions, but instead under a Delaware program as Delaware uses the "dual source" definition of stationary source as opposed to the federal plant-wide definition. In the permit application, the applicant identified that the LAER limit of 15 ppm represented an advance in permitted level for NO_x emissions, as prior to this facility the most stringent emissions limit was the 25-ppm limit that is in place for the Polk facility.

In the permit application document, Star Enterprises identifies the reason that an emissions level less than 25 ppmvd may be achievable:

> "However, because of more recent advances in diluent and fuel rate control and combustor design, lower levels (below 20 ppmvd) may be possible."

This turbine incorporates an incremental advance in emissions control technology in the combustor design, and is considered one generation of development ahead of the turbine installed at the Polk facility. An essential element of this design improvement is a relatively larger air separation plant than at Polk to provide additional diluent to the combustion turbine. The combustor modification would be of no value for NO_x reduction without the availability of additional diluent. This facility gasifies petroleum coke in Texaco quench gasifiers to produce the syngas fuel, and the syngas composition is expected to be similar to Polk's.

To locate other coal gasification CTs, the analysis expands to facilities located abroad. Note that these facilities are subject to a different set of environmental regulations than the Polk facility. However, they are used for reference when analyzing performance of somewhat similar facilities. There are two facilities in this category. The Demkolec plant located at Buggenum in the Netherlands, and the Elcogas facility funded by the EEC at Puertollano in Spain. Buggenum employs the Shell coal gasification technology and has operated primarily on various coal feedstocks but is currently blending in some waste materials. Puertollano has a very similar gasification technology, the Prenflo process, gasifying a 50/50 blend of local coal and petroleum coke. Buggenum uses a Siemens V94.2 combustion turbine (250 MW) while Puertollano uses the more advanced Siemens V94.3 (300 MW). Both use a combination of syngas saturation and nitrogen injection for NO_x control. Puertollano's permitted NO_x emissions are 150 milligrams per normal cubic meter (mg/Nm^3) at 6 percent O_2 (approximately 29 ppmvd at 15 percent O_2). The facility has reported that they are able to operate within their permit limits. Buggenum has reported that they typically operate at less than 10 ppmvd NO_x but graphical data presented at the 1998 Gasification Technology Conference shows many points up to 20 ppmvd.

There are also four recently constructed IGCC plants which produce syngas from heavy oil gasification. These four facilities, all are located in Europe, are discussed following:

- API (Falconara, Italy).
- Sarlux/Enron (Italy).
- ISAB (Priolo, Italy).
- Shell (Pernis Refinery, Netherlands).

API uses an ABB type 13E2 CT, with nitrogen diluent for syngas-fired NO_x emissions control and water injection for diesel oil-fired NO_x emissions control. API is also equipped with an SCR. The SCR may approach technical feasibility at this facility since API utilizes a more expensive deeper sulfur removal system, resulting in a fuel gas containing approximately 80 percent less sulfur than Polk's syngas fuel. The permitted NO_x emissions limits are 17 ppmvd for syngas and 42 ppmvd for oil firing. The current operational experience indicates NO_x emissions of 20 to 30 ppmvd for diesel firing and 15 to 20 ppmvd for syngas firing; however, the data collected for syngas firing are only at 66 percent of full load. Thus, it may be inferred that the facility is having some difficulty in achieving the 17-ppmvd emissions limit for syngas firing. One possible explanation for this difficulty is that, according to our information, the SCR system has not been operated, at least in part due to Greenpeace objections to the NH_3 emissions associated with SCR.

The total nominal power output rating of the Sarlux/Enron facility is 550 MW. Three GE Model 109E CTs are operated in combined-cycle mode. Each turbine is rated at 123 MW on natural gas firing and 138 MW on syngas. The facility started full operation on syngas in August 2000. The NO_x emissions limit for the facility is 60 milligrams per normal cubic meter (mg/Nm^3) at 15-percent oxygen. This limit is comparable to 30 ppmvd at 15-percent oxygen. The facility uses a high moisture fuel feed (approximately 42 percent) as the primary NO_x control mechanism. Preliminary performance information from the facility indicates this emissions limit is being met.

The ISAB facility uses two Siemens/Ansaldo V94.2K combustion turbines in combined cycle mode for a total output of 512 MW. Like Sarlux, they use syngas saturation for NO_x control, and like API, ISAB is also equipped with SCR. The permitted NO_x emissions limit is 18 ppmv and the reported operation is in the 10 to 15 ppmvd range.

Shell Pernis produces syngas that is used to supplement natural gas fuel to 2 GE MS6451B combustion turbines. This plant also is equipped with duct firing. It is reported to control NOx emissions to less than 30 ppmvd (15 percent O_2) using steam injection. This configuration is so different from Polk's that the associated NO_x experience is the least relevant of all facilities discussed in this section.

As discussed earlier in this section, these additional facilities were examined in the spirit of providing the agency with a comprehensive review of other IGCC plant operating experience. However, due to differences in turbine make, model, and vintage, fuels gasified, NOx control, and methods of operation, none of these additional facilities can be considered similar for the purposes of this review.

9.0 MANUFACTURER'S RESEARCH

GE is considering several advances in syngas fired CT design to potentially allow new model 7FA CTs to attempt to achieve 9- to 15-ppmvd NO_x emissions rates in a new and clean configuration. This range is the lower anticipated limit of NO_x performance, which incorporates both recent modifications to IGCC plant designs (i.e., greater quantity of diluent supply) along with larger combustors as described following this section. This anticipated performance is comparable to the performance that can be achieved using natural gas as a fuel. However, the advances in technology proposed to achieve this reduced emission operation are not readily adapted to the current Polk IGCC configuration without major capital expenditures (i.e., on the order of several million dollars) and successful development and application of an unproven design concept.

These changes in NO_x emissions rates will be achieved through years of development work and essentially two major generations of equipment changes. In general, it is not a simple matter to implement these changes to the equipment at Polk.

These planned advances in CT emissions performance arise from two main areas, combustor redesign to accommodate additional diluent flow and fuel plant modifications to provide the additional diluent. The Polk facility CT has a 14-inch diameter and 22-inch-long combustor, and the latest turbine design has a larger diameter and longer combustor. This increase in combustor size allows for reduced NO_x emissions by providing adequate residence time and mixing for the additional diluent. This possible combustion modification is not currently commercially available for a GE 7FA turbine. If this type of modification were to be implemented, this change would involve considerable modifications to the associated piping and physical configuration, which would involve considerable turbine downtime and substantial capital expenditures. Another concern is that this possible modification would require additional diluent to achieve any of the emissions reductions, as described in the following.

The second main area involved in the reduced emissions is the supply of additional diluent. The Polk facility uses nitrogen as a diluent. The facility is designed such that the diluent is supplied by the cryogenic air separation plant at the facility. As air is cooled, nitrogen condenses before oxygen does. The nitrogen is used as the diluent, and the oxygen is used as part of the gasification process. As part of the design of the Polk facility, the supply and demand for nitrogen diluent and oxygen supply for the gasification process were balanced. Thus, it is not a simple matter to add more diluent to the CT without affecting the relationship between the related processes. The facility is currently using the maximum amount of nitrogen diluent that is available in a stable, reliable supply, while maintaining consistent power output. Short of making major modifications to the facility or the processing parameters for essentially the entire facility, there is not an opportunity to create additional diluent for the CT.

Additionally, the Polk IGCC facility test results were reviewed with several combustion and environmental experts of GE's Power Systems Division. This review was held at the conclusion of the demonstration period and involved meetings and discussions between TEC and GE staff. Based on this review, GE has reiterated their support for a 25-ppm NO_x emissions limit for the PPS facility. This support is included in Appendix A of this submittal.

APPENDIX A

LETTER FROM GE REGARDING ANTICIPATED PERFORMANCE FOR THE PPS FACILITY TURBINE

GE Power Systems

Douglas M. Todd
Manager – Process Power Plants

General Electric Company
1 River Road, Bldg. 2 - Room 720
Schenectady, NY 12345
518 385-3791 Fax 518 385-2590

November 7, 2000

Mr. Shannon K. Todd
Tampa Electric Co.
PO Box 111
Tampa, Florida 33601-0111

Dear Mr. Todd:

GE is pleased to support Tampa Electric in the effort to complete the BACT determination for the 107FA IGCC at Polk Power Station. We have reviewed in detail your submittal to the Florida Department of Environmental Protection and concur with the conclusions.

In 1995, GE developed special technology for IGCC combustors which was based on standard size 7FA diffusion combustors modified for specific quantities of diluent waste Nitrogen available from the Texaco gasification process. The goal was to lower NOx emissions from coal fired power plants below 25 ppmvd at 15 % oxygen without using extensive amounts of diluent water. As demonstrated by some of the test results, this effort was successful. However, due to fluctuations in ambient conditions, process parameters, and fuel characteristics, NOx emissions can vary greatly as seen in the wide range of measured results.

Since 1995, GE has continued with extensive combustion development in cooperation with gasification suppliers to lower NOx emissions further as shown in your report. The current state of the art requires additional diluent injection and larger size combustors to accommodate the added diluent.

Because we understand that there is no additional diluent available from the gasification process at Polk and SCR is not suitable for the sulfur levels of the syngas, we concur that 25 ppmvd NOx at 15% oxygen is a limit with which Tampa Electric Company can reasonably assure compliance at all times.

Douglas M Todd

Douglas M. Todd

E-mail douglas.todd@ps.ge.com

APPENDIX B

EMISSIONS TEST DATA, DETAILED SUMMARY AND STATISTICAL MEASURES

TECO Polk Power Station
NOx Emissions Test Data Summary

Test Date	NO_x Emission Factor (ppmdv) - average	Load (MW)	test 1	test 2	test 3
October 14, 1999	16.7	191	16.7	16.7	16.7
December 7, 1999	14.6	190	14.6	15.1	14.0
February 7, 2000	19.0	192	19.0	19.2	18.8
April 17, 2000	17.0	191	17.4	17.0	16.6
June 14, 2000	18.1	190	18.2	18.2	18.1
August 15, 2000	16.6	192	16.7	16.7	16.5
October 17, 2000	22.5	192	22.5	22.5	22.5
Average	17.80	191.14			
Median	17.00	191			
Range	8.50	2			
Median plus 1/2 range	21.25	192			
Std. Dev.	2.38	0.90			
Average + 2 sigma	22.55	N/A			
Average + 3 sigma	24.93	N/A			
Average + 6 sigma	32.06	N/A			
number of one hour tests	21				

Note: N/A = not an appropriate statistical measure for load, maximum load is established as 192 MW.

APPENDIX C

VENDOR INFORMATION FOR SCONO$_X$ SYSTEM

Environmental Consulting & Technology, Inc.

ABB ALSTOM
POWER

INTRODUCTION

ABB Alstom Power Environmental Systems (AAP) has licensed the SCONOx™ technology from Goal Line Environmental Technologies for NOx abatement on combined cycle gas turbines. Goal Line is involved in catalytic research and development, and has developed processes for the control of CO, VOC, NOx, and SOx emissions from combustion processes such as turbines, boilers and engines.

The SCONOx™ system is a breakthrough in control technology that greatly reduces NOx, CO and non-methane VOC emissions from exhaust streams without the use of ammonia. The system does not produce by-products that can coat boiler tubes, causing performance loss and corrosion. SCONOx™ also has the capacity to reduce emissions to lower levels as regulations change by simply adding more catalyst.

This ultra-clean technology is ideal for retrofit projects because of its wide operating temperature range (300°F to 700°F). This wide range offers maximum flexibility in unit location and allows for installation downstream of the HRSG. Retrofit installations do not require boiler splitting and installation can be accomplished in much less time as a result.

Because the inputs that are needed to run SCONOx™ (natural gas, water, steam, electricity, and ambient air) are already present at most power plants, the logistics of plant operation do not change when the system is installed.

Section 1

Process Details and Control

The SCONOx™ system is a breakthrough in pollution control technology that utilizes a single catalyst for the reduction of CO and NOx. The system uses no ammonia, and can operate effectively at temperatures ranging from 300°F to 700°F; making it well suited to both new and retrofit applications. Because the inputs that are needed to run SCONOx™ (natural gas, water, steam, and electricity) are already present at most power plants, the logistics of plant operation do not change when the system is installed.

Oxidation/Absorption Cycle

The SCONOx™ catalyst works by simultaneously oxidizing CO to CO_2, NO to NO_2, and then absorbing NO_2 onto its surface through the use of a potassium carbonate absorber coating. These reactions are shown below, and are referred to as the "Oxidation/Absorption Cycle".

$$CO + \tfrac{1}{2}O_2 \rightarrow CO_2$$
$$NO + \tfrac{1}{2}O_2 \rightarrow NO_2$$

$$2NO_2 + K_2CO_3 \rightarrow CO_2 + KNO_2 + KNO_3$$

The CO_2 in the above reactions exhausts up the stack. Note that during this cycle, the potassium carbonate coating reacts to form potassium nitrites and nitrates, which are then present on the surface of the catalyst. This reaction can be compared to a sponge absorbing water--just as a sponge absorbs water and must be wrung out periodically, the SCONOx™ catalyst must be regenerated to maintain maximum NOx absorption. The carbonate absorber coating on the surface of the catalyst absorbs nitrogen compounds, and the catalyst must enter the regeneration cycle.

Regeneration Cycle

The regeneration of the SCONOx™ catalyst, one of the features that makes the system so unique, is accomplished by passing a controlled mixture of regeneration gases across the surface of the catalyst in the absence of oxygen. The regeneration gases react with nitrites and nitrates to form water and elemental nitrogen. Carbon dioxide in the regeneration gas reacts with potassium nitrites and nitrates to form potassium carbonate, which is the absorber coating that was on the surface of the catalyst before the oxidation/absorption cycle began. This cycle is referred to as the "Regeneration Cycle", and the relevant reaction is shown below.

$$KNO_2 + KNO_3 + 4H_2 + CO_2 \rightarrow K_2CO_3 + 4H_2O + N_2$$

Water (as steam) and elemental nitrogen are exhausted up the stack instead of NOx, and potassium carbonate is once again present on the surface of the catalyst, allowing the oxidation/absorption cycle to begin again. There is no net gain or net loss of potassium carbonate after both the oxidation/absorption cycle and the regeneration cycle have been completed; the process operates as a true catalyst.

Because the regeneration cycle must take place in an oxygen free environment, a section of catalyst undergoing regeneration must be isolated from exhaust gases. This is accomplished using a set of louvers, one upstream of the section being regenerated and one downstream. During the regeneration cycle, these louvers close and a valve opens, allowing regeneration gas into the section. Tadpole seals on the isolation louvers provide a durable and effective barrier against leaks during operation. At any given time four of five of these sections are in the oxidation/absorption cycle and one of five are in the regeneration cycle. Because the same number of rows is always in the regeneration cycle, the production of regeneration gas always proceeds at a constant rate. A regeneration cycle typically is set to last for three to seven minutes, so each section is in the oxidation/absorption cycle for twelve to twenty eight minutes.

Regeneration Gas Production

The technology for producing a regeneration gas containing a dilute concentration of hydrogen from natural gas is well developed, and there are numerous reactions by which this can be accomplished. For installations below 450°F the SCONOx™ system uses an inert gas generator for the production of hydrogen and carbon dioxide. The regeneration gas will be diluted to under 4% hydrogen using steam as a carrier gas; the typical system is designed for 2% hydrogen. The appropriate reaction for producing regeneration gas is listed below.

$$CH_4 + \frac{1}{2}O_2 + H_2O \rightarrow CO_2 + 3H_2$$

For installations with operating temperatures greater than 450°F, the catalyst can be regenerated by introducing a small quantity of natural gas with a carrier gas, such as steam, over a steam reforming catalyst and then to the SCONOx™ catalyst. The reforming catalyst intiates the conversion of methane to hydrogen, and the conversion is completed over the SCONOx catalyst.

The Reformer Catalyst works to partially reform the methane regeneration gas to hydrogen (2% by volume) to be used in the regeneration of the SCONOx™ and SCOSOx™ catalysts. The reformer converts methane to hydrogen by the steam reforming reaction shown in the equation below.

$$CH_4 + 2H_2O \rightarrow 4H_2 + CO_2$$

The Reformer Catalyst is placed upstream of the SCONOx™ catalyst in a Steam Reformer Reactor. The catalyst is designed for a minimum 50% conversion of methane to hydrogen.

A gradual decrease in temperature is indicative of sulfur masking. To impede the rate of catalyst masking a Sulfur Filter is recommended. The Sulfur Filter is placed in the inlet natural gas feed prior to the regeneration production skid. The Sulfur Filter consists of impregnated granular activated carbon that is housed in a stainless steel vessel. Spent media is discarded as a non-hazardous waste.

SCOSOx™ Sulfur Removal Catalyst

The SCOSOx™ Sulfur Removal Catalyst works in conjunction with the SCONOx™ system and removes sulfur compounds from the exhaust stream. The SCOSOx™ Sulfur Removal Catalyst utilizes the same oxidation/absorption cycle and a regeneration cycle as the SCONOx™ system. However, SCOSOx™ selectively removes the sulfur from the exhaust stream. Chemical reactions for the SCOSOx™ system oxidation/absorption cycle are shown below.

$$CO + \tfrac{1}{2}O_2 \rightarrow CO_2$$
$$SO_2 + \tfrac{1}{2}O_2 \rightarrow SO_3$$

$$SO_3 + \text{SORBER} \rightarrow [SO_3 + \text{SORBER}]$$

For the SCOSOx™ process below 500°F, the reaction for the regeneration cycle is also similar to that of the SCONOx™ catalyst:

$$[SO_3 + \text{SORBER}] + 4H_2 \rightarrow H_2S + 3H_2O + [\text{SORBER}]$$

For the SCOSOx™ process above 500°F, the reaction for the regeneration cycle follows another similar path:

$$[SO_3 + \text{SORBER}] + H_2 \rightarrow SO_2 + H_2O + [\text{SORBER}]$$

Note that the regeneration gas used for the both types of catalyst (SCONOx™ and SCOSOx™ is the same (hydrogen), allowing them to be regenerated simultaneously. The SCOSOx™ catalyst is placed upstream of the SCONOx™ catalyst, and enhances the efficiency of NOx absorption as well as removing sulfur compounds.

SCONOx™ Control System

A Programmable Logic Controller (PLC) controls the SCONOx™ system. This controller is programmed to control all essential SCONOx™ functions, including the opening and closing of louver doors and regeneration gas inlet and outlet valves, and the maintaining of regeneration gas flow to achieve positive pressure in each section during the regeneration cycle.

A control program run on a PC, supervises the system. The control program monitors, records, and reports system performance. It sends notifications and warnings when appropriate, and it allows the user to control the system by changing set points, such as pressures, regeneration cycle times, and flows. The PLC can, however, operate independently of the control program--a PC crash or loss of power will not interrupt the operation of the system.

Section 2

Project Scope

The AAP Environmental Systems Scope of Supply for execution of the Project will include services and equipment as described below. In general, the Scope of Supply can be defined by the following categories:

Process Design, Engineering and Design of the System
Project Management and Project Services
SCONOx™ and SCOSOx™ Catalyst
Catalyst Rack and Reactor Housing
Inlet and Outlet Transitions including Expansion Joints
Catalyst Module Inlet and Outlet Dampers
Regeneration Gas Production and Distribution
Regeneration Gas Condensing and Scrubbing System (Optional)
Catalyst Removal System
Control System (PLC)

Equipment and Services Provided by Others

All required permits (air, site, construction, etc.)
Supply of 480 volt power to the SCONOx system
Supply of natural gas for the SCONOx system
Supply of cooling water for the SCONOx system
Supply of 600 degree steam for the SCONOx system
Supply of compressed air for the SCONOx system
Supply of Continuous Emission Monitoring System
Mechanical Installation of the System
Electrical Installation of the System

Section 3

Equipment List

SCONOx™ Reactor Assembly

The installation will have a SCONOx™ reactor assembly that will be constructed of sub-assembled modules to form the complete assembly.

Each section will have a set of dampers, front and back, to be closed when the section is in regeneration mode. Dampers will have tadpole seals to help isolate the section during regeneration. Each section will have one inlet regeneration gas valve and two outlet regeneration gas valves, which will open sequentially when the section is in regeneration mode. Two sections will be in the regeneration cycle at any given time.

Regeneration Gas Mixing Assembly

The Regeneration Gas Mixing Assembly will contain all pressure reducing valves, flow meters, and other equipment necessary to ensure the correct ratios of inert gas and steam that are introduced into the SCONOx™ catalyst.

Regeneration Gas Distribution Piping and Valves

The regeneration gas is piped to the reformer catalyst and then to the reactor via a main header and distributed to each of the ten sections of catalyst. Each catalyst section has one inlet regeneration gas valve and two outlet regeneration gas valves at the gas entrance side of the catalyst section.

SCONOx™ Catalyst

The SCONOx™ catalyst is a proprietary catalyst manufactured by Goal Line, which simultaneously oxidizes and absorbs CO and NOx through the use of a potassium carbonate absorber coating.

SCOSOx™ Catalyst

The SCOSOx™ catalyst is very similar to the SCONOx™ catalyst, and is also manufactured only by Goal Line. The SCOSOx™ catalyst favors the absorption of sulfur compounds instead of NOx, and works to enhance the efficiency of the SCONOx™ process in the removal of NOx. SCOSOx™ catalyst blocks have the same cross-sectional dimensions as SCONOx™ blocks, but will not be as deep.

Catalyst Removal System

The catalyst is removed and replaced using a service platform, which is raised and lowered to any one of the catalyst shelves. A mechanical winch is used to pull the catalyst in and out of the selected shelf.

Control System

A programmable logic controller (PLC) runs the control system with inputs made from a PC. The PLC controls all aspects of operation for the SCONOx system. The control system is shipped pre-wired and factory tested to the extent possible. All interconnecting wiring between the control panel and the field instruments is by others.

APPENDIX D

VENDOR QUOTES FOR COMPARABLE CONTROL EQUIPMENT

ENGELHARD

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

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

DATE:	October 25, 2000	NO. PAGES	3
TO:	ECT ATTN: John Shrock ENGELHARD ATTN: Nancy Ellison	via e-mail	
FROM:	Fred Booth	Ph 410-569-0297 // FAX 410-569-1841	

RE: **ECT 000610-0200**
Camet® CO and NOxCAT™ VNX™ SCR Catalyst Systems
Engelhard Budgetary Proposal EPB00990

We provide Engelhard Budgetary Proposal EPB00990 for Engelhard **Camet®** CO and **NOxCAT™ VNX™** vanadia-titania SCR Catalyst systems per your e-mail request of October 23, 2000.

Our Proposal is based on:

- CO Catalyst for 80% CO reduction;
- SCR Catalyst for NOx reduction from given inlet levels to 3.5 ppmvd @ 15% O_2 with ammonia slip of 5 ppmvd @ 15% O_2 ; We note your request for design with ammonia slip of 9 ppmvd @ 15% O_2. There will be only minor changes to data herein.
- Assumed HRSG inside liner dimensions of 67 ft. H x 26 ft. W;
- Assumed 19% aqueous ammonia to ammonia skid;
- Scope as noted: Typical to HRSG supplier

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

Sincerely yours,

ENGELHARD CORPORATION

Frederick A. Booth

Frederick A. Booth
Senior Sales Engineer

4

ENGELHARD CORPORATION
CAMET® CO CATALYST SYSTEM
NOxCAT™ VNX™ SCR NOx ABATEMENT CATALYST SYSTEM

Engelhard Corporation ("Engelhard") offers to supply to Buyer the **Camet®** metal substrate CO System and **NOxCAT™ VNX™** ceramic substrate SCR systems summarized per the technical data and site conditions provided.

Scope of Supply: The equipment supplied is installed by others in accordance with Engelhard design and installation instructions.
Engelhard **Camet®** CO and **NOxCAT™ VNX™** SCR catalyst in modules;
Internal support frames for catalyst modules - installed inside internally insulated casing (casing by others);
Ammonia Delivery System Components: Aqueous (19% Sol.) Ammonia to skid
- Ammonia Injection Grid (AIG);
- AIG manifold with flow control valves ;
- NH_3/Air dilution skid: Pre-piped & wired (including all valves and fittings)
  - Two (2) dilution air fans, one for back-up purposes
  - Panel mounted system controls for:
  - Blowers (on/off/flow indicators)
  - Air/ammonia flow indicator and controller
  - System pressure indicators
  - Main power disconnect switch

BUDGET PRICES: **Per Turbine** **See Performance data**

Excluded from Scope of Supply:
Ammonia storage and pumping
Any transitions to and from reactor
Electrical grounding equipment
Foundations
Internally insulated reactor Housing (HRSG Casing)
Any interconnecting field piping or wiring
Utilities
All Monitors
All other items not specifically listed in Scope of Supply

WARRANTY AND GUARANTEE:

Mechanical Warranty:	One year of operation* or 1.5 years after catalyst delivery, whichever occurs first.
Performance Guarantee:	Three (3) Years of operation* or 3.5 years after catalyst delivery, whichever occurs first. Catalyst warranty is prorated over the guaranteed life.
Expected Life	5 - 7 years

CO / SCR SYSTEM DESIGN BASIS:

Gas Flow from:	Combustion Turbine + Duct Burner
Gas Flow:	Horizontal
Fuel:	Natural Gas
Gas Flow Rate (At catalyst face):	See Performance data - Designed for Gas Velocities within $\pm$15% at the reactor inlet
Temperature (At catalyst face):	Designed for Gas Temperature with maximum range $\pm 20^{\circ}F$ at the reactor inlet
CO Inlet (At catalyst face):	See Performance Data
CO Reduction	80% Reduction
NOx Inlet (At catalyst face):	See Performance Data
NOx Reduction :	To 3.5 ppmvd @ 15% O_2 (NG)
NH_3 Slip:	5 ppmvd @ 15%O_2
HRSG Cross Section	67 ft. H x 26 ft. W

ENGELHARD

ECT 000610-0200
CO and SCR Catalyst Systems
Engelhard Budgetary Proposal EPB00990
October 25, 2000

Performance Data and Budget Pricing

GIVEN / CALCULATED DATA	100% - FIRED	100% - UNFIRED	75% - UNFIRED	65% - UNFIRED
TURBINE EXHAUST FLOW, lb/hr	3,515,500	3,484,300	2,886,000	2,628,300
TURBINE EXHAUST GAS ANALYSIS, % VOL. N2	74.43	74.52	74.64	74.72
O2	12.46	12.75	13.15	13.36
CO2	3.82	3.69	3.51	3.41
H2O	8.42	8.17	7.82	7.63
Ar	0.87	0.87	0.88	0.88
GIVEN: TURBINE CO, ppmvd @ 15% O2	10	10	10	10
CALC.: TURBINE CO, lb/hr	39.3	37.5	29.5	26.1
GIVEN: TURBINE NOx, ppmvd @ 15% O2	35	35	35	35
CALC.: TURBINE NOx, lb/hr	225.7	215.7	169.4	149.9
BURNER INPUT, MMBtuh	95	0	0	0
BURNER CO ADDED, lb/MMBtuh	0.09	0.09	0.09	0.09
BURNER CO ADDED, lb/hr	8.2	0.0	0.0	0.0
BURNER NOx ADDED, lb/MMBtuh	0.08	0.08	0.08	0.08
BURNER NOx ADDED, lb/hr	7.6	0.0	0.0	0.0
TOTAL GAS FLOW AFTER BURNER, lb/hr	3,520,052	3,484,300	2,886,000	2,628,300
GAS ANALYSIS AFTER BURNER, % VOL. N2	74.26	74.52	74.64	74.72
O2	11.98	12.75	13.15	13.36
CO2	4.04	3.69	3.51	3.41
H2O	8.85	8.17	7.82	7.63
Ar	0.87	0.87	0.88	0.88
CALC. GAS MOL. WT. AFTER BURNER	28.36	28.40	28.43	28.44
TOTAL CO AFTER BURNER, lb/hr	47.5	37.5	29.5	26.1
TOTAL CO AFTER BURNER, ppmvd @ 15% O2	11.4	10.0	10.0	10.0
TOTAL NOx AFTER BURNER, lb/hr	233.3	215.7	169.4	149.9
TOTAL NOx AFTER BURNER, ppmvd @ 15% O2	34.1	35.0	35.0	35.0
FLUE GAS TEMP. @ CO and SCR CATALYST, F (+/-20)	650	650	650	650
DESIGN REQUIREMENTS				
CO CATALYST CO OUT, ppmvd @ 15% O2	3.0	3.0	3.0	3.0
SCR CATALYST NOx OUT, ppmvd @ 15% O2	3.5	3.5	3.5	3.5
NH3 SLIP, ppmvd @ 15% O2	5	5	5	5
GUARANTEED PERFORMANCE DATA				
CO CATALYST CO CONVERSION, % - Min.	80.0%	80.0%	80.0%	80.0%
CO OUT, lb/hr - Max.	9.5	7.5	5.9	5.2
CO OUT, ppmvd @ 15% O2 - Max.	2.3	2.0	2.0	2.0
CO PRESSURE DROP, "WG - Max.	0.6	0.6	0.5	0.4
SCR CATALYST NOx CONVERSION, % - Min.	89.7%	90.0%	90.0%	90.0%
NOx OUT, lb/hr - Max.	24.0	21.6	16.9	15.0
NOx OUT, ppmvd @ 15% O2 - Max.	3.5	3.5	3.5	3.5
EXPECTED AQUEOUS NH3 (19% SOL.) FLOW, lb/hr	458.4	437.4	343.7	304.1
NH3 SLIP, ppmvd @ 15% O2 - Max.	5	5	5	5
SCR PRESSURE DROP, "WG - Max.	2.7	2.7	2.1	1.9

CO SYSTEM	**$585,000**
REPLACEMENT CO CATALYST MODULES	**$483,000**
SCR SYSTEM	**$1,738,000**
REPLACEMENT SCR CATALYST MODULES	**$1,250,000**

Dear Mr. Shrock,

Please note the following in response to your inquiry of last week, requesting budget pricing for two SCONOx systems on S-W V84.3a2 CCGTs. Pricing provided is on a per unit basis.

The specified temperature range was 300 to 700 degrees F. We have assumed an operating temperature of 600 degrees F, consistent with typical SCR operating temperatures. Should the temperature be significantly lower than 600 F, additional catalyst may be required.

The NOx emission reduction from 35 to 2 ppm is more than the typical application with 25 ppm or less NOx emissions. This reduction efficiency requirement of 95% results in additional catalyst, and this is reflected in the cost.

The SCONOx system will reduce CO emissions by 90%, so the system will exceed the specified CO reduction requirement, at no additional cost.

Leasing of the catalyst utilized in the SCONOx system is our preferred commercial framework, as this reduces the initial cost and provides our customers with a long-term commitment by ALSTOM Power for the performance of the SCONOx system. In this arrangement, the physical and mechanical equipment only is sold, and the required catalyst is leased on a long term basis, complete with catalyst and equipment maintenance.

Budgetary numbers for the leasing program include $7 million dollars for the initial equipment, with a annual lease cost of $2.5 million dollars. These numbers are budgetary only and are subject to change pending resolution of technical, scope, and commercial terms.

The budgetary price for the supply of the complete system, in accordance with the information provided, including catalyst, based on the prevailing price of platinum, is $20 million dollars.

I trust this meets with your immediate needs, but please call me if you have any questions.

Sincerely,

Rick Oegema
Product Manager

(Embedded image moved to file: pic22424.pcx)	jshrock@ectinc.com 10/16/2000 09:45 AM

Please respond to jshrock@ectinc.com