Department of Environmental Protection

Jeb Bush
Governor

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3900 Commonwealth Boulevard
Tallahassee, Florida 32399-3000

David B. Struhs
Secretary

February 23, 2000

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, 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, other similar facilities, 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 natural gas fired 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 might be at the CPV Gulf Coast facility does not seem to take into account environmental, energy, and other costs as prescribed in the definition of BACT. In addition, this conclusion does not seem to consider the operation of 'other similar facilities' or 'manufacturer's research' as called for in Specific Condition A.50 of the Polk Power Station Title V Permit.

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.

April 21, 2000

NO$_x$ CONTROL ON COMBINED CYCLE TURBINES
Issues Regarding Best Available Control Technology for Low NOx Turbines

Introduction

This paper is a review of issues brought to EPA's attention as a result of several recent controversies involving state permitting agencies, utilities, and turbine manufacturers over appropriate best available control technology (BACT) controls for NO$_x$ at natural gas combined cycle turbines for electric power generation. Selective Catalytic Reduction (SCR) has been considered BACT for limiting NO$_x$ emissions on many natural gas combined cycle turbines in ozone attainment areas. Some have argued that dry low NO$_x$ (DLN) turbines, manufactured by GE Company, should not need to apply SCR in attainment areas Even though SCR, when used with dry low NO$_x$ turbines would limit NO$_x$ emissions to below the level of a dry low NO$_x$ turbine alone, they argue that it may be environmentally preferable to operate these turbines without SCR. The cost of SCR may mean that, if these turbines must use SCR, more electricity will be produced by dirtier plants and therefore total NO$_x$ emissions would increase, not decrease. Further some have argued that the ammonia that is required for SCR to operate has its own set of environmental problems that outweigh any benefit of the small increment of NO$_x$ reduction that is achieved by putting SCR on dry low NO$_x$ turbines. Also, the dry low NO$_x$ turbine is a pollution prevention technology that limits NO$_x$, formation unlike SCR which is designed to control NO$_x$ that has been formed. Preventing pollution rather than controlling it is the Agency's and the Federal government's stated preference.

Pollution control technologies and NO$_x$ control technologies specifically are evolving rapidly. New technologies that may eventually replace SCR are already becoming available and a new generation of combined cycle turbines is being designed. Each will have its own set of issues that may make them more or less suitable for a given plant and location when they are used in an ozone attainment area A site specific BACT analysis is meant to allow the permit applicants and permitting authorities an opportunity to review those issues. This paper reviews the issues that have been raised concerning SCR and dry low NO$_x$ turbines and provides information that would be useful to consider in making BACT determinations that will achieve the most benefit for the public.

Background NO$_x$ Control

Combined cycle natural gas turbines that are widely available today produce less NO$_x$ than other types of fossil fuel electricity generating plants GE will conditionally guarantee that its DLN turbines will emit no more than 9 parts per million (ppm) of NO$_x$. Other manufacturers' turbines typically emit up to 25 ppm NO$_x$ and are usually permitted at between 2.5 ppm and 4.5 ppm with SCR. A GE DLN turbine with SCR will also emit NO$_x$ in the 2.5 ppm to 4.5 ppm range. Exhibit 1 compares these emission concentrations to emission rates in units of tons of

NO_X per year for typical 200 MW power plants operating at 100% load for 80% of the year. Exhibit 1 also compares the emission concentrations and emission rates of combined cycle natural gas plants to those for coal fired power plants of the same generating capacity that are uncontrolled and those that comply with the 1998 SIP call's levels of NO_x control.

Exhibit 1
NO_x Emissions
Representative 200MW Coal and Natural Gas Combined Cycle Power Plants

Plant Type/ NO_x Emissions	*Approximate NO_x Concentration (ppm)*	*Approximate Tons of NO_x Emitted per Year*
Existing Uncontrolled Coal Plant	240	3000
Coal Plant with SIP Call Level of Control	90	1100
F Class Natural Gas Combined Cycle Plant without SCR	25	140
F Class Natural Gas Combined Cycle Dry Low NO_x, without SCR	9	50
F Class Natural Gas Combined Cycle with SCR	3.5	20

SCR is a widely used technology for controlling NO_x emissions from a wide variety of stationary combustion sources. SCR selectively reduces NO_x emissions by injecting ammonia into the exhaust gas upstream of a catalyst where the NO_x reacts with the ammonia and oxygen to form N_2 and water. SCR is most effective within a certain temperature range and higher or lower temperatures and other operating conditions can cause some of the NO_x and ammonia to pass through the catalyst without reacting. Catalysts degrade eventually and that also can cause ammonia to pass through the catalyst unreacted.

The ammonia that is emitted is called the ammonia slip. Plant operators can minimize the ammonia slip by replacing catalyst as it degrades. Some states specify a limit for the ammonia slip, usually between 5 ppm and 10 ppm, in permits for combined cycle natural gas turbines. Plants operate well below the limit for most of time they are operating so as not to exceed the permitted limit.

NO_x control technology is evolving. Recently ABB Alstom Power announced the availability of SCONOX , a NO_x control technology that does not depend on ammonia. This technology is currently expensive and it has not yet been used on large combined cycle natural gas turbines.

BACT in the Clean Air Act: the Legal Background

Best available control technology, or BACT, is required for new or modified major sources in order to prevent significant deterioration of air quality in attainment areas.[1] The Clean Air Act allows permitting authorities to weigh environmental, energy and economic concerns against the proven environmental benefits of technologies such as SCR in making BACT determinations in order to determine whether a less effective technology for NO_x control is warranted in specific cases. See In re Kawaihae Cogeneration Project, 7 E.A.D. 107 at 115-119 (EAB 1997).

The Clean Air Act defines "best available control technology," or BACT, as

> [A]n emission limitation based on the maximum degree of reduction of each pollutant subject to regulation under this chapter emitted from or which results from any major emitting facility, which the permitting authority, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such facility. 42 U.S.C. § 7479(3).

Taking these "collateral" impacts into account, the permitting authority may reject the most effective control technology as BACT, but only in limited circumstances. In re Columbia Gulf Transmission Co., 2 E.A.D. 824, 827 (Adm'r 1989)("[T]he collateral impacts clause operates primarily as a safety valve whenever unusual circumstances specific to the facility make it appropriate to use less than the most effective technology."); In re World Color Press, Inc., 3 E.A.D. 474, 478 (Adm'r 1990) ("[T]he collateral impacts clause focuses upon specific local impacts which constrain a particular source from using the most effective control technology."). More specifically, with respect to the consideration of collateral environmental impacts, the Environmental Appeals Board has explained that the definition of BACT has been interpreted to mean that "if application of a control system results directly in the release (or removal) of pollutants that are not currently regulated under the Act, the net environmental impact of such emissions is eligible for consideration in making the BACT determination." Kawaihae, 7 E.A.D. at 116, citing In re North County Resource Recovery Associates, 2 E.A.D. 229, 230 (Adm'r 1986).

A decision by a permitting authority to reject the most effective control technology, due to environmental concerns, must be based on sound evidence that the environmental concerns associated with the use of this technology outweigh the benefits. Thus for, example, in Kawaihae, the EAB rejected a claim "that purely hypothetical catastrophic failure of the SCR ammonia system...warrants further consideration as a 'collateral environmental impact' in [the State's] BACT analysis." 7 E.A.D. at 117. The State had considered the risks associated with the use of ammonia and found them to be minimal. The EAB, also found that the source must use

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[1] In non- attainment areas new and modified sources have to meet a different standard, Lowest Achievable Emissions Rate, or LAER, which is not discussed in this paper.

the most effective technology unless it is demonstrated to the permitting authority's satisfaction that unique circumstances specific to the facility would make the use of that technology inappropriate. Similarly, the New Source Review Workshop Manual (Draft 1990) makes clear that if a control technology has been applied to similar facilities elsewhere, it may still be rejected as BACT if the permit applicant can show that unusual circumstances at the proposed facility create greater problems than experienced elsewhere.[2] In the same way, if the permit applicant can convincingly show evidence that the environmental impacts associated with a control technology outweigh the benefits, that can be taken into account in the BACT determination. Thus, a permitting authority could appropriately conclude that BACT in a specific case was DLN turbines without additional controls for a combined cycle gas turbine if a case-by-case assessment of the environmental, energy, and economic impacts demonstrates that the collateral environmental impacts associated with a control technology such as SCR outweighed the benefits of additional NOx reduction.

Pollution Prevention and DLN Turbines

The Pollution Prevention Act of 1990 made pollution prevention a national policy goal.[3] The 1990 Act asserts that reducing pollution is fundamentally different from and preferable to controlling emissions. This policy is affirmed in the Administrator s Policy Statement on Pollution Prevention, which states that "pollution should be prevented or reduced at the source whenever feasible" and cites the importance of encouraging the private sector to commit resources to pollution prevention.[4] In the long run, encouraging continued investment in the development of pollution prevention technology may have a very important environmental benefit.

GE's DLN turbines are the result of the type of private industry investment that the Agency seeks to encourage. The DLN turbines were developed in cooperation with the U.S. Department of Energy (DOE) with the specific goal of achieving acceptably low emissions without the use of post-combustion controls. The goals of the DOE program were to develop a turbine with less than 10 ppm of NO_X emissions. Protection of public health and the environment is of paramount concern, but the potential future public health and environmental benefits of encouraging the development of cleaner technology, such as the DLN turbines, merits attention.

Displacement and the Aggregate Effects on National NO_x Emissions

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[2] U.S. EPA, NSR Draft Manual at B.47.

[3] 44 U.S.C.§§13101(a) (4).

[4] Carol M. Browner, *New Directions for Environmental Protection,* US EPA, June 15, 1993.

The national implications of requiring SCR on combined cycle turbines can be analyzed with the Integrated Planning Model (IPM)[5]. EPA's Office of Air and Radiation published a report in March of 1999, that used the IPM to examine emissions of NO_x, SO_2, CO_2, and mercury from the electric power industry under a set of hypothetical pollution control scenarios.[6] In the course of that effort, an analysis was made comparing the total NO_x emissions across the country with and without a requirement that SCR be used on combined cycle gas turbines.[7] The results of the analysis for the year 2010 are shown below in Exhibit 2.

Exhibit 2
2010 Annual National Capacity, Generation and NO_x Emissions With and Without SCR on Combined Cycle Natural Gas Units

	SCR Required	*SCR Not Required*
Total CC capacity (MW)	112,161	115,224
Total coal, oil and gas steam capacity (MW)	473,397	470,486
Total CC generation (GWh)	622,008	634,475
Total coal, oil and gas steam generation (GWh)	2,251,443	2,238,869
Total NO_x emissions	4,147,240	4,132,113

The analysis forecasted slightly lower NO_x emissions nationally from all utility sources when SCR is not required for new combined cycle gas turbines. When SCR is required, less combined cycle capacity is constructed and less existing combined cycle capacity is used for generation. Thus, more power is generated by higher emitting sources and total NO_x emissions are higher when combined cycle gas plants are required to use SCR.

We see these effects for two reasons. First adding SCR to a natural gas combined cycle turbine increases its capital costs. The increase is modest and therefore has a modest effect on the number of units built. Also, SCR adds to a unit's variable operating costs, and therefore increases the cost of generating electricity at that unit. Because electric power is dispatched in order of the least expensive power first, any increase in operating costs is reflected in a lower dispatch order so that the generating unit is run less often and the difference is made up by another unit that is less expensive to operate. Often these less expensive plants emit more NOx

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[5] The Integrated Planning Model predicts the actions of power plant operators over time in response to alternative levels of air pollution controls. It was developed by ICF Resources as a commercial capacity planning tool and for policy applications over wide geographic areas or for the entire country. EPA has used this model extensively to analyze the emissions reductions and costs for the electric power industry under a variety of policy options.

[6] EPA.1999. *Analysis of Emissions Reduction Options for the Electric Power Industry*, Office of Air and Radiation, Washington, DC, March 1999. Available at the web site: *www.epa.gov/capi.*

[7] The results of that analysis, presented here, were not included in the published report.

and other fine particle precursors than natural gas combined cycle generation with or without SCR.

The results shown in Exhibit 2 could vary if different assumptions are used and the results presented here are not offered as hard evidence that requiring SCR is having a negative effect on NO_x emissions nationally.[8] But these results do suggest that a policy that requires these relatively low NO_x emitting sources to apply SCR does not necessarily reduce national NOx emissions. Rather it may reduce the amount of combined cycle capacity and generation in favor of other less clean existing generation which could, on a national basis increase, or at least not decrease, NO_x emissions. Generally, natural gas combined cycle generation also produces lower levels of other pollutants than the generation it displaces, including lower SO_2, mercury and CO_2 emissions. So a policy that limits the use of this lower emitting generation would have a negative impact on air quality nationally from that perspective as well.

The results discussed consider national emission levels. Locally, in areas where new natural combined cycle units are built, emissions of NO_x may increase or not depending on the extent to which the new plant is displacing existing capacity and whether the displaced capacity is local or more distant. Thus, locally, requiring SCR on combined cycle units may reduce NO_x emissions.

Furthermore, the relationship between NOx emissions and ozone formation is not linear. Smaller sources of NO_x emissions are more efficient at producing ozone than are large sources of NO_x. The difference in emissions is larger than the difference in ozone formation.[9] So the analysis presented here may overstate the air quality benefit of not requiring SCR on combined cycle turbines.

It is useful to keep these issues in mind when considering the more site specific environmental considerations, discussed below, that may affect a BACT determination.

Site Specific Tradeoffs of NO_X and Ammonia Emissions

In making a case-by-case BACT determination, the permitting authority must weigh the environmental impacts of the various control options. In the case of DLN turbines with and without SCR, the change in NO_X emissions (approximately 5.5 ppm of NO_X) is small in comparison to NO_X emissions from other types of combustion power plants, and therefore, it is

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[8] Among the assumptions used for this analysis is that sources will have complied with federal regulations that had been promulgated at the time the report was published including phase two of the acid rain program and the NO_x SIP call. For a full discussion of the assumptions used in the study see the study or *www.epa.gov/capi.*

[9] Ryerson, T.B., M.P. Buhr, and F.C. Fehsenfeld (1998). Journal of Geophysical Research, D. Atmospheres, 103(17):22569. September 20, 1998.

important to compare the impacts from this increment of NO_X emissions to the small amount of ammonia slip emissions that result from the use of SCR (often less than 5 to 10 ppm of ammonia).

The tradeoffs between NO_X and ammonia emissions are not simple. Both NO_X and ammonia are acutely toxic; both contribute to fine particle formation, acidifying deposition, eutrophication, and enrichment of terrestrial soils; and both may be converted to nitrous oxide (N_2O), a powerful greenhouse gas. In addition, NO_X (as NO_2) is a chronic toxin and an essential precursor for the formation of tropospheric ozone. The contribution of NO_X or ammonia emissions from a single facility to any of these environmental problems is primarily determined by existing levels of NO_X and ammonia in the area of a source and the availability of other pollutants in the atmosphere that react with and transform the emitted oxidized or reduced nitrogen.

With respect to comparing the incremental impact of a new source to the overall inventory of NO_X or ammonia emissions, it is important to realize that the emissions inventories of both pollutants are not of equal quality. While NO_X emissions and ambient concentrations are measured routinely, there is little data available on ambient ammonia concentrations and the emission inventories for ammonia are highly uncertain. Agricultural operations are the largest source of ammonia emissions nationwide, however urban areas may have significant ammonia emissions from industrial sources, as well as from catalyst equipped automobiles.[10]

Each of the potential environmental problems associated with NO_X and ammonia emissions is discussed qualitatively below.

