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January 19, 2001

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

Via FedEx
Airbill No. 7919 5024 5070

Re: Comments on Remaining Issues
Project No. 0570040-013-AC (PSD-FL-301)
Bayside Power Station (Gannon Repowering Project)

Dear Mr. Koerner:

Thank you for providing Tampa Electric Company with the opportunity to review and discuss the remaining issues associated with the Bayside Power Station Air Construction Permit Application. Out of the meeting that took place on January 12, 2001 several issues arose that Tampa Electric Company would like to take this opportunity to comment on. For your convenience, TEC has stated each issue and provided associated comments.

Issue 1-Ammonia Slip

According to the Discussion Purposes document provided during the January 12, 2001 meeting, FDEP indicated that it would limit ammonia slip from each Bayside CT to 5 ppmvd @ 15% O_2 during natural gas-firing.. The Department stated that this limit is based on other similar projects that have undergone BACT evaluations for NOx and is intended to provide the Department with reasonable assurance that each SCR system is operating properly.

The main difference between the Bayside repowering project and other similar projects in terms of NOx emissions is that the Bayside repowering project did not undergo PSD review for NOx. Accordingly, BACT for NOx is not applicable to this situation; TEC is only required to meet a NOx emission limit of 3.5 ppm @ 15% O_2 when firing natural gas. Due to this, coupled with the fact that ammonia is not a regulated air pollutant, TEC believes that FDEP does not have the authority to limit the ammonia slip emissions to 5 ppm and that an ammonia slip limit of 10 ppm during natural gas-firing for this project is reasonable.

Issue 2 - Carbon Monoxide Emissions Monitoring

The Discussion Paper mentioned above indicated that CO continuous emissions monitoring systems (CEMS) would be required for each combustion turbine at Bayside Power Station. However, TEC does not believe that CO CEMS are warranted for the Bayside Power Station. A periodic demonstration of compliance with all applicable CO emission rates on an annual basis should provide the Department with reasonable assurance that all permit limits are complied with. Furthermore, based on modeling evaluations, CO emissions will not cause any health or safety concerns during the operation of Bayside Unit 1 and 2.

Issue 3 - Particulate Matter BACT Evaluation

Per FDEP request, an analysis of PM/PM_{10} BACT demonstrating that the use of clean fuels represents BACT for this project is enclosed.

Issue 4 - Revised NOx Emission Limits During Oil Firing

Emissions of NO_x during oil-firing were estimated based on the same SCR control efficiency for natural gas-firing; i.e., 61 percent. Because the Bayside project is not subject to NO_x BACT review, TEC requests that the oil-firing NO_x permit limitations be set consistent with those submitted to the FDEP in the Air Construction Permit Application.

Issue 5 - CT Maximum Permitted Heat Input When Firing Natural Gas or Distillate Oil

Although the Department is considering a maximum permitted heat input for each CT when firing natural gas of 1603 MMBtu/hr and when firing distillate oil of 1822 MMBtu/hr, TEC believes that CT vendors are typically conservative when guaranteeing heat input rates. In addition, over time, thermal efficiency degradation occurs as evidenced in the enclosed curves. As such, these limits may prove to be unnecessarily restrictive. Tampa Electric Company will demonstrate compliance with all applicable emissions limits regardless of the heat input limit. Therefore, TEC requests that the permit condition addressing heat input limits includes the following language:

"The maximum permitted heat inputs shall be revised upward if actual performance testing indicates that the guaranteed heat input rates provided by the vendor are conservative.

To account for age related thermal efficiency degradation, the maximum permitted heat inputs shall be revised upward by 3.5%."

Issue 6 - CT MACT Evaluation

Although TEC continues to support the position that Bayside Units 1 and 2 are separate processes or production units as defined in 40 CFR 63.41, TEC will agree to defer the MACT determination for Bayside Units 1 and 2 until actual testing is performed.

Issue 7 - Excess Emissions During Startup

During the January 12, 2001 meeting, the Department provided a handout identified as 'Handout A' with suggested language that would apply to the startup of a cold steam turbine. TEC suggests using the language from Option 2 below. However, since the Department is authorized to allow excess emissions without establishing additional limits during startup, TEC does not feel that emissions of CO and NOx should be subject to a cold steam startup limit. This is consistent with the language found in Specific Condition 24 of FDEP Air Construction Permit number 071002-004-AC which provides for excess emissions allowances during a cold combined cycle steam turbine startup without establishing additional emissions limits.

" A "steam turbine cold startup" is defined as startup after the steam turbine has been offline for 24 hours or more, or the first stage turbine metal temperature is 250° F or less. During any steam turbine cold startup, no more than one gas turbine shall be operated. Steam turbine cold startups shall be complete within 16 hours. The SCR system shall be operated to the maximum extent possible. CEMS data collected during a steam turbine cold startup shall be excluded from the 24-hour block CEMS compliance average. The 24-hour block CEMS compliance averages shall be based on the remaining available CEMS data and must include at least three valid 1-hour CEMS averages."

Issue 8 - Future SO_2 Air Quality Analyses

The Department has indicated that it would like to see an air quality analysis of the SO_2 impacts of any future projects that may occur at Gannon Station. Since this requirement pertains to future projects, it should be addressed during the permitting of any future projects that trigger PSD review for SO_2 emissions, not during the permitting of Bayside Units 1 and 2.

Issue 9 - Continuous Emission Monitoring System Requirements

During the January 12, 2001 meeting, the Department provided TEC with suggested language outlining the requirements of the Bayside Power Station CEM systems. After a detailed review of the suggested language, TEC has determined that much of the language is not applicable to this project. Instead, TEC suggests the language specified in Conditions 39. through 44. of Final Permit Number PSD-FL-263 issued for the new TEC Polk Power Station CTs.

TEC appreciates the opportunity to provide the Department with comments on the remaining issues associated with the permitting of Bayside Units 1 and 2.

If you have any questions, please call Shannon Todd or me at (813) 641-5125.

Sincerely,

Gregory M. Nelson

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

EP\gm\SKT224

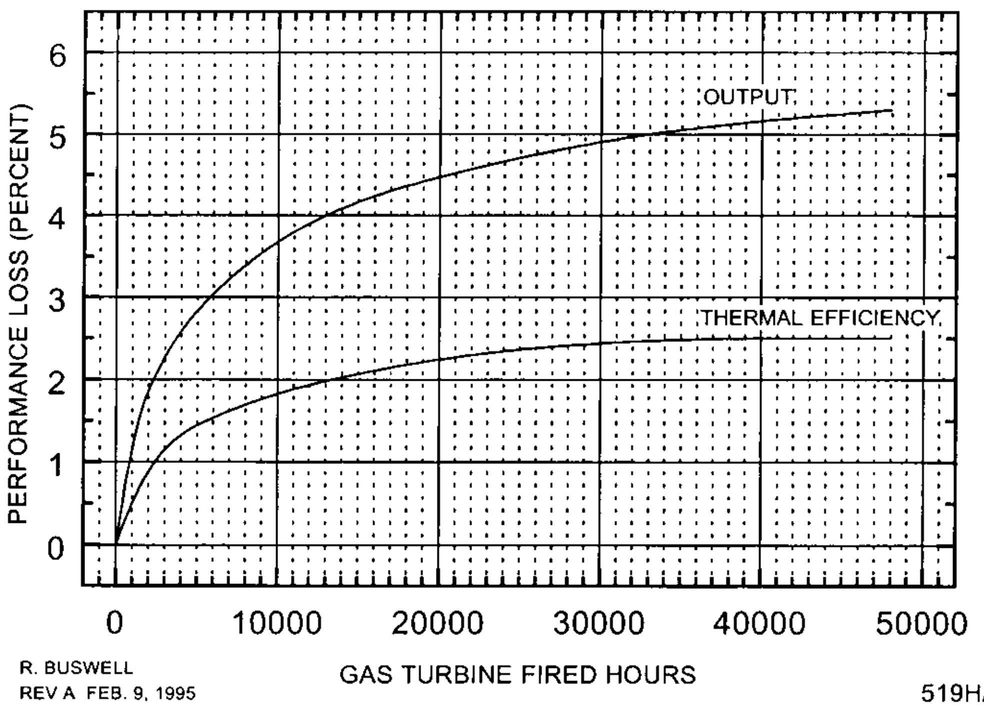
Enclosure

c: Mr. Jerry Kissel, FDEP - SWD
Mr. Jerry Campbell, EPCHC
Mr. John Bunyak, NPS
Ms. Katy Forney, EPA Region 4

EXPECTED GAS TURBINE PLANT PERFORMANCE LOSS FOLLOWING NORMAL MAINTENANCE AND OFF-LINE COMPRESSOR WATER WASH

THE AGED PERFORMANCE EFFECTS REPRESENTED BY THESE CURVES ARE BASED ON THE FOLLOWING:

- PERFORMANCE IS RELATIVE TO THE GUARANTEE LEVEL.
- ALL GAS TURBINE PLANT EQUIPMENT SHALL BE OPERATED AND MAINTAINED IN ACCORDANCE WITH GE'S RECOMMENDED PROCEDURES FOR OPERATION, PREVENTIVE MAINTENANCE, INSPECTION AND BOTH ON-LINE AND OFF-LINE CLEANING.
- ALL OPERATIONS SHALL BE WITHIN THE DESIGN CONDITIONS SPECIFIED IN THE RELEVANT TECHNICAL SPECIFICATIONS.
- A DETAILED OPERATIONAL LOG SHALL BE MAINTAINED FOR ALL RELEVANT OPERATIONAL DATA, TO BE AGREED TO AMONGST THE PARTIES PRIOR TO COMMENCEMENT OF CONTRACT.
- GE TECHNICAL PERSONNEL SHALL HAVE ACCESS TO PLANT OPERATIONAL DATA, LOGS, AND SITE VISITS PRIOR TO CONDUCTING A PERFORMANCE TEST. THE OWNER WILL CLEAN AND MAINTAIN THE EQUIPMENT. THE DEGREE OF CLEANING AND MAINTENANCE WILL BE DETERMINED BASED ON THE OPERATING HISTORY OF EACH UNIT, ATMOSPHERIC CONDITIONS EXPERIENCED DURING THE PERIOD OF OPERATION, THE PREVENTIVE AND SCHEDULED MAINTENANCE PROGRAMS EXECUTED, AND THE RESULTS OF THE GE INSPECTION.
- THE GAS TURBINE WILL BE SHUT DOWN FOR INSPECTION AND OFF-LINE COMPRESSOR WATER WASH, AS A MINIMUM, IMMEDIATELY PRIOR TO PERFORMANCE TESTING TO DETERMINE PERFORMANCE LOSS. THE GAS TURBINE PERFORMANCE TEST SHALL OCCUR WITHIN 100 FIRED HOURS OF THESE ACTIONS.
- DEMONSTRATION OF GAS TURBINE PLANT PERFORMANCE SHALL BE IN ACCORDANCE WITH TEST PROCEDURES WHICH ARE MUTUALLY AGREED UPON.



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4.0B BEST AVAILABLE CONTROL TECHNOLOGY ANALYSIS FOR PARTICULATE MATTER

4.1B METHODOLOGY

The BACT analysis for particulate matter and particulate matter less than ten microns in size (PM/PM_{10}) was performed as previously described in the September 2000 permit application.

4.2B FEDERAL AND FLORIDA EMISSION STANDARDS

Pursuant to Rule 62-212.400(5)(b), F.A.C., BACT emission limitations must be no less stringent than any applicable NSPS (40 CFR Part 60), NESHAPs (40 CFR Parts 61 and 63), and FDEP emission standards (Chapter 62-296, F.A.C., *Stationary Sources—Emission Standards*).

On the federal level, emissions from gas turbines are regulated by NSPS Subpart GG. Subpart GG establishes emission limits for gas turbines that were constructed after October 3, 1977, and that meet any of the following criteria:

- Electric utility stationary gas turbines with a heat input at peak load of greater than 100 MMBtu/hr based on the LHV of the fuel.
- Stationary gas turbines with a heat input at peak load between 10 and 100 MMBtu/hr based on the fuel LHV.
- Stationary gas turbines with a manufacturer's rated baseload at ISO standard day conditions of 30 MW or less.

The electric utility stationary gas turbine NSPS applicability criterion applies to stationary gas turbines that sell more than one-third of their potential electric output to any utility power distribution system. The Bayside Units 1 and 2 CTs qualify as electric utility stationary gas turbines and, therefore, are subject to the NO_x and SO_2 emission limitations of NSPS 40 CFR 60, Subpart GG, 60.332(a)(1) and 60.333, respectively. However, NSPS Subpart GG does not include any PM/PM_{10} emission limitations.

FDEP emission standards for stationary sources are contained in Chapter 62-296, F.A.C., *Stationary Sources—Emission Standards.* Visible emissions are limited to a maximum of 20 percent opacity pursuant to Rule 62-296.320(4)(b), F.A.C. Sections 62-296.401 through -.417, F.A.C., specify emission standards for 17 categories of sources; none of these categories are applicable to CTs. Rule 62-204.800(7) incorporates the federal NSPS by reference, including Subpart GG.

Section 62-204.800, F.A.C., adopts federal NSPS and NESHAP, respectively, by reference. As noted previously, NSPS Subpart GG, *Stationary Gas Turbines* is applicable to the Bayside Unit 1 and 2 CTs. However, Subpart GG does not contain any PM/PM_{10} emission limitations. There are no applicable NESHAP requirements.

In summary, there are no federal or state PM/PM_{10} emission limitations applicable to Bayside Units 1 and 2.

4.3B <u>BACT ANALYSIS FOR PM/PM_{10}</u>

PM/PM_{10} emissions resulting from the combustion of natural gas and distillate fuel oil are due to oxidation of ash and sulfur contained in these fuels. Due to their low ash and sulfur contents, natural gas and distillate fuel oil combustion generate inherently low PM/PM_{10} emissions.

4.3.1B POTENTIAL CONTROL TECHNOLOGIES

Available technologies used for controlling PM/PM_{10} include the following:

- Centrifugal collectors.
- Electrostatic precipitators (ESPs).
- Fabric filters or baghouses.
- Wet scrubbers.

Centrifugal (cyclone) separators are primarily used to recover material from an exhaust stream before the stream is ducted to the principal control device since cyclones are effective in removing only large sized (greater than 10 microns) particles. Particles generated from natural gas and distillate fuel oil combustion are typically less than 1.0 micron in size.

ESPs remove particles from a gas stream through the use of electrical forces. Discharge electrodes apply a negative charge to particles passing through a strong electrical field. These charged particles then migrate to a collecting electrode having an opposite, or positive, charge. Collected particles are removed from the collecting electrodes by periodic mechanical rapping of the electrodes. Collection efficiencies are typically 95 percent for particles smaller than 2.5 microns in size.

A fabric filter system consists of a number of filtering elements, bag cleaning system, main shell structure, dust removal system, and fan. PM/PM_{10} is filtered from the gas stream by various mechanisms (inertial impaction, impingement, accumulated dust cake sieving, etc.) as the gas passes through the fabric filter. Accumulated dust on the bags is periodically removed using mechanical or pneumatic means. In pulse jet pneumatic cleaning, a sudden pulse of compressed air is injected into the top of the bag. This pulse creates a traveling wave in the fabric that separates the cake from the surface of the fabric. The cleaning normally proceeds by row, all bags in the row being cleaned simultaneously. Typical air-to-cloth ratios range from 2 to 8 cubic feet per minute-square foot (cfm-ft^2). Collection efficiencies are on the order of 99 percent for particles smaller than 2.5 microns in size.

Wet scrubbers remove PM/PM_{10} from gas streams principally by inertial impaction of the particulate onto a water droplet. Particles can be wetted by impingement, diffusion, or condensation mechanisms. To be wetted, PM/PM_{10} must either make contact with a spray droplet or impinge upon a wet surface. In a venturi scrubber, the gas stream is constricted in a throat section. The large volume of gas passing through a small constriction gives a high gas velocity and a high pressure drop across the system. As water is introduced into the throat, the gas is forced to move at a higher velocity, causing the water to shear into droplets. Particles in the gas stream then impact onto the water droplets produced. The entrained water droplets are subsequently removed from the gas stream by a cyclone separator. Venturi scrubber collection efficiency increases with increasing pressure drop for a given particle size. Collection efficiency will also increase with increasing liquid-to-gas ratios up to the point where flooding of the system occurs. Packed-bed and venturi scrubber collection efficiencies are typically 90 percent for particles smaller than 2.5 microns in size.

While all of these postprocess technologies would be technically feasible for controlling PM/PM_{10} emissions from CTs, none of the previously described control equipment have been applied to CTs because exhaust gas PM/PM_{10} concentrations are inherently low. CTs operate with a significant amount of excess air, which generates large exhaust gas flow rates. The Bayside CTs will be fired with natural gas as the primary fuel and distillate fuel oil as the back-up fuel source. Combustion of natural gas and distillate fuel oil will generate low PM/PM_{10} emissions in comparison to other fuels due to their low ash and sulfur contents. The minor PM/PM_{10} emissions coupled with a large volume of exhaust gas produces extremely low exhaust stream PM/PM_{10} concentrations. The estimated PM/PM_{10} exhaust concentration for the Bayside CTs during oil-firing at base load and 59°F is approximately 0.005 grains per dry standard cubic foot (gr/dscf). Exhaust stream PM/PM_{10} concentrations of such low magnitude are not amenable to control using available technologies because removal efficiencies would be unreasonably low and costs excessive.

4.3.2B PROPOSED BACT EMISSION LIMITATIONS

Recent Florida BACT determinations for natural gas- and distillate fuel oil-fired CTs are based on the use of clean fuels and good combustion practice.

Because postprocess stack controls for PM/PM_{10} are not appropriate for CTs, the use of good combustion practices and clean fuels is considered to be BACT. The Bayside CTs will use the latest combustor technology to maximize combustion efficiency and minimize PM/PM_{10} emission rates. Combustion efficiency, defined as the percentage of fuel completely oxidized in the combustion process, is projected to be greater than 99 percent. The CTs will be fired primarily with pipeline quality natural gas. Low-sulfur, low-ash distillate fuel oil will serve as a back-up fuel source. Due to the difficulties associated with stack testing exhaust streams containing very low PM/PM_{10} concentrations and consistent with recent FDEP BACT determinations for CTs, a visible emissions limit of 10-percent opacity is proposed as a surrogate BACT limit for PM/PM_{10}. Table 4-1B summarizes the PM/PM_{10} BACT emission limits proposed for the Bayside CTs.

Table 4-1B. Proposed PM/PM_{10} BACT Emission Limits

Emission Source	Proposed PM/PM_{10} BACT Emission Limits opacity (%)
GE PG7241 (FA) CT/HRSGs (Per CT/HRSG Unit)	
PM/PM_{10} (Natural Gas)	10.0
PM/PM_{10} (Distillate Fuel Oil)	10.0

Sources: ECT, 2000.
S&L, 2000.
TEC, 2000.

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oxidized mercury can be removed (7). Additional tests showed that the oxidized mercury removal efficiency was limited only by gas-film mass transfer. Elemental mercury vapor does not appear to be removed by an FGD system. This is not surprising since elemental mercury has a very low solubility in water. Other tests of mercury removal by FGD systems have shown similar results, with little or no removal of elemental mercury (1,8).

The testing at the ECTC determined that all of the mercury removed by the FGD system was incorporated into the byproduct solids, although the exact chemical form was not reported (7). No elevated levels of mercury were found in the process liquor or system blowdown stream.

3.6 Lime- and Limestone-Based FGD Process Material Balance

Figure 3-6 illustrates an overall material balance for a lime- or limestone-based FGD process. The primary inlet stream (in terms of mass flow rate) is the flue gas. In most cases, prior to entering the FGD system, the flue gas is treated by a particulate control device such as a high-efficiency electrostatic precipitator (ESP) or fabric filter. These devices are capable of removing over 99.5% of the fly ash in the flue gas. Although some lime- and limestone-based wet FGD systems are designed to remove fly ash from the flue gas or to use alkaline fly ash as a reagent, fly ash can have several detrimental effects on the process and is normally removed upstream of the FGD system. In any case, however, some fly ash passes through the particulate control device and enters the FGD process. Major components of the inlet flue gas include nitrogen, carbon dioxide, water vapor, and oxygen. Minor components include sulfur dioxide, nitrogen oxides, hydrogen chloride, hydrogen fluoride, and sulfuric acid vapor. Some additional soluble trace elements may be present in the flue gas or fly ash.

In the FGD system, SO_2 and some oxygen are removed from the flue gas. In the limestone-based process, about one mole of CO_2 is added to the flue gas per mole of SO_2 absorbed. In the lime-based process, a small amount of CO_2 may be removed from the flue gas (typically, < 0.1 mole CO_2/mole SO_2). An FGD process that removes 95% of the SO_2

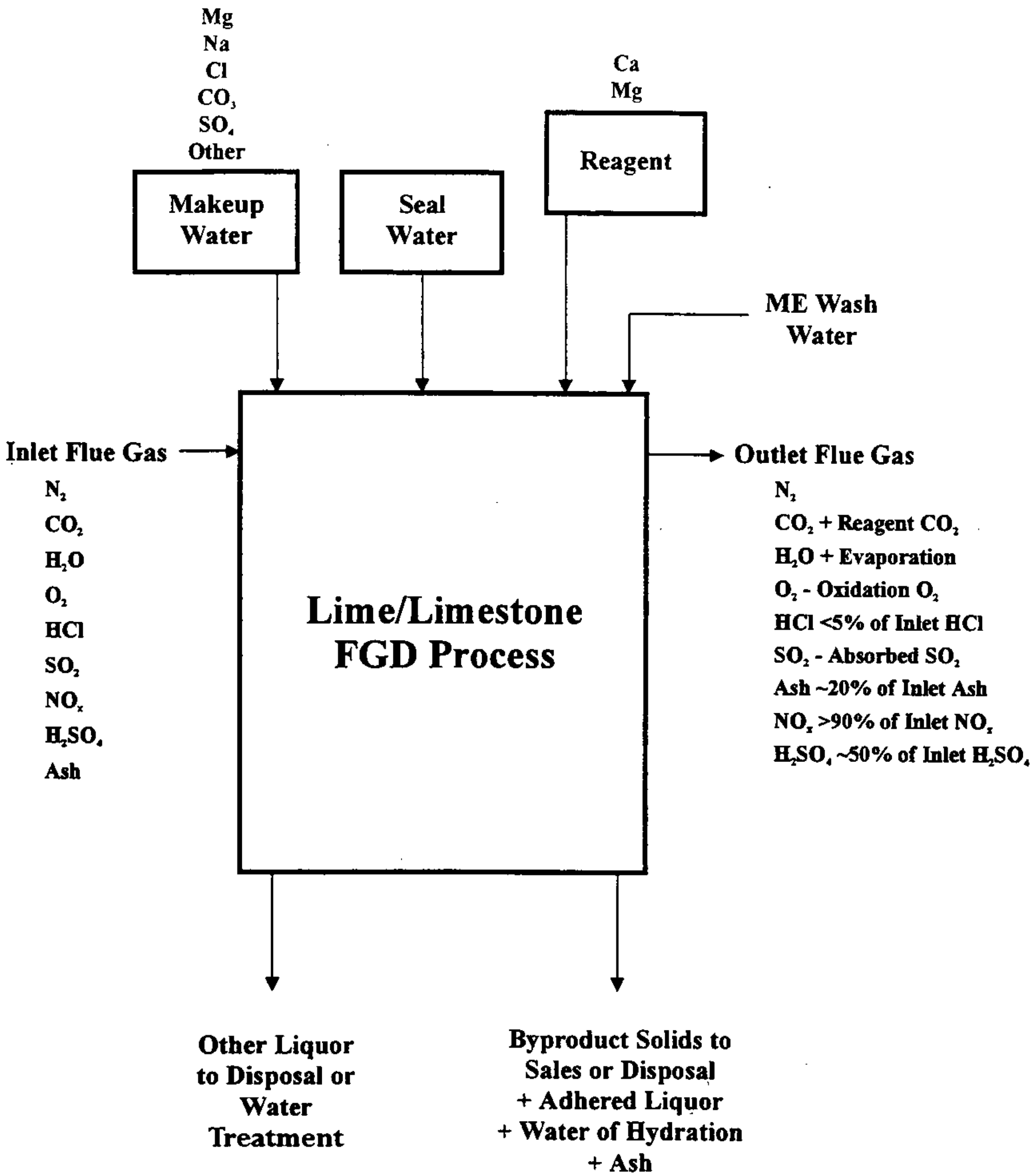

Figure 3-6. Overall System Material Balance

will also remove essentially all of the hydrogen chloride (HCl) from the flue gas because HCl is more readily absorbed than SO_2. Chloride introduced to the FGD system by the flue gas plays an important role in process chemistry. Nitric oxide (NO) that is present in the inlet flue gas typically passes through the FGD system. Although nitrogen dioxide (NO_2) may be absorbed, it is typically only a small fraction of the total nitrogen oxides in the flue gas.

Some vapor-phase sulfuric acid is typically present in the inlet flue gas. Although the H_2SO_4 (g) concentration is only about 1% of the SO_2 concentration, the presence of H_2SO_4 can have significant consequences. When the flue gas is first cooled at the absorber inlet, vapor-phase H_2SO_4 rapidly condenses to form a submicrometer-sized acid mist. Typically, less than about 50% of this mist is removed in the absorber. The remaining mist that penetrates the absorber module may cause a visible stack plume as a result of light scattering by the submicrometer-sized particles.

If the FGD system is downstream of a high-efficiency ESP, up to 80% of the residual fly ash that escapes the particulate control device may be removed in the FGD system. This fly ash typically accounts for only a small fraction of the total FGD byproduct solids, but trace chemical species introduced with the ash can affect process chemistry, especially if wastewater is to be discharged. Trace chemical species, such as iron and manganese, introduced with the ash can also act as oxidation catalysts, providing a benefit to forced-oxidation systems or a detriment to inhibited-oxidation processes.

In the absorber, the flue gas becomes saturated with water. Water evaporation in the absorber is an extremely important material balance term. The amount of water evaporated depends on coal composition, the inlet gas temperature, and inlet gas moisture content, but is usually about 0.06 to 0.07 L/s (1 to 1.2 gpm) for each megawatt of electrical power produced if all of the flue gas is treated.

Water also leaves the process as liquor that is lost with the dewatered byproduct solids. The amount of water that leaves with the solids is small compared to the

Table 1. Bayside Station Units 1 and 2
Netting Analysis - F.J. Gannnon Station Unit 5 Historical Emissions

	Unit 5 (tpy)						
	1995	1996	1997	1998	1999	95-99, 5 Yr Avg	98,99 Avg
Coal Usage (tons)	519,780.0	574,584	450,802	556,487	541,559	528,642	549,023
Wt % Ash	6.98	7.47	8.26	8.15	7.58	7.69	7.87
Wt % S	1.11	1.19	1.16	1.21	1.17	1.17	1.19
Oil Usage (10^3 gal)	332.6	311.0	600.9	599.0	397.0	448.1	498.0
Wt % S	0.16	0.30	0.15	0.28	0.41	0.26	0.35
NO_x [a] AOR (CEMS Data)	883.6	1,063.0	451.5	470.6	478.7	669.5	474.7
CO Gannon Unit 5 4/7,8/00 Stack Test Avg. = 0.295 lb/MMBtu E.F. = 7.488 lb/ton	← AOR Data 157.0	→ 173.0	← Stack Test Data 1,687.7	 2,083.4	→ 2,027.5	1,225.7	2,055.5
SO_2 [a] AOR (CEMS Data)	1,037.4	1,296.8	1,075.3	1,370.1	1,260.1	1,207.9	1,315.1
H_2SO_4 [b] AP-42 (1998)	32.2	38.2	29.2	37.7	35.4	34.5	36.6
PM_{10} [c] AP-42	47.2	55.8	48.4	59.0	53.4	52.7	53.7
PM [c] AP-42	127.0	150.2	130.3	158.7	143.7	142.0	144.5
Pb AOR	3.5	3.8	3.0	3.7	3.6	3.5	3.7
VOC AP-42 (1998)	10.4	11.5	9.1	11.2	10.9	10.6	11.0

(a) Actual emissions reduced by 90% to reflect retroactive BACT.
(b) Actual emissions reduced by 35% to reflect retroactive BACT.
(c) AP-42 uncontrolled emissions reduced by 99% to reflect retroactive BACT.

Sources: ECT, 2000.
TEC, 2000.

Table 2. Bayside Station Units 1 and 2
Netting Analysis - F.J. Gannnon Station Unit 6 Historical Emissions

	Unit 6 (tpy)						
	1995	1996	1997	1998	1999	95-99, 5 Yr Avg	97,98 Avg
Coal Usage (tons)	897,070.0	892,742	920,526	860,597	693,039	852,795	890,562
Wt % Ash	7.22	7.48	8.79	8.41	7.28	7.84	8.60
Wt % S	1.10	1.19	1.18	1.22	1.13	1.16	1.20
Oil Usage (10^3 gal)	378.9	311.0	639.9	599.0	362.0	458.1	619.4
Wt % S	0.16	0.30	0.15	0.28	0.41	0.26	0.22
NO_x (a) AOR (CEMS Data)	1,525.5	1,652.0	1,092.9	1,093.4	958.8	1,264.5	1,093.2
CO Gannon Unit 5 4/7,8/00 Stack Test Avg. = 0.295 lb/MMBtu E.F. = 7.488 lb/ton	← AOR Data 270.0	→ 269.0	← Stack Test Data 3,446.3	3,221.9	→ 2,594.6	1,960.4	3,334.1
SO_2 (a) AOR (CEMS Data)	1,880.1	2,030.8	2,282.9	2,370.4	1,602.9	2,033.4	2,326.7
H_2SO_4 (b) AP-42 (1998)	55.0	59.3	60.6	58.7	43.8	55.5	59.6
PM_{10} (c) AOR	84.2	86.8	105.2	94.1	65.6	87.2	99.6
PM (c) AOR	226.7	233.7	283.2	253.3	176.6	234.7	268.3
Pb AOR	6.0	5.9	6.1	5.7	4.6	5.7	5.9
VOC AP-42 (1998)	18.0	17.9	18.5	17.3	13.9	17.1	17.9

(a) Actual emissions reduced by 90% to reflect retroactive BACT.
(b) Actual emissions reduced by 35% to reflect retroactive BACT.
(c) AP-42 uncontrolled emissions reduced by 99% to reflect retroactive BACT.

Sources: ECT, 2000.
TEC, 2000.

Table 3. Bayside Station
Bayside Units 1 & 2/F.J. Gannon Units 5 & 6 Emissions Netting Analysis

	Units 5 & 6 (tpy)					Unit 5	Unit 6	Total		Net	PSD	PSD
	1995	1996	1997	1998	1999	2 Yr [a] Avg	2 Yr [b] Avg	2 Yr [a], [b] Avg	CT 1A-2D (tpy)	Change (tpy)	Threshold (tpy)	Review (Y/N)
Coal Usage (tons)	1,416,850	1,467,326	1,371,328	1,417,084	1,234,598	549,023	890,562	1,439,585	N/A	N/A	N/A	N/A
Wt % Ash	7.10	7.48	8.53	8.28	7.43	7.87	8.60	8.23	N/A	N/A	N/A	N/A
Wt % S	1.11	1.19	1.17	1.22	1.15	1.19	1.20	1.20	N/A	N/A	N/A	N/A
Oil Usage (10^3 gal)	711.5	622.0	1,240.8	1,198.0	759.0	498.0	619.4	1,117.4	N/A	N/A	N/A	N/A
Wt % S	0.16	0.30	0.15	0.28	0.41	0.35	0.22	0.28	N/A	N/A	N/A	N/A
NO_x [c] AOR (CEMS Data)	2,409.1	2,715.0	1,544.4	1,564.0	1,437.5	474.7	1,093.2	1,567.8	1,018.2	-549.6	40.0	N
CO AOR & Stack Test	427.0	442.0	5,134.0	5,305.3	4,622.1	2,055.5	3,334.1	5,389.6	989.7	-4,399.9	100.0	N
SO_2 [c] AOR (CEMS Data)	2,917.5	3,327.6	3,358.2	3,740.5	2,863.0	1,315.1	2,326.7	3,641.8	576.3	-3,065.4	40.0	N
H_2SO_4 [d] AP-42 (1998)	87.2	97.5	89.8	96.3	79.2	36.6	59.6	96.2	96.7	0.5	7.0	N
PM_{10} [e] AOR	131.4	142.6	153.6	153.1	119.0	53.7	99.6	153.3	721.4	568.1	15.0	Y
PM [e] AOR	353.7	384.0	413.5	412.1	320.3	144.5	268.3	412.8	721.4	308.6	25.0	Y
Pb AOR	9.4	9.8	9.1	9.4	8.2	3.7	5.9	9.6	1.1	-8.5	0.6	N
VOC AP-42 (1998)	28.4	29.4	27.6	28.5	24.8	11.0	17.9	28.9	99.6	70.7	40.0	Y

(a) Fuel data represents 1998, 1999 average for Unit 5.
(b) Fuel data represents 1997, 1998 average for Unit 6.
(c) Actual emissions reduced by 90% to reflect retroactive BACT.
(d) Actual emissions reduced by 35% to reflect retroactive BACT.
(e) AP-42 uncontrolled emissions reduced by 99% to reflect retroactive BACT.

Sources: ECT, 2000.
TEC, 2000.

Unit 5	1995	1996	1997	1998	1999	Average	Maximum
Fuel Heat Content - Coal (MMBtu/ton)	12.39	24.65	23.96	24.00	24.00	21.80	24.65
Fuel Heat Content - Oil (MMBtu/10^3 gal)	138.40	138.56	137.99	138.55	138.00	138.30	138.56
Heat Input (MMBtu/hr)	6,486,102	14,208,885	10,884,135	13,438,679	13,052,202	11,614,000	14,208,885
PM/PM_{10} - AOR (tpy)	193.0	212.3	392.3	273.0	196.7	253.5	392.3
PM/PM_{10} - AOR (lb/MMBtu)	0.0595	0.0299	0.0721	0.0406	0.0301	0.0465	0.0721
H_2SO_4 - AOR (tpy)	49.54	58.75	44.95	57.95	54.53	53.14	58.75
H_2SO_4 - AOR (lb/MMBtu)	0.0153	0.0083	0.0083	0.0086	0.0084	0.0098	0.0153

Unit 6	1995	1996	1997	1998	1999	Average	Maximum
Fuel Heat Content - Coal (MMBtu/ton)	12.47	24.85	24.28	24.01	24.00	21.92	24.85
Fuel Heat Content - Oil (MMBtu/10^3 gal)	138.40	138.56	137.99	138.55	138.00	138.30	138.56
Heat Input (MMBtu/hr)	11,238,901	22,229,515	22,438,664	20,745,925	16,682,892	18,667,179	22,438,664
PM/PM_{10} - AOR (tpy)	1,116.0	1,109.3	818.6	911.0	765.1	944.0	1,116.0
PM/PM_{10} - AOR (lb/MMBtu)	0.1986	0.0998	0.0730	0.0878	0.0917	0.1102	0.1986
H_2SO_4 - AOR (tpy)	84.69	91.21	93.26	90.24	67.34	85.35	93.26
H_2SO_4 - AOR (lb/MMBtu)	0.0151	0.0082	0.0083	0.0087	0.0081	0.0097	0.0151

Table 1. Bayside Station Units 1 and 2
Netting Analysis - F.J. Gannnon Station Unit 5 Historical Emissions

	Unit 5 (tpy)						
	1995	1996	1997	1998	1999	95-99, 5 Yr Avg	98,99 Avg
Coal Usage (tons)	519,780.0	574,584	450,802	556,487	541,559	528,642	549,023
Wt % Ash	6.98	7.47	8.26	8.15	7.58	7.69	7.87
Wt % S	1.11	1.19	1.16	1.21	1.17	1.17	1.19
Oil Usage (10^3 gal)	332.6	311.0	600.9	599.0	397.0	448.1	498.0
Wt % S	0.16	0.30	0.15	0.28	0.41	0.26	0.35
NO_x [(a)] AOR (CEMS Data)	883.6	1,063.0	451.5	470.6	478.7	669.5	474.7
CO Gannon Unit 5 4/7,8/00 Stack Test Avg. = 0.295 lb/MMBtu E.F. = 7.488 lb/ton	← AOR Data 157.0	→ 173.0	← Stack Test Data 1,687.7	2,083.4	→ 2,027.5	1,225.7	2,055.5
SO_2 [(a)] AOR (CEMS Data)	1,037.4	1,296.8	1,075.3	1,370.1	1,260.1	1,207.9	1,315.1
H_2SO_4 [(b)] AP-42 (1998)	32.2	38.2	29.2	37.7	35.4	34.5	36.6
PM_{10} [(c)] AP-42	47.2	55.8	48.4	59.0	53.4	52.7	53.7
PM [(c)] AP-42	127.0	150.2	130.3	158.7	143.7	142.0	144.5
Pb AOR	3.5	3.8	3.0	3.7	3.6	3.5	3.7
VOC AP-42 (1998)	10.4	11.5	9.1	11.2	10.9	10.6	11.0

(a) Actual emissions reduced by 90% to reflect retroactive BACT.
(b) Actual emissions reduced by 35% to reflect retroactive BACT.
(c) AP-42 uncontrolled emissions reduced by 99% to reflect retroactive BACT.

Sources: ECT, 2000.
TEC, 2000.

Table 2. Bayside Station Units 1 and 2
Netting Analysis - F.J. Gannnon Station Unit 6 Historical Emissions

	Unit 6 (tpy)						
	1995	1996	1997	1998	1999	95-99, 5 Yr Avg	97,98 Avg
Coal Usage (tons)	897,070.0	892,742	920,526	860,597	693,039	852,795	890,562
Wt % Ash	7.22	7.48	8.79	8.41	7.28	7.84	8.60
Wt % S	1.10	1.19	1.18	1.22	1.13	1.16	1.20
Oil Usage (10^3 gal)	378.9	311.0	639.9	599.0	362.0	458.1	619.4
Wt % S	0.16	0.30	0.15	0.28	0.41	0.26	0.22
NO_x[a] AOR (CEMS Data)	1,525.5	1,652.0	1,092.9	1,093.4	958.8	1,264.5	1,093.2
CO Gannon Unit 5 4/7,8/00 Stack Test Avg. = 0.295 lb/MMBtu E.F. = 7.488 lb/ton	← AOR Data → 270.0	269.0	← Stack Test Data → 3,446.3	3,221.9	2,594.6	1,960.4	3,334.1
SO_2[a] AOR (CEMS Data)	1,880.1	2,030.8	2,282.9	2,370.4	1,602.9	2,033.4	2,326.7
H_2SO_4[b] AP-42 (1998)	55.0	59.3	60.6	58.7	43.8	55.5	59.6
PM_{10}[c] AOR	84.2	86.8	105.2	94.1	65.6	87.2	99.6
PM[c] AOR	226.7	233.7	283.2	253.3	176.6	234.7	268.3
Pb AOR	6.0	5.9	6.1	5.7	4.6	5.7	5.9
VOC AP-42 (1998)	18.0	17.9	18.5	17.3	13.9	17.1	17.9

(a) Actual emissions reduced by 90% to reflect retroactive BACT.
(b) Actual emissions reduced by 35% to reflect retroactive BACT.
(c) AP-42 uncontrolled emissions reduced by 99% to reflect retroactive BACT.

Sources: ECT, 2000.
TEC, 2000.

Table 3. Bayside Station
Bayside Units 1 & 2/F.J. Gannon Units 5 & 6 Emissions Netting Analysis

	Units 5 & 6 (tpy)					Unit 5 2 Yr [a] Avg	Unit 6 2 Yr [b] Avg	Total 2 Yr [a, b] Avg	CT 1A-2D (tpy)	Net Change (tpy)	PSD Threshold (tpy)	PSD Review (Y/N)
	1995	1996	1997	1998	1999							
Coal Usage (tons)	1,416,850	1,467,326	1,371,328	1,417,084	1,234,598	549,023	890,562	1,439,585	N/A	N/A	N/A	N/A
Wt % Ash	7.10	7.48	8.53	8.28	7.43	7.87	8.60	8.23	N/A	N/A	N/A	N/A
Wt % S	1.11	1.19	1.17	1.22	1.15	1.19	1.20	1.20	N/A	N/A	N/A	N/A
Oil Usage (10^3 gal)	711.5	622.0	1,240.8	1,198.0	759.0	498.0	619.4	1,117.4	N/A	N/A	N/A	N/A
Wt % S	0.16	0.30	0.15	0.28	0.41	0.35	0.22	0.28	N/A	N/A	N/A	N/A
NO_x [c] AOR (CEMS Data)	2,409.1	2,715.0	1,544.4	1,564.0	1,437.5	474.7	1,093.2	1,567.8	1,018.2	-549.6	40.0	N
CO AOR & Stack Test	427.0	442.0	5,134.0	5,305.3	4,622.1	2,055.5	3,334.1	5,389.6	989.7	-4,399.9	100.0	N
SO_2 [c] AOR (CEMS Data)	2,917.5	3,327.6	3,358.2	3,740.5	2,863.0	1,315.1	2,326.7	3,641.8	576.3	-3,065.4	40.0	N
H_2SO_4 [d] AP-42 (1998)	87.2	97.5	89.8	96.3	79.2	36.6	59.6	96.2	96.7	0.5	7.0	N
PM_{10} [e] AOR	131.4	142.6	153.6	153.1	119.0	53.7	99.6	153.3	721.4	568.1	15.0	Y
PM [e] AOR	353.7	384.0	413.5	412.1	320.3	144.5	268.3	412.8	721.4	308.6	25.0	Y
Pb AOR	9.4	9.8	9.1	9.4	8.2	3.7	5.9	9.6	1.1	-8.5	0.6	N
VOC AP-42 (1998)	28.4	29.4	27.6	28.5	24.8	11.0	17.9	28.9	99.6	70.7	40.0	Y

(a) Fuel data represents 1998, 1999 average for Unit 5.
(b) Fuel data represents 1997, 1998 average for Unit 6.
(c) Actual emissions reduced by 90% to reflect retroactive BACT.
(d) Actual emissions reduced by 35% to reflect retroactive BACT.
(e) AP-42 uncontrolled emissions reduced by 99% to reflect retroactive BACT.

Sources: ECT, 2000.
TEC, 2000.

Unit 5	1995	1996	1997	1998	1999	Average	Maximum
Fuel Heat Content - Coal (MMBtu/ton)	12.39	24.65	23.96	24.00	24.00	21.80	24.65
Fuel Heat Content - Oil (MMBtu/10^3 gal)	138.40	138.56	137.99	138.55	138.00	138.30	138.56
Heat Input (MMBtu/yr)	6,486,102	14,208,885	10,884,135	13,438,679	13,052,202	11,614,000	14,208,885
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PM/PM_{10} - AOR (lb/MMBtu)	0.0595	0.0299	0.0721	0.0406	0.0301	0.0465	0.0721
H_2SO_4 - AOR (tpy)	49.54	58.75	44.95	57.95	54.53	53.14	58.75
H_2SO_4 - AOR (lb/MMBtu)	0.0153	0.0083	0.0083	0.0086	0.0084	0.0098	0.0153

Unit 6	1995	1996	1997	1998	1999	Average	Maximum
Fuel Heat Content - Coal (MMBtu/ton)	12.47	24.85	24.28	24.01	24.00	21.92	24.85
Fuel Heat Content - Oil (MMBtu/10^3 gal)	138.40	138.56	137.99	138.55	138.00	138.30	138.56
Heat Input (MMBtu/yr)	11,238,901	22,229,515	22,438,664	20,745,925	16,682,892	18,667,179	22,438,664
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PM/PM_{10} - AOR (lb/MMBtu)	0.1986	0.0998	0.0730	0.0878	0.0917	0.1102	0.1986
H_2SO_4 - AOR (tpy)	84.69	91.21	93.26	90.24	67.34	85.35	93.26
H_2SO_4 - AOR (lb/MMBtu)	0.0151	0.0082	0.0083	0.0087	0.0081	0.0097	0.0151

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JAN 16 2001

BUREAU OF AIR REGULATION

January 10, 2001

Ms. Diana Lee, P.E
Mr. Rob Kalch.
Environmental Protection Commission
of Hillsborough County
1900 9th Avenue
Tampa, Florida 33605

Via Fed Ex
Airbill No. 7919 4206 1967

Re: Request for Additional Information
Bayside Power Station (Gannon Repowering Project)

Dear Ms. Lee and Mr. Kalch:

Tampa Electric Company (TEC) submits this letter as a follow up to the meeting between our parties on December 13, 2000 regarding the Gannon repowering project. TEC has restated each EPC comment below followed by a response from TEC.

EPC Comment No. 1:
In a letter addressed to Mr. Jamie Hunter, Tampa Electric Company, dated August 22, 2000, a determination was made that a new fuel oil tank did not need a construction permit due to the low emissions from the tank. The letter further stated that the emissions from the tank did need to be included in the pre-construction review of the planned Bayside re-powering. The construction application states that a 5.85 million gallon fuel oil storage tank will be added as part of the construction project, but the tank that was evaluated in the letter dated August 22, 2000 was an 8 million gallon tank. Are the two tanks the same or has the 8 million gallon tank been omitted?

TEC Response:
The two tanks are the same. The 8 million-gallon tank will also be used in existing Gannon Station operations.

EPC Comment No. 2:
It was noted that the combined MW to be produced by Bayside Units 1 and 2 do not add up correctly. Please provide clarification on this. As an example Bayside Units 1 and 2 are evaluated:

Bayside Unit No.1	
3 CTs at	**166 MW**
1 ST (unit no.5)	**239 MW**
EPC calculated total MW produced	**737 MW**
TEC projected total MW produced	**753 MW**
Bayside Unit No. 2	
4 CTs at	**166 MW**

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P. O. BOX 111 TAMPA, FL 33601-0111

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1 ST (unit no.6)	**414 MW**
EPC calculated total MW produced	**1078 MW**
TEC projected total MW produced	**975 MW**

TEC Response:
Under current operating conditions, steam is removed from the strategic locations in turbine serving Gannon Units 5 and 6 and used in other locations in the process. When the Bayside power station comes online, it is anticipated that this steam will no longer need to be removed and will thus provide additional capacity to each steam turbine. This is the reason that the capacity of Bayside Unit 1 is higher than the sum of the permitted capacity of the steam turbine serving Gannon Unit 5 and the design capacities of the combustion turbines serving Bayside Unit 1. Bayside Unit 2 should be higher in capacity for the same reason that Bayside Unit 1 will be, however, it is anticipated that the steam turbine serving Gannon Unit 6 will operate at a much lower capacity than it is currently permitted due to the fact that the HRSGs serving the unit will not produce enough steam for the turbine to achieve full load. Therefore, the overall output of Bayside Unit 2 is less than the sum of the permitted capacity of Gannon Unit 6 and the design capacities of the combustion turbines serving Bayside Unit 2. It is also worth noting that the capacities contained in the permit application reflect maximum output design data, and the actual output of each combustion turbine and steam turbine may vary depending on ambient conditions, operation of the inlet fogging systems, age related degradation and other operational factors.

EPC Comment No. 3:
EPC staff noted on Page 1-2 in the project description that Units 5 and 6 will permanently cease coal fired operations. What about wood derived fuels (WDF) and tire derived fuels (TDF)?

TEC Response:
When combusting WDF or TDF, TEC actually combusts a weight percent blend of each fuel with coal. Typically, these blends are less than 10% by weight of WDF or less than 20% by weight of TDF. It would be very difficult, if not impossible to combust 100% WDF or 100% TDF due to operational issues that arise from handling and firing each fuel. Therefore, TEC does not anticipate operating the existing coal fired boilers at Gannon Station with WDF or TDF. If TEC does, however, decide to fire a fuel other than coal in any existing Gannon boiler, it will submit a permit application before doing so as mandated by both the Consent Decree and Consent Final Judgement.

EPC Comment No. 4:
EPC staff noted on Page 1-2 in the project description that it is proposed that one "Bayside Unit" be equipped with "SCONO$_x$" technology. Has this technology been approved by EPA as required by Consent Agreement 99-2524, CIV-T-23F? Does the term "unit" mean one individual CT or a group of CTs? If the term "unit" is to be a group of CTs which group is to be controlled with the SCONO$_x$ technology, and if the term "unit" is to be a single CT, which one will be equipped with the SCONO$_x$ technology?

TEC Response:
At this time, both TEC and FDEP agree that the SCONOx technology is not economically feasible as defined by Condition V.B. of the Consent Final Judgement. In this particular case, the term 'unit' is intended to mean an individual CT. However, in most other cases, the term 'unit' is taken to mean the collection of combustion turbines that provide steam to an existing steam turbine.

EPC Comment No. 5:
What percentage of the total cost of re-powering Bayside does the installation of the oxidation catalyst system represent? What percentage of the present annual operating and maintenance costs does the projected annual operating cost associated with the oxidation catalyst system represent?

TEC Response:
Although no final costs for the Bayside project are available yet, the repowering is expected to cost about $740 million, and the total capital investment of an oxidation catalyst system is $9,586,600. The resulting ratio of cost of oxidation catalyst system to total cost of the Bayside project is 0.013. The average Annual Operating and Maintenance Costs for Gannon Station between the years 1996-1999 was approximately $32.7 million and TEC projects that it will cost approximately $2,599,199 to operate and maintain the oxidation catalyst system. Therefore, the annual operating cost associated with the oxidation catalyst system represents about 7.9% of the current Gannon operating and maintenance costs.

EPC Comment No. 6:
Has TEC performed modeling using the SCONO$_x$ technology? If so, what are the results?

TEC Response:
No, TEC has not performed modeling using the SCONOx technology. Since SCONOx has never been installed on a GE 7F combustion turbine, most of the emissions are unknown. However, it is not anticipated that modeling would reveal greater ambient impacts as a result of installing the SCONOx technology when compared to SCR systems.

EPC Comment No. 7:
EPC staff noted on Page 2-8 (third paragraph), of the project description, that both of the heat inputs do not agree with the requested heat input listed on Page 14, Section B, Item no.1 of the construction application. The values listed on page 2-8 are 1779.4 and 1928.0 MMBtu/hr and the construction application requests 1940 MMBtu/hr.

TEC Response
The paragraph referenced above on Page 2-8 goes on to read in part, "However, CT vendors typically include a margin in guaranteed heat rates and therefore actual heat inputs could be somewhat higher than provided on the vendor expected performance data sheets. TEC therefore requests a permit condition that would allow for a higher maximum heat input rate based on actual performance tests." This is the reason for the difference in heat inputs.

EPC Comment No. 8:
EPC staff noted that on Page 2-9 of the project description TEC requested 18 hours per cold start for the steam turbines. What is the time frame is being set for the 18 hour request (i.e. 18 hours per 24 hours)? Please note, since the steam turbine(s) are connected to the CT exhausts, allowing excess emissions from the steam turbines for a period of 18 hours would effectively allow excess emissions for a period of 18 hours for the CTs as well. What excess emissions does TEC expect to be emitted from an unfired steam turbine?

TEC Response:
Based on further discussions with the Bayside engineering team, only one CT will generate excess emissions during a cold steam turbine startup. This period of excess emissions is expected to last for 16 hours during which the CT will operate at less than 50% load.

EPC Comment No. 9:
Please note, EPC staff noted on Page 3-1 of the project description that TEC has stated that Hillsborough County is attainment for ozone, but Hillsborough County is a maintenance area for ozone.

TEC Response:
TEC does not object to this issue.

EPC Comment No. 10:
EPC staff noted that TEC has requested the option of firing fuel oil in the CTs for 876 hr equivalents at 100 % base load. The Consent Agreement limits the hour equivalents to 875 hrs per year at 100 % of the base load. All of the potential emissions calculations contained in the construction permit application are also based on 876 hr/yr and need to be updated to reflect 875 hrs/yr as required by the consent order.

TEC Response:
TEC requests a permit limit of 875 full load equivalent hours of operation per year on oil. Since the calculations based on 876 hours of full load equivalent operation represent a worst case scenario, TEC suggests that the potential calculations are conservative and do not need to be revised.

EPC Comment No. 11:
EPC staff noted on Page 22 of the construction application that the CO Potential Emissions are based on 876 hrs per year firing fuel oil at 100 % load and 59°F. EPC staff believes that the potential emissions

should be based on firing fuel oil at 50 % load and 93°F for 1750 hours per year since the hourly emissions are greater at the reduced load and TEC has requested the option of operating at less than 100% of the base load.

TEC Response:
The emission rate at 93°F and 50% load represents a short-term worst case emission rate. The annual emission rate calculated at 100% load and 59°F represents a reasonable annual average and is used for annual modeling. TEC feels that the modeling performed was done so correctly; as the emission rate calculated at 59°F and 100% load is an industry accepted standard.

EPC Comment No. 12:
Will TEC be removing or permanently disabling the coal fired boilers at Gannon (Bayside) after construction is complete? If the coal fired units are to remain on-site and functional, EPC staff feels that the potential emissions from these units should be included evaluated as well.

TEC Response:
TEC is not permitted by law to fire coal in any of those boilers after December 31, 2004 and, as such, will disable each coal fired boiler. Therefore, the boilers will not have any emissions to evaluate.

EPC Comment No. 13:
EPC staff noted that on Pages 24 and 26 of the construction permit application that PM and PM_{10} emissions are based on modeling performed at 59°F but the application states the modeling was performed at 18°F, which is the worst case for PM and PM_{10}. Please clarify which is correct.

TEC Response
The hourly emission rates of PM and PM_{10} are based on an ambient temperature of 18°F. This represents a short-term worst case emission rate of each species. The annual emission rates of PM and PM_{10} are based on an ambient temperature of 59°F, which is an industry standard that represents a reasonable annual average temperature.

EPC Comment No. 14
EPC staff noted that on Page 30 of the construction permit application that the annual H_2SO_4 emissions were based on modeling performed for 59°F, but the modeling predicts the worst case at 18°F. What is the basis for basing annual emissions at 59°F instead of the worst case?

TEC Response
See the response to Comment 13.

EPC Comment No. 15:
EPC staff noted that on Page 32 of the construction permit application that the annual VOC emissions were based on modeling performed for 59°F, but the modeling predicts the worst case at 18°F. What is the basis for basing annual emissions at 59°F instead of the worst case?

TEC Response
See the response to Comment 13.

TEC appreciates the opportunity to work with EPC to resolve these issues in an expedited manner. This will help to ensure that construction will commence on the Bayside Power Station under a schedule that will allow TEC to comply with the dates outlined in the FDEP Consent Final Judgement and the EPA Consent Decree. If you have any questions, please feel free to telephone me at (813) 641-5125.

Sincerely,

Shannon K. Todd
Environmental Engineer
Environmental Affairs

EP\gm\SKT209

c: Mr. Jerry Kissel, FDEP - SWD
Mr. Jeffrey Koerner, FDEP
Mr. Jerry Campbell, EPCHC
Mr. John Bunyak, NPS
Mr. Gregg Worley, EPA Region 4
Ms. Katy Forney, EPA Region 4

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DEC 26 2000

BUREAU OF AIR REGULATION

December 22, 2000

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

Via FedEx
Airbill No. 7904 3137 2873

Re: Second Request for Additional Information
Project No. 0570040-013-AC (PSD-FL-301)
Bayside Power Station (Gannon Repowering Project)

Dear Mr. Koerner:

Tampa Electric Company (TEC) has received your letter of incompleteness dated December 15, 2000 addressing the proposed repowering of F.J. Gannon Station to Bayside Power Station. For your convenience, TEC has restated each point and provided a response below each specific issue.

1. **Netting Analysis: Please verify that *all* emissions increases and decreases for *all* emissions units have been included in the netting analysis for the contemporaneous period. Describe any outstanding air permitting projects that TEC has for the Gannon Plant, including any projects submitted to either the Department's Tallahassee Office as well as the Southwest District Office. For example, please describe the addition of wood-derived fuels (WDF) as authorized fuels for Gannon Units 1 – 4. What is the purpose of adding new fuels for these boilers? Will this result in an increase in actual annual emissions? Is this request related to the shutdown of Units 5 and 6 or the re-powering project in any way?**

TEC Response

Most emissions increases and decreases for all emissions units have been included in the netting analysis for the contemporaneous period. One outstanding project, the combustion of Wood Derived Fuel blends, however, was not included in the netting analysis. This project involves the combustion of paper pellets and /or yard trash as part of Tampa Electric Company's Smart Source Program. The Smart Source Program provides the opportunity for TEC customers to purchase electricity generated from alternative and renewable sources such as Wood Derived Fuel. During calendar year 2001, Tampa Electric expects to fire up to 1,250 tons of Wood Derived Fuel at Gannon Station which will result in emissions decreases of SO_2 and NO_x, while PM emissions will remain unchanged. Based on the stack tests performed and submitted to the Department, TEC intends to fire yard trash composed of wood chips up to 4% by weight.

Finally, TEC is not required by this permit to fire Wood Derived Fuel, so considering any emissions decreases in the netting analysis would be inappropriate. This project is in no way related to the repowering of Gannon Station to Bayside Station.

2. **<u>Gas Turbines / HRSGs</u>: Please provide the "preliminary design" data for the Heat Recovery Steam Generators (HRSGs), including the maximum steam production rate (lb/hour), steam temperature (° F), and steam pressure (psig) for each HRSG. Will each HRSG be identical?**

TEC Response

The requested information is provided below. TEC has provided this information with the understanding that it will be used for descriptive purposes, only and will not be used to limit the operation of either Bayside Unit 1 or 2. Furthermore, this is preliminary design data and, as such, is subject to change as the design changes. The HRSG's serving Bayside Unit 1 are identical and the HRSG's serving Bayside Unit 2 are also identical.

	Natural Gas Fired Operation (per HRSG)	*Fuel Oil Fired Operation (per HRSG)*
Bayside Unit 1		
HP Steam flow [lbm/hr]	455,450	478,250
IP Steam flow [lbm/hr]	508,540	525,120
LP steam flow [lbm/hr]	44,860	0
Total steam flow [lbm/hr]	1,008,850	1,003,370
Max. Steam Temperature [°F]	1,011	1,012
Max. Steam Pressure [psia]	1,597	1629
Bayside Unit 2		
HP Steam flow [lbm/hr]	447,100	449,400
IP Steam flow [lbm/hr]	518,100	515,200
LP steam flow [lbm/hr]	18,300	0
Total steam flow [lbm/hr]	983,500	964,600
Max. Steam Temperature [°F]	1,010	1,010
Max. Steam Pressure [psia]	1,796	1,837

3. **<u>Proposed Control Equipment</u>: The Department is working with TEC to resolve the evaluation of zero ammonia technologies. Please note that this issue must be resolved before the Department will deem the Bayside PSD permit application complete.**

TEC Response

TEC understands that the evaluation of zero ammonia technologies has been completed and that the SCONOx system will not be applied to any combustion turbine at the Bayside Power Station. Since the issue is now resolved, TEC understands that the Department is free to deem the application complete relative to this item.

4. **<u>BACT Determination for CO</u>: The Department does not believe a one-time emissions performance test conducted on Gannon Unit 5 in April of 2000 to be representative of actual CO emissions from Gannon Units 5 and 6 for the base years of 1997, 1998, and 1999. Again, please submit a top-down BACT analysis for the control of carbon monoxide. When evaluating the oxidation catalyst, please include the items previously addressed for the revised cost analysis for the VOC oxidation catalyst. Note that a CO control efficiency of at least 90% would be expected. If no CO BACT is proposed, the Department will establish a CO BACT standard without input from TEC.**

TEC Response

Recent conversations between Sheila McDevitt, General Counsel of TECO Energy and USEPA have resulted in the determination that NSR was not intended to apply to the Bayside repowering project. In addition, Condition M. of the Consent Final Judgement states that:

> *"Tampa Electric Company shall also be protected from triggering NSR requirements with respect to repairs, maintenance, and physical or operation changes during the term of the Consent Final Judgement which term shall remain effective until the actions required hereunder have been implemented."*

Although TEC believes that the performance test on Gannon Unit 5 does, in fact, represent actual CO emissions from Units 5 and 6 for the base years of 1997, 1998, and 1999, and that the Bayside repowering was never intended to be subject to PSD review, a BACT analysis is enclosed. The total cost of CO control is $2,918 per ton of CO removed, which has historically been considered economically infeasible by the Department.

5. **<u>MACT Determination for Hazardous Air Pollutants (HAPs)</u>: As previously discussed, the EPA and the Department disagree with TEC's interpretation regarding the applicability of a case-by-case MACT determination. TEC has stated that Bayside Units 1 and 2 are attached to separate stream turbines and should therefore be evaluated as individual process units. The Department believes that TEC's interpretation is flawed because it would lead to a conclusion that *each* combined cycle gas turbine could be evaluated as a separate "process unit" and evaluated for MACT applicability based on the individual emissions. Further, each gas turbine is connected to an individual HRSG, after which any additional controls would be added.**

   The Department believes that the HAP emissions from all of the Bayside gas turbines must be aggregated for comparison to the HAP major source thresholds. Jim Little of EPA Region 4 confirmed the Department's interpretation with Sims Roy, the author of EPA's interpretative rule for MACT determinations regarding gas turbines. In addition, Mr. Little confirmed the Department's interpretation with Kathy Kaufman, the EPA 112(g) MACT coordinator. TEC's interpretation is not in accordance with MACT program as interpreted by the Department and EPA. Please submit a case-by-

case MACT analysis for the Bayside. If no MACT is proposed, the Department will establish case-by-case MACT standards without input from TEC.

TEC Response

TEC maintains the position that Bayside Units 1 and 2 should be considered separately when considering MACT applicability. This would not, however, lead to the conclusion that each CT should be considered separately. According to 40 CFR 63.41, the term 'Construct a Major Source' means, in part:

> *"(2) To fabricate, erect, or install at any developed site a new process or production unit which in and of itself emits or has the potential to emit 10 tons per year of any HAP or 25 tons per year of any combination of HAP...."*

According to the same rule, the definition of 'Process or Production Unit' mentioned above is:

> *"...any collection of structures and/or equipment, that processes assembles, applies, or otherwise uses material inputs to produce or store an intermediate or final product. A single facility may contain more than one process or production unit." (Emphasis added)*

Bayside Power Station clearly represents the construction and operation of two separate production units as evidenced by the facts below:

- *Each production unit will be constructed and begin operation independently.*
- *Each production unit will operate independently of the other.*
- *Each production unit will produce steam to supply a separate steam turbine.*

Furthermore, the definition of 'Process or Production Unit' allows for the siting of more than one unit per facility. TEC does not claim that the individual combustion turbines that provide heat and power to serve Bayside Units 1 and 2 should be considered individually for MACT applicability. These individual combustion turbines do not fit the definition of Processes or Production Units anymore than the individual burners that provide energy in operating a coal fired unit.

Based on this definition and the fact that Bayside Units 1 and 2 each produce steam for separate, individual steam turbines, it is clear that they must be defined as separate production units when considering MACT applicability.

6. **Excess Emissions: Will the gas turbines be operated below 50% load during a steam turbine cold startup? If so, for how long? From the response provided, TEC is unsure of the emission rates from the gas turbines during a steam turbine cold startup. The Department understands that the steam turbine cold startup may last for 14 to 16 hours, but that emissions may not be elevated during the entire period. Please provide data regarding the emission levels during this type of startup and/or the duration of gas turbine operation below 50% load.**

TEC Response

Based on continued discussions with the Bayside engineering team, TEC has determined that it is only necessary to operate one combustion turbine per production unit below 50% load per *cold steam turbine startup. Consequently, TEC requests an allowance for excess emissions for 16 hours for only one CT per production unit during a cold steam turbine startup.*

7. **<u>Requirements of the EPA/TEC Consent Decree</u>: EPA Region 4 is reviewing the Bayside application and the Department expects comments shortly. When received, the Department will forward any EPA Region 4 questions TEC for a response.**

TEC Response

TEC appreciates the opportunity to comment on any EPA Region 4 questions raised regarding the Bayside Power Station permit application.

TEC appreciates the opportunity to work with the Department to resolve these issues in an expedited fashion, as the receipt of the final Air Construction Permit is critical to maintain a construction schedule that will support the commencement of operation of the Bayside Power Station as outlined in the Consent Final Judgement and the Consent Decree. If you have any questions, please call Shannon Todd or me at (813) 641-5125.

Sincerely,

Karen Sheffield

Karen Sheffield
General Manager-Bayside Power
Station
Tampa Electric Company

EP\gm\

Enclosure

c: Mr. Jerry Kissel, FDEP - SWD
Mr. Jerry Campbell, EPCHC
Mr. John Bunyak, NPS
Mr. Gregg Worley, EPA Region 4
Ms. Katy Forney, EPA Region 4

4.0A BEST AVAILABLE CONTROL TECHNOLOGY ANALYSIS FOR CARBON MONOXIDE

4.1A METHODOLOGY

The CO BACT analysis was performed as previously described in the September 2000 permit application.

4.2A FEDERAL AND FLORIDA EMISSION STANDARDS

Pursuant to Rule 62-212.400(5)(b), F.A.C., BACT emission limitations must be no less stringent than any applicable NSPS (40 CFR Part 60), NESHAPs (40 CFR Parts 61 and 63), and FDEP emission standards (Chapter 62-296, F.A.C., *Stationary Sources—Emission Standards*).

On the federal level, emissions from gas turbines are regulated by NSPS Subpart GG. Subpart GG establishes emission limits for gas turbines that were constructed after October 3, 1977, and that meet any of the following criteria:

- Electric utility stationary gas turbines with a heat input at peak load of greater than 100 MMBtu/hr based on the LHV of the fuel.
- Stationary gas turbines with a heat input at peak load between 10 and 100 MMBtu/hr based on the fuel LHV.
- Stationary gas turbines with a manufacturer's rated baseload at ISO standard day conditions of 30 MW or less.

The electric utility stationary gas turbine NSPS applicability criterion applies to stationary gas turbines that sell more than one-third of their potential electric output to any utility power distribution system. The Bayside Units 1 and 2 CTs qualify as electric utility stationary gas turbines and, therefore, are subject to the NO_x and SO_2 emission limitations of NSPS 40 CFR 60, Subpart GG, 60.332(a)(1) and 60.333, respectively. However, NSPS Subpart GG does not include any CO emission limitations.

FDEP emission standards for stationary sources are contained in Chapter 62-296, F.A.C., *Stationary Sources—Emission Standards*. Visible emissions are limited to a maximum of 20 percent opacity pursuant to Rule 62-296.320(4)(b), F.A.C. Sections 62-296.401 through -.417, F.A.C., specify emission standards for 17 categories of sources; none of these categories are applicable to CTs. Rule 62-204.800(7) incorporates the federal NSPS by reference, including Subpart GG.

Section 62-204.800, F.A.C., adopts federal NSPS and NESHAP, respectively, by reference. As noted previously, NSPS Subpart GG, *Stationary Gas Turbines* is applicable to the Bayside Unit 1 and 2 CTs. However, Subpart GG does not contain any CO emission limitations. There are no applicable NESHAP requirements.

In summary, there are no federal or state CO emission limitations applicable to Bayside Units 1 and 2.

4.3A BACT ANALYSIS FOR CO

CO emissions result from the incomplete combustion of carbon and organic compounds. Factors affecting CO emissions include firing temperatures, residence time in the combustion zone, and combustion chamber mixing characteristics. Because higher combustion temperatures will increase oxidation rates, emissions of CO will generally increase during turbine partial load conditions when combustion temperatures are lower. Decreased combustion zone temperature due to the injection of water or steam for NO_x control will also result in an increase in CO emissions.

An increase in combustion zone residence time and improved mixing of fuel and combustion air will increase oxidation rates and cause a decrease in CO emission rates. Emissions of NO_x and CO are inversely related; i.e., decreasing NO_x emissions will result in an increase in CO emissions. Accordingly, combustion turbine vendors have had to consider the competing factors involved in NO_x and CO formation in order to develop units that achieve acceptable emission levels for both pollutants.

4.3.1A POTENTIAL CONTROL TECHNOLOGIES

There are two available technologies for controlling CO from gas turbines: (1) combustion process design and (2) oxidation catalysts.

Combustion Process Design

Combustion process controls involve combustion chamber designs and operation practices that improve the oxidation process and minimize incomplete combustion. Due to the high combustion efficiency of CTs, approximately 99 percent, CO emissions are inherently low.

Oxidation Catalysts

Noble metal (commonly platinum or palladium) oxidation catalysts are used to promote oxidation of CO to carbon dioxide (CO_2) and water at temperatures lower than would be necessary for oxidation without a catalyst. The operating temperature range for oxidation catalysts is between 650 and 1,150°F.

Efficiency of CO oxidation varies with inlet temperature. Control efficiency will increase with increasing temperature for CO up to a temperature of approximately 1,100°F; further temperature increases will have little effect on control efficiency. Significant CO oxidation will occur at any temperature above roughly 500°F. The catalyst inlet temperature must also be maintained below 1,350 to 1,400°F to prevent thermal aging of the catalyst which will reduce catalyst activity and pollutant removal efficiencies. Removal efficiency will also vary with gas residence time which is a function of catalyst bed depth. Increasing bed depth will increase removal efficiencies but will also cause an increase in pressure drop across the catalyst bed. For combustion turbine applications, oxidation catalyst systems are typically designed to achieve a CO control efficiency of 80 to 90 percent.

Oxidation catalysts are susceptible to deactivation due to impurities present in the exhaust gas stream. Arsenic, iron, sodium, phosphorous, and silica will all act as catalyst poisons causing a reduction in catalyst activity and pollutant removal efficiencies.

Oxidation catalysts are nonselective and will oxidize other compounds in addition to CO. The nonselectivity of oxidation catalysts is important in assessing applicability to exhaust streams containing sulfur compounds. Sulfur compounds that have been oxidized to SO_2 in the combustion process will be further oxidized by the catalyst to sulfur trioxide (SO_3). SO_3 will, in turn, combine with moisture in the gas stream to form H_2SO_4 mist. Due to the oxidation of sulfur compounds and excessive formation of H_2SO_4 mist emissions, oxidation catalysts are not considered to be an appropriate control technology for combustion devices that are fired with fuels containing significant amounts of sulfur.

Technical Feasibility

Both CT combustor design and oxidation catalyst control systems are considered to be technically feasible for the Bayside Units 1 and 2. Information regarding energy, environmental, and economic impacts and proposed BACT limits for CO are provided in the following sections.

4.3.2A ENERGY AND ENVIRONMENTAL IMPACTS

There are no significant adverse energy or environmental impacts associated with the use of good combustor designs and operating practices to minimize CO emissions.

The use of oxidation catalysts will, as previously noted, result in excessive H_2SO_4 mist emissions if applied to combustion devices fired with fuels containing high sulfur contents. Increased H_2SO_4 mist emissions will also occur, on a smaller scale, from CTs fired with natural gas.

Because CO emission rates from CTs are inherently low, further reductions through the use of oxidation catalysts will result in minimal air quality improvements; i.e., below the defined PSD significant impact levels for CO. The location of Bayside Units 1 and 2 (Hillsborough County) is classified attainment for all criteria pollutants, including CO. As noted in the Department's 1999 Air Monitoring Report, there have been no exceedances of the CO ambient air quality standards (AAQSs) in Florida during the last twelve years. Maximum CO concentrations for all Florida monitoring sites during 1999 were less than 30 percent of the 35 ppm one-hour AAQS, and less than 65 percent of the 9 ppm eight-hour AAQS. From an air quality perspective, the only potential benefit of CO oxidation catalyst is to prevent the possible formation of a localized area with elevated concentrations of CO. The catalyst does not remove CO but rather simply accelerates the natural atmospheric oxidation of CO to CO_2. Dispersion modeling of Bayside Units 1 and 2 CO emissions indicate that maximum CO impacts, without oxidation catalyst, will be insignificant. The highest, second highest 1- and 8-hour average CO impacts during natural gas-firing (the primary fuel for the Bayside Power Station) are projected to be only 0.3 and 0.5 percent of the Florida and Federal CO AAQS.

The application of oxidation catalyst technology to a gas turbine will result in an increase in back pressure on the CT due to a pressure drop across the catalyst bed. The increased back pressure will, in turn, constrain turbine output power thereby increasing the unit's heat rate. An oxidation catalyst system for the Bayside Units 1 and 2 CTs is projected to have a pressure drop across the catalyst bed of approximately 1.1 inch of water (H_2O). This pressure drop will result in a 0.22 percent energy penalty due to reduced turbine output power. The reduction in turbine output power (lost power generation) will result in an energy penalty of 3,199,152 kilowatt-hours (kwh) (10,163 MMBtu) per year at baseload (166-MW) operation and 100 percent capacity factor per CT. This energy penalty is equivalent to the use of 72.8 million cubic feet (ft^3) of natural gas annually based on a natural gas heating value of 1,050 British thermal units per cubic foot (Btu/ft^3) for all seven CTs. The lost power generation energy penalty, based on a power cost of \$0.030/kwh, is \$671,822 per year for all seven CTs.

4.3.3A ECONOMIC IMPACTS

An economic evaluation of an oxidation catalyst system was performed using OAQPS factors and the project-specific economic factors provided in Table 4-1A. Specific capital and annual operating costs for the oxidation catalyst control system are summarized in Tables 4-2A and 4-3A.

Table 4-1A. Economic Cost Factors

Factor	Units	Value
Interest rate	%	7.0*
Control system life	Years	15
Oxidation catalyst life	Years	5
Oxidation catalyst control efficiency	%	90.0*
Electricity cost	$/kWh	0.030*
Labor costs (base rates)	$/hour	
Operator		22.00
Maintenance		22.00

* Per FDEP request.

Sources: ECT, 2000.
TEC, 2000.

Table 4-2A. Capital Costs for Oxidation Catalyst System, Seven CT/HRSGs

Item	Dollars	OAQPS Factor
Direct Costs		
Purchased equipment	4,921,000	A
Sales tax	295,260	0.06 x A
Instrumentation	492,100	0.10 x A
Freight	246,050	0.05 x A
Subtotal Purchased Equipment	**5,954,410**	**B**
Installation		
Foundations and supports	476,353	0.08 x B
Handling and erection	833,617	0.14 x B
Electrical	238,176	0.04 x B
Piping	119,088	0.02 x B
Insulation for ductwork	59,544	0.01 x B
Painting	59,544	0.01 x B
Subtotal Installation Cost	**1,786,323**	
Total Direct Costs (TDC)	**7,740,733**	
Indirect Costs		
Engineering	595,441	0.10 x B
Construction and field expenses	297,721	0.05 x B
Contractor fees	595,441	0.10 x B
Startup	119,088	0.02 x B
Performance test	59,544	0.01 x B
Contingency	178,632	0.03 x B
Total Indirect Costs (TIC)	**1,845,867**	
TOTAL CAPITAL INVESTMENT (TCI)	**9,586,600**	TDC + TIC

Source: ECT, 2000.

Table 4-3A. Annual Operating Costs for Oxidation Catalyst System, Seven CT/HRSGs

Item	Dollars	OAQPS Factor
Direct Costs		
Catalyst costs		
Replacement (materials and labor)	4,855,872	
Credit for used catalyst	(655,200)	15% credit
Annualized Catalyst Costs	**1,024,505**	
Energy Penalties		
Turbine backpressure	671,822	0.2% penalty
Total Direct Costs (TDC)	**1,696,327**	
Indirect Costs		
Administrative charges	191,732	0.02 x TCI
Property taxes	95,866	0.01 x TCI
Insurance	95,866	0.01 x TCI
Capital recovery	519,409	15 yrs @ 7.0%
Total Indirect Costs (TIC)	**902,873**	
TOTAL ANNUAL COST (TAC)	**2,599,199**	TDC + TIC

Sources: ECT, 2000.
TEC, 2000.

The base case Bayside Units 1 and 2 annual CO emission rate (i.e., for all seven CT /HRSG units) is 989.7 tpy based on CT baseload operation at 59°F for 7,884 and 876 hr/yr for natural gas and distillate fuel oil firing, respectively. The controlled annual CO emission rate, based on 90 percent control efficiency, is 99.0 tpy. Base case and controlled CO emission rates are summarized in Table 4-4A.

The cost effectiveness of oxidation catalyst for CO emissions was determined to be $2,918 per ton of CO removed. Based on the high control costs, use of oxidation catalyst technology to control CO emissions is not considered to be economically feasible. For example, the California San Joaquin Valley Unified Air Pollution Control District's BACT policy considers CO control costs of less than $300 per ton to be cost effective; i.e., CO control costs equal to or greater than $300 per ton are not considered cost effective. Results of the oxidation catalyst economic analysis are summarized in Table 4-4A.

4.3.4A PROPOSED BACT EMISSION LIMITATIONS

The use of oxidation catalyst to control CO from CTs is typically required only for facilities located in CO nonattainment areas. A summary of recent FDEP CO BACT determinations for natural gas- and distillate fuel oil-fired combustion turbines is provided in Tables 4-5A and 4-6A, respectively.

The use of oxidation catalysts will, as previously noted, result in excessive H_2SO_4 mist emissions if applied to combustion devices fired with fuels containing appreciable amounts of sulfur. Increased H_2SO_4 mist emissions will also occur, on a smaller scale, from CTs fired with natural gas. Because CO emission rates from CTs are inherently low, further reductions through the use of oxidation catalysts will result in only minor improvement in air quality, i.e., well below the defined PSD significant impact levels for CO.

Use of state-of-the-art combustor design and good operating practices to minimize incomplete combustion is proposed as BACT for CO. These control techniques have been considered by FDEP to represent BACT for CO for recent CT projects.

Table 4-4A. Summary of CO BACT Analysis

Control Option	Emission Impacts: Emission Rates (lb/hr)	Emission Impacts: Emission Rates (tpy)	Emission Impacts: Emission Reduction (tpy)	Economic Impacts: Installed Capital Cost ($)	Economic Impacts: Total Annualized Cost ($/yr)	Economic Impacts: Cost Effectiveness Over Baseline ($/ton)	Energy Impacts: Increase Over Baseline (MMBtu/yr)	Environmental Impacts: Toxic Impact (Y/N)	Environmental Impacts: Adverse Envir. Impact (Y/N)
Oxidation catalyst	22.6	99.0	890.7	9,586,600	2,599,199	2,918	76,412	N	Y
Baseline	226.0	989.7	N/A	N/A	N/A	N/A	N/A	N/A	N/A

Basis: Seven GE PG7241 (FA) CTs, 100-percent load, natural gas-firing for 7,884 hr/yr, and fuel oil-firing for 876 hr/yr.

Sources: ECT, 2000.
GE, 2000.
TEC, 2000

Table 4-5A Florida BACT CO Summary—Natural Gas-Fired CTs

Permit Date	Source Name	Turbine Size (MW)	CO Emission Limit (ppmvd)	Control Technology
9/28/95	City of Key West	23	20	Good combustion
5/98	City of Tallahassee Purdom Unit 8	160	25	Good combustion
7/10/98	City of Lakeland McIntosh Unit 5	250	25	Good combustion
9/28/98	Florida Power Corp. Hines Energy Complex	165	25	Good combustion
11/25/98	Florida Power & Light Fort Myers Repowering	170	12	Good combustion
12/4/98	Santa Rosa Energy, LLC (DB Off)	167	9	Good combustion
12/4/98	Santa Rosa Energy, LLC (DB On)	167	24	Good combustion
7/23/99	Seminole Electric Cooperative, Inc., Payne Creek	158	20	Good combustion
10/8/99	Tampa Electric Company – Polk Power Station	165	15	Good combustion
10/8/99	TECO Power Services – Hardee Power Station	75	25	Good combustion
10/18/99	Vandolah Power Project	170	12	Good combustion
12/28/99	Reliant Energy Osceola	170	10.5	Good combustion
1/13/00	Shady Hills Generating Station	170	12	Good combustion
2/00	Kissimmee Utility – Cane Island Unit 3 (DB Off)	167	12	Good combustion
2/00	Kissimmee Utility – Cane Island Unit 3 (DB On)	167	20	Good combustion
2/24/00	Gainesville Regional Utilities	83	25	Good combustion
5/11/00	Calpine Osprey (Draft – DB Off)	170	10	Good combustion
5/11/00	Calpine Osprey (Draft – DB On)	170	17	Good combustion
7/31/00	Gulf Power – Smith Unit 3 (DB On)	170	16	Good combustion
Draft	CPV Gulfcoast, Ltd. (Power Augmentation Off)	170	9	Good combustion
Draft	CPV Gulfcoast, Ltd. (Power Augmentation On)	170	15	Good combustion

Source: FDEP, 2000.

Table 4-6A Florida BACT CO Summary—Distillate Fuel Oil-Fired CTs

Permit Date	Source Name	Turbine Size (MW)	CO Emission Limit (ppmvd)	Control Technology
5/98	City of Tallahassee Purdom Unit 8	160	90	Good combustion
7/10/98	City of Lakeland McIntosh Unit 5	250	90	Good combustion
9/28/98	Florida Power Corp. Hines Energy Complex	165	30	Good combustion
7/23/99	Seminole Electric Cooperative, Inc., Payne Creek	158	25	Good combustion
10/8/99	Tampa Electric Company – Polk Power Station	165	20	Good combustion
10/8/99	TECO Power Services – Hardee Power Station	75	20	Good combustion
10/18/99	Vandolah Power Project	170	12	Good combustion
12/28/99	Reliant Energy Osceola	170	20	Good combustion
1/13/00	Shady Hills Generating Station	170	20	Good combustion
2/00	Kissimmee Utility – Cane Island Unit 3 (DB Off)	167	20	Good combustion
2/00	Kissimmee Utility – Cane Island Unit 3 (DB On)	167	30	Good combustion
2/24/00	Gainesville Regional Utilities	83	20	Good combustion
Draft	CPV Gulfcoast, Ltd. (90 – 100 % Load)	170	20	Good combustion
Draft	CPV Gulfcoast, Ltd. (75 – 89 % Load)	170	22	Good combustion
Draft	CPV Gulfcoast, Ltd. (50 – 74 % Load)	170	29	Good combustion

Source: FDEP, 2000.

Maximum natural gas and distillate fuel oil firing CO exhaust concentrations from the CT/HRSG units will be less than or equal to 9.0 and 39.0 ppmvd, respectively. These CO exhaust concentrations are consistent with recent FDEP CO BACT determinations for CT/HRSG units. CO BACT emission limits proposed for Bayside Units 1 and 2 are provided in Table 4-7A.

Table 4-7A. Proposed CO BACT Emission Limits

Emission Source	Proposed CO BACT Emission Limits ppmvd	lb/hr
GE PG7241 (FA) CT/HRSGs (Per CT/HRSG Unit)		
CO (Natural Gas)	9.0	31.1
CO (Distillate Fuel Oil)	39.0	81.3

Sources: ECT, 2000.
S&L, 2000.
TEC, 2000.

Department of Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

December 15, 2000

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Karen Sheffield, General Manager
Bayside Power Station, Tampa Electric Company
Port Sutton Road
Tampa, FL 33619

Re: Request for Additional Information No. 2
Project No. 0570040-013-AC (PSD-FL-301)
Bayside Power Station (Gannon Repowering Project)

Dear Ms. Sheffield:

On November 17, 2000, the Department received the additional information with attachments for the Bayside Power Station, a project intended to re-power the Gannon Plant. The Department has reviewed this information and the application remains incomplete. In order to continue processing your application, the Department will need the additional information requested below. Should your response to any of these items require new calculations, please submit the new calculations, assumptions, reference material and appropriate revised pages of the application form.

1. Netting Analysis: Please verify that *all* emissions increases and decreases for *all* emissions units have been included in the netting analysis for the contemporaneous period. Describe any outstanding air permitting projects that TEC has for the Gannon Plant, including any projects submitted to either the Department's Tallahassee Office as well as the Southwest District Office. For example, please describe the addition of wood-derived fuels (WDF) as authorized fuels for Gannon Units 1 – 4. What is the purpose of adding new fuels for these boilers? Will this result in an increase in actual annual emissions? Is this request related to the shutdown of Units 5 and 6 or the re-powering project in any way?

2. Gas Turbines / HRSGs: Please provide the "preliminary design" data for the Heat Recovery Steam Generators (HRSGs), including the maximum steam production rate (lb/hour), steam temperature (° F), and steam pressure (psig) for each HRSG. Will each HRSG be identical?

3. Proposed Control Equipment: The Department is working with TEC to resolve the evaluation of zero ammonia technologies. Please note that this issue must be resolved before the Department will deem the Bayside PSD permit application complete.

4. BACT Determination for CO: The Department does not believe a one-time emissions performance test conducted on Gannon Unit 5 in April of 2000 to be representative of actual CO emissions from Gannon Units 5 and 6 for the base years of 1997, 1998, and 1999. Again, please submit a top-down BACT analysis for the control of carbon monoxide. When evaluating the oxidation catalyst, please include the items previously addressed for the revised cost analysis for the VOC oxidation catalyst. Note that a CO control efficiency of at least 90% would be expected. If no CO BACT is proposed, the Department will establish a CO BACT standard without input from TEC.

5. MACT Determination for Hazardous Air Pollutants (HAPs): As previously discussed, the EPA and the Department disagree with TEC's interpretation regarding the applicability of a case-by-case MACT determination. TEC has stated that Bayside Units 1 and 2 are attached to separate stream turbines and should therefore be evaluated as individual process units. The Department believes that TEC's interpretation is flawed because it would lead to a conclusion that *each* combined cycle gas turbine could be evaluated as a separate "process unit" and evaluated for MACT applicability based on the individual emissions. Further, each gas turbine is connected to an individual HRSG, after which any additional controls would be added.

The Department believes that the HAP emissions from all of the Bayside gas turbines must be aggregated for comparison to the HAP major source thresholds. Jim Little of EPA Region 4 confirmed the Department's interpretation with Sims Roy, the author of EPA's interpretative rule for MACT determinations regarding gas turbines. In addition, Mr. Little confirmed the Department's interpretation with Kathy Kaufman, the EPA 112(g) MACT coordinator. TEC's interpretation is not in accordance with MACT program as interpreted by the Department and EPA. Please submit a case-by-case MACT analysis for the Bayside. If no MACT is proposed, the Department will establish case-by-case MACT standards without input from TEC.

6. Excess Emissions: Will the gas turbines be operated below 50% load during a steam turbine cold startup? If so, for how long? From the response provided, TEC is unsure of the emission rates from the gas turbines during a steam turbine cold startup. The Department understands that the steam turbine cold startup may last for 14 to 16 hours, but that emissions may not be elevated during the entire period. Please provide data regarding the emission levels during this type of startup and/or the duration of gas turbine operation below 50% load.

7. Requirements of the EPA/TEC Consent Decree: EPA Region 4 is reviewing the Bayside application and the Department expects comments shortly. When received, the Department will forward any EPA Region 4 questions TEC for a response.

The Department will resume processing your application after receipt of the requested information. Rule 62-4.050(3), F.A.C. requires that all applications for a Department permit must be certified by a professional engineer registered in the State of Florida. This requirement also applies to responses to Department requests for additional information of an engineering nature. For material changes to the application, please submit a new certification statement by the authorized representative or responsible official. Rule 62-4.055(1), F.A.C. now requires permit applicants to response to requests for information within 90 days. If there are any questions, please contact me at 850/414-7268.

Sincerely,

Jeffery F. Koerner

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

AAL/jfk

Mr. Patrick Shell, TEC
Mr. Shannon Todd, TEC
Mr. Thomas Davis, ECT
Mr. Jerry Kissel, SWD
Mr. Jerry Campbell, EPCHC
Mr. John Bunyak, NPS
Mr. Gregg Worley, EPA Region 4
Ms. Katy Forney, EPA Region 4

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Street, Apt. No.; or PO Box No.
Port Sutton Road
City, State, ZIP+4
Tampa, FL 33619

PS Form 3800, July 1999 See Reverse for Instructions

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Karen Sheffield
General Manager
Bayside Power Station
Tampa Electric Company
Port Sutton Road
Tampa, FL 33619

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UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 4
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ATLANTA, GEORGIA 30303-8960

DEC 15 2000

4 APT-ARB

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DEC 21 2000
BUREAU OF AIR REGULATION

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

SUBJ: PSD Permit Application for TECO Gannon/Bayside Power Station (PSD-FL-301) located in Hillsborough County, Florida

Dear Mr. Linero:

Thank you for sending the draft prevention of significant deterioration (PSD) permit application for the Tampa Electric Company (TECO) Gannon/Bayside Power Station dated September 27, 2000. The PSD permit application is for a repowering project involving the shutdown of TECO Gannon's coal-fired units 5 and 6 and the addition of seven combined cycle combustion turbines (CTs) with a total nominal generating capacity of 1728 MW. The combustion turbines proposed for the facility are General Electric (GE), frame 7FA units. The CTs will primarily combust pipeline quality natural gas with No. 2 fuel oil combusted as backup fuel. As proposed, the CTs would fire natural gas up to 8,760 hours per year and fire No. 2 fuel oil a maximum of 876 hours per year.

Based on our review of the PSD permit application, we have the following comments:

Netting Analysis

TECO's estimates of the net emission changes from the proposed project are a decrease of 14,659.8 tons per year (TPY) of nitrogen oxides, a decrease of 4,399.9 TPY of carbon monoxide, a decrease of 35,841.2 TPY of sulfur dioxide, a decrease of 51.3 TPY of sulfuric acid mist, a decrease of 378.2 TPY of particulate matter, a decrease of 8.5 TPY of lead and an increase of 70.7 TPY of volatile organic compounds. These net emission changes are based on the potential emission increases from the seven new CTs and the actual emission decreases resulting from the shutdown of boiler units 5 and 6. In reference to this subject, the Consent Decree signed by TECO and the U.S. Environmental Protection Agency (EPA) on February 28, 2000, is being interpreted as described below. It is EPA's opinion that emission reductions can be used in part to avoid PSD review for this project; however, a more appropriate method of calculating the net emission changes from this repowering project is to include the emission reductions resulting from the shutdown of boiler units 5 and 6 as if best available control technology (BACT) had been applied to the boilers. In other words, the emission reductions which are available for use in avoiding PSD review for this project would be the actual emission levels for the coal-fired boilers if present-day BACT methods were in use. Additionally, any remaining emission reductions not needed at this time to avoid PSD review may potentially be used by TECO in future netting analyses. Consequently, EPA recommends that TECO revise the netting analysis for this project and re-evaluate which pollutants are subject to PSD review. For clarity, the Consent Decree will be modified in the near future to reflect the above described interpretation.

112(g) Applicability

Consistent with previous discussions between EPA Region 4 and the Florida Department of Environmental Protection, our opinion is that total hazardous air pollutant emissions combined from all CTs being added to a facility should be used to determine if 112(g) case-by-case maximum achievable control technology requirements apply.

Thank you for the opportunity to comment on the TECO Gannon/Bayside Power Station PSD permit application. If you have any questions regarding these comments, please direct them to either Katy Forney at 404-562-9130 or Jim Little at 404-562-9118.

Sincerely,

Paul Wagner

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

cc: J. Koerner
C. Carlson
S. Todd, TECO
J. Kissel, SWD
J. Campbell, EPC
NPS

FAX Cover Sheet

USEPA - Region 4
61 Forsyth St., SW
Atlanta, Georgia 30303

TO: Jeff Koerner
FDEP

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DEC 18 2000
BUREAU OF AIR REGULATION

FAX #: 850-922-6979

RE: TECO

FROM: Katy Forney
Air Permits Section, Region 4 USEPA

Phone #: 404-562-9130

Date: 12-15-00

# of Pages (including cover): 3

COMMENTS:

If this FAX is poorly received, please call
Katy Forney: 404-562-913

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

DEC 1 5 2000

4 APT-ARB

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

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Sincerely,

Paul Wagner

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

TAMPA ELECTRIC

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NOV 17 2000

BUREAU OF AIR REGULATI

November 14, 2000

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

Via FedEx
Airbill No. 7923 8230 3267

Re: Request for Additional Information
Project No. 0570040-013-AC (PSD-FL-301)
Bayside Power Station (Gannon Repowering Project)

Dear Mr. Koerner:

Tampa Electric Company (TEC) has received your letter of incompleteness dated October 16, 2000 addressing the proposed repowering of F.J. Gannon Station to Bayside Power Station. For your convenience, TEC has restated each point and provided a response below each specific issue. TEC intends to complete this project in accordance with the deadlines outlined in the Consent Final Judgement and the Consent Decree and looks forward to the resolution of these issues by working closely with the Department in all phases of the process. Below, the Company has provided comprehensive responses to each specific incompleteness issue and, with this submission, TEC understands that the Department will continue processing the application.

1. <u>Netting Analysis</u>: **Attachment D of the PSD permit application provides a netting analysis that summarizes the actual emissions decreases from the shut down of Gannon Units 5 and 6 and the potential emissions increases from operation of the new Bayside Units. Previous EPA guidance suggests that emissions decreases needed to meet regulatory requirements should not be included in calculating net emissions increases for a project. Please explain TEC's understanding of the DEP/TEC Consent Final Judgement related to the issue of netting. Note that the remaining questions presume netting.**

TEC Response

The Consent Final Judgement (CFJ) and the Consent Decree (CD) represent agreements between the DEP and the EPA respectively. These agreements and any subsequent modifications that may be made to the CFJ or CD, provide the conditions under which the parties are required to operate in order to satisfy the terms of the agreement and to be deemed in compliance with law. The terms of the CFJ and the CD were negotiated resolutions to disputed claims and address discrete subject matters. There is nothing contained in either the CFJ or the CD that requires a reduction in emissions to meet regulatory requirements. Therefore, the guidance referenced by DEP is not applicable for the reasons cited. It is clear that the emission reductions resulting from the implementation of the any component of the CFJ or the CD may be used in the calculation of net emissions for this and other projects.

Tampa Electric agrees that the CFJ and the CD are designed to achieve significant emission reductions from the repowering of the Gannon Station and other projects identified in the CFJ and CD. To meet this requirement, it is appropriate for the Department to expect significant and reasonable emission reductions from the implementation of the requirements of the CFJ or the CD that can be expected to produce emission reductions.

2. <u>Gas Turbines / HRSGs</u>
   a. **Please identify the model of dry low NOx combustor that will be installed on each General Electric Model PG 7241(FA) gas turbine. Is this the latest version?**

TEC Response

A General Electric Co. (GE) Model PG 7241 (FA) gas turbine will be provided with GE's standard Dry Low NO_x (DLN) 2.6 combustion system.

   b. **Please identify the automated gas turbine control system that will be installed with each unit. Describe how this system will interact with the SCR and SCONOx™ control systems to reduce NOx emissions.**

TEC Response

Each gas turbine will be provided with GE's standard Mark VI controls. The system may or may not interact with the SCR and/or $SCONO_x$ depending on the control configuration established by Alstom Power. If an exhaust gas flow meter and uncontrolled NO_x monitor is installed (see response to Item 3a), then Mark VI interaction or feedback of unit operation, such as load, anticipated uncontrolled NO_x exhaust gas flow, etc., may not be required.

   c. **Is the evaporative cooler a high-pressure direct spray system? Please describe the system and identify the manufacturer, model, designed cooling reduction (°F), operating pressure, and water consumption rate.**

TEC Response

The evaporative cooler is not a high-pressure spray or fogging type of system. The evaporative cooler consists of a water distribution system and media packed blocks made of corrugated layers of fibrous material. Water is distributed over the top of the blocks and flows down through a set of channels. The air passes over alternate channels, which are wetted by the wicking action of the media. It is supplied as part of the GE package. The manufacturer has not been selected at this time. TEC will supply this information when it is available.

   d. **Will this project include natural gas fuel heaters or cooling towers? If so, please provide the information required on the permit application form for these emissions units.**

TEC Response

The Bayside project does not include a natural gas "fired" fuel heater. Fuel gas heating, to attain superheat requirements imposed by GE DLN 2.6 combustors during startup, is provided by an electric heater. During base load operation, fuel heating is performed by hot water extracted from the Heat Recovery Steam Generator (HRSG). The Bayside Plant design includes two small cooling towers, which will provide cooling water to various equipment associated with the new gas turbines and HRSGs. Note that the cooling towers are currently being bid and the configuration, performance and design is dependent on the vendor selected.

Required cooling tower information (per tower): *Unit 1** *Unit 2**

1.	*Recirculation water flow rate; gpm*	*5,100*	*6,800*
2.	*Recirculation water total dissolved solids (TDS); ppmw*	*1,000 to 1,855*	*1,000 to 1,855*
3.	*Recirculation water total suspended solids (TSS); ppmw*	*<5*	*<5*
4.	*Tower drift loss rate; % of recirculation water*	*0.08*	*0.08*
5.	*If available, PM_{10} fraction of PM drift; weight %*	*N/A*	*N/A*
6.	*Number of cells per tower*	*3*	*3*
7.	*Tower dimensions – length, width, and height (from grade to deck); ft*	*90 X 35 X 41*	*90 X 35 X 41*
8.	*Height of exhaust stack outlet above deck; ft*	*8*	*8*
9.	*Exhaust stack outlet inner diameter; ft*	*21*	*21*
10.	*Design exhaust flow rate per cell; acfm*	*150,000 to 190,000*	*150,000 to 190,000*
11.	*Location of tower on facility plot plan*	*See Item 37 on G/A*	*See Item 37 on G/A*

**These are approximate values only. Since the units are currently in the bidding process, exact values are unknown at this time.*

e. **Is each Heat Recovery Steam Generator (HRSG) identical? What is the designed maximum steam production rate (lb/hour), steam temperature (° F), and steam pressure (psig) for each HRSG? What are the current existing maximum and design capacities of the steam turbines for Gannon Units 5 and 6?**

TEC Response

The HRSG designs have not yet been finalized, and as such, the maximum steam production rate, steam temperature, and steam pressure for each HRSG are not yet available. Currently, the steam turbine serving Gannon Unit 5 is permitted for 239.4 MW and the steam turbine serving Gannon Unit 6 is permitted for 414 MW. These capacities may change depending on the final HRSG design. TEC will provide the requested information when it is available.

f. **The application established maximum mass emission rates at an ambient temperature of 17° F. Based 48 years of data from the www.weatherbase.com Internet web site, the lowest "average daily" temperatures in Tampa occurred during the months of January (61° F), February (62° F), and December (62° F). The average "low temperatures" for these months are January (50° F), February (52° F), and December (52° F). The "lowest recorded temperatures below 32° F" occur in January (21° F), February (24° F), March (29° F), November (23° F), and December (18° F). The "average number of days below 32° F" is one each for the months of January, February, and December. Please revise the mass emission rates for the Model PG7241(FA) to reflect a more reasonable "low temperature" of 32° F for the Tampa area. Permit conditions for gas turbines typically allow adjustment of the mass emission rate for compressor inlet temperature, if necessary. Otherwise, the Department is considering mass emission rates based on a compressor inlet temperature of 59° F or other available information.**

TEC Response

Mass emission rates from combustion turbines (CTs) will vary with ambient temperatures. Due to increased air density at lower temperatures, CT fuel flows and emission rates will increase with decreasing ambient temperatures and vice versa.

To provide the Department with reasonable estimates of maximum hourly emission rates as required by the Department's Application for Air Permit – Title V Source form, a minimum ambient temperature of 18°F was selected. TEC understands that CT mass emission rates will fluctuate with ambient temperature and will accept a permit condition limiting mass emission rates consistent with the emission rates submitted by TEC to the Department and that also allows Bayside Units 1 and 2 to operate in compliance under all ambient conditions. Accordingly, submittal of additional (and lower) mass emission rate data for a 32°F operating scenario is not considered necessary.

g. **Please provide the "Emissions Performance Estimates" from General Electric for the proposed Model PG 7241(FA) gas turbine. This specification sheet identifies the emission rates for CO, NOx, PM/PM10, SO2, and VOC in terms of ppmvd and lb/hour as estimated by the manufacturer. In addition to the emission rates, these performance specification sheets should also include the unit performance, load conditions, power generation, heat input, fuel consumption, stack conditions, compressor inlet temperature, and fuel type. Specifically, the Department requests "Emissions Performance Estimate" data sheets from General Electric for:**

- **Gas firing at 100% base load with an inlet compressor temperature of 59° F;**
- **Gas firing at 100% base load with an inlet compressor temperature of 32° F;**
- **Oil firing at 100% base load with an inlet compressor temperature of 59° F; and**
- **Oil firing at 100% base load with an inlet compressor temperature of 32° F.**
- **Oil firing at 50% base load with an inlet compressor temperature of 93° F.**

If necessary, the Department will provide an example from a similar project.

TEC Response

As discussed, GE data for the 32 °F case is not available at this time. The raw data obtained from GE, which was used in the emission calculations for the cases requested, is attached. This transmittal includes:

- *Gas firing at 100% base load with inlet compressor temperature of 59 °F*
- *Oil firing at 100% base load with inlet compressor temperature of 59 °F*
- *Oil firing at 50% base load with an inlet compressor temperature of 93 °F*

3. <u>Proposed Control Equipment</u>

a. **Does the proposed Selective Catalytic Reduction (SCR) system include a NOx emissions monitor prior to the ammonia injection grid to measure uncontrolled NOx emissions? Please identify and describe the automated control system that will be used to adjust the ammonia injection rates based on uncontrolled NOx emissions. What are the input parameters to this system? How will the ammonia slip concentration be determined? What is the proposed test method and frequency for the determination of ammonia slip? For similar combined cycle projects, maximum ammonia slip has been limited to 5 ppm. Please comment.**

TEC Response

There is still very little information on the Selective Catalytic Reduction (SCR) system design. The system design has just recently been awarded by Alstom Power (AP) to a subcontractor. AP is responsible for providing a working system and as such the system configuration and control philosophy *are currently being finalized. Part of the design does include an uncontrolled NO_X monitor upstream of the ammonia injection grid (AIG). Similarly, an NO_X and a NH_3 monitor are included downstream of the AIG.*

To calculate ammonia slip, TEC intends to use the following formula:

$$Ammonia\ slip\ @\ 15\%O_2 = (A - (\frac{B*C}{1000000}))*\frac{1000000}{B}*D$$

Where: A = ammonia injection rate (lb/hr) / 17 lb/lb-mol

B = dry gas exhaust flow rate (lb/hr) / 29 lb/lb-mol

C = change in measured NO_x (ppmv@15% O_2) across catalyst

D = correction factor, derived annually during compliance testing by comparing actual to tested ammonia slip

TEC proposes stack testing for ammonia slip annually after three years of operation using either EPA Conditional Method 027 or Method ST-1B. TEC is aware of other projects requesting an ammonia slip of 5 ppm. However, ammonia is not a regulated air pollutant, and as such, is not subject to a formal limit in the manner that NO_x, SO_2, PM and others are. TEC has selected an ammonia slip limit of 10 ppm based on anticipated best operational practices and feels that considering the overall reduction of all regulated air pollutants that will take place upon the repowering of Gannon Station, this is a reasonable limit.

b. The DEP/TEC Consent Final Judgement requires an evaluation of zero ammonia NOx control technologies. (Question No. 11 summarizes these issues.) The PSD permit application identifies SCONOx™ as such a technology. Please indicate which Emission Unit the SCONOx™ system would be installed on, provide a process flow diagram, and identify emission levels for all pollutants from the combined cycle unit controlled with a SCONOx™ system.

Please note that the issue concerning the evaluation of zero ammonia technologies must be resolved before the Department will deem the Bayside PSD permit application complete.

TEC Response

The $SCONO_X$ system has never before been applied to a GE 7 FA combustion turbine. In addition, TEC proposes to evaluate the SCONOx system on Unit 2D if the system meets the cost, guarantee and remedy requirements of the CFJ. TEC has attached the available process flow diagrams for the SCONOx system. The $SCONO_X$ system is currently out for bid by Alstom Power. As such, the expected emission levels of pollutants are not available.

Please see TEC's response in question 11.e. for a response to the issue concerning the Bayside PSD permit and resolution of the zero ammonia technology evaluation required under the CFJ.

c. For each NOx control system, describe any unique performance or operating conditions related to startups, shutdowns, or maintenance requirements.

TEC Response

The response to this issue is largely dependent on the interpretation of what is 'unique'. The SCR performance during startup is described in the response to Question 9. SCR systems have been installed on several other combined cycle installations, and the operation of the TEC units during shutdown and *maintenance is not expected to deviate significantly from those applications. The performance of the SCONOx system during startup, shutdown or maintenance is unknown at this time because (1) TEC has not yet received the SCONOx bid package from Alstom Power and (2) the SCONOx system has never been operated on a GE 7F combustion turbine. As such, many of the operational characteristics of the system will not be known without operational experience.*

4. <u>Operation</u>

   a. **The application requests continuous operation (8760) for each gas turbine unit with up to 876 hours of operation per unit when firing low sulfur distillate oil. No other methods of operation are requested. Is this correct?**

TEC Response

TEC has based this request on 876 equivalent full load hours of operation. This translates into approximately 1,797,552 MMBtu/yr (HHV) or 12,720 x 10^3 gallons of fuel oil combusted per year. TEC understands the meaning of "method of operation" in this question to mean type of fuel firing. TEC is not requesting any other method of operation other than natural gas and low sulfur fuel oil firing.

5. <u>BACT Determination for CO</u>

A review of the Annual Operation Reports filed by TEC with the Department indicates the following inconsistency with information submitted as part of the application (Attachment D, Tables 1 – 3):

Gannon Unit	1997		1998		1999		2-Year Average	
	AOR	App.	AOR	App.	AOR	App.	AOR	App.
5	---	---	140.00	2083.40	136.38	2027.50	138.19	2055.5
6	278.00	3446.30	216.00	3221.90	---	---	247.00	3334.1
						Totals	385.19	5389.60

Note: An equipment explosion affected operation of Unit No. 6 in 1999. Therefore, 1997 and 1998 data was used to establish actual emissions representative of "normal operation".

   a. **The application briefly notes that CO emissions were based on tests conducted in April of 2000. Neither the Department's Southwest District Office nor the Air Quality Division of the Hillsborough County Environmental Protection Commission have any records related to these emission performance tests. There is no information on record of the test methods, duration, number of tests, performance conditions, levels of other pollutants during these tests, or submittal of a test report. The Department is interested in TEC's rationale for, and the support of, the submitted values. However, TEC is required to submit a top-down BACT analysis for the control of carbon monoxide based upon the Department's records and ensuing conclusion regarding the applicability of BACT. When evaluating the oxidation catalyst, please include the items listed below under "Proposed VOC BACT". Note that a CO control efficiency of at least 90% would be expected.**

TEC Response

TEC feels that the CO emissions based on the test results are reasonable and applicable to this analysis. As documented in numerous EPA and industry reports and publications increased CO emission rates are commonly associated with operational changes made to reduce emissions of oxides of nitrogen (NO_x). In *response to recent Title IV regulations requiring NO_x emission reductions and previous reductions achieved to meet the Memorandum of Understanding between the Environmental Protection Commission of Hillsborough County and TEC, TEC implemented starting in 1996 several NO_x control strategies at the Gannon Station. These strategies included the combustion of low heat content, high moisture fuels, combustion optimization/air flow modifications and the use of lower excess air (LEA) operations. These operations have resulted in the common impacts such as increased Loss of Ignition (LOI), increased tube metal wear and other effects. These are all side effects of the reduction in the available oxygen, higher moisture coal and the resulting lower flame temperature intended to reduce the formation of NO_x. TEC has implemented operational measures to optimize the reduction of NO_x emissions while at the same time ensuring that LOI formation is maintained at the lowest possible levels. Unfortunately, the reductions have been demonstrated to be mutually exclusive for the Gannon Units, like many other units in the United States.*

Historically TEC has relied on AP-42 emission factors for the calculation of annual CO emissions. TEC accepted these emission factors as representative of the CO emissions for the specific classification of boiler combusting its design coal. After the implementation of the NO_x control measures discussed above and the resulting increase in LOI (a common indicator of increased LOI), it became apparent that these AP-42 emission factors may not longer be valid, therefore TEC tested the emission rates in early 2000 to establish the actual emission rates. Unit 5 was tested to provide a representation of the CO emissions from the Gannon turbo-fired wet-bottom units and Unit 1 was tested to represent emissions from the cyclone units. The testing was conducted in accordance with EPA methodology and copies of the above referenced test reports have been attached for review by FDEP and EPCHC. The results of the test indicate the Gannon 5 CO concentration was 117 ppm. This is a reasonable concentration for a unit with the combustion modifications and LEA operation optimized for low NOx operation. This conclusion is supported by various EPA documents such as Alternative Control Techniques Document—NO_x Emissions from Utility Boilers and Electric Power Research Institute (EPRI) documentation. Copies of portions of the EPA documentation are provided in Attachment 1.

Based on this information and the enclosed test reports, TEC believes that the Department will understand and accept the rationale and documentation for the use of the revised CO emission rates and will utilize the reasonable and proven emission factors for CO in the Bayside Air Construction application.

Please identify the controlled CO emission levels from a combined cycle unit controlled by a SCONOx™ system.

TEC Response

The SCONOx system has never been applied to a GE 7 FA combustion turbine and is currently in the bidding process. Therefore, the CO emission levels from the system are unknown at this time. TEC will provide the requested information when it is available from AP.

6. **Proposed VOC BACT**

   a. **With regard to the oxidation catalyst cost analysis, please provide:**

      - **Vendor quotes for the oxidation catalyst system, replacement catalyst, and instrumentation.**
      - **Supporting documentation for a VOC control efficiency of only 33% or revise the cost analysis based on a VOC control efficiency of at least 50%.**

- **Supporting documentation showing a cost of $0.04/kwh for TEC to generate electricity, otherwise revise the energy penalty accordingly. (The Department believes the actual cost for TEC to be lower than the stated cost.)**
- **A revised cost analysis using a 7% interest rate or provide substantial detail for the assumed interest rate of 9.55%. (TEC's parent company, TECO Energy, Inc., states in its annual report issuance of fixed rate bonds with interest rates of 6% to 8% for terms of over 20 years. It appears that Tampa Electric can issue tax-exempt bonds, which usually carry a lower interest rate than comparable corporate bonds. It is also noted that the federal 30-year bond rate is less than 5.9%.)**
- **A revised cost analysis if the contracted package for the HRSG that will be supplied by Alstom Power already includes the spool piece for an oxidation catalyst. (Costs estimated for foundations, supports, handling, erection, engineering, construction field expenses, and contractor fees appear excessive and/or unnecessary.)**

TEC Response

Alstom Power information to substantiate the oxidation catalyst estimate is attached. Please note that the email from AP dated July 10, 2000, discusses the capital costs of the CO/VOC catalyst, including the sunk cost of the spool piece.

Furthermore, TEC feels that the values used in the original analysis are reasonable and provide a comprehensive BACT evaluation. However, per the request of the Department, the interest rate, removal efficiency, and energy costs have been revised for demonstration purposes and the resulting analysis is enclosed. Based on the revised analysis, the cost of VOC removal remains excessive at $47,251 per ton of VOC removed.

b. The application (Table 4-5) indicates that TEC rejects the oxidation catalyst based on high costs and the adverse environmental impacts related to collateral increases of sulfuric acid mist emissions (SAM). The Department will review the revised cost analysis, but notes that natural gas and low sulfur distillate oil contain minimal amounts of sulfur. The application does not discuss the amount and consequences of additional SAM emissions. In addition, the Department would expect an oxidation catalyst to result in a significant reduction of hazardous air pollutants for which this project appears to be major. Therefore, the Department disagrees that the addition of an oxidation catalyst would result in net adverse environmental impacts. Please comment.

TEC Response

An assessment of collateral environmental impacts associated with the application of VOC oxidation catalyst controls is provided in Section 4.3.2 of the submitted PSD permit application. The Bayside PSD permit application did not indicate that there would be a "net adverse environmental impact" due to the use of oxidation catalyst. As stated on Page B.46 of EPA's Draft October 1990 New Source Review Workshop Manual, "the environmental impacts portion of the BACT analysis concentrates on impacts other than impacts on air quality standards due to emissions of the regulated pollutant in question, such as solid or hazardous waste generation, discharges of polluted water from a control device, visibility impacts, or emissions of unregulated pollutants". The submitted PSD permit application simply noted that there will be an increase in emissions of sulfuric acid mist resulting from the use of oxidation catalyst.

TEC also notes that the use of an oxidation catalyst system for Bayside Units 1 and 2 will have an insignificant impact on CO and VOC ambient air quality (including HAPs). As previously noted, the VOC stack exhaust concentrations proposed for Bayside Units 1 and 2, without the application of oxidation catalyst controls, are only 1.3 and 3.0 ppmvd at 15% O_2 for natural gas and distillate fuel oil firing, respectively. Organic HAP exhaust concentrations, being a subset of VOCs, will be much lower. The highest, second highest 1- and 8-hour average CO impacts during natural gas-firing (the primary fuel for the Bayside Power Station) are projected to be only 0.3 and 0.5 percent of the Florida and Federal CO ambient air quality standards.

c. **Please complete the appropriate emissions unit pages of the permit application form for the distillate oil tank. The Department previously allowed construction of this tank contingent on TEC including it as part of the BACT analysis in the application to repower the Gannon Station. Also, please propose a VOC BACT for this emissions unit.**

TEC Response

TEC intends to use this tank to support existing operations at Gannon Station. As such, TEC did not feel that it was appropriate to include the tank in the Bayside air construction permit application. Enclosed is the exemption letter from permitting issued by FDEP. The letter states in part "...emissions associated with the construction of this new fuel oil tank will need to be evaluated during preconstruction review of the planned Bayside repowering project." Since the emissions from the tank represent a contemporaneous increase in VOC emissions, its contribution to the netting will be evaluated. Since the Bayside project represents a significant increase in VOC emissions, this evaluation will not make a difference when considering whether or not the project in total results in a significant increase in VOC emissions.

Since (1) the tank is considered by FDEP to be a minor source that is exempt from permitting and (2) the tank will be used for existing operations at Gannon Station, TEC believes that a BACT analysis is not applicable to this unit. Furthermore, the tank will be light in exterior color and will be equipped with pressure/vacuum conservation vent.

7. **MACT Determination for Hazardous Air Pollutants (HAPs)**

a. **The application (Page 1-5) indicates that this project will NOT be a major source of hazardous air pollutants (HAPs) because potential emissions are less than 10 TPY of any individual HAP and 25 TPY for all HAPs. However, the supporting documentation (Attachment C, Table 7) shows total potential HAP emissions for Bayside Units 1 and 2 combined will be 27.87 TPY, which is greater than the 25 TPY threshold for total HAPs. Projects that are major for HAP emissions are required to obtain case-by-case MACT determinations until EPA promulgates a final NESHAP for gas turbines. Please submit a technical review and proposal for MACT.**

TEC Response

EPA Rule 40 CFR 63, Subpart B directs any owner or operator who constructs or reconstructs a major source of HAP's to undergo a case by case MACT evaluation. Specifically, the source, whether constructed or reconstructed is considered to be subject to a MACT evaluation if it ***in and of itself*** *emits or has the potential to emit 10 tons per year of any HAP or 25 tons per year of any combination of HAPs. Since Bayside Units 1 and 2 can operate independently of one another, they are considered separate processes or production units for the purpose of HAP MACT analysis per the preamble to 40*

CFR 63 Subpart B. Hence, HAP emissions were not aggregated for this analysis and each unit in and of itself is not subject to a MACT evaluation.

The Department notes that EPA issued a December 30, 1999 memorandum entitled, "Hazardous Air Pollutant (HAP) Emission Control Technology for New Stationary Combustion Turbines". This guidance discusses the use of an oxidation catalyst for the control of HAP emissions.

b. **The HAP emission calculations (Attachment C) were based on selected test rates from data used to compile EPA's recent AP-42 update for gas turbines. TEC believes the selected rates are more representative of large frame-type gas turbines. Please provide specific HAP emission rates for the Model PG7241(FA) from General Electric and revise the potential emissions calculations accordingly.**

TEC Response

To TEC's knowledge, HAP emission rates are not currently available from GE for the Model PG7241(FA). This is the reason that TEC based the HAP emission calculations on the selected test results from the data used to compile EPA's AP-42 database.

8. **<u>Emissions Standards Proposed in the Application</u>**

   a. **Please comment on the following items:**

      - **CEMS have been required to demonstrate compliance with CO emission standards for similar combined cycle projects currently under review by the Department (e.g. Calpine, FPC).**

TEC Response

CO is not regulated under the Acid Rain program, the Bayside Units are not subject to BACT for CO and the installation and operation of the Bayside Station will result in significant reductions of CO emissions. In addition, ISCST3 modeling results demonstrate that the maximum highest, second highest 1- and 8-hour CO impacts are 1% and 1.3% of the Federal and Florida AAQS, respectively. Therefore, TEC believes that an annual stack test will be sufficient to provide the Department with reasonable assurance that all CO emission standards are complied with.

- **For similar combined cycle projects, compliance with a NOx emission standard for gas firing of 3.5 ppmvd corrected to 15% oxygen has been based on CEMS data for both a 3-hour rolling average as well as a 24-hour block average of actual operating hours.**

TEC Response

For the purposes of demonstrating compliance, TEC believes that a 24-hour block average is the appropriate to provide the Department with reasonable assurance that the NOx emission standard is being complied with. Like most industrial processes, this process may be variable in nature from time to time, therefore a 3-hour rolling average may not allow for intermittent fluctuations in operation.

- **For recent gas turbine projects, annual tests for volatile organic compounds and particulate matter have been required to demonstrate compliance with the applicable emission standards.**

TEC Response

Emissions from natural gas fired combined cycle units do not vary significantly over time with proper maintenance and operation. Therefore, TEC feels that initial compliance tests for PM and VOC coupled with an annual opacity limit as a surrogate measure of PM emissions and the use of the annual CO stack test as a surrogate for VOC emissions will be sufficient to provide the Department with reasonable assurance that Bayside Power Station will operate in compliance with the respective standards.

- **EPA Region 4 has recently recommended testing for selected emissions of hazardous air pollutants, such as formaldehyde.**

TEC Response

Although typically emitted at extremely low rates (in the PPB range) formaldehyde is the HAP emitted in the greatest quantity when compared to others. Other HAP's are typically emitted at rates 2 to 100 times lower than formaldehyde in combustion turbines. There are no existing emission limitations for formaldehyde nor are there any health-related concerns resulting from formaldehyde exposure in the Tampa Bay area. Since Bayside Units 1 and 2 are minor sources of HAP's, TEC feels that testing each unit for formaldehyde emissions is not necessary. In addition, due to low emission rates, the current methods for formaldehyde testing are often not capable of consistently detecting this compound at the levels emitted from gas turbines. Finally, other similar projects have recently been permitted without a requirement for formaldehyde testing. Based on the above discussion, TEC feels that formaldehyde testing is not necessary for this project.

b. The application states that maximum CO emissions (30.3 ppmvd @ 15% oxygen) occur at 50% base load when firing oil with a compressor inlet temperature of 93° F. Please provide supporting documentation from General Electric.

TEC Response

CO emissions for 50% load case at 93 ^{O}F ambient condition appear correct. As indicated on the GE data sheets (see Item 2g), CO production at this ambient/load condition is 82 lbs/hr, which is very close to the calculated value of 81.3 lbs/hr shown on Table 3 of the air permit.

c. Is TEC proposing an Alternate Monitoring Plan to demonstrate compliance with the NSPS Subpart GG monitoring requirements for NOx and SO2?

TEC Response

TEC requests that the alternative monitoring included in recent FDEP permits for similar projects be included in the Bayside Power Project permit. The following permit language is proposed:

"Alternate Monitoring Plan: Subject to EPA approval, the following alternate monitoring may be used to demonstrate compliance.

(a) NO_x CEM data may be used in lieu of the monitoring system for water-to-fuel ratio and the reporting of excess emissions in accordance with 40 CFR 60.334(c)(1), Subpart GG. Subject to EPA approval, the calibration of the water-to-fuel ratio-monitoring device required in 40 CFR 60.335(c)(2) will be replaced by the 40 CFR 75 certification tests of the NO_x CEMS.

(b) NO_x CEM data shall be used in lieu of the requirement for reporting excess emissions in accordance with 40 CFR 60.334(c)(1), Subpart GG.

(c) *When requested by the Department, the CEMS emission rates for NO_x shall be corrected to ISO conditions to demonstrate compliance with the NOx standard established in 40 CFR 60.332.*

(d) *A custom fuel monitoring schedule pursuant to 40 CFR 75 Appendix D for natural gas may be used in lieu of the daily sampling requirements of 40 CFR 60.334 (b)(2) provided the following conditions are met.*

(1) *The permittee shall apply for an Acid Rain permit within the deadlines specified in 40 CFR 72.30.*

(2) *The permittee shall submit a monitoring plan, certified by signature of the Authorized Representative, that commits to using a primary fuel of pipeline supplied natural gas containing no more than 2 grains of sulfur per 100 SCF of gas pursuant to 40 CFR 75.11(d)(2);*

(3) *Each unit shall be monitored for SO_2 emissions using methods consistent with the requirements of 40 CFR 75 and certified by the USEPA.*

This custom fuel-monitoring schedule will only be valid when pipeline natural gas is used as a primary fuel. If the primary fuel for these units is changed to a higher sulfur fuel, SO_2 emissions must be accounted for as required pursuant to 40 CFR 75.11(d)."

9. <u>Excess Emissions</u>

The application (Page 2-8) requests the following periods of permitted excess emissions:

- ***Typical Operation*: Up to 2 hours in any 24-hour period due to startup, shutdown, or unavoidable malfunction.**
- ***CT Warm Startup*: Up to 3 hours in any 24-hour period when the CT/HRSG has been down for more than 2 hours and less than or equal to 24 hours.**
- ***CT Cold Startup*: Up to 4 hours in any 24-hour period when the CT/HRSG has been down for more than 24 hours.**
- ***Steam Turbine Cold Startup*: Up to 18 hours of excess emissions resulting from the cold startup of the repowered steam turbines due to metal temperature limitations.**

a. Please describe the warm and cold startups of the CT/HRSG units and the associated excess emissions. Please provide supporting documentation to include the duration of each startup and the quantity and duration of excess emissions. How many warm and cold CT/HRSG startups are predicted for each year?

TEC Response

Based on further design development of the Bayside Unit's steam systems, TEC believes that the combustion turbine warm and cold startups will be conducted within the allowable 2 hour of excess emissions for startup.

b. Please describe the process of bringing the repowered steam turbines back on-line during a cold startup and define "cold startup" for this equipment. Please provide data that indicates the exhaust gas emissions from the gas turbines will be in excess of the proposed standards for the entire 18-hour cold startup of a steam turbine. Please identify any startup methods that could be used to minimize damage to the steam turbine while allowing the gas turbines to

achieve steady-state operation and avoid excess emissions. For example, is it possible to operate a single gas turbine at 75% load to gradually heat up the repowered steam turbine? Is it possible to use steam from the other Bayside Unit to gradually heat up the repowered steam turbine? How many cold startups of each steam turbine are predicted for each year?

TEC Response

A cold startup occurs either (1) when the first stage turbine metal temperature is 250°F or colder or (2) when the steam turbine has been offline for 24 hours or longer. During a cold startup, great care must be taken to ensure that steam turbine is heated gradually to prevent the premature fatiguing of metal parts due to thermal expansion. As such, TEC intends to perform a cold startup as follows:

1. *The combustion turbine will be fired and brought online at a minimum load to generate steam that will not damage the steam turbine through rapid thermal expansion. This initial combustion turbine startup lasts approximately one hour.*

2. *As the main steam pressure piping warms, the condenser will be brought online. Due to the length of the piping, this typically takes approximately three hours. During this three hours, the main steam temperature should reach the required 100°F superheat to begin the steam turbine roll to 2,250 rpm.*

3. *After thirty minutes, the steam turbine will reach 2,250 rpm. To prevent thermal stress and degradation of the 2,000 feet of hot reheat, cold reheat and low pressure steam lines, four hours will be necessary to gradually increase the temperature of this equipment. During this four hour period at 2,250 rpm, the intermediate pressure inlet steam temperature (IPT) will reach 500°F*

4. *Once the turbine IPT has reached 500°F, it must be maintained at 2,250 rpm for approximately three hours to allow for the rotating elements and fixed parts to heat and expand at an acceptable rate. Once all rotating elements and fixed parts have been heated to an acceptable temperature, the unit can be brought online at 3,600 rpm within thirty minutes.*

5. *Finally, the steam turbine rotor and casing as well as the steam piping and HRSG must thermally stabilize. This process takes approximately two hours to complete.*

The process as described above takes approximately 14 hours to complete. However, considering the lack of experience in the industry with operating a plant with a configuration similar to the Bayside project, TEC requests that an additional two hours be added to the startup allowance for operational contingencies. This would bring the total allowance for excess emissions to 16 hours during startup. TEC is estimating that the total number of cold starts could be as many as 26 per steam turbine per year. This number of cold steam turbine startups may vary. This estimate is subject to change based on system demand, fuel availability, and other unit specific process parameters.

c. **For each requested period of excess emissions, what is the duration (hours), amount (ppmvd and lb/hour), frequency (incidents per year), and resulting annual emissions (tons per year).**

TEC Response

The amount and duration of warm and cold starts have been described in bullets a and b. Because this is a unique project with no operational experience, the resulting emissions due to startup are unknown at this time.

d. **Note that the permit can only allow excess emissions for pollutants for which the compliance status would be known. For this project, compliance should be readily identifiable for CO (CEMS), NOx (CEMS), and visible emissions (EPA Method 9 observation). Please comment.**

TEC Response

Per Rule 62-210.700(2), TEC will limit periods of excess emissions during startup, shutdown or malfunction by utilizing best operational practices. This rule covers excess emissions of all pollutants regardless of monitoring methodology. TEC feels that annual stack testing for CO will provide the Department with reasonable assurance that all CO limits are complied with.

10. <u>Repowering - Bayside Startup and Gannon Shutdown</u>

a. **As stated in the application (Attachment D), the actual emissions decreases from the Gannon Units must take place on or before the date that emissions from the modification project (new Bayside Units) first occur and must be federally enforceable on and after the date the Department issues a permit for the modification project. However, the Project Summary indicates that each Gannon Unit will be shut down after installation and "commercial startup" of the corresponding Bayside Unit. Please define "commercial startup" in specific terms.**

b. **For each new combined cycle unit, please provide an estimated schedule for the start of construction, the completion of construction, the shakedown period, the initial performance testing, "commercial startup", and initial power generation. Also, please indicate when each of the six coal-fired Gannon Units will be shut down.**

TEC Response

Because TEC must shutdown Gannon Unit 5 in order to tie in the steam piping to the Gannon Unit 5 steam turbine the Gannon unit will be shutdown prior to the "commercial startup" date, TEC is planning on February 11, 2003 as the late schedule date for this event. See attachment for specific dates.

c. **Gannon Units that are not being repowered are required to be shutdown between January 1, 2003 and December 31, 2004. It is expected that any permit issued for this project would be conditioned to require:**

- **Permanent shutdown of the Gannon Units within this time frame.**
- **A reduction in the current annual "heat input" limit on the Gannon coal yard by an amount equivalent to that for Gannon Unit 5 when shutdown.**
- **A reduction in the current annual "heat input" limit on the Gannon coal yard by an amount equivalent to that for Gannon Unit 6 when shutdown.**
- **Permanent shutdown of all coal-fired Gannon units when both Bayside Units are operational.**

Otherwise, allowing the remaining Gannon Units 1 – 4 to fire additional coal could cause actual emissions increases and trigger additional PSD requirements. Please comment.

TEC Response

TEC is obligated by both the Consent Final Judgement and Consent Decree to permanently cease coal fired operations at Gannon Station by January 1, 2005, and TEC intends to comply with these *conditions. Therefore, if the text from the Consent Decree and/or Consent Final Judgement addressing this situation is included in the Bayside Air Construction Permit, TEC will not object. TEC is not obliged to shut down operations of any type, but to shut down "coal-fired" operations by January 1, 2005. If other fuel and/or technologies are employed in the future, such activities would be subject to all required permitting.*

The start up of Bayside Units 1 and 2 will coincide with the shutdown of Gannon Units 5 and 6, respectively. However, TEC does not feel that a reduction of the heat input limit on the fuel yard would be appropriate when Gannon Units 5 and 6 are shut down. The installation and operation of Bayside Units 1 and 2 may cause temporary significant emissions increases, but the Department has reasonable assurance that TEC will minimize these increases through the use of natural gas as a primary fuel for PM and SO_2 control and the application of SCR (and possibly SCONOx) for NO_x control. It is conceivable that TEC could find it necessary to operate Gannon Units 1-4 more frequently than expected to meet increasing customer demand or to compensate for lost generation due to potential process upsets in the new Bayside Units. Finally, PSD rules allow for an emissions source to increase utilization to accommodate load growth. Further limiting the heat input on the fuel yard may not allow TEC to serve demand resulting from load growth and will not allow TEC to compensate for process upsets during the 'shakedown' of the Bayside Units.

11. **Requirements of the DEP/TEC Consent Final Judgement**
Paraphrasing Section V of the DEP/TEC Consent Final Judgement (CFJ), this agreement requires the following for the Gannon Station:

CFJ Section V, A: **TEC shall shut down coal-fired Units 1, 2, and 6 at Gannon Station and repower Units 3, 4, and 5 to be phased-in between January 1, 2003 and December 31, 2004. The repowered units shall fire gas and meet a NOx emission rate of 3.5 ppm.**

a. **The application indicates that the steam boilers for Gannon Units 5 and 6 will be shutdown and the steam turbines for Gannon Units 5 and 6 will be repowered with steam from Bayside Units 1 and 2. How does this comply with the requirements of the CFJ to repower Gannon Units 3, 4, and 5?**

TEC Response

Based on correspondence between Sheila McDevitt, General Counsel of TEC and Teri Donaldson, General Counsel of FDEP, the parties agreed to modify the requirements of Section V. A. of the CFJ such that the repowering of specific units was not required, but rather a minimum number of megawatts of generation as described in the Consent Decree was to be repowered. The referenced correspondence is enclosed.

b. **The CFJ requires the shutdown of Gannon Units 1, 2, and 6. The application does not appear to discuss the future status of any Gannon units that are not being repowered. The Department understands that the steam boilers for any repowered Gannon units must be permanently shut down prior to operation of any corresponding Bayside Unit. The steam boilers for the remaining Gannon units must be shut down between January 1, 2003 and December 31, 2004. In addition, all coal-fired Gannon Units must be permanently shutdown when both Bayside Units are operational. These emissions decreases will not be available for any future projects at the Bayside Station. Please comment.**

TEC Response

TEC has submitted an application for the repowering of Gannon Units 5 & 6. This application is not intended to address the status of the other coal-fired units as their emission reductions were not considered in the netting analysis. The future status of these units are described in the Title V permit for the Gannon Station and the CFJ and CD which are incorporated into the Title V permit. The requirements for cessation of coal-firing for the Gannon Station units are the repowering of no less than 200 MW by May 1, 2003 and the cessation of operation of all six Gannon coal fired units on or before December 31, 2004. It is not intended or anticipated that the repowering component will involve the continued operation of the furnace for the repowered units for any length of time after shutdown to disconnect the turbine from the unit. Because Tampa Electric is repowering Gannon Unit 5 to meet the requirement to repower 200 MW by May 1, 2003, it is appropriate for the Department to assume the air emission from that Gannon Unit will permanently cease by May 1, 2003.

Neither the CFJ nor the CD require that, "all coal fired Gannon Units must be permanently shutdown when both Bayside Units are operational". Both the CFJ and the CD require that, all coal fired units at the Gannon Station will cease operation by December 31, 2004 and that emission reductions resulting from this activity may be considered in future permitting as allowed by Florida and federal laws and regulations.

c. **In several places, the application indicates that Gannon Units 5 and 6 will "... permanently cease coal-fired operation." The Department understands this to mean that the steam boilers for Gannon Units 5 and 6 will be permanently shutdown and rendered incapable of operation prior to beginning operations of the corresponding Bayside Unit. Please comment.**

TEC Response

The Department is correct in the understanding that the repowered Gannon Units 5 & 6 steam boilers will be rendered incapable of operation as their associated steam turbines and other non air emission components will be utilized by Bayside Units 1 & 2 respectively.

d. **The application requests 876 hours per year of very low sulfur distillate oil firing as a backup fuel with an emission standard of 16.4 ppmvd corrected to 15% oxygen. How does this meet the requirements of the CFJ to repower with *gas-fired* units meeting a NOx emissions standard of *3.5 ppm*?**

TEC Response

Tampa Electric is proposing the use of oil firing only as a backup fuel as described in the specific and restricting requirements of the Consent Decree (see condition below). The ability to fire the Bayside Units with oil is requested only to ensure that Tampa Electric can meet it's legal requirement to provide power to it's customers in the event the Bayside units cannot be fired with natural gas.

Condition 26. 3. (Consent Decree)

A Unit Re-Powered under this or any other provision of this Consent Decree may be fired with No. 2 fuel oil if and only if: (1) the Unit cannot be fired with natural gas; (2) the Unit has not yet been fired with No. 2 fuel oil as a back up fuel for more than 875 full load equivalent hours in the calendar year in which Tampa Electric wishes to fire the Unit with such oil; (3) the oil to be used in firing the Unit has a sulfur content of less than 0.05 percent (by weight); (4)

> *Tampa Electric uses all emission control equipment for that Unit when it is fired with such oil to the maximum extent possible; and (5) Tampa Electric complies with all applicable permit conditions, including emission rates for firing with No. 2 fuel oil, as set forth in applicable preconstruction and operating permits.*

Because the CFJ does not prohibit oil firing and the requirements of the CD allow for the combustion of oil only when natural gas can not be fired, Tampa Electric believes that these requirements are consistent with the CFJ. In addition, by limiting the potential hours of operation on oil, the Bayside Units meet the definition of natural gas fired units as defined under state and federal regulations.

It is clear that the intended NO_x limit on natural gas is 3.5 ppmvd, but it is further clarified in Condition 26. 2 that the NO_x emission rate limit is required only for the primary fuel. Further the intent of the CD was not to hold the oil firing NO_x limit to a limit of 3.5 ppmvd, but rather to a rate equivalent to the level of NO_x removal efficiency achieved to meet 3.5 ppmvd on natural gas. It is Tampa Electric's understanding that this interpretation agrees with the intent of the CFJ because oil firing will only occur if natural gas can not be fired and Best Available Control Technology (BACT) is utilized to control NO_x.

***CFJ Section V, B*: TEC must evaluate "zero ammonia" NOx control technologies for the Gannon facility. If the capital cost differential above Selective Catalytic Reduction (SCR) does not exceed $8 million and TEC obtains acceptable performance guarantees and remedies from the manufacturer, TEC shall install such technology on one repowered unit no later than December 31, 2004. Otherwise, TEC shall spend up to $8 million to demonstrate alternative commercially viable NOx control technologies for natural gas or coal-fired generating units.**

e. **SCONOx™ is identified as a commercially viable "zero ammonia" NOx control technology and is available for large frame-type units from Alstom Power. Please describe the progress to date on obtaining capital cost estimates, manufacturer performance guarantees and remedies (in accordance with generally recognized industry standards), and all other information necessary for the Department to conclude the required evaluation.**

   Please note that the issue of evaluating "zero ammonia" NOx control technologies must be resolved before the Department will deem the Bayside PSD permit application complete.

TEC Response

Tampa Electric has been working diligently with the DEP to develop an appropriate Request for Proposal (RFP) for submittal to Alstom Power (AP). The RFP has been reviewed by the DEP and it is Tampa Electric's understanding from verbal conversations with DEP staff, that the RFP is acceptable and requests the necessary information to evaluate the capital cost of the components of the $SCONO_x$ system. Tampa Electric has requested from AP, information on the assembly and construction of the $SCONO_x$ system in order to develop a RFP for the construction of the $SCONO_x$ system. Tampa Electric will work with DEP on the development of this RFP as we did for the previous RFP. The RFP for the components of the $SCONO_x$ was submitted to AP on October 23, 2000. Tampa Electric is currently awaiting a response from AP on the RFP. AP has indicated that they will provide a response the week of November 13th.

It is Tampa Electric's position that the evaluation of the non-ammonia nitrogen oxide control technology is a separate issue from the air construction permit for the Bayside Units 1 & 2 and therefore does not have to be resolved for the Department to deem the PSD permit application complete and resume it's processing. Tampa Electric believes that it is not only reasonable but also necessary for the Department *to proceed with the permitting process in order for TEC to meet the deadlines for compliance with the CFJ and the CD. The Department can certainly impose reasonable conditions if necessary to address the installation of the SCONO$_x$ system if required prior to issuing the final permit.*

f. **The Department expects that any permit issued for the proposed Bayside project will comport with the Consent Final Judgement. Please comment.**

TEC Response

Tampa Electric's will comply with all provisions of the CFJ. In furtherance Tampa Electric has submitted the application for construction of Bayside Units 1 & 2. Tampa Electric expects to work with the Department to implement all provisions of the CFJ.

12. Requirements of the EPA/TEC Consent Decree

a. **The Department notes that TEC has signed a separate Consent Decree with the U.S. Environmental Protection Agency. The conditions of the order vary from the requirements of the Department's Consent Final Judgement. EPA Region 4 is currently reviewing the permit application for purposes of PSD as well as compliance with the federal order. When received, the Department will forward any questions from EPA to TEC for comment.**

TEC Response

TEC appreciates the opportunity to review and comment on EPA's review of the application. TEC believes that the CFJ and the CD are consistent in all material respects.

13. Air Quality Analysis

a. **Please review Table 6-1 on pages 6-2, 6-3, and 6-4. The data presented in these tables does not appear consistent with the data provided in the electronic modeling files. Also, please revise the AAQS modeling analysis to include impacts from nearby major sources.**

TEC Response

The files have been corrected and sent to FDEP for review.

b. **Please provide an additional modeling analysis for SO2 that demonstrates compliance with the AAQS for the following case: Bayside Unit 1 is on-line, repowered Gannon Unit 5 is permanently shut down, and the remaining Gannon Units are on-line. This new analysis should also include impacts from nearby major sources.**

TEC Response

The analysis of ambient air quality was revised in response to the questions raised in the Department's October 16, 2000 correspondence and October 19, 2000 e-mail from Mr. Jeff Koerner.

A revised Section 6.0 and Table 6-1 are attached. In addition to the ambient air quality impacts shown on Table 6-1 (reflecting impacts due to distillate fuel oil-firing), Table 6-2 attached also provides the air quality impacts due to combustion of the primary fuel – natural gas. As noted in the submitted application, use of backup low sulfur distillate fuel oil will be limited to an annual capacity factor of no more than 10 percent.

With reference to the Department's October 19, 2000 e-mail, evaluation of ambient air quality impacts for the Existing Case (Gannon Units 1-6 in operation) was previously conducted by the Department as part of the Title V operation permit review process. Due to the potential for the Gannon Station to *contribute to exceedances of Florida's SO_2 ambient air quality standards (AAQS), TEC initially proposed to increase the stack heights of Gannon Units 5 and 6 and implement an additional 24-hour average SO_2 emission limit for Gannon Units 1-6; reference the F.J. Gannon Station Title V SO_2 Air Dispersion Modeling Report dated October 1998. As a result of Bayside repowering project, modifications to physical stack heights and fuel contracts are no longer appropriate due to the short life remaining for the Gannon Station coal-fired units. In accordance with the CFJ, all Gannon coal-fired units will be removed from service by December 31, 2004. Instead, TEC has proposed a SO_2 "glidepath" to address the issue of SO_2 air quality impacts during the period prior to December 31, 2004.*

In response to the Department's October 19, 2000 e-mail, an assessment of SO_2 ambient air quality impacts resulting from Interim Case 1 (Bayside Unit 1 and Gannon Units 1, 2, 3, 4, and 6 in operation) was also conducted. This analysis evaluated the SO_2 air quality impacts resulting from the operation of Bayside Unit 1 (during back-up low sulfur distillate fuel oil-firing, Case 4) and Gannon Units 1-4 and 6 (at a station-wide SO_2 emission rate of 8.3 tons per hour [24-hour average] - equivalent to 1.7 lb SO_2/MMBtu). The results of this assessment are provided on Table 6-3.

The dispersion model results shown on Tables 6-1 through 6-3 provide reasonable assurance that operation of the Bayside Units 1 and 2 will not contribute to any exceedances of an AAQS. Following installation of Bayside Units 1 and 2 and cessation of Gannon coal-fired operations, the highest, second highest (HSH) 24-hour average SO_2 impact will be only 4.2 percent of the Florida AAQS during natural gas-firing (the primary fuel for Bayside Power Station) and only 32.7 percent of the Florida AAQS during back-up distillate fuel oil-firing.

14. Miscellaneous

a. **The application does not indicate whether or not the application for an Acid Rain permit has been submitted. The new Bayside Units will be subject to the Acid Rain (Title IV) provisions. You are notified that an application for a Title IV Acid Rain Permit must be submitted at least 24 months before the date on which a new unit begins serving an electrical generator greater than 25 MW. The application must be submitted to the Region 4 office of the U.S. Environmental Protection Agency in Atlanta, Georgia with a copy to the Department's Bureau of Air Regulation in Tallahassee.**

TEC Response

The Acid Rain permit application is currently under development and will be submitted 24 months prior to the commencement of operation.

b. **Please be aware that the anhydrous ammonia storage tanks will require an update of the current Risk Management Plan for this site.**

TEC Response

A Risk Management Plan for the anhydrous ammonia storage tanks is currently under development.

TEC appreciates the opportunity to work with the Department to resolve these issues in an expedited fashion, as the receipt of the final Air Construction Permit is critical to maintain a construction schedule that will support the commencement of operation of the Bayside Power Station as outlined in the Consent Final Judgement and the Consent Decree. If you have any questions, please call Shannon Todd or me at (813) 641-5125.

Sincerely,

Karen Sheffield

Karen Sheffield
General Manager-Bayside Power Station
Tampa Electric Company

EP\gm\SKT209

Enclosures

c: Mr. Jerry Kissel, FDEP - SWD
Mr. Jerry Campbell, EPCHC
Mr. John Bunyak, NPS
Mr. Gregg Worley, EPA Region 4
Ms. Katy Forney, EPA Region 4

Question 2.g. Attachment

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BUREAU OF AIR REGULATION

TECO Bayside

ESTIMATED PERFORMANCE PG7241(FA)

Load Condition		BASE
Ambient Temp.	Deg F.	59.
Fuel Type		Cust Gas
Fuel LHV	Btu/lb	20,886
Fuel Temperature	Deg F	60
Output	kW	169,400.
Heat Rate (LHV)	Btu/kWh	9,465.
Heat Cons. (LHV) X 10^6	Btu/h	1,603.4
Exhaust Flow X 10^3	lb/h	3535.
Exhaust Temp.	Deg F.	1125.
Exhaust Heat (LHV) X 10^6	Btu/h	966.9

EMISSIONS

NOx	ppmvd @ 15% O2	9.
NOx AS NO2	lb/h	59.
CO	ppmvd	9.
CO	lb/h	29.
UHC	ppmvw	7.
UHC	lb/h	14.
VOC	ppmvw	1.4
VOC	lb/h	2.8
Particulates	lb/h	9.0

EXHAUST ANALYSIS % VOL.

Argon	0.90
Nitrogen	74.36
Oxygen	12.33
Carbon Dioxide	3.89
Water	8.53

SITE CONDITIONS

Elevation	ft.	9.0
Site Pressure	psia	14.7
Inlet Loss	in Water	4.0
Exhaust Loss	in Water	14.0
Relative Humidity	%	60
Application		7FH2 Hydrogen-Cooled Generator
Combustion System		9/42 DLN Combustor

Emission information based on GE recommended measurement methods. NOx emissions are corrected to 15% O2 without heat rate correction and are not corrected to ISO reference condition per 40CFR 60.335(c)(1). NOx levels shown will be controlled by algorithms within the SPEEDTRONIC control system.

Sulfur Emissions Based On 0.0002 WT% Sulfur Content in the Fuel.

IPS- 90510 version code- 2 . 0 . 1 Opt: N 72411298
HENRYCO 02/02/2000 17:22 TECO Bayside gas60 59pp 14 020200.dat

GENERAL ELECTRIC PROPRIETARY INFORMATION

TECO Bayside

ESTIMATED PERFORMANCE PG7241(FA)

Load Condition		BASE
Ambient Temp.	Deg F.	59.
Fuel Type		Liquid
Fuel LHV	Btu/lb	18,550
Fuel Temperature	Deg F	60
Liquid Fuel H/C Ratio		1.78
Output	kW	181,500.
Heat Rate (LHV)	Btu/kWh	10,040.
Heat Cons. (LHV) X 10^6	Btu/h	1,822.3
Exhaust Flow X 10^3	lb/h	3677.
Exhaust Temp.	Deg F.	1100.
Exhaust Heat (LHV) X 10^6	Btu/h	1013.8
Water Flow	lb/h	119,680.

EMISSIONS

NOx	ppmvd @ 15% O2	42.
NOx AS NO2	lb/h	319.
CO	ppmvd	20.
CO	lb/h	65.
UHC	ppmvw	7.
UHC	lb/h	15.
VOC	ppmvw	3.5
VOC	lb/h	7.5
SO2	ppmvw	11.0
SO2	lb/h	93.0
SO3	ppmvw	1.0
SO3	lb/h	7.0
Sulfur Mist	lb/h	10.0
Particulates	lb/h	17.0

EXHAUST ANALYSIS % VOL.

Argon	0.85
Nitrogen	71.29
Oxygen	11.05
Carbon Dioxide	5.51
Water	11.30

SITE CONDITIONS

Elevation	ft.	9.0
Site Pressure	psia	14.7
Inlet Loss	in Water	4.0
Exhaust Loss	in Water	14.0
Relative Humidity	%	60
Application		7FH2 Hydrogen-Cooled Generator
Combustion System		9/42 DLN Combustor

Emission information based on GE recommended measurement methods. NOx emissions are corrected to 15% O2 without heat rate correction and are not corrected to ISO reference condition per 40CFR 60.335(c)(1). NOx levels shown will be controlled by algorithms within the SPEEDTRONIC control system.

Liquid Fuel is Assumed to have 0.05% Fuel-Bound Nitrogen, or less.
FBN Amounts Greater Than 0.05% Will Add to the Reported NOx Value.
Sulfur Emissions Based On 0.05 WT% Sulfur Content in the Fuel.

IPS- 90510 version code- 2 . 0 . 1 Opt: N 72411298
HENRYCO 02/02/2000 17:33 TECO Bayside dis59pp 14 020200.dat

GENERAL ELECTRIC PROPRIETARY INFORMATION

TECO Bayside

ESTIMATED PERFORMANCE PG7241(FA)

Load Condition		50%
Ambient Temp.	Deg F.	93.
Fuel Type		Liquid
Fuel LHV	Btu/lb	18,550
Fuel Temperature	Deg F	60
Liquid Fuel H/C Ratio		1.78
Output	kW	80,600.
Heat Rate (LHV)	Btu/kWh	13,420.
Heat Cons. (LHV) X 10^6	Btu/h	1,081.7
Exhaust Flow X 10^3	lb/h	2357.
Exhaust Temp.	Deg F.	1200.
Exhaust Heat (LHV) X 10^6	Btu/h	713.3
Water Flow	lb/h	50,030.

EMISSIONS

NOx	ppmvd @ 15% O2	42.
NOx AS NO2	lb/h	185.
CO	ppmvd	39.
CO	lb/h	82.
UHC	ppmvw	7.
UHC	lb/h	10.
VOC	ppmvw	3.5
VOC	lb/h	5.
SO2	ppmvw	11.0
SO2	lb/h	55.0
SO3	ppmvw	0.0
SO3	lb/h	4.0
Sulfur Mist	lb/h	6.0
Particulates	lb/h	17.0

EXHAUST ANALYSIS % VOL.

Argon	0.86
Nitrogen	71.69
Oxygen	11.90
Carbon Dioxide	5.00
Water	10.56

SITE CONDITIONS

Elevation	ft.	9.0
Site Pressure	psia	14.7
Inlet Loss	in Water	4.0
Exhaust Loss	in Water	14.0
Relative Humidity	%	50
Application		7FH2 Hydrogen-Cooled Generator
Combustion System		9/42 DLN Combustor

Emission information based on GE recommended measurement methods. NOx emissions are corrected to 15% O2 without heat rate correction and are not corrected to ISO reference condition per 40CFR 60.335(c)(1). NOx levels shown will be controlled by algorithms within the SPEEDTRONIC control system.

Liquid Fuel is Assumed to have 0.05% Fuel-Bound Nitrogen, or less.
FBN Amounts Greater Than 0.05% Will Add to the Reported NOx Value.
Sulfur Emissions Based On 0.05 WT% Sulfur Content in the Fuel.

IPS- 90510 version code- 2 . 0 . 1 Opt: N 72411298
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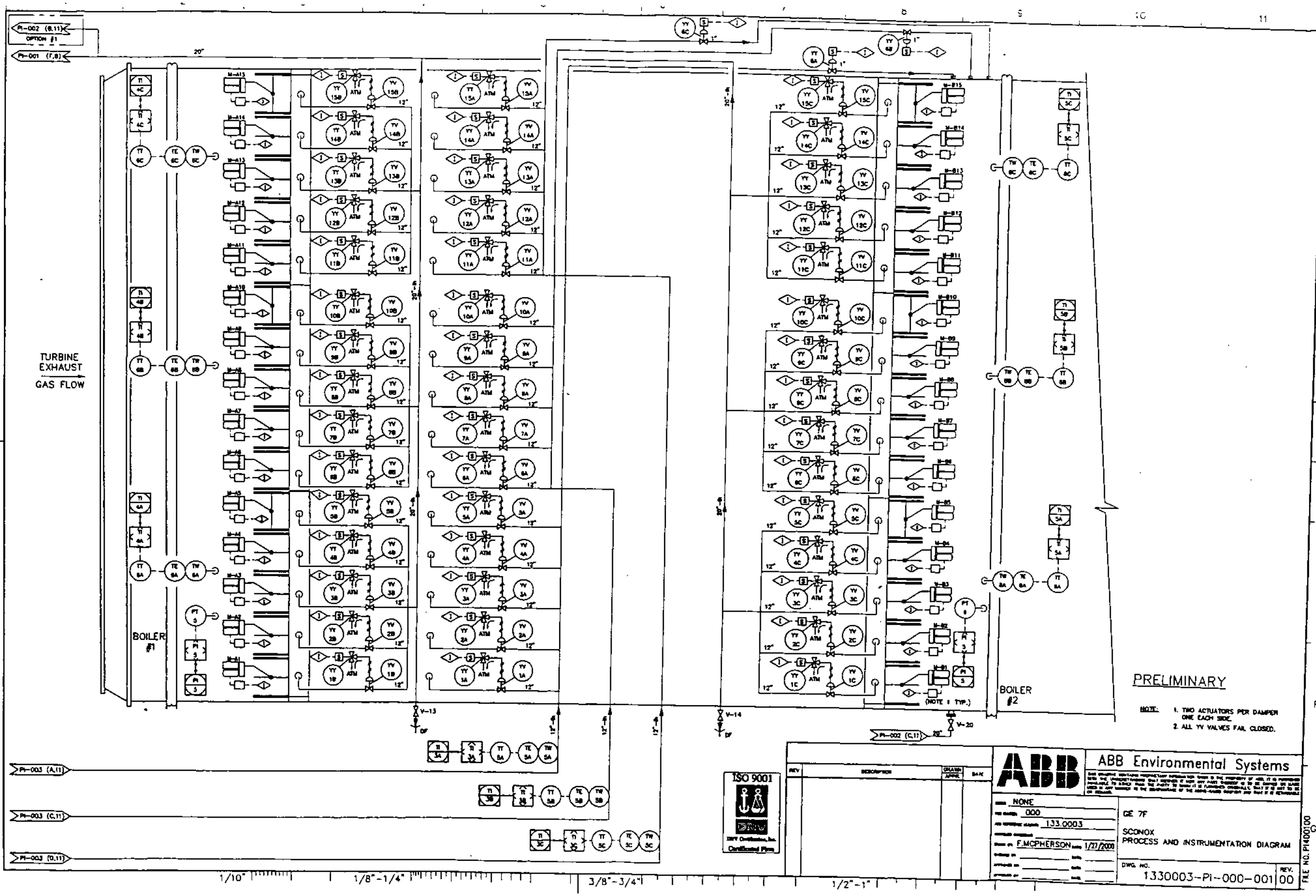
Question 3.b. Attachment


PI-002 (B,11)
OPTION #1
PI-001 (F,8)
TURBINE EXHAUST
GAS FLOW
BOILER #1
BOILER #2
PRELIMINARY
NOTE:
1. TWO ACTUATORS PER DAMPER ONE EACH SIDE.
2. ALL YV VALVES FAIL CLOSED.
V-13
V-14
V-20
PI-002 (C,11)
PI-003 (A,11)
PI-003 (C,11)
PI-003 (D,11)
(NOTE 1 TYP.)
ISO 9001
ABB Environmental Systems
NONE
000
133.0003
F.MCPHERSON
1/27/2000
GE 7F
SCONOX
PROCESS AND INSTRUMENTATION DIAGRAM
DWG. NO.
1330003-PI-000-001
REV.
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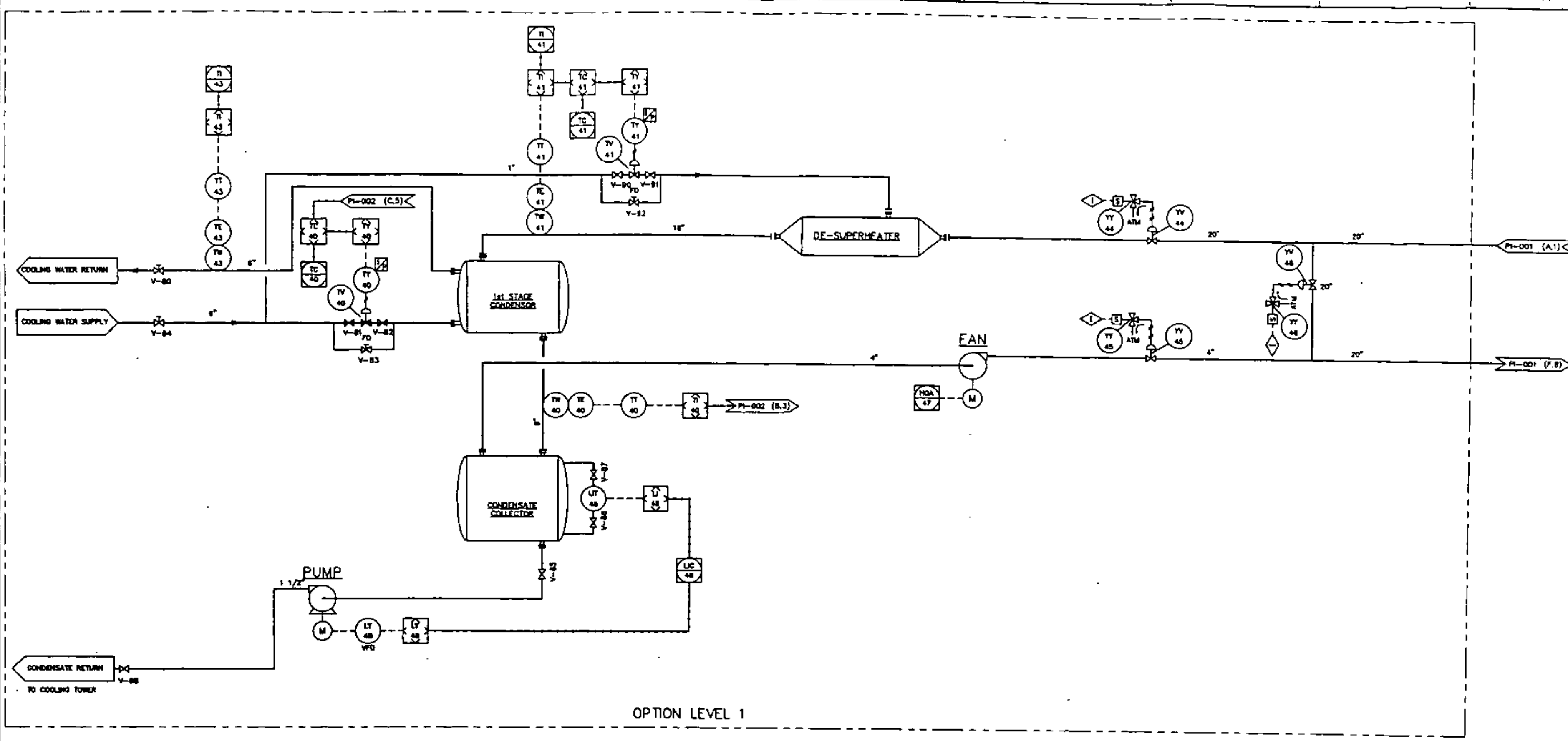
FILE NO. PI400100
1/10"
1/8"-1/4"
3/8"-3/4"
1/2"-1"



PRELIMINARY

ABB Environmental Systems

SCALE NONE

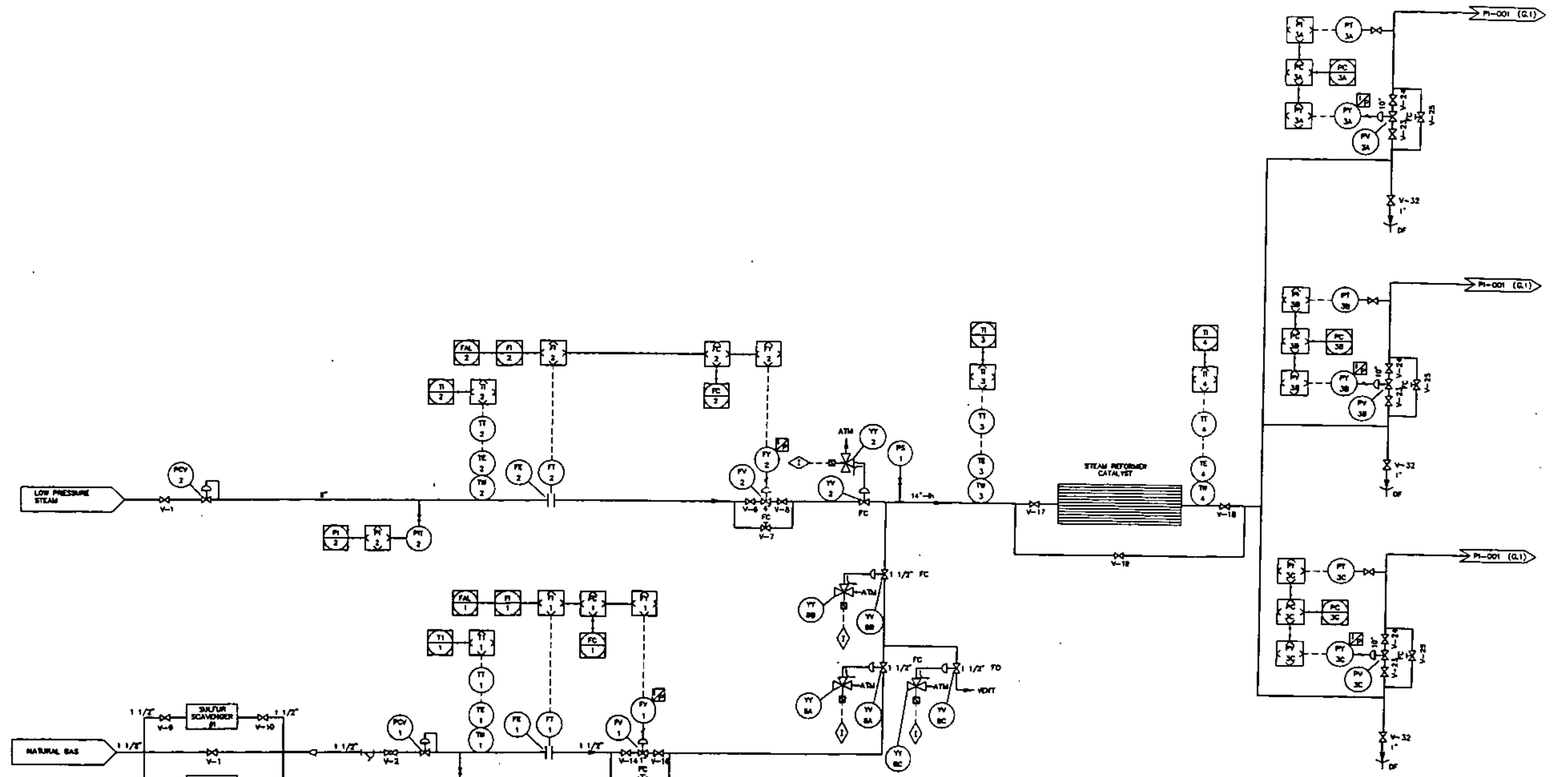
GE 7F

PROCESS AND INSTRUMENTATION DIAGRAM

F.MCPHERSON 1/27/2000

DWG. NO. 1330003-PI-000-002 REV. 00

FILE NO PI400202



PRELIMINARY

ISO 9001

DNV

REV.	DESCRIPTION	DRAWN / APPR.	DATE

ABB

ABB Environmental Systems

SCALE NONE

000

133.0003

F.MCPHERSON 1/27/2000

CE 7F

PROCESS AND INSTRUMENTATION DIAGRAM

DWG. NO. 1330003-PI-000-003

REV. 00

FILE NO PI400300G

1/10" 1/8"-1/4" 3/8"-3/4" 1/2"-1"

Question 5.a. Attachments

United States
Environmental Protection
Agency

Office of Air Quality
Planning and Standards
Research Triangle Park NC 27711

EPA-453/R-94-023
March 1994

Air

EPA

Alternative Control Techniques Document -- NOx Emissions from Utility Boilers

ESD

TABLE 5-1. NO_x EMISSION CONTROL TECHNOLOGIES FOR FOSSIL FUEL UTILITY BOILERS

NO_x control options	Fuel applicability
Combustion Modifications	
Operational Modifications	Coal, natural gas, oil
- Low excess air - Burners-out-of-service - Biased burner firing	
Overfire Air	Coal, natural gas, oil
Low NO_x Burners (except cyclone furnaces)	Coal, natural gas, oil
Low NO_x burners and overfire air	Coal, natural gas, oil
Reburn	Coal, natural gas, oil
Flue gas recirculation	Natural gas, oil
Postcombustion Flue Gas Treatment Controls	
Selective noncatalytic reduction	Coal, natural gas, oil
Selective catalytic reduction	Coal, natural gas, oil

5.1 COMBUSTION CONTROLS FOR COAL-FIRED UTILITY BOILERS

There are several combustion control techniques for reducing NO_x emissions from coal-fired boilers:

- Operational Modifications
  - Low excess air (LEA);
  - Burners-out-of-service (BOOS); and
  - Biased burner firing (BF);
- Overfire air (OFA);
- Low NO_x burners (LNB); and
- Reburn.

Operational modifications such as LEA, BOOS, and BF are all relatively simple and inexpensive techniques to achieve some NO_x reduction because they only require changing certain boiler operation parameters rather than making hardware modifications. These controls are discussed in more detail in section 5.1.1.

Overfire air and LNB are combustion controls that are gaining more acceptance in the utility industry due to increased experience with these controls. There are numerous ongoing LNB demonstrations and retrofit projects on large coal-fired boilers; however, there are only a couple of projects in which LNB and OFA are used as a retrofit combination control. Both OFA and LNB require hardware changes which may be as simple as replacing burners or may be more complex such as modifying boiler pressure parts. These techniques are applicable to most coal-fired boilers except for cyclone furnaces. Overfire air and LNB will be discussed in sections 5.1.2 and 5.1.3, respectively.

Reburn is another combustion hardware modification for controlling NO_x emissions. There are four full-scale retrofit demonstrations on U. S. coal-fired utility boilers. Reburn will be discussed in section 5.1.5.

5.1.1 Operational Modifications

5.1.1.1 Process Description. Several changes can be made to the operation of some boilers which can reduce NO_x emissions. These include LEA, BOOS, and BF. While these changes may be rather easily implemented, their applicability and effectiveness in reducing NO_x may be very unit-specific. For example, some boilers may already be operating at the lowest excess air level possible or may not have excess pulverizer capacity to bias fuel or take burners out of service. Also, implementing these changes may reduce the operating flexibility of the boiler, particularly during load fluctuations.

Operating at LEA involves reducing the amount of combustion air to the lowest possible level while maintaining efficient and environmentally compliant boiler operation. With less oxygen (O_2) available in the combustion zone, both thermal and fuel NO_x formation are inhibited. A range of optimum O_2 levels exist for each boiler and is inversely proportional to the unit load. Even at stable loads, there are small variations in the O_2 percentages which depend upon overall equipment condition, flame stability, and carbon monoxide (CO) levels. If the O_2 level is reduced too low, upsets can occur such as smoking or high CO levels.[1]

Burners-out-of-service involves withholding fuel flow to all or part of the top row of burners so that only air is allowed to pass through. This is accomplished by removing the pulverizer (or mill) that provides fuel to the upper row of burners from service and keeping the air registers open. The balance of the fuel is redirected to the lower burners, creating fuel-rich conditions in those burners. The remaining air required to complete combustion is introduced through the upper burners. This method simulates air staging, or overfire air conditions, and limits NO_x formation by lowering the O_2 level in the burner area.

Burners-out-of-service can reduce the operating flexibility of the boiler and can largely reduce the options available to a coal-fired utility during load fluctuations. Also, if BOOS is improperly implemented, stack opacity and CO levels may increase. The success of BOOS depends on the initial NO_x level; therefore, higher initial NO_x levels promote higher NO_x reduction.[2]

Biased burner firing consists of firing the lower rows of burners more fuel-rich than the upper row of burners. This may be accomplished by maintaining normal air distribution in all the burners and injecting more fuel through the lower burners than through the upper burners. This can only be accomplished for units that have excess mill capacity; otherwise, a unit derate (i.e., reduction in unit load) would occur. This method provides a form of air staging and limits fuel and thermal NO_x formation by limiting the O_2 available in the firing zone.

5.1.1.2 Factors Affecting Performance. Implementation of LEA, BOOS, and BF technologies involve changes to the normal operation of the boiler. Operation of the boiler outside the "normal range" may result in undesirable conditions in the furnace (i.e., slagging in the upper furnace), reduced boiler efficiency (i.e., high levels of CO and unburned carbon [UBC]), or reductions in unit load.

The appropriate level of LEA is unit-specific. Usually at a given load, NO_x emissions decrease as excess air is decreased. Lower than normal excess air levels may be achievable for short periods of time; however, slagging in the upper furnace or high CO levels may result with longer periods of LEA. Therefore, the minimum excess air level is generally defined by the acceptable upper limit of CO emissions and high emissions of UBC, which signal a decrease in boiler efficiency. Flame instability and slag deposits in the upper furnace may also define the minimum excess air level.[3]

The applicability and appropriate configuration of BOOS are unit-specific and load dependent. The mills must have excess capacity to process more fuel to the lower burners. Some boilers do not have excess mill capacity; therefore, full load may not be achievable with a mill out of service. Also, the upper mill and corresponding burners would be required to operate at full capacity during maintenance periods for mills that serve the lower burners. The BOOS pattern may not be constant. For example, a BOOS pattern at low load may be very different than that at high load.[1]

The same factors affecting BOOS also applies to BF, but to a lesser degree. Because all mills and burners remain in service for BF, it is not necessary to have as much excess mill capacity as with BOOS. Local reducing conditions in the lower burner region caused by the fuel-rich environment associated with BOOS and BF may cause increased tube wastage. Additionally, increased upper furnace slagging may occur because of the lower ash fusion temperature associated with reducing conditions.

5.1.1.3 Performance of Operational Modifications. Table 5-2 presents data from four utility boilers that use operational modifications to reduce NO_x emissions. Three of the boilers, (Crist 7, Potomac River 4, and Johnsonville) are not subject to new source performance standards (NSPS) and do not have any NO_x controls; Mill Creek 3 and Conesville 5 are subject to subpart D standards; and Hunter 2 is subject to subpart Da standards. Mill Creek 3 has dual-register burners (early LNB), Conesville 5 has OFA ports, and Hunter 2 has OFA and LNB in order to meet the NSPS NO_x limits. The data presented show only the effect of reducing the excess air level on three of these units. On one unit (Crist 7), the fuel was biased in addition to lowering the excess air.

As shown in table 5-2, LEA reduced NO_x emissions by as much as 21 percent from baseline levels for the subpart D and subpart Da units. These three units had uncontrolled NO_x levels of 0.63 to 0.69 pound per million British thermal unit (lb/MMBtu) and were reduced to 0.53 to 0.56 lb/MMBtu with LEA. For several units at the Johnsonville plant, LEA reduced the NO_x levels to 0.4-0.5 lb/MMBtu, or 10-15 percent while BOOS reduced the NO_x to 0.3-0.4 lb/MMBtu or 20-35 percent. A boiler tuning program at Potomac River 4 reduced NO_x by

TABLE 5-2. PERFORMANCE OF OPERATIONAL MODIFICATIONS ON U. S. COAL-FIRED UTILITY BOILERS

Utility	Unit (standard)[a]	Rated capacity (MW)	OEM[b]	Control type[c]	Length of test[d]	Capacity tested (%)	Uncontrolled NO_x emissions (lb/MMBtu)	Controlled NO_x emissions (lb/MMBtu)	Reduction in NO_x emissions (%)	Reference
TANGENTIALLY-FIRED BOILERS, BITUMINOUS COAL										
Potomac Electric Power Co.	Potomac River 4 (Pre)	108	ABB-CE	Tuned	Short	100 60	0.62 0.59	0.39 0.34	37 42	4
Tenn. Valley Authority	Johnsonville (1-6) (Pre)	120	ABB-CE	LEA BOOS	Short Short	UNK[e] 83	0.5-0.55 0.5-0.55	0.43-0.5 0.34-0.4	10-15 20-35	5
Columbus Southern Power Co.	Conesville 5 (D)	420	ABB-CE	LEA	Short	80-100	0.69	0.53	21[f]	6
Utah Power and Light Co.	Hunter 2 (Da)	446	ABB-CE	LEA	Short	100	0.64	0.55	14[g]	7
Tenn Valley Authority	Johnsonville (1-6)	120	ABB-CE	BOOS	Short	83	0.50-0.55	0.34-0.40	20-35	5
WALL-FIRED BOILERS, BITUMINOUS COAL										
Louisville Gas and Electric Co.	Mill Creek 3 (D)	420	B&W.	LEA	Short	80-100	0.63	0.56	10	6
Gulf Power Co.	Crist 7 (Pre)	500	FW	BF + LEA	Short	80-100	1.27	1.00	21	6

[a]Standard: Da = Subpart Da; D = Subpart D; and Pre = Pre-NSPS

[b]OEM = Original equipment manufacturer; ABB-CE = Asea Brown Boveri-Combustion