Tropospheric Ozone

NO_X is an essential precursor to the formation of ozone, which is formed through a series of reactions of NO_X and volatile organic compounds (VOCs) in the presence of sunlight. More specifically, ozone is formed through the photolysis of NO_2 to NO. Instead of playing a direct role in the formation of ozone, the presence of VOCs affect the efficiency with which NO_X forms ozone. VOCs are oxidized in a chain of reactions that recycles NO to NO_2 so that it can be photolyzed again. The efficiency of this system of reactions (i.e., the number of ozone molecules produced per molecule of NO_2) is largely a function of the amount and composition of the VOCs that are present and the availability of sunlight. This photochemical recycling continues until the NO_X is converted to nitric acid (HNO_3) or an organic nitrate, such as peroxyacetylnitrate (PAN).

While nitric acid readily deposits on surfaces or dissolves in cloud or fog water droplets, PAN is relatively inert and can be transported long distances before thermally decomposing to

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[10] Fraser and Cass (1998) demonstrated that catalyst-equipped automobiles in the South Coast Air Basin surrounding Los Angeles emit between 24 and 29 tons of ammonia per day, which is 11-18% of the total ammonia emissions and equivalent to the emissions from all of the livestock operations in the Basin. Environmental Science and Technology, 32(8):1053-1057.

recreate NO_2. Thus, PAN acts as a “reservoir species” that allows the nitrogen to be transported over 100's of kilometers, projecting the impact of emissions regionally, far beyond the immediate source area.

The impact of NO_X emissions on ozone concentrations are functions of the levels of NO_X, VOCs, and sunlight that are available, and the impacts may be different on the local scale than on the regional scale. As noted above, the efficiency of ozone formation in small NO_X plumes is greater than that in large NO_X plumes, such that a small emission source may produce the same peak concentration that results from a larger emission source. Thus, the nonlinearity of photochemistry can require large NO_X emission decreases to achieve small improvements in ozone air quality. In ozone nonattainment areas and attainment areas that are immediately upwind of nonattainment or Class I areas, the impact of NO_X emissions on regional ozone concentrations should be an important consideration in any permitting decision.

Fine Particles

Both NO_X and ammonia emissions contribute to the formation of fine particles. As the primary chemical base in the atmosphere, the primary fate of ammonia is the neutralization of acids either in the gas, liquid, or particle phase. Ammonia reacts preferentially with acid sulfate aerosols, which are formed from the oxidation of SO_2 emissions. The acid sulfate aerosols, which may contain sulfuric acid or ammonium bisulfate, react with ammonia to form ammonium sulfate particles, $(NH_4)_2SO_4$. This reaction increases the mass of the sulfate particles and increases the rate of formation of particles by increasing the rate of SO_2 oxidation.[11] Ammonium sulfate is the dominant form of ammonium aerosols and a primary constituent of fine particle concentrations in many parts of the U.S., particularly in the East.

Ammonia also reacts with nitric acid, derived from NO_X emissions, to form ammonium nitrate particles, NH_4NO_3. In areas where SO_2 emissions are low, as in some areas of the West, ammonium nitrate particles are the dominant component of fine particle concentrations. Ammonium nitrate formation is more prevalent under cooler and drier conditions and, thus, plays an important role in visibility impairment during the winter months. Under these conditions, fine particles can be decreased by controlling either the NO_X or the ammonia emissions, whichever is more limiting. In ammonia-rich areas, controlling ammonia has little effect on fine particle formation, and NO_X control has more of an impact.[12] However, in some situations, fine particle

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[11] See Weber, R.J., et al., (1999). Geophysical Research Letters, 26:307-310.

[12] The Northern Front Range Air Quality Study showed that the Denver area was so ammonia-rich that a 50% decrease in ammonia emissions would result in only a 15% decrease in fine particle formation and a doubling of ammonia emissions would have a negligible effect. [Watson, J.G., et al. (1998). *Northern Front Range Air Quality Study Final Report*. Reno, NV: Desert Research Institute.]

concentrations may exhibit nonintuitive sensitivities to NO_X controls due to the linkage between nitric acid formation and the complex oxidant photochemistry described above.[13]

While both nitric acid and ammonia readily deposit on surfaces or dissolve in cloud or fog water, ammonium nitrate and ammonium sulfate do not deposit as quickly. Therefore, once the NO_X or ammonia has been converted to fine particles, it may be transported much farther downwind.

The sensitivity of particle formation to changes in ammonia is dependent on the ambient concentrations of ammonia, nitric acid, and sulfate, as well as relative humidity and temperature. In urban areas where the ambient concentrations of sulfuric acid, from SO_2 emissions, or nitric acid, from NO_X emissions, are high, and ammonia emissions are relatively low, ammonia emissions are likely to increase fine particle formation. In rural areas where sulfuric and nitric acid concentrations are low and ammonia emissions are high, an incremental increase in ammonia emissions may have little impact on fine particle formation.

Acidifying Deposition

In the atmosphere, NO_X contributes to the formation of acid aerosols, while ammonia neutralizes atmospheric acidity. Once deposited, however, both NO_X and ammonia contribute to the acidification of terrestrial soils and surface waters.

While sulfuric acid derived from SO_2 emissions is the most important contributor to chronic acidification in the eastern U.S., nitric acid, derived from NO_X emissions, is a significant contributor to dry or wet acidic deposition nationwide. The relative importance of nitric acid deposition as compared to sulfuric acid deposition varies according to geographic location, season, and nature of the acidifying event. In general, nitric acid is a more important contributor to acidification in the West than in the East, and more important during winter than in summer. Nitric acid is also the primary contributor to episodic acidification regardless of location and season.[14]

As noted above, ammonia reacts with acids in the atmosphere to form neutral ammonium nitrates and ammonium sulfates. Once deposited on soils, ammonium ions are converted to nitrates by soil microbes in a process known as nitrification. This process releases hydrogen ions, increasing the acidity of the soil. On a molar basis, ammonium deposition on soil is more acidifying than nitric (or even sulfuric) acid deposition. Thus, the deposition of base cations,

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[13] Pun, Betty K. and Christian Seigneur (1999). *Sensitivity of PM Nitrate Formation to Precursor Emissions in the California San Joaquin Valley* (Draft). San Ramon CA: Atmospheric and Environmental Research Inc. for Pacific Gas and Electric Company, CP045-4-99.

[14] U.S. EPA (1995) Acid Deposition Standard Feasibility Study Report to Congress. Washington DC: Office of Air and Radiation, EPA 430-R-95-001a.

such as ammonium, may play as important if not more important a role in the acidification of soils than the deposition of acidic anions, such as sulfate and nitrate.

When deposited on water, ammonia or ammonium ions may stay in solution as ammonium ions, be taken up directly by aquatic plants, undergo microbial nitrification contributing to acidification, or undergo subsequent microbial denitrification increasing the pH of the water. Any nitrogen input into an aquatic system will have an effect on the alkalinity, or acid neutralizing capacity, of the water. However, the direction and magnitude of the effect is dependent on the chemical and physical properties of each water body. The nutrient effects of nitrogen deposition are discussed in the following section.

When considering the impacts of acidifying deposition, it may be more important to limit emissions of ammonia than to limit emissions of NO_X, given the acidifying effects of the nitrification of ammonium.

Nitrogen Deposition and Eutrophication

When oxidized or reduced nitrogen is deposited on soils or surface waters, the nitrogen serves as a biological fertilizer, regardless of whether the nitrogen came from NO_X or ammonia emissions, respectively. In surface waters, nitrogen deposition stimulates the growth of organic matter, an effect known as eutrophication. The results of eutrophication include the growth of algal blooms and the depletion of dissolved oxygen, both of which can be toxic to higher marine and estuarine plants and animals. Similar effects occur in terrestrial ecosystems when nitrogen supply exceeds plant and microbial demand. Nitrogen saturation of soils may lead to impacts on vegetation including changes in the uptake of nutrients, increased acidification, increased susceptibility to damage or attack, altered reproductive processes, and ultimately, changes in species composition and diversity. While the speed and mechanisms by which aquatic or terrestrial biological systems make use of the nitrogen may differ depending on whether the nitrogen is in oxidized or reduced form, the overall fertilization effect is the same. Thus, on the basis of these impacts, the tradeoff between NO_X and ammonia emissions should be made in favor of the option that decreases the total amount of oxidized or reduced nitrogen being emitted.[15]

With respect to the range of influence or potential for long range transport, nitric acid, derived from NO_X emissions, and ammonia have similar lifetimes in the atmosphere and, thus, similar potential for long range transport. PAN and ammonium sulfate, however, are longer lived and can spread the influence of both NO_X and ammonia sources over a wide area. Nationally, a significant fraction of NO_X emissions come from the tall stacks of electric power plants and other combustion sources, which propel the emissions high into atmosphere, enabling the nitrogen to travel long distances before being deposited. Ammonia emissions come primarily from ground level sources, such as agricultural operations, and thus, the nitrogen contained in ammonia emissions tend not to travel as far. In the case of combined cycle natural gas turbines and associated control equipment, both NO_X and ammonia are emitted from a stack and would have relatively similar potentials for long range transport.

Global Warming and Stratospheric Ozone Depletion

As noted above, to the extent that it reduces displacement of coal, oil and gas steam generation, the addition of SCR on new natural gas combined cycle generating capacity may reduce the CO_2 benefit of this type of plant. There is also a negligible power penalty associated with SCR of between 0.2 percent to 0.25 percent.

A small fraction of ammonia emissions, once deposited on soils, is converted by soil microbes to nitrous oxide (N_2O), a powerful greenhouse gas and a stratospheric ozone depleter. As described above, soil microbes oxidize ammonium to nitrates in a process known as nitrification. Microbes further convert nitrates to molecular nitrogen, NO_X, and nitrous oxide in a process known as denitrification. While some nitrous oxide is produced as a by-product during nitrification, denitrification is a larger source and acts equally on nitrates regardless of whether the nitrogen originated as NO_X or ammonia. On the basis of impacts associated with nitrous oxide, once again, the tradeoff between NO_X and ammonia emissions should be made in favor of the option that decreases the total amount of nitrogen being emitted.

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[15] In terms of nitrogen emitted, 1 ton of ammonia is equal to 1.7 tons of NO and 2.7 tons of NO_2.

Ammonia Safety

GE and some permit applicants have cited ammonia safety concerns as an issue that mitigates the benefit of using SCR to control NO_x. Ammonia is identified by EPA as an extremely hazardous substance.[16] It is toxic if swallowed or inhaled and can irritate or burn the skin, eyes, nose or throat. Vapors may form an explosive mixture with air. None-the-less, ammonia is a commonly used material. OSHA regulations require that employees of facilities where ammonia is used be trained in safe use of ammonia, and it is typically handled safely and without incident.[17] Facilities that handle over 10,000 pounds of anhydrous ammonia or more than 20,000 pounds of ammonia in an aqueous solution of 20 percent ammonia or greater must prepare a Risk Management Plan (RMP) and implement a Risk Management Program to prevent accidental releases. The RPM provides information on the hazards of the substance handled at the facility and the programs in place to prevent and respond to accidental releases. The accident prevention and emergency response requirements reflect existing safety regulations and sound industry safety codes and standards. The Chemical Emergency Preparedness and Prevention Office (CEPPO) received RMPs from 97 electric generating facilities that use ammonia to control air emissions. Facilities that have filed RMPs report storing either anhydrous ammonia or aqueous ammonia.

GE provided no information on ammonia related accidents as a result of SCR use, and the Institute for Clean Air Companies is unaware of any releases of ammonia used for catalytic control that resulted in a workplace injury. CEPPO's RMP database, however, reports that of the 97 power plants that prepared Risk Management Plans a total of six accidental releases ammonia were reported at three facilities using ammonia for catalytic control since 1992. This is a somewhat better record than the overall accident record for all substances for facilities that submitted RMPs. There were no deaths or environmental damage reported for the ammonia related accidents but there were 12 reported injuries. All of the facilities that reported accidents were handling anhydrous ammonia. GE reports that plants "typically" transport and store ammonia in aqueous form.

As discussed earlier, the Environmental Appeals Board, in reviewing a challenge to a BACT determination requiring the use of SCR, In Re Kawaihae Cogeneration Project, 7 E.A.D. 107, 116 (EAB 1997), addressed the issue of possible catastrophic releases of ammonia. In upholding the permitting authority's decision to require SCR, the Board held that the permit applicant had failed to show that "any facility anywhere utilizing SCR technology had experienced such a catastrophic failure" nor, that there were unusual circumstances specific to the facility that would make ammonia safety concerns a compelling reason not to use SCR.

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[16] NO_2 is also toxic if inhaled in high enough concentrations. The EPA has set a primary and secondary National Ambient Air Quality Standard (NAAQS) for NO_2 equal to an annual arithmetic average concentration not to exceed 100 ug/m3. While potential violations of the ambient standards for NO_X should be taken into consideration in any permitting decision, these levels are high enough that it is unlikely that the types of emissions being considered here will violate the NO_2 standards.

[17] *Chemical Emergency Preparadness and Prevention Advisory,* USEPA, September, 1991, (OSWER 91-008.2).

Waste Issues

The use of SCR systems results in spent catalyst waste. The amount of spent catalyst waste generated is dependent on the amount of catalyst used,[18] the life of the catalyst, and the amount of recycling of spent catalyst that occurs.

Catalysts need to be replaced when they degrade to the point that they cease to function effectively. When used with combined cycle gas turbines, it becomes necessary to replace catalyst mainly because of thermal degradation. Conservative cost estimates assume that catalyst life for these units is about 7 to 10 years. However, real experience indicates that SCR catalysts can last much longer on gas turbines.[19] In addition, coal-fired units have easily achieved catalyst lives of 7 years[20], thus a gas-fired unit should be expected to achieve a longer catalyst life.

Given low catalyst replacement rates, SCR users must dispose of spent catalyst very infrequently. Most catalyst manufacturers offer a disposal service for spent catalyst. Catalyst manufacturers can reactivate the catalyst for reuse, or recycle catalyst components for other uses or dispose the catalyst as waste.[21] Currently, no data is available on how much catalyst is recycled or reused and how much is disposed of as waste. Spent catalyst is not a listed hazardous waste and therefore (when abandoned) would only be subject to the hazardous waste regulations if it exhibits one or more of the hazardous waste characteristics (i.e., ignitability, corrosivity, reactivity, or toxicity).[22] In general, spent catalyst should not meet these hazardous waste characteristics and therefore would not be classified as a hazardous waste.

Summary of Environmental Impact Tradeoffs

The site specific tradeoffs that are discussed above can be important when determining BACT for NO_x in attainment areas. As shown in the earlier analysis, the emissions reductions that can be achieved by putting SCR on natural gas combined cycle units are very small compared to the reductions that SCR can achieve on other types of power plants. In addition, nationally, and perhaps locally as well, displacement will compromise some or all of the emissions reductions that SCR offers for these turbines, highlighting the importance of carefully

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[18] Note that using more catalyst results in lower NO_X and ammonia slip emissions, but higher costs and more spent catalyst waste.

[19] One the first installations of SCR on an all natural gas-fired turbine occurred in 1986 is still operating without catalyst replacement. The ammonia slip was originally at 2 ppm and is now operating with a slip of 4 ppm. Telephone contact on February 15, 2000 did not wish to be identified by name or company.

[20] *Performance of Selective Catalytic Reduction on Coal-Fired Steam Generating Units*, US EPA, June 1997.

[21] *Selective Catalytic Reduction (SCR) Control of NOx Emissions*, ICAC, November 1997.

[22] Straus, M.A., Memorandum to John L. Cherill. September 4, 1986.

considering the site specific conditions that should influence a BACT determination to assure that there is not an environmental cost to the use of SCR.

The various environmental impacts described above are appropriate to consider for a site specific BACT determination. They point to different conclusions as to whether it is environmentally preferable to limit NO_X emissions or to limit ammonia emissions. With respect to tropospheric ozone, the tradeoffs favor limits on NO_X emissions, especially in areas immediately upwind of ozone nonattainment areas or Class I areas. With respect to eutrophication and other nutrient-related impacts and global warming and stratospheric ozone depletion caused by nitrous oxide, the tradeoff between NO_X and ammonia emissions should be made in favor of the overall control strategy that lowers total nitrogen emissions. With respect to acidification impacts and safety and waste concerns, the tradeoffs favor limiting the emissions and use of ammonia. With respect to fine particles, however, the tradeoffs are not clear but, in general, appear to favor limiting ammonia emissions, especially in areas where ammonia sources are low. In any case, the incremental change in the formation of particles due to an incremental change in the emissions from a single source is likely to be small if the change in emissions from that source is small compared to the overall emission inventory, regardless of whether the emissions are NO_X or ammonia. However if the plant is located in an are where fine particles and/or acid soils are of primary concern and tropospheric ozone is of less concern, a permitting authority could appropriately conclude that BACT in a specific case was DLN turbines without additional controls for a combined cycle gas turbine.

TECO
TAMPA ELECTRIC

RECEIVED
NOV 27 2000
BUREAU OF AIR REGULATION

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

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

TAMPA ELECTRIC COMPANY
P. O. BOX 111 TAMPA, FL 33601-0111
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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)

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$_2$S 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

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TECO SM

TAMPA ELECTRIC

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.

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.

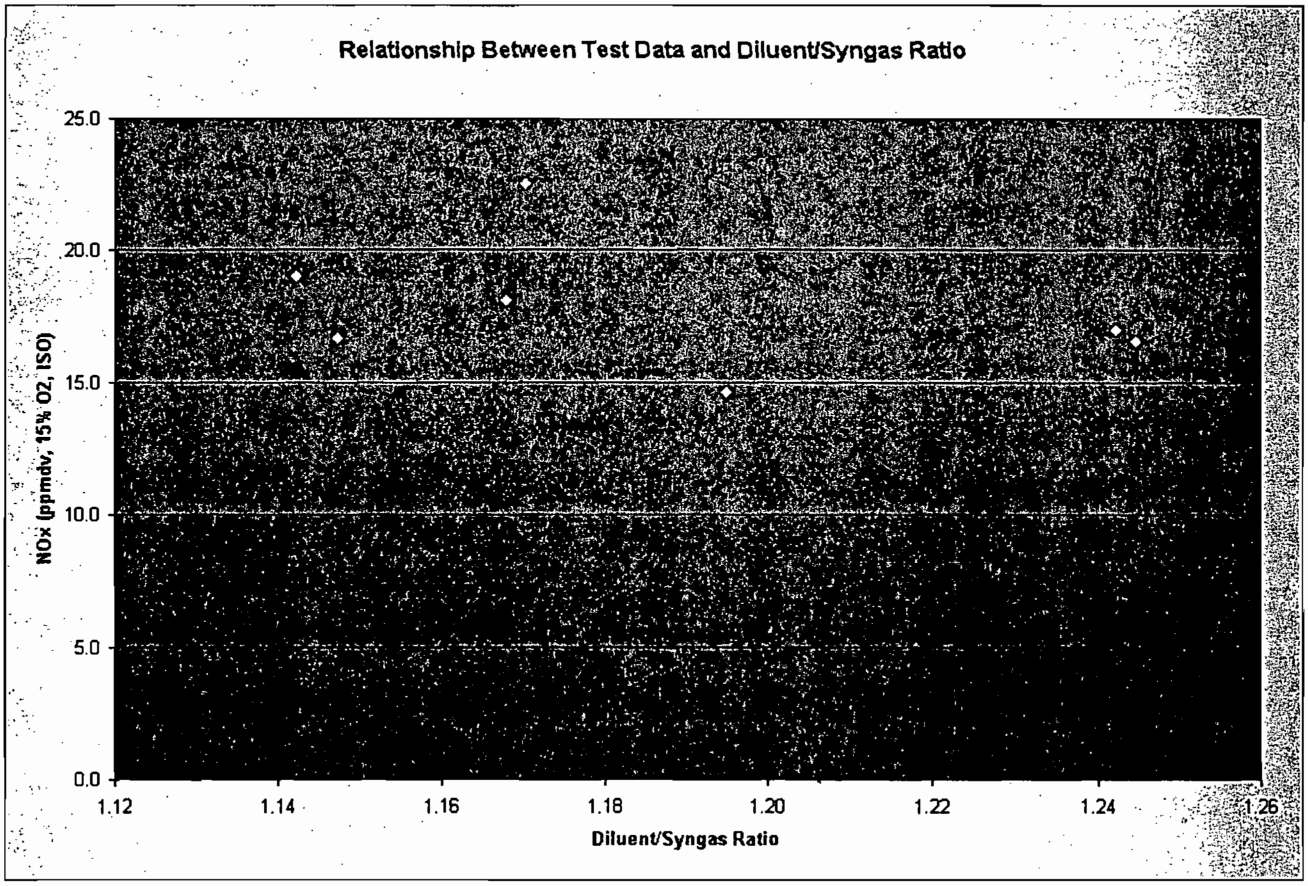

Figure 1

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

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	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	
1999	Synfuel	Oil		Synfuel	Oil	Synfuel	Oil		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	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	
1999	**Synfuel**	**Oil**		**Synfuel**	**Oil**	**Synfuel**	**Oil**		**Synfuel**	**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	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	
2000	Synfuel	Oil		Synfuel	Oil	Synfuel	Oil		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		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)		(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	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	
2000	**Synfuel**	**Oil**		**Synfuel**	**Oil**	**Synfuel**	**Oil**		**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	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	
2000	Synfuel	Oil		Synfuel	Oil	Synfuel	Oil		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	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	
2000	**Synfuel**	**Oil**		**Synfuel**	**Oil**	**Synfuel**	**Oil**		**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	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	
2000	Synfuel	Oil		Synfuel	Oil	Synfuel	Oil		Synfuel	Oil
	(lbs)		(lb / hr)	(hr)		(MMBTU / day)		(MW)	(lbs)	
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	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	
2000	**Synfuel**	**Oil**		**Synfuel**	**Oil**	**Synfuel**	**Oil**		**Synfuel**	**Oil**
	(lbs)		(lb / hr)	(hr)		(MMBTU / day)		(MW)	(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		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)		(lb / hr)	(hr)		(MMBTU / day)		(MW)	(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	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	
2000	**Synfuel**	**Oil**		**Synfuel**	**Oil**	**Synfuel**	**Oil**		**Synfuel**	**Oil**
	(lbs)		(lb / hr)	(hr)		(MMBTU / day)		(MW)	(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	30-Day Average NO_X Emissions		NO_X Emissions	Daily Hours of Operation		Total Daily Heat Input		Daily Average MW Output	30-Day Rolling Average SO_2 Emission	
2000	**Synfuel**	**Oil**		**Synfuel**	**Oil**	**Synfuel**	**Oil**		**Synfuel**	**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	30-Day Average NO_X Emissions		NO_X Emissions	Daily Hours of Operation		Total Daily Heat Input		Daily Average MW Output	30-Day Rolling Average SO_2 Emission	
2000	**Synfuel**	**Oil**		**Synfuel**	**Oil**	**Synfuel**	**Oil**		**Synfuel**	**Oil**
	(lbs)		(lb / hr)	(hr)		(MMBTU / day)		(MW)	(lbs)	
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

GER 4172

GE Power Generation

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

Marvin M. Schorr, Consulting Engineer
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General Electric Power Systems
Schenectady, New York

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

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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 backend 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 build-up 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

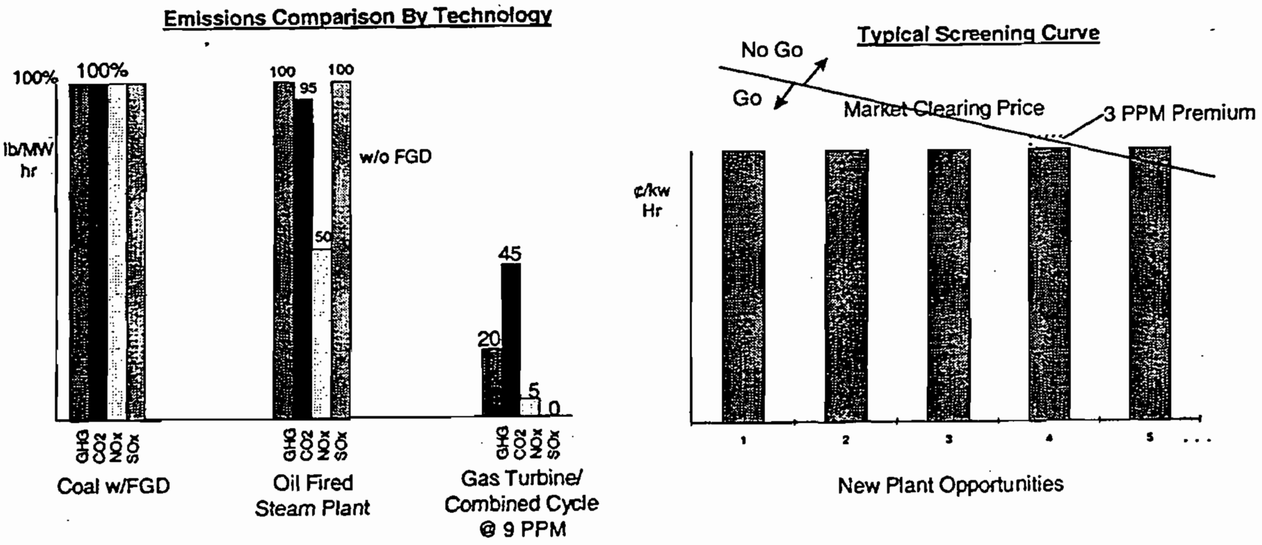
1. Schorr, M.M.; "NOx Emission Control for Gas Turbines: A 1995 Update on Regulations and Technology," CIBO NOx Control Conference, March 1995.

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)

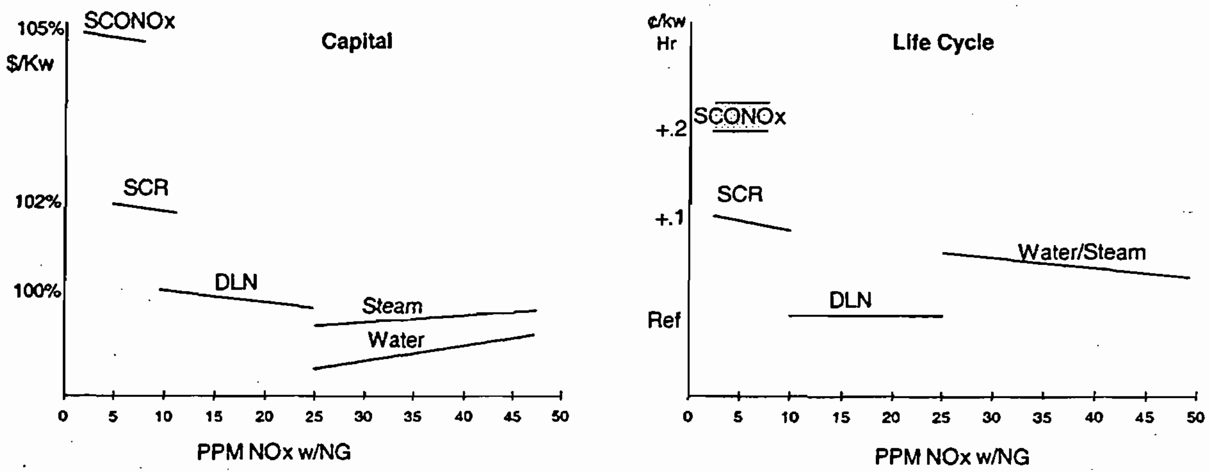
	9 ppm NOx w/o SCR	3.5 ppm NOx w/SCR	TPY	3.5 ppm NOx w/SCR & COC	TPY
Natural Gas Only					
NOx	240	92	-148	92	–148
PM	36	41.6	+5.6	69.6	+33.6
NH	0	172	+172	164	+164
SO	40	39	–1	25	–15
Gas+400 hr/yr Oil					
NOx	294	116	–178	116	–178
PM	37.6	45.8	+8.2	86	+48.4
NH	0	172	+172	161	+161
SO	57	56	–1	36	–21

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



e.g., St. Johns River Jacksonville Electric
e.g., Brayton Point, NEES
e.g., Sithe Independence
w/o FGD: Wansley; Georgia Power (10xSOx)
GHG = Green House Gases

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

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[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

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[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).

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[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

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.

APPENDIX BD - 2001
BEST AVAILABLE CONTROL TECHNOLOGY DETERMINATION (BACT) FOR NO_X

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

BACKGROUND

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

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

BACT ANALYSIS:

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

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

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

BACT DETERMINATION PROCEDURE:

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

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

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

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

STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES:

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

DETERMINATIONS BY EPA AND STATES:

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

TABLE 1

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

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

IGCC PLANT INFORMATION:

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

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

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

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

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

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

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

TEXACO GASIFIER INFORMATION:

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

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

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

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

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

COMBUSTION TURBINE INFORMATION:

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

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

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

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

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

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

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

Cool Water

The Cool Water Coal Gasification Program was the first commercial demonstration of integrated coal gasification combined cycle power generation. The gasification island included a 1200-ton per day, oxygen-blown Texaco gasifier with full heat recovery using both radiant and convective syngas coolers.

Wabash River (PSI)

The Wabash River Coal Gasification Repowering Project is a joint project between the U.S. Department of Energy and a Joint Venture formed in 1990 between Destec Energy Inc. and Public Service of Indiana (PSI). The gasification island includes a Destec two-stage, oxygen blown gasifier including full heat recovery steam integration with the power island.

Tampa Electric

The Tampa Electric Co. Polk Power coal gasification project is partially funded by the U.S. Department of Energy, and includes a Texaco oxygen blown gasifier with full heat recovery using both radiant and convective syngas coolers. Process syngas, steam, and nitrogen are integrated with the GE STAG-107FA power block.

Pinon Pine

The Pinon Pine Power Project - Undertaken by Sierra Pacific Power Company at its Tracy station in Sparks, Nevada, with support from the U.S. Department of Energy, includes a KRW air-blown fluidized bed gasifier with hot gas cleanup. Air extraction from the GE 6FA gas turbine is integrated with the process island to produce high temperature low Btu syngas for the 100 MW combined cycle power block.

Texaco El Dorado

The El Dorado gasification facility, developed by Texaco Alternative Energy Inc., is fully commercial without government subsidies. The project incorporates a Texaco oxygen blown quench type gasifier fired on a mixture of petroleum coke (approx. 166 tpd), and about 15 tpd of waste streams provided from the Texaco refinery site in El Dorado, Kansas. A 35 MW GE MS6001B gas turbine is co-fired with syngas and natural gas to meet the refinery's total internal power needs.

ILVA- ISE

The ILVA Sistemi Energia (ISE) cogeneration project is located at the ILVA steelworks in Taranto, Italy. Three GE 109E combined cycle units operate on a variable mixture of compressed steel mill recovery gases (coke oven gas, blast furnace gas, and LD furnace gas), which normally combine to an equivalent low heating value fuel (140 Btu/scf-LHV). The combined facility output is 520 MW, with 150 tons/hr of steam feed to the steel mill. Each gas turbine generator unit is directly coupled to a centrifugal fuel gas compressor in a single shaft lineup with a separate steam turbine generator unit.

Schwarze Pumpe

The Sekundarrohstoff-Verwertungszentrum Schwarze Pumpe GmbH (SVZ) is a waste utilization facility, established and privatized in 1995. The facility contains seven fixed bed gasifiers, which gasify a mixture of waste combustibles with the help of oxygen and hydrogen. The synthesis gases from these facilities are used for methanol production and to fuel a combined cycle plant built around a MS6001B gas turbine provided by Thomassen under GE license. The turbine also combusts purge gas from the methanol plant and operates on distillate as backup and startup fuel.

Shell Pernis

The PER+ project is an upgrade of the existing Shell Pernis refinery. A new hydrocracker unit was added for the conversion of heavy, high-sulfur crudes into light low-sulfur fuels. Hydrogen required for the conversion process is supplied by the Shell Gasification Hydrogen Process plant, which gasifies heavy residues with oxygen and water to yield syngas. Most of the hydrogen is then removed to feed the hydrocracker, and the depleted syngas is then used as fuel in a combined cycle cogeneration facility. The syngas is blended with LPG and/or natural gas when the heating value in combination with the amount of the syngas is insufficient for the desired load of the turbines. The turbines can also fire 100% natural gas, which is used for startup and as backup fuel.

Fife Energy

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

Motiva Enterprises

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

Sarlux

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

Fife Electric

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

Exxon Singapore

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

IBIL Sanghi

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

Bioelettrica (TEF)

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

OTHER INFORMATION AVAILABLE TO THE DEPARTMENT:

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

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

REVIEW OF NITROGEN OXIDES CONTROL TECHNOLOGIES:

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

Nitrogen Oxides Formation

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

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

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

NO_X Control Techniques

Diluent Injection

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

Combustion Controls

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

Selective Catalytic Reduction

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

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

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

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

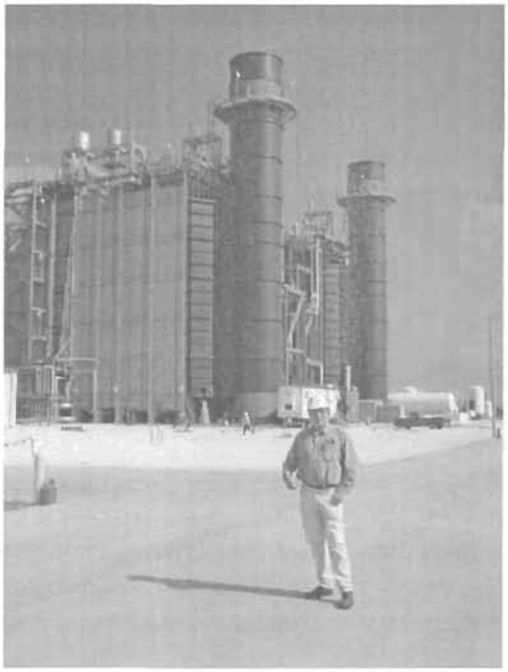


Figure B

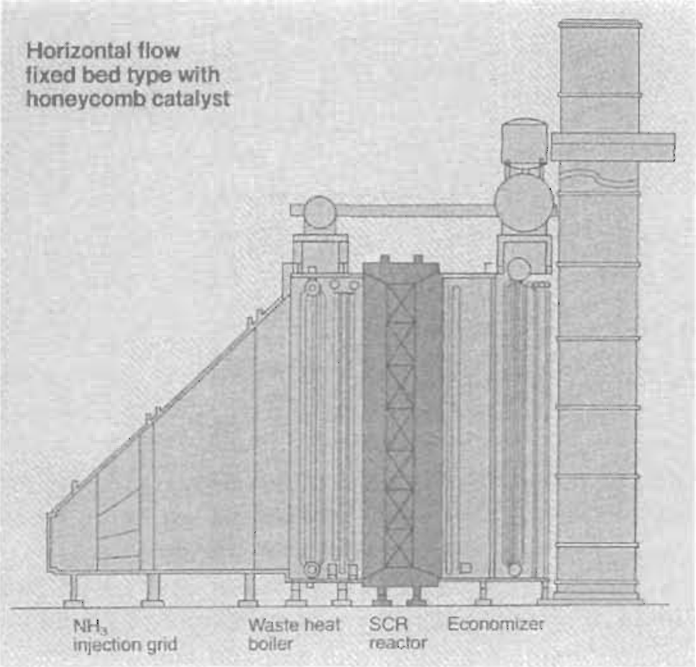


Figure C

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

Selective Non-Catalytic Reduction

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

Emerging Technologies: SCONOx^{TM} and XONON^{TM}

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

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

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

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

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

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

PLANT SPECIFIC ANALYSIS

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

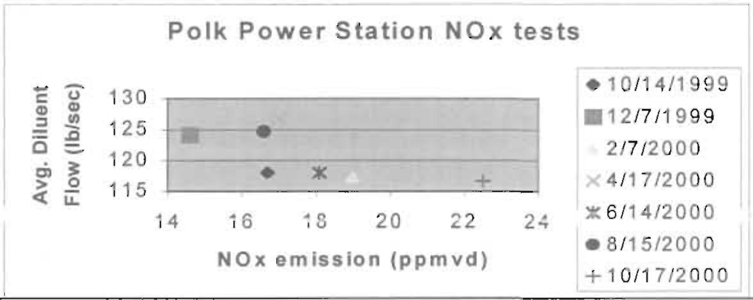
Applicant Comment: The cost to control NO_X emissions through the use of an SCR system on Polk Unit 1 presented in the analysis submitted to FDEP was based on a limited number of estimated costs. Since SCR has not been required for any IGCC installation in the United States, it is not possible to compare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

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

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

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

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



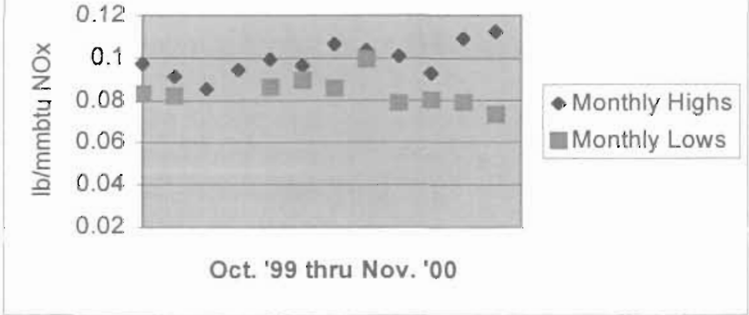
TEC has cautioned against an analysis of NO_X emissions as compared to diluent flow, noting that "*although the diluent flow is an important parameter for controlling NO_X emissions, a more appropriate measure is the ratio of diluent flow to syngas flow. On an overall basis, this ratio represents the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

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

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

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

CEMS DATA



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

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

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

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

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

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

EPA Comments regarding Kentucky Pioneer:

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

DEPARTMENT BACT DETERMINATION:

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

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

DETAILS OF THE ANALYSIS MAY BE OBTAINED BY CONTACTING:

Michael P. Halpin, P.E. Review Engineer
Department of Environmental Protection
Bureau of Air Regulation
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Recommended By:	Approved By:
C. H. Fancy, P.E., Chief Bureau of Air Regulation	Howard L. Rhodes, Director Division of Air Resources Management
Date:	Date:

TECO
TAMPA ELECTRIC

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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 L. 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

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								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	2,836,200	3,499

Table 3. Capital Cost Summary (Both Cases)

Direct Costs	($)	OAQPS Factor
Purchased Equipment (PE)		
SCR Control System	3,110,000	Deltak Quote 4/19/01
Aqueous Ammonia Storage Tank	0	Included with SCR System
Purchased Equipment Total	3,110,000	A
Instrumentation	311,000	0.10 * A
Sales Tax	186,600	0.06 * A
Freight	155,500	0.05 * A
HRSG Modifications	300,000	ngineering Estimate, allows for cleanin
Total Purchased Equipment	4,063,100	B
Installation		
Foundations & Supports	325,000	0.08 * B
Handling & Erection	568,800	0.14 * B
Electrical	162,500	0.04 * B
Piping	81,300	0.02 * B
Insulation For Ductwork	40,600	0.01 * B
Painting	40,600	0.01 * B
Total Installation Cost	1,218,800	
Total Direct Cost	5,281,900	TDC
Indirect Costs	**($)**	**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:

Section B, Part 1, Operating Limitations

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).

Section B, Part 2, Emission Limitations

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."

Section B, Part 3, Testing Requirements

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

Department of Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

May 10, 2001

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

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

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

Dear Mr. Hornick:

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

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

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

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

Sincerely,

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

CHF/mph

Enclosures

TE
TAMPA ELECTRIC

RECEIVED
MAY 02 2001
BUREAU OF AIR REGULATION

May 1, 2001

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

AN EQUAL OPPORTUNITY COMPANY
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CUSTOMER SERVICE:
HILLSBOROUGH COUNTY (813) 223-0800
OUTSIDE HILLSBOROUGH COUNTY 1 (888) 223-0800

In the Matter of an
Application for Permit by:

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

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

INTENT TO ISSUE PSD PERMIT MODIFICATION

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

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

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

The Department intends to issue this PSD permit modification based on the belief that reasonable assurances have been provided to indicate that operation of these emission units will not adversely impact air quality, and the emission units will comply with all appropriate provisions of Chapters 62-4, 62-204, 62-210, 62-212, 62-296, and 62-297, F.A.C. and 40 CFR 52.21.

Pursuant to Section 403.815, F.S., and Rule 62-110.106(7)(a)1., F.A.C., the Department will publish the enclosed ""Public Notice of Intent to Issue PSD Permit Modification". The notice shall be published one time only in the legal advertisement section of a newspaper of general circulation in the area affected. For the purpose of these rules, "publication in a newspaper of general circulation in the area affected" means publication in a newspaper meeting the requirements of Sections 50.011 and 50.031, F.S., in the county where the activity is to take place.

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

The Department will accept written comments concerning the proposed permit issuance action for a period of 14 (fourteen) days from the date of publication of "Public Notice of Intent to Issue PSD Permit Modification". Written comments should be provided to the Department's Bureau of Air Regulation at 2600 Blair Stone Road, Mail Station #5505, Tallahassee, FL 32399-2400. Any written comments filed shall be made available for public inspection. If written comments received result in a significant change in the proposed agency action, the Department shall revise the proposed permit and require, if applicable, another Public Notice.

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

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

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

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

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

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

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

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

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

Executed in Tallahassee, Florida.

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

CERTIFICATE OF SERVICE

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

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

Clerk Stamp

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

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

PUBLIC NOTICE OF INTENT TO ISSUE PSD PERMIT MODIFICATION

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

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

TEC Polk Power Station
Polk County

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

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

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

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

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

The Department will accept written comments concerning the proposed permit issuance action for a period of 14 days from the date of publication of this Public Notice of Intent to Issue PSD Permit Modification. Written comments should be provided to the Department's Bureau of Air Regulation at 2600 Blair Stone Road, Mail Station #5505, Tallahassee, FL 32399-2400. Any written comments filed shall be made available for public inspection. If written comments received result in a significant change in the proposed agency action, the Department shall revise the proposed permit and require, if applicable, another Public Notice.

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

Mediation is not available in this proceeding.

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

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

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

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

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

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

Dept. of Environmental Protection
Bureau of Air Regulation
Suite 4, 111 S. Magnolia Drive
Tallahassee, Florida, 32301
Telephone: 850/488-0114
Fax: 850/922-6979

Department Environmental Protection
Southwest District Office
3804 Coconut Palm Drive
Tampa, Florida 33619-8218
Telephone: 813/744-6100
Fax: 813/744-6084

Polk County Environmental Services
Natural Resources & Drainage Division
4177 Ben Durrance Road
Bartow, Florida 33830
Telephone: 941/534-7377
Fax: 941/534-7374

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

PERMITTEE

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

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

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

PROJECT AND LOCATION

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

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

STATEMENT OF BASIS

This construction permit is issued under the provisions of Chapter 403 of the Florida Statutes (F.S.), and Chapters 62-4, 62-204, 62-210, 62-212, 62-296, and 62-297 of the Florida Administrative Code (F.A.C.). The above named permittee is authorized to modify the facility in accordance with the conditions of this permit and as described in the application, approved drawings, plans, and other documents on file with the Department of Environmental Protection (Department).

ATTACHED APPENDICES MADE A PART OF THIS PERMIT

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

Howard L. Rhodes, Director
Division of Air Resources Management

FACILITY DESCRIPTION

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

REGULATORY CLASSIFICATION

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

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

PERMIT SCHEDULE

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

RELEVANT DOCUMENTS

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

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

PERMIT SPECIFIC CONDITIONS

This permit addresses the following emissions unit:

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

1. The provisions of the Title V Operating Permit 1050233-001-AV remain in effect. However, an application shall be submitted to revise that permit upon completion of construction and satisfactory emissions performance testing of the Unit 1 SCR.
2. The provisions of air construction permits PSD-FL-194, PSD-FL-194A, PSD-FL-194C, PSD-FL-194D and PSD-FL-194E are incorporated into this air construction permit except for the changes that follow in Specific Conditions F, H, J and M below.

F. Fuel Consumption

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

H. Emission Limits

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

POLLUTANT	FUEL	BASIS$_a$	LB/HR*	TPY$_b$
NO$_X$	Oil	9 ppmvd***	74.1	32.5
	Syngas	5 ppmvd***	44.1	206.6
VOC^c	Oil	0.028	32 lb/MMBtu	N/A
	Syngas	0.0017	3 lb/MMBtu	38.5
CO	Oil	40 ppmvd	99	N/A
	Syngas	25 ppmvd	98	430.1
PM/PM$_{10}^{d}$	Oil	0.009 lb/MMBtu	17	N/A
	Syngas	0.013 lb/MMBtu	17	74.5
Pb	Oil	5.30E-5 lb/MMBtu	0.101	N/A
	Syngas	2.41E-6 lb/MMBtu	0.0035	0.067
SO$_2$	Oil	0.048 lb/MMBtu	92.2	N/A
	Syngas	0.17 lb/MMBtu	357	1563.7
V.E.	Syngas	10 percent opacity		
	Oil	20 percent opacity.		

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

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

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

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

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

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

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

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

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

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

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

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

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

J. Performance Testing

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

M. Notification, Reporting, and Recordkeeping

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

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

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

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

APPENDIX BD - 2001
BEST AVAILABLE CONTROL TECHNOLOGY DETERMINATION (BACT) FOR NO_X

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

BACKGROUND

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

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

BACT ANALYSIS:

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

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

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

BACT DETERMINATION PROCEDURE:

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

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

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

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

STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES:

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

DETERMINATIONS BY EPA AND STATES:

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

TABLE 1

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

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

IGCC PLANT INFORMATION:

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

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

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

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

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

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

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

TEXACO GASIFIER INFORMATION:

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

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

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

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

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

COMBUSTION TURBINE INFORMATION:

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

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

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

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

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

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

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

Cool Water

The Cool Water Coal Gasification Program was the first commercial demonstration of integrated coal gasification combined cycle power generation. The gasification island included a 1200-ton per day, oxygen-blown Texaco gasifier with full heat recovery using both radiant and convective syngas coolers.

Wabash River (PSI)

The Wabash River Coal Gasification Repowering Project is a joint project between the U.S. Department of Energy and a Joint Venture formed in 1990 between Destec Energy Inc. and Public Service of Indiana (PSI). The gasification island includes a Destec two-stage, oxygen blown gasifier including full heat recovery steam integration with the power island.

Tampa Electric

The Tampa Electric Co. Polk Power coal gasification project is partially funded by the U.S. Department of Energy, and includes a Texaco oxygen blown gasifier with full heat recovery using both radiant and convective syngas coolers. Process syngas, steam, and nitrogen are integrated with the GE STAG-107FA power block.

Pinon Pine

The Pinon Pine Power Project - Undertaken by Sierra Pacific Power Company at its Tracy station in Sparks, Nevada, with support from the U.S. Department of Energy, includes a KRW air-blown fluidized bed gasifier with hot gas cleanup. Air extraction from the GE 6FA gas turbine is integrated with the process island to produce high temperature low Btu syngas for the 100 MW combined cycle power block.

Texaco El Dorado

The El Dorado gasification facility, developed by Texaco Alternative Energy Inc., is fully commercial without government subsidies. The project incorporates a Texaco oxygen blown quench type gasifier fired on a mixture of petroleum coke (approx. 166 tpd), and about 15 tpd of waste streams provided from the Texaco refinery site in El Dorado, Kansas. A 35 MW GE MS6001B gas turbine is co-fired with syngas and natural gas to meet the refinery's total internal power needs.

ILVA- ISE

The ILVA Sistemi Energia (ISE) cogeneration project is located at the ILVA steelworks in Taranto, Italy. Three GE 109E combined cycle units operate on a variable mixture of compressed steel mill recovery gases (coke oven gas, blast furnace gas, and LD furnace gas), which normally combine to an equivalent low heating value fuel (140 Btu/scf-LHV). The combined facility output is 520 MW, with 150 tons/hr of steam feed to the steel mill. Each gas turbine generator unit is directly coupled to a centrifugal fuel gas compressor in a single shaft lineup with a separate steam turbine generator unit.

Schwarze Pumpe

The Sekundarrohstoff-Verwertungszentrum Schwarze Pumpe GmbH (SVZ) is a waste utilization facility, established and privatized in 1995. The facility contains seven fixed bed gasifiers, which gasify a mixture of waste combustibles with the help of oxygen and hydrogen. The synthesis gases from these facilities are used for methanol production and to fuel a combined cycle plant built around a MS6001B gas turbine provided by Thomassen under GE license. The turbine also combusts purge gas from the methanol plant and operates on distillate as backup and startup fuel.

Shell Pernis

The PER+ project is an upgrade of the existing Shell Pernis refinery. A new hydrocracker unit was added for the conversion of heavy, high-sulfur crudes into light low-sulfur fuels. Hydrogen required for the conversion process is supplied by the Shell Gasification Hydrogen Process plant, which gasifies heavy residues with oxygen and water to yield syngas. Most of the hydrogen is then removed to feed the hydrocracker, and the depleted syngas is then used as fuel in a combined cycle cogeneration facility. The syngas is blended with LPG and/or natural gas when the heating value in combination with the amount of the syngas is insufficient for the desired load of the turbines. The turbines can also fire 100% natural gas, which is used for startup and as backup fuel.

Fife Energy

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

Motiva Enterprises

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

Sarlux

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

Fife Electric

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

Exxon Singapore

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

IBIL Sanghi

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

Bioelettrica (TEF)

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

OTHER INFORMATION AVAILABLE TO THE DEPARTMENT:

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

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

REVIEW OF NITROGEN OXIDES CONTROL TECHNOLOGIES:

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

Nitrogen Oxides Formation

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

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

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

NO_X Control Techniques

Diluent Injection

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

Combustion Controls

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

Selective Catalytic Reduction

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

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

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

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

Figure B

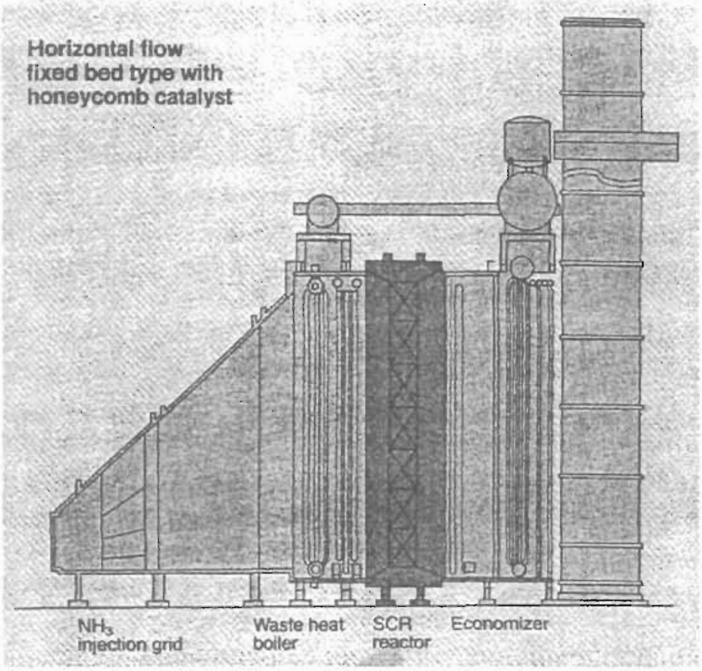


Figure C

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

Selective Non-Catalytic Reduction

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

Emerging Technologies: SCONOx™ and XONON™

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

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

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

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

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

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

PLANT SPECIFIC ANALYSIS

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

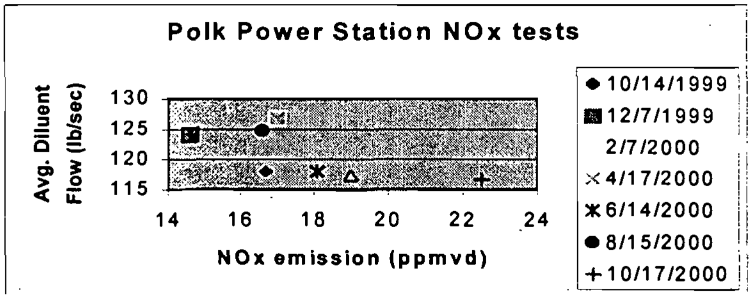
Applicant Comment: The cost to control NO_X emissions through the use of an SCR system on Polk Unit 1 presented in the analysis submitted to FDEP was based on a limited number of estimated costs. Since SCR has not been required for any IGCC installation in the United States, it is not possible to compare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

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

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

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

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



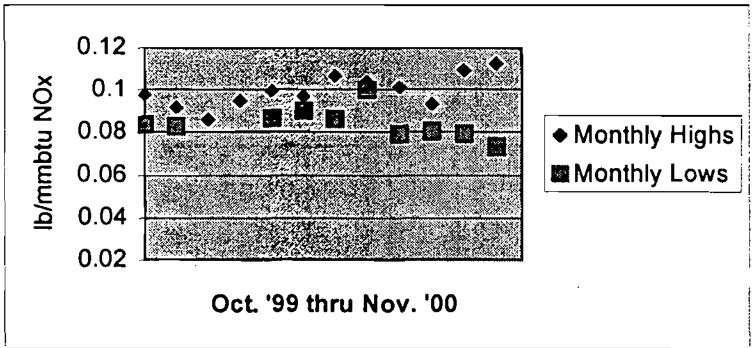
TEC has cautioned against an analysis of NO_X emissions as compared to diluent flow, noting that "*although the diluent flow is an important parameter for controlling NO_X emissions, a more appropriate measure is the ratio of diluent flow to syngas flow. On an overall basis, this ratio represents the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

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

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

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

CEMS DATA



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

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

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

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

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

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

EPA Comments regarding Kentucky Pioneer:

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

DEPARTMENT BACT DETERMINATION:

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

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

APPENDIX BD - 2001

BEST AVAILABLE CONTROL TECHNOLOGY DETERMINATION (BACT) FOR NO_X

DETAILS OF THE ANALYSIS MAY BE OBTAINED BY CONTACTING:

Michael P. Halpin, P.E. Review Engineer
Department of Environmental Protection
Bureau of Air Regulation
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Recommended By:	Approved By:
C. H. Fancy, P.E., Chief Bureau of Air Regulation	Howard L. Rhodes, Director Division of Air Resources Management
Date:	Date:

DRAFT

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THE TAMPA TRIBUNE

Published Daily

Tampa, Hillsborough County, Florida

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State of Florida }
County of Hillsborough } ss.

Before the undersigned authority personally appeared J. Rosenthal, who on oath says that she is Classified Billing Manager of The Tampa Tribune, a daily newspaper published at Tampa in Hillsborough County, Florida; that the attached copy of advertisement being a

LEGAL NOTICE

in the matter of

PUBLIC NOTICE OF INTENT

was published in said newspaper in the issues of MAY 23, 2001

Affiant further says that the said The Tampa Tribune is a newspaper published at Tampa in said Hillsborough County, Florida, and that the said newspaper has heretofore been continuously published in said Hillsborough County, Florida, each day and has been entered as second class mail matter at the post office in Tampa, in said Hillsborough County, Florida for a period of one year next preceding the first publication of the attached copy of advertisement; and affiant further says that she has neither paid nor promised any person, this advertisement for publication in the said newspaper.

J Rosenthal

Sworn to and subscribed by me, this 24 day

of MAY, A.D. 20 01

Personally Known ✓ or Produced Identification ______
Type of Identification Produced ______

OFFICIAL NOTARY SEAL
SUSIE LEE SLATON
COMMISSION NUMBER
DD000060
MY COMMISSION EXP.
APRIL 16, 2005

Susie Lee Slaton

CC: M. Halpin
B. Thomas, SWD
G. Spinell, Polk Co ESD
B. Oven, DEP
G. Worley, EPA
J. Bunyak, NPS

ISSUE PSD PERMIT MODIFICATION
STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

DEP File No. 1050233-007-AC,
PSD-FL-194F
TEC Polk Power Station
Polk County

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

This is an existing facility consisting of an integrate gasification combined cycl (IGCC) unit, referred to as Uni 1. Major components of PP Unit 1 include solid fuel handling and gasification systems, a sulfuric acid plant fo processing of the solid fue gasification system gas cleanup stream, an auxiliary boile fired with No. 2 distillate fue oil, and one integrated gasification combined cycle (IGCC General Electric (GE) 7F combustion turbine (CT) fired wit synthetic natural gas (syngas or No. 2 distillate fuel oil. Th unit is additionally authorize to burn syngas produced fro the gasification of fuel blend of up to 60 percent petroleu coke. The unit has a PSD Permit (1050233-001-AC) issue by the State of Florida.

In accordance with the conditions of the PSD permit, a determination of Best Availabl Control Technology (BACT) fo Nitrogen Oxides (NOx) was required to be completed following a pre-defined "demonstration period". The permit condition reads as follows: "On month after the test perio ends (estimated to be by Jun 1, 2001), the Permittee wi submit to the Department a NOx recommended BACT Determination as if it were a ne 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 NOx onl and adjust the NOx emissio limits accordingly." The Department has determined tha the demonstration (test) period ended during Novembe 2000. Based upon the Department's evaluation, PPS Unit will be required to install a SCR unit in order to contro NOx emissions from the IGC unit as per the conditions outlined in the draft permit.

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

The Department will issue the Final permit modificatio in accordance with the referenced draft permit condition unless a response received i accordance with the followin procedures results in a different decision or significan change of terms or conditions.

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

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

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emissions of NOx will be reduced.

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

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

Mediation is not available in this proceeding.

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

A petition that disputes the material facts on which the Department's action is based must contain the following information: (a) The name and address of each agency affected and each agency's file or identification number, if known; (b) The name, address, and telephone number of the petitioner, the name, address, and telephone number of the petitioner's representative, if any, which shall be the address for service purposes during the course of the proceeding; and an explanation of how the petitioner's substantial interests will be affected by the agency determination; (c) A statement of how and when petitioner received notice of the agency action or proposed action; (d) A statement of all disputed issues of material

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dicated above at the time of filing. The failure of any person to file a petition within the appropriate time period shall constitute a waiver of that person's right to request an administrative determination (hearing) under sections 120.569 and 120.57 F.S., or to intervene in this proceeding and participate as a party to it. Any subsequent intervention will be only at the approval of the presiding officer upon the filing of a motion in compliance with Rule 28-106.205 of the Florida Administrative Code.

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

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

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

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

Dept. of Environmental Protection
Bureau of Air Regulation
Suite 4, 111 S. Magnolia Drive
Tallahassee, Florida. 32301
Telephone: 850/488-0114
Fax: 850/922-6979

Department Environmental Protection
Southwest District Office
3804 Coconut Palm Drive
Tampa, Florida 33619-8218
Telephone: 813/744-6100
Fax: 813/744-6084

Polk County Environmental Services
Natural Resources & Drainage Division
4177 Ben Durrance Road
Bartow, Florida 33830
Telephone: 941/534-7377
Fax: 941/534-7374

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

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

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4 APT-ARB

Mr. A. A. Linero, P.E.
Florida Department of Environmental Protection
Mail Station 5500
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Dear Mr. Linero:

The Region 4 office of the U.S. Environmental Protection Agency (EPA) thanks you for sending the draft PSD permit modification and associated draft best available control technology (BACT) determination dated May 10, 2001, for the Tampa Electric Company (TEC) Polk Power Station. The Polk Power Station is an existing facility consisting of an integrated gasification combined cycle (IGCC) combustion turbine system. The primary fuel burned in the combustion turbine is "syngas" produced from the gasification of coal and petroleum coke. The original permit for this facility provided for a deferral of a final BACT determination for nitrogen oxides (NO_x) until an initial "demonstration period" had been completed. The demonstration period has now ended and the Florida Department of Environmental Protection (FDEP) has issued a draft BACT determination that, if finalized as proposed, would require use of selective catalytic reduction (SCR) to control NO_x emissions.

Based on our review of the draft PSD permit modification and draft BACT determination, we have the following comments:

1. Because the TEC Polk Power Station PSD permit was issued under the Site Certification requirements of the Florida Power Plant Siting Act, the permit is considered an EPA-issued permit for purposes of federal law. This is because PSD permits for projects subject to the Site Certification process are issued under delegation from EPA and not under the FDEP SIP-approved PSD permit program that applies to all other types of projects in Florida. Our opinion is that FDEP has carried out the permit revision and BACT reassessment for the TEC Polk Power Station in accordance with the procedures appropriate to EPA-delegated PSD permits.

2. While recognizing TEC's concerns about the long-term feasibility of SCR with syngas combustion, we believe FDEP has arrived at a well-reasoned basis to support use of SCR as BACT for control of NO_x emissions. In particular, our opinion is that FDEP has developed an appropriate response to TEC's main concern about SCR - the deposition of ammonium salts in the heat recovery steam generator downstream of the SCR device. We concur with FDEP that design and operational features can be applied to minimize ammonia slip and subsequent reaction of ammonia with sulfur oxides to form ammonium

sulfate and bisulfate. Furthermore, the added cost of such design and operational features should not result in annualized costs that are prohibitive in comparison with SCR costs incurred with conventional fuel combined cycle combustion turbine facilities.

3. We believe confusion may have arisen concerning a control technology assessment for another recent IGCC project, the Motiva Enterprises (Motiva) IGCC project in Delaware City, Delaware. Motiva uses diluent nitrogen to control NO_x emissions rather than an add-on control method such as SCR. Information obtained from EPA Region 3 indicates that the NO_x control method approved for the Motiva was not a lowest achievable emission rate (LAER) determination as we have seen referenced in some discussions. Rather, we understand Motiva was able to net out of major new source review for NO_x and a LAER determination was not required.

If you have any questions regarding the comments in this letter, please call Jim Little at 404-562-9118.

Sincerely,

Douglas Neeley

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

cc: M. Halpin
C. Holladay
M. Hornick, TEC
B. Oven, DEP PPSO
B. Thomas, SWD
J. Spence, Polk Co. ESD
T. Davis, P.E., ECT
J. Bunyak NPS

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June 5, 2001

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

Via FedEx
Airbill No. 7915 7594 7432

Re: Tampa Electric Company (TEC) – Polk Power Station Unit 1
PSD Permit Modification and NO_x Recommended BACT Determination
DEP File No. PSD-FL-194F

Dear Mr. Linero:

Tampa Electric Company has received and reviewed the above referenced Draft PSD Permit Modification and oxides of nitrogen (NO_x) recommended Best Available Control Technology (BACT) Determination dated May 11, 2001 and offers the following comments for your review.

Comment 1 - Notice of Intent to Issue PSD Permit Modification
The fourth paragraph of this section indicates that

> *"No annual increases of regulated pollutants will occur as a result of the modification and emissions of* NO_x *will be reduced."*

This statement does not appear to be correct due to the fact that sulfuric acid mist emissions will increase due to the catalysis of sulfur dioxide (SO_2) to sulfur trioxide (SO_3) in the SCR. The magnitude of this increase is unknown because some of the SO_3 will be combined with excess ammonia to form ammonium sulfate and ammonium bisulfate. In addition, this statement may be misleading due to the fact that ammonia will be both introduced to the Polk Power Station and emitted from Unit 1 as "slip." TEC estimates that the requirement to install and operate a Selective Catalytic Reduction (SCR) system on Polk Unit 1 will generate approximately 72 tons of airborne ammonia emissions per year. This is compared to a NO_x reduction of approximately 495 tons per year assuming that the SCR system does not impact the availability of Polk Unit 1. These are significant issues, and TEC requests that the Department include it in its analysis of this project.

Comment 2 - PSD Permit Modification, Page 1 of 4, Paragraphs 4 and 5

On May 10, 2001, TEC submitted additional information including a revised vendor quotation for a SCR system, a revised cost effectiveness analysis for the application of a SCR system to Polk Unit 1, an overview of the recently issued draft permit and EPA response with respect to the Kentucky Pioneer Project, and, most importantly, a proposal to work with the Department to reduce NO_x emissions from Polk Unit 1 through the implementation of a Continuous Improvement Plan (CIP). This letter was not referenced in either paragraph 4 or 5 on page 1 of 4, and TEC requests that the Department acknowledge the submittal of this document.

Comment 3 - Permit Modification, Page PM-3, Footnote

In the footnote, the Department has imposed an ammonia slip emissions limit of 5 ppmvd at the SCR exit. However, as found in specific condition 24 of the recently permitted Bayside Power Station PSD permit, ammonia slip emissions were limited to the following:

> "*Additional Ammonia Slip Testing: If the tested ammonia slip rate for a gas turbine exceeds 5 ppmvd corrected to 15% oxygen when firing natural gas during the annual test, the permittee shall:*
>
> a. *Begin testing and reporting the ammonia slip for each subsequent calendar quarter;*
> b. *Take corrective actions before the ammonia slip exceeds 7 ppmvd corrected to 15% oxygen that lowers the ammonia slip to less than 5 ppmvd corrected to 15% oxygen; and*
> c. *Test and demonstrate that the ammonia slip is less than 5 ppmvd corrected to 15% oxygen within 15 days after completing the corrective actions.*
>
> *Corrective actions may include, but are not limited to, adding catalyst, replacing catalyst, or other SCR system maintenance or repair. After demonstrating that the ammonia slip level is less than 5 ppmvd corrected to 15% oxygen, testing and reporting shall resume on an annual basis. [Rules 62-4.070(3) and 62-297.310(7)(b), F.A.C.]*"

This provides TEC with the flexibility to operate a baseloaded unit through a peak generating season such as summer without being forced to remove the unit from service to replace SCR catalyst. If a SCR system is ultimately required to be installed on the Polk Unit 1 CT, TEC requests that the same language found in the Bayside Power Station air construction permit be included in the draft permit modification.

Comment 4 - BACT Determination, Page BD-1, Paragraph 3

The Department indicates that it received the original BACT submittal on 11/27/00. This contradicts the statement on page 1 of 4 of the PSD permit modification in which the Department indicates that it received the submittal on 11/17/00. TEC requests that the Department clarify this inconsistency.

Comment 5 - BACT Determination, Page BD-1, Paragraph 4

The Department indicates that it will consider a number of additional factors when making the final BACT Determination. The factors include:

- *Any Environmental Protection Agency determination of BACT pursuant to Section 169, and any emission limitation contained in 40 CFR Part 60 - Standards of Performance for New Stationary Sources or 40 CFR Part 61 - National Emission Standards for Hazardous Air Pollutants.*
- *All scientific, engineering, and technical material and other information available to the Department.*
- *The emission limiting standards or BACT determination of any other state.*
- *The social and economic impact of the application of such technology.*

While it is fair to consider these factors under normal circumstances, the PSD and Title V permits governing the operation of Polk Unit 1 clearly mandate that this BACT Determination be made by considering:

> *"data gathered on this facility, other similar facilities, and the manufacturer's research."*

TEC feels that this BACT Determination is a special case, it should be carried out as defined by the above referenced permits.

Comment 6 - BACT Determination, Page BD-2, Second Bullet

The second bullet on Page BD-2 indicates that the Department would consider the emission limiting standards or BACT determinations of any other state when considering the appropriate NO_x limit for the Polk facility. Although TEC feels that this is outside of the defined scope of this particular BACT Determination, it is nonetheless important to note that if the Department takes this position, it would be prudent to await the issuance of the final Kentucky Pioneer PSD permit, since this is a new and clean IGCC facility. As the Department is aware, this permit currently exists in draft form and limits NO_x emissions to 15 ppmvd @ 15% O_2 through the use of steam injection. This limit is actually less stringent than the limit proposed by the Department.

Comment 7 - BACT Determination, Page BD-2, Paragraph 3

In paragraph 3, the Department identifies several recently permitted IGCC facilities and their NO_x emissions limits found in Table 1 on the same page. However, the Department does not specify the basis how each limit was established. Specifically, it is worth noting that the Delaware City Motiva project was permitted under a delegated Lowest Achievable Emission Rate (LAER) determination, and was not required to install SCR for NO_x control. TEC feels that this is a significant omission, and requests that the Department add a column to indicate the basis for each NO_x emission limit.

Comment 8 - BACT Determination, Page BD-2, Paragraph 3

The Department identifies SCR as the "typical BACT determination for pipeline natural gas fired combined cycle CT's" and states that:

> *"the application of SCR with an emission limit of 0.125 lb/MMBtu has been determined to represent BACT for a (conventional) Florida coal-fired unit."*

However, no reference is given to the typical (or recent) BACT determination for a syngas fired combined cycle CT. Since this project involves the permitting of a syngas fired combined cycle CT, TEC requests that the Department include this language in Paragraph 3 of Page BD-2 to complete the discussion.

Comment 9 - BACT Determination, Page BD-2, Table 1

As mentioned above, Table 1 lists five IGCC projects (including the Polk facility) and their representative NO_x emission limits. However, some of the limits are represented in units of lb/MMBtu, while the Delaware City Motiva project is listed in terms of ppmvd. In order to accurately compare the limits for each facility, they should be presented in equivalent units. For example, the permit governing the Wabash River Station facility contains the language below in condition D.2.3 limiting NO_x emissions:

> *"Pursuant to CP 167-2610-00021 (Issued May 27, 1993), the nitrogen oxides (NO_x) emissions from the gas turbine shall not exceed 25 ppmdv at 15 percent oxygen for syngas or natural gas combustion."*

It is unclear why the Department has represented the emissions limits in different units, but in order to make a complete and accurate comparison, TEC requests that all NO_x emissions limits found in this table be represented in terms of the same units.

Comment 10 - BACT Determination, Page BD-3, Paragraph 2

Paragraph 2 states that:

> *"The gasifier feedstock is more or less completely gasified to so-called synthesis gas (syngas)...."*

Although this is true in theory, this is not true for Polk Power Station. In fact, in most cases, the feedstock is not completely gasified, and some carbon exits the process as residual fuel material. The extent of gasification depends on the characteristics of the feedstock, the availability of pure oxygen for the reaction, and other reaction characteristics such as temperature and pressure. TEC requests that the description of the gasification process found on Page BD-3 be corrected to reflect site specific operation.

Comment 11 - BACT Determination, Page BD-4

The discussion found on Page BD-4 centers on the Texaco gasification process, and, specifically, identifies other facilities that use the Texaco gasification process to produce some end product.

These end products include ammonia, methanol, syngas, hydrogen, and electricity. While this discussion is interesting from a technical standpoint, it does not seem to be relevant to this project because the IGCC applications are completely unrelated and/or not similar to the Polk Power Station IGCC. Further, of the twelve facilities listed on Page BD-4, only five actually combust syngas for the purpose of power production. As such, the other seven listed projects should be stricken from the discussion because they are not relevant to this project.

Of the twelve projects listed on Page BD-4, only one domestic unit (Delaware City Motiva) uses the Texaco gasification process to produce syngas for firing in two GE 6FA combustion turbines. As noted previously, this unit was permitted under a LAER Determination and is limited to emit no more than 16 ppmvd NO_x @ 15% O_2. This facility uses steam injection for NO_x control and is one technical generation ahead of the Polk IGCC facility. This is the only domestic project (subject to the same Federal rules and regulations as the Polk facility) listed on Page BD-4 that utilizes the Texaco gasification process, and is the only project that should be considered within the scope of this project. This project was discussed in detail on page 8-2 and 8-3 of TEC original submittal. As noted in the submittal:

> *"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."*

In other words, even though the Delaware facility uses the Texaco gasification process to produce syngas for firing in two GE 6FA combustion turbines, there are significant technical differences between the facilities that prevent one from considering them to be 'similar' as applied to this project. In fact, the improved emissions performance of the Delaware facility was made possible by analyzing and improving on the process implemented at the Polk site. The discussion on Page BD-4 as it relates to the Delaware facility is interesting from a technological standpoint, but the Department should note that significant technical differences do exist between the Delaware and Polk IGCC facilities.

Comment 12 - BACT Determination, Pages BD-5, BD-6 and BD-7

On pages BD-5, BD-6 and BD-7, the Department lists several installations of GE CTs that fire syngas from various feedstocks. Of the units listed and discussed on these pages, only one (the Polk Unit 1 CT) is a GE 107FA unit, and many do not fire syngas produced from coal. Further, the Department gives a broad overview of each facility without providing any details regarding the NO_x emissions limits or the actual operating history. In many cases, the NO_x control strategy for a facility is not identified. Of those that are identified, none utilize a SCR system for NO_x control. As such, TEC requests that the Department add this critical detailed information for completeness.

The only unit identified on Pages BD-5, BD-6 or BD-7 that TEC believes can be considered similar for the purposes of this BACT Determination is the Wabash River IGCC facility located in Terre Haute, Indiana. This facility fires syngas derived from a coal feedstock in a GE 7FA combustion turbine and was discussed technically as well as identified as the only other IGCC facility that could be considered 'similar' for the purposes of this BACT Determination on Page

8-1 of the November 17, 2000 TEC BACT submittal. Although the technical discussion found on Pages BD-5, BD-6 and BD-7 is interesting, it is unclear how it applies to this special case. If the Department has provided this discussion to establish similarity between these units and the Polk IGCC facility, the reasoning and logic behind this conclusion should be discussed. Otherwise, since this discussion has no apparent relevance to this project, TEC requests that it be stricken from the BACT Determination.

Comment 13 - BACT Determination, Page BD-9, Paragraph 4

In Paragraph 4 of Page BD-9, the Department estimates that uncontrolled NO_x emissions from the Polk Unit 1 CT are as high as 200 ppmvd @ 15% O_2. TEC requests that the Department clarify how this estimate was arrived at.

Comment 14 - BACT Determination, Page BD-9, Paragraph 5

This paragraph discusses diluent injection as a means of NO_x control, indicating that the Polk facility utilizes advanced combustor design to reduce NO_x emissions to 25 ppmvd for gas firing. TEC requests that language be added to this section to specify that the fuel is syngas and the combustors are Multinozzle Quiet Combustors (MNQCs).

Comment 15 - BACT Determination, Page BD-10, Paragraph 3

A large portion of the Department's argument for the applicability of a SCR system to Polk Unit 1 centers on the fact that SCR systems are now being successfully applied to combined cycle units without the occurrence of sulfur poisoning due to the application of advanced catalysts. In the above referenced paragraph, the Department discusses the fact that SCR has been successfully applied to natural gas fired combined cycle CTs, oil fired boilers, and coal fired boilers. While this may be the case, there are significant technical differences between a syngas fired combined cycle CT and the three technologies cited above.

The main difference between a natural gas fired combined cycle CT and a syngas fired combined cycle CT lies in the composition of each fuel. According to the Department, when firing natural gas, a SCR system experiences inlet sulfur loading in the range of 0.0006 lb SO_2/MMBtu. Conversely, when firing syngas, the SCR experiences an inlet loading of 0.032 - 0.146 lb SO_2/MMBtu. This is in the range of (if not higher than) the diesel backup fuel fired in a combined cycle combustion turbine such as the one permitted by CPV Gulf Coast.

As the Department points out in paragraph 3 of Page BD-10, the CPV Gulf Coast facility would be <u>capable</u> of firing 0.05 % sulfur diesel oil for up to 30 days per year while emitting 10 ppmvd @ 15% O_2 of NO_x. The Polk NO_x BACT Determination, however, requires that Unit 1 utilize a SCR for NO_x control for up to 7,884 hours per year while accommodating an inlet sulfur loading as great or greater than that of the CPV Gulf Coast facility when firing distillate oil. Since, in the view of the Department, the CPV Gulf Coast facility is only capable of firing fuel oil for up to 30 days (equivalent to720 hours) per year while using a SCR for NO_x control, it seems inappropriate to expect that Polk Unit 1, with the same or greater SCR inlet sulfur loading would be capable of controlling NO_x through the use of a SCR for a period that is over ten times greater. TEC therefore requests that the Department provide further technical justification identifying why the Polk Unit 1 facility would be able to control NO_x through the use of SCR for up to 7,884 hours per year at an emission rate of 5 ppmvd @ 15% O_2 while the CPV Gulf Coast facility would only be capable of controlling NO_x for up to 720 hours per year at an emission rate of 10 ppmvd @ 15% O_2. This is a critical point, and should be addressed.

Additionally, in Paragraph 3 on Page BD-10, the Department asserts that SCR systems have been successfully applied to coal and oil fired utility boilers that experience high inlet SO_2 loading. Although this is an accurate statement, the fact that SCR can be successfully applied to coal and oil fired utility boilers does not necessarily mean that it can be successfully applied to a syngas fired combined cycle CT. The primary technical concern that TEC has raised regarding the application of a SCR system to Polk Unit 1 involves the formation of ammonium sulfate and ammonium bisulfate compounds in the HRSG section. Coal and oil fired boilers, however, do not share this technical concern for the following two reasons: (1) Most coal and oil fired boilers do not utilize HRSGs for additional heat transfer; and (2) The ammonia that reacts with SO_3 in a coal fired boiler is preferentially adsorbed onto the flyash. However, in a syngas fired combined cycle combustion turbine, there is not as much flyash in the flue gas stream. As such, the excess ammonia in a syngas fired combined cycle application is free to react with the sulfur compounds present in the flue gas stream.

In summary, it is inappropriate to conclude that because SCR has been successfully applied to coal and oil fired boilers, it can necessarily be successfully applied to a syngas fired combined cycle CT. The technologies are completely different, with different characteristics and different reaction mechanisms.

Comment 16 - BACT Determination, Page BD-10, Paragraph 4
This paragraph is an overview of recently permitted combined cycle CT projects in the State of Florida. Since the Bayside Power Station is a combined cycle CT application, TEC requests that it be included in this summary.

Comment 17 - BACT Determination, Page BD-11, Paragraph 1
In this paragraph, the Department indicates that SCR is the technology of choice for reducing NO_x emissions from F class combustion turbines. However, it is important to specify that the primary fuel in these applications is natural gas, not syngas. Due the significant fuel differences, this is an important distinction to make and TEC requests that the Department make this clear in its description.

Comment 18 - BACT Determination, Page BD-12, Paragraph 2
The Department indicates that, given the opportunity, it would be willing to reevaluate the cost effectiveness of the application of $SCONO_x$ control technology to Polk Unit 1. Since both the Department and TEC have rejected the $SCONO_x$ technology, there is no reason for the inclusion of this language, and TEC requests that it be stricken.

Comment 19 - BACT Determination, Page BD-13, Paragraph 3 and Table

In this paragraph, the Department indicates that it compared SCR inlet streams found in the associated table for various technologies to determine the chemical constituents for which the application of a SCR system to a syngas fired CT would be of possible concern. For the syngas inlet stream, the Department used values from TEC publications and the United States Environmental Protection Agency (USEPA) Acid Rain website to represent sulfur compound loading, and emission factors from the Kentucky Pioneer PSD permit application for all other constituents. This comparison seems to include several assumptions by the Department, which may be flawed or inappropriate when applied to the Polk IGCC facility.

First, by using the sulfur emission factor from the Polk IGCC facility and the metals emission factors from the Kentucky Pioneer PSD permit application, the Department has assimilated data from two different sources to arrive at a syngas composition that may not be representative of either facility. Each facility uses a different feed stock to produce syngas, which will ultimately affect the emissions from the combustion turbines. The Polk IGCC facility uses coal and, on occasion, a mixture of coal and up to 60% petcoke to produce the syngas fired in the CT. On the other hand, the Kentucky Pioneer IGCC facility will utilize a mixture of municipal solid waste and petcoke to produce the syngas fired in the CT. Clearly, since the two feedstocks are different, it can be concluded that the emissions resulting from firing each syngas would be different. In light of this, it is unclear why the Department assumed that it would be appropriate to combine the emissions data from each facility, and TEC requests that FDEP provide the reasoning behind this assumption.

Second, the Department has highlighted Cobalt and Nickel as constituents of concern when considering the application of a SCR system to a syngas fired unit. However, as discussed in the attached February 14, 2001 comment letter to FDEP, TEC feels that sulfur should be a significant concern also. TEC understands that SCR systems have been successfully applied to natural gas fired combined cycle units as well as coal and oil fired boilers. However, natural gas fired combined cycle units have a significantly lower sulfur inlet loading than do syngas fired combined cycle units, and the chemistry in coal and oil fired boilers is different than that in a syngas fired combined cycle application (see Comment 15). As such, TEC requests that the Department provide additional details regarding the exclusion of sulfur as a constituent of concern, as well as provide additional supporting data showing why cobalt and nickel are the only two constituents of concern for a syngas fired IGCC. Finally, TEC requests that the Department identify the algorithm or criteria used to determine which constituents are of concern.

Finally, as discussed in Comment 15, the technologies listed in the Table on Page BD-13 are all completely different for a variety of reasons. It is unclear why the Department has chosen to compare such a wide variety of technologies fired by such a diverse array of fuels. TEC feels that it would be prudent to identify the significant differences that exist between each of the technologies in the Table on Page BD-13, and requests that the Department either incorporate some discussion to that effect in the paragraph immediately preceding the Table, or eliminate the Table altogether.

Comment 20 - BACT Determination, Page BD-13, Paragraph 4

In Paragraph 4, the Department identifies several coal fired facilities and oil refineries that have applied SCR systems, but gives no indication of the operating history. In addition, FDEP indicates that a Polish IGCC facility which is currently proposed will be designed to gasify a variety of oils and refinery resids while controlling NO_x through the use of SCR. TEC feels that it is inappropriate to compare any of these units to the Polk IGCC facility because they either: (1) are completely different in technology and/or feedstock and (2) have no operating history from which to draw a reasonable evaluation of the effectiveness of SCR operation. TEC would like to take this opportunity to caution against making these types of comparisons. They are extremely risky due to the reasons discussed above and it is inappropriate to assume that because an IGCC facility is proposed to control NO_x emissions through the use of SCR that it will be successful in doing so.

Comment 21 - BACT Determination, Page BD-13, Paragraph 4

At the end of paragraph 4, the Department points out that TEC obtained SCR performance guarantees from Engelhard, which is accurate. However, due to the fact that TEC was constrained by a 30 day deadline after the last NO_x stack test to submit the BACT analysis, this quote was based on general information. Subsequently, TEC solicited additional bids from several catalyst vendors based on project and site specific data. Engelhard, which had previously offered general information used in this analysis, elected not to bid on the Polk IGCC project upon review of the site specific information. One catalyst vendor, Deltak, did offer a guarantee for this project of 5 ppmvd @ 15% O_2 NO_x emissions and 5 ppmvd @ 15% O_2 ammonia slip emissions. However, in the cover letter, Deltak stated:

> *"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."*

This letter was submitted to FDEP both by e-mail and Federal Express on May 10, 2001 and is enclosed. However, since the information was neither requested nor required to complete the project, it was not considered by the Department in this Determination. This information is significant, and TEC requests that the Department review it as part of this Determination.

Comment 22 - BACT Determination, Page BD-14, Paragraph 1

This paragraph is a paraphrase of a comment submitted to the Department as part of a letter submitted in response to a request for additional information. The response was submitted on

February 14, 2001 and contained several additional comments that have not been addressed by the Department. Furthermore, the comment addressed by the Department in this paragraph is not an accurate representation of the comment submitted by TEC. Specifically, the Department has omitted the first sentence from the original comment, which states:

> *"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."*

It is unclear why this language was omitted, but TEC requests that it be reinserted into the BACT Determination to accurately reflect the intentions of TEC. The omitted language was meant to emphasize the fact that although BACT for combustion turbines had been established as 3.5 ppm, it was established for a combustion turbine that fired a fuel with very different characteristics than syngas.

Comment 23 - BACT Determination, Page BD-14, Paragraph 3
In this paragraph, the Department indicates that it has authored the PSD permit to allow for SCR induced, unscheduled shutdowns. Since the Polk CT is not designed for bypass operation in the event of a SCR induced, unscheduled shutdown, it is unclear which part or which condition of the permit is referred to in this section. TEC requests that the Department clarify this statement.

Comment 24 - BACT Determination, Page BD-15, Paragraph 1
This paragraph was part of the same comment addressed on Page BD-14, Paragraph 1. Again, it is unclear why the response has not been represented as written by TEC, and TEC requests that the Department present the response to its request for additional information as submitted to FDEP and respond to all of the material contained therein. TEC feels that there were several significant issues outlined in the response, and, for the record, TEC has enclosed the subject comment letter containing the complete text of its responses.

Comment 25 - BACT Determination, Page BD-15, Paragraph 2
This Paragraph reiterates the fact that SCR has been successfully applied to coal fired boilers. However, as found in previous sections of the BACT Determination, the Department has not considered the differences in technology or chemistry between coal fired boilers and syngas fired combined cycle CTs. TEC requests that the Department consider these differences before concluding that because SCR can be applied to a coal fired boiler, it can necessarily be applied to a syngas fired combined cycle CT.

Comment 26 - BACT Determination, Page BD-16, Paragraph 1
In this paragraph, the Department has presented portions of two separate paragraphs contained in the enclosed February 14, 2001 response to additional information as one comment. It is unclear why TEC's comments are misrepresented in this fashion, and for the record, the actual text submitted is presented below:

> *"The conclusion that SCR must be applied to Polk Unit 1 simply because the cost of NO_x control is lower than what the cost of NO_x control might be at the CPV Gulf Coast facility does not seem to take into account environmental, energy, and other costs as prescribed in the definition of BACT. In addition, this conclusion does not seem to consider the operation of 'other similar facilities' or 'manufacturer's research' as called for in Specific Condition A.50 of the Polk Power Station Title V Permit.*
>
> *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)"*

In combining the two paragraphs in the BACT Determination (in reverse order), the Department omitted the reference to the fact that "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." As noted in previous comments, TEC requests that the Department present TEC's responses to the request for additional information as written, to avoid confusion.

Comment 27 - BACT Determination, Page BD-16, Paragraph 3

The Department indicates in this paragraph that the portion of the SCR system costs due to replacing the power lost in the event that Polk Unit 1 cannot operate because of a SCR system malfunction are not appropriate in this evaluation. TEC does not feel that it is appropriate to strike these costs, as they are real and will be incurred by the Company when a forced outage due to a SCR system malfunction occurs. Furthermore, in determining this cost, TEC used the incremental cost of power generation; that is the difference between the cost of operating Polk Unit 1 and the cost of operating another typical unit within the TEC generating system rather than estimating the cost of purchasing the lost power during a peak generating period such as the summer months. This creates a cost analysis that is extremely conservative. As such, TEC requests that the Department include the cost of lost power generation due to SCR malfunction when estimating the cost effectiveness of a SCR system for Polk Unit 1.

Comment 28 - BACT Determination, Page BD-16, Paragraph 3

In the middle of the paragraph, the Department makes the statement:

> *"Since the basis of these costs was $0.04/kwh, the Department presumes that each cost was developed based upon some measure of lost revenue and not increased natural gas costs. Accordingly, the Department will reject these line items...."*

The Department should identify how it arrived at this presumption, as it may be inaccurate.

Comment 29 - BACT Determination, Page BD-17, Paragraph 1

The Department claims that:

> *"Since diluent flow will likely increase with generating load (up to some load point) and since syngas flow is directly proportional to unit load, it is likely that a measure of diluent flow to syngas flow (which the applicant purports is more appropriate) makes some sense, as in the case of reviewing the entire load range of a combustion turbine. However, the Department wishes to better understand the impact of diluent flow on NO_x emissions, given that the diluent is the control media for NO_x. Since the tests are at a similar load point, the syngas flow and its associated variability can be effectively ignored."*

The last sentence of this statement is inaccurate, since the variability of the syngas flow cannot be ignored any more than the variability of the associated feedstock can. The Polk facility uses a variety of fuels in the gasification process to produce the syngas fired in the CT. The variety of fuels fired produces a variety of syngases, each with different heat contents. This is a critical point to understand, as it explains why, in some cases, a syngas with a higher heat content can be fired at a lower flow rate than a syngas with a lower heat content, while still producing the same amount of power. Accordingly, as TEC pointed out in its original response to FDEP incompleteness issues, a better measure of evaluating the effectiveness of the Unit's ability to control NO_x is to examine the ratio of diluent flow to syngas flow. This allows one to determine whether or not the NO_x control system is being operated properly. If the Department wishes to better understand the impact of diluent flow on NO_x emissions, it must also consider the heat content of the syngas when making its evaluation. As such, TEC requests that the Department acknowledge the importance of the syngas variability when conducting its evaluation, and adjust its conclusions accordingly.

Comment 30 - BACT Determination, Page BD-21, Paragraph 2

The Department has rejected the costs due to HRSG modifications, claiming that they will not be necessary if the NO_x emissions are held to 5 ppmvd and the ammonia slip emissions are minimized. However, without any operational experience on any unit in the country, this is an assumption that cannot be made. In addition, based on the statement made by Deltak, (see Comment 21) it appears that there are significant concerns with respect to ammonium sulfate and ammonium bisulfate pluggage, indicating that the unit will, in fact, need to be cleaned. It is also important to note that this statement was made despite the fact that the quote guarantees 5 ppmvd NO_x @ 15% O_2 with an ammonia slip level of 5 ppmvd @ 15% O_2. This is the level of NO_x emissions and ammonia slip emissions that the Department claims will eliminate plugging and fouling concerns. Furthermore, since no operational experience exists regarding the operation of SCR on an IGCC system, failure to modify the HRSG in preparation for possible cleaning would be shortsighted. As such, TEC requests that the cost to install a SCR system should be adjusted to include the cost of modify the HRSG for cleaning.

Comment 31 - BACT Determination, Page BD-21, Paragraph 3

The Department indicates that, since data were not available for other IGCC facilities operating SCR systems, it has:

> *"...compensated for the shortage of IGCC specific data through a reasonable extrapolation of SCR and fuel data from utility units and refineries."*

This does not comport with the requirements of the permit to perform the analysis based on 'test data gathered at this facility, other similar facilities, and manufacturer's research.' The permit condition does not specify that it is appropriate to extrapolate data from other dissimilar facilities. Furthermore, as discussed extensively in this document, there are significant technical differences between 'utility units and refineries' that prevent 'reasonable extrapolation of SCR and fuel data.' Since FDEP used this as the basis for the BACT determination, the overall conclusion that SCR should be applied to Polk Unit 1 should be rejected.

Comment 32 - BACT Determination, General Comment

In general, it appears as though the Department has concluded that SCR technology should be applied to Polk Unit 1 based on data gathered from several other, technically different facilities. TEC has significant concerns with this approach, noting that although SCR has been successfully demonstrated on natural gas fired combined cycle facilities as well as coal and oil fired boilers, the differences between these facilities should not be discounted. In addition, due to these differences, it is not reasonable to conclude that because SCR technology was proven effective, it will necessarily be effective on a syngas fired IGCC. In addition, by comparing the Polk IGCC facility to dissimilar facilities such as coal and oil fired boilers and natural gas fired combined cycle combustion turbines, the Department seems to be violating the conditions of the PSD and Title V permits governing the facility. Specifically, both permits indicate that this BACT Determination must be carried out considering:

> *"data gathered on this facility, other similar facilities, and the manufacturer's research."*

Although it is somewhat unclear what the meaning of the word 'similar' is, TEC feels that it is not reasonable to consider coal and oil fired boilers as similar to the Polk IGCC facility because the technologies and fuels used to generate electricity are not comparable. Furthermore, it is not reasonable to consider a natural gas fired combined cycle combustion turbine as similar to the Polk Power Station syngas fired combustion turbine because of considerable differences in the fuel compositions. As indicated in the original BACT submittal received by the Department on November 17, 2000, TEC feels that the only facility that can be reasonably considered 'similar' in both technology and fuel fired is the Wabash River Station IGCC facility. This facility gasifies coal and fires the syngas in a GE 7FA combustion turbine.

The Department has addressed in this BACT Determination a number of responses by TEC to its original request for additional information. The Departments treatment of these responses was questionable due to the fact that the responses that were addressed were presented out of context, and in some cases, were misrepresented. In addition, TEC submitted several other responses that were not considered by FDEP, and TEC feels that they should be addressed in this Determination as well.

Finally, on May 10, 2001, TEC submitted additional information to the Department that was not considered in this Determination. This submittal included: (1) a revised SCR cost analysis, (2) a new site specific SCR quote from Deltak indicating that significant technical concerns exist for the application of SCR to the Polk IGCC facility, (3) confirmation that Engelhard, after reviewing the site specific information had chosen not to bid on this project, (4) an overview of the Kentucky Pioneer draft permit and, most importantly, (5) a request to work with the Department on implementing a continuous improvement program with the goal of reducing NO_x emissions from the Polk IGCC facility through the use of process optimization. This information was not considered in the current draft of the BACT Determination, and TEC requests that the Department reevaluate TEC's requests, as significant technical concerns still exist regarding the application of a SCR system to Polk Unit 1.

TEC appreciates the opportunity to provide comments in this matter, and if you have any questions, please 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\SKT258

Enclosures

c/enc: Mr. Michael Halpin – FDEP
Mr. Syed Arif - FDEP
Mr. Jerry Kissel - FDEP SW

Department of
Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

July 25, 2001

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

Re: Request for Guidance
Polk Power Station

Dear Mr. Hornick:

The Title V Section has received and reviewed your request for guidance to combust a combination of syngas and fuel oil dated July 10, 2001. Our review of your current operating permit has yielded the following:

The current Title V operating permit for the facility allows for the combustion of either syngas or Number 2 fuel oil in Polk Unit 1. Syngas is permitted as the primary fuel. Fuel oil is permitted to be fired no more than 876 hours per year, determined by using an annual capacity factor calculation. Recordkeeping requirements are included in the permit to assure compliance with this capacity factor limitation. The permit contains emission limits when firing either fuel is fired. The permit does not address emission limits when a combination of the two fuels are fired.

Since there are no emission limits included in the permit for the co-firing of syngas and fuel oil, it is presumed that co-firing of the two fuels was not anticipated at the time Polk Unit 1 underwent PSD and Preconstruction review. Since the Title V operating permit is dependent on these permits, it appears that the co-firing of the two fuels is not currently allowed.

If you have any other questions, please contact Edward J. Svec at 850/921-8985.

Sincerely,

Scott M. Sheplak, P.E.
Administrator
Title V Section

SMS/es

copy furnished to:
Mr. A. Linero, P.E., FDEP, NSR
Mr. J. Kissel, P.E., FDEP, SWD

TECO
TAMPA ELECTRIC

FACSIMILE TRANSMITTAL SHEET

ENVIRONMENTAL AFFAIRS
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DATE: 1-30-02 X **FOR IMMEDIATE DELIVERY**

TO: Mr. Howard Rhodes

COMPANY: Division of Air Resources Management

NUMBER OF PAGES (Including cover page): 3

FROM: Greg Nelson

COMMENTS:

BEST AVAILABLE COPY

TAMPA ELECTRIC

January 30, 2002

Mr. Howard Rhodes
Division Director
Division of Air Resources Management
Florida Department of Environmental Protection
2600 Blair Stone Road
MS 5500
Twin Towers Office Building
Tallahassee, Florida 32399-2400

Via Fax and Mail

Re: Tampa Electric Company (TEC)
Polk Power Station
Biomass Test Burn

Dear Mr. Rhodes:

The purpose of this letter is to update you on the progress of Tampa Electric Company's ("TEC") attempt to use biomass as a gasification feedstock in Polk Unit 1 and to request that you consider some additional factors in making a determination of Best Available Control Technology ("BACT"). As you are aware, TEC received authorization to perform the test burn from the Florida Department of Environmental Protection ("Department") on December 21, 2001. Upon receipt of the authorization, TEC immediately began procuring biomass fuel to facilitate the test burn. On December 30 and 31, 2001, TEC successfully gasified a blend of biomass, coal and pet coke, in accordance with the authorization. The blend consisted of approximately one percent biomass by weight, which equates to approximately one ton of biomass gasified per hour.

Due to the initial success of the biomass test burn, TEC would like to continue to test other renewable fuels in Polk Unit 1. This is a process that TEC is undertaking in an attempt to introduce a portion of biomass into the fuel mix for Polk Unit 1. At this time, TEC is evaluating the use of eucalyptus, cottonwood, switchgrass and other similar wood products. However, the introduction of biomass as a viable alternative fuel in Polk Unit 1 is developmental in nature and will need to be evaluated over a period of time based on numerous factors, including fuel suppliers, economics, operational constraints and unit capabilities. The ability to gasify these renewable fuels and other environmentally beneficial fuel sources complements TEC's green energy program for which it has an approved tariff in place. In addition, the use of biomass as a feedstock will provide environmental benefits to the public.

The recent Department draft determination (DEP File Nos. 1050233-007-AC and PSD-FL-194F), requiring the application of a Selective Catalytic Reduction System (SCR) on Polk Unit 1, would jeopardize the viability of TEC's renewable energy program at Polk Power Station. TEC believes that the application of an SCR to Polk Unit 1 will further complicate operation of the unit and thereby discourage further exploration of renewable fuel sources at the site. The application of SCR to Polk Unit 1 will also introduce additional factors that will make it difficult to determine the effects of biomass fuel and operation variations versus those caused by SCR on the overall reliability of Unit 1.

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

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

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

In light of our continued desire to test beneficial alternative feedstocks, TEC requests that the Department reconsider this determination and establish a BACT limit for NO_x, when firing syngas, of 15 ppmvd @ 15% O_2 on a 30-day rolling average. TEC will be able to achieve continuous compliance with this limit through the modification of existing equipment and control systems as well as the installation of additional equipment used to minimize NO_x emissions by July 1, 2003. TEC proposes to submit, for Department approval, a NO_x compliance plan outlining the specific modifications necessary to achieve continuous compliance with the proposed BACT limit for NO_x.

The current NO_x emission limit for Polk Unit 1, when firing syngas, is 25 ppmvd @ 15% O_2, which represents the interim BACT in accordance with the initial permit for this facility. The proposed NO_x emission limit will result in a reduction in allowed NO_x emissions from Polk Unit 1 of 40%, while maintaining the unit's ability to gasify renewable fuels.

We note that TEC is not inherently opposed to SCR technology on conventional combined cycle plants. In accordance with our agreements with the Department and EPA we will install SCR on eleven (11) new natural gas-fired combustion turbines at the nearby Bayside Station using combustion turbines manufactured by General Electric. On these new units, SCR will be applied to achieve 3.5 ppmvd on units that can achieve 9 ppmvd without SCR. Similarly, the United States Department of Energy is not inherently opposed to SCR as it has funded several demonstration projects on coal-fired plants and hosts conferences on this subject.

TEC believes that its BACT proposal fits well the utilization of biomass fuel. We would be happy to work with you to more definitively substantiate this position. TEC appreciates the Department's cooperation in the review of this matter. If you need any additional information or clarification on any of the issues presented above, please do not hesitate to contact me at (813) 641-5016

Sincerely,

Gregory M. Nelson

Gregory M. Nelson
Director
Environmental Affairs

EA/bmr/GMN128

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
NOTICE OF FINAL PERMIT

In the Matter of an
Application for Permit by:

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

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

Enclosed is Final Permit Number 1050233-007-AC for the Polk Power Station IGCC unit, Emission Unit 001. This permit requires Tampa Electric Company to comply with a NO_X emission limit of 15 ppmvd @ 15% O_2 on a 30-day rolling average effective July 1, 2003. This permit is issued pursuant to Chapter 403, Florida Statutes.

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

Executed in Tallahassee, Florida.

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

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this Notice of Final Permit (including the Final permit) was sent by certified mail (*) and copies were mailed by U.S. Mail before the close of business on 2/5/02 to the person(s) listed:

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

Clerk Stamp

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

Victoria Gibson February 5, 2002
(Clerk) (Date)

FLORIDA

Department of
Environmental Protection

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

Jeb Bush
Governor

David B. Struhs
Secretary

PERMITTEE

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

DEP File No. 1050233-007-AC
Permit No. PSD-FL-194F
Emission Unit 001
NO_X Emissions Reduction
SIC No. 4911

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

PROJECT AND LOCATION

As per the original PSD permit: "*One month after the test period ends (estimated to be by June 1, 2001), the Permittee will submit to the Department a NO_X recommended BACT Determination as if it were a new source using the data gathered on this facility, other similar facilities and the manufacturer's research. The Department will make a determination on the BACT for NO_X only and adjust the NO_X emission limits accordingly.*" Based upon the Department's review of the permittee's submittals, the Department has determined that the NO_X emission limits for Emission Unit 001 should be reduced.

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

STATEMENT OF BASIS

This construction permit is issued under the provisions of Chapter 403 of the Florida Statutes (F.S.), and Chapters 62-4, 62-204, 62-210, 62-212, 62-296, and 62-297 of the Florida Administrative Code (F.A.C.). The above named permittee is authorized to modify the facility in accordance with the conditions of this permit and as described in the application, approved drawings, plans, and other documents on file with the Department of Environmental Protection (Department).

ATTACHED APPENDIX MADE A PART OF THIS PERMIT

Appendix BD-2001

Howard L Rhodes

Howard L. Rhodes, Director
Division of Air Resources Management

FACILITY DESCRIPTION

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

REGULATORY CLASSIFICATION

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

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

PERMIT SCHEDULE

- 05/23/01 Department published the Public Notice in the Tampa Tribune.
- 05/10/01 Department distributed initial Intent to Issue Permit.
- 02/15/01 Department received additional information; application deemed complete.
- 12/04/00 Department requested additional information.
- 11/17/00 Department received applicant's BACT submittal

RELEVANT DOCUMENTS

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

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

PERMIT SPECIFIC CONDITIONS

This permit addresses the following emissions unit:

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

1. The provisions of the Title V Operating Permit 1050233-001-AV remain in effect. However, an application shall be submitted to revise that permit consistent with the emission limit changes herein.
2. The provisions of air construction permits PSD-FL-194, PSD-FL-194A, PSD-FL-194C, PSD-FL-194D and PSD-FL-194E are incorporated into this air construction permit except for the changes to the NO_X emission limit while firing syngas in the affected portions of Specific Condition H below.

H. Emission Limits

1. The maximum allowable emissions from the IGCC combustion turbine, when firing syngas and low sulfur fuel oil, in accordance with the BACT determination, shall not exceed the following:

EMISSIONS LIMITATIONS - 7F CT POST DEMONSTRATION PERIOD

POLLUTANT	FUEL	BASIS[a]	LB/HR*	TPY[b]
NO_X	Oil	42 ppmvd**	311	N/A
	Syngas	~~25~~ 15 ppmvd	~~222.5~~ 132	~~1,044~~ 620

(*) Emission limitations in lbs/hr are 30-day rolling averages, except for NO_X while firing syngas, which as of July 1, 2003 is limited in ppmvd (at 15% oxygen) and complied with on a 30-day rolling average via CEMS. Pollutant emission rates may vary depending on ambient conditions and the CT characteristics. Manufacturer's curves for the emission rate correction to other temperatures at different loads shall be provided to DEP for review 120 days after the Siting Board approval of the site certification. Subject to approval by the Department, the manufacturer's curves may be used to establish pollutant emission rates over a range of temperatures for the purpose of compliance determination.

5. After the demonstration period, permittee shall operate the combustion turbine to achieve the lowest possible NO_X emission limit but shall not exceed 25 ppmvd corrected to 15 percent oxygen and ISO conditions. Effective July 1, 2003, permittee shall operate the combustion turbine to achieve the lowest possible NO_X emission limit but shall not exceed 15 ppmvd corrected to 15 percent oxygen and ISO conditions.

APPENDIX BD - 2001

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

BACKGROUND

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

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

PROPOSAL SUBMITTED BY APPLICANT:

TEC submitted a revised proposal on January 30, 2002 recommending an emission limits as follows:

POLLUTANT	CONTROL TECHNOLOGY	TEC PROPOSAL
NO_X	Syngas firing - N_2 diluent	15 ppmvd @ 15% O_2

This proposal would provide for a 40% reduction in the current (temporary) emission limit while firing syngas.

STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES:

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

DETERMINATIONS BY EPA AND STATES:

The following table is a sample of information on some recent determinations by states for combined cycle stationary gas turbine projects. This particular review has been limited to gas turbines in the United States which are permitted to combust coal or pet-coke produced syngas. The applicant's proposal is included for reference.

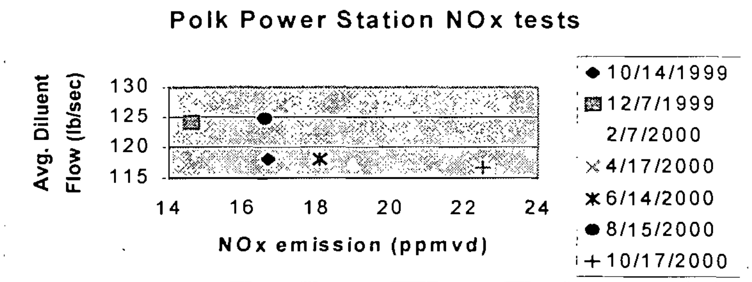
TABLE 1

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

Project Location	Power Output Megawatts	NO_X Emission Rate	Gasification Technology	Comments
Pinon Pine; Sierra Pacific, NV	100	0.07 lb/MMBtu	KRW air-blown pressurized fluidized bed	95% SO_2 removal
Wabash River; Terre Haute, IN	262	0.096 lb/MMBtu	Destec two-stage pressurized oxygen-blown entrained flow	
Kentucky Pioneer **(proposed)**	580	0.07 lb/MMBtu	British Gas / Lurgi slagging fixed bed	99% SO_2 removal
Motiva; Delaware City, DE	240	16 ppmvd	Texaco pressurized oxygen-blown entrained-flow	
TECO POLK; Polk County FL)	260	15 ppmvd (approx. equiv. 0.076 lb/MMBtu)	Texaco pressurized oxygen-blown entrained-flow	96% SO_2 removal

EVALUATION BY DEPARTMENT:

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



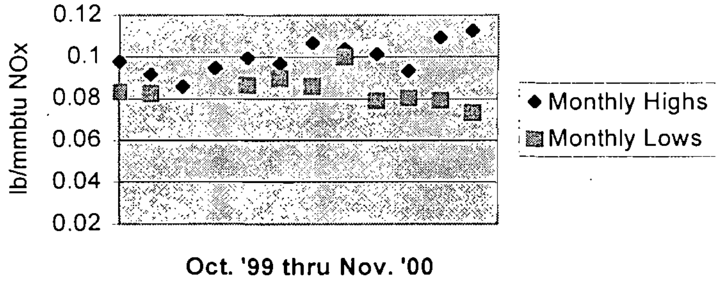
TEC has cautioned against an analysis of NO_X emissions as compared to diluent flow, noting that "*although the diluent flow is an important parameter for controlling NO_X emissions, a more appropriate measure is the ratio of diluent flow to syngas flow. On an overall basis, this ratio represents the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

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

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

Each analysis of the facility data referred to herein suggests that a NO_X limit of 0.09 lb/MMBtu (approximately 18 ppmvd) would likely be reasonable, given that certain changes may be required.

CEMS DATA



DEPARTMENT DETERMINATION:

Although little incentive existed to maintain a NO_X limit below 25 ppm, the data shows that emissions can be maintained at much lower levels with minor changes.

POLLUTANT	DETERMINATION
NO_X (syngas - all operating modes)	15.0 ppmvd – 30-day rolling average via CEMS

The rationale is:

1) Polk IGCC is not a green-field unit, and additional controls effectively result in a retrofit
2) Other (similar) domestic IGCC units are able to comply with an emission limit of 15 ppmvd and
3) The process of gasification is likely to expand to renewable fuels, possibly complicating the application of more stringent controls.

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DETAILS OF THE ANALYSIS MAY BE OBTAINED BY CONTACTING:

Michael P. Halpin, P.E. Review Engineer
Department of Environmental Protection
Bureau of Air Regulation
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Recommended By:

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

2/4/02
Date:

Approved By:

Howard L. Rhodes

Howard L. Rhodes, Director
Division of Air Resources Management

2/4/02
Date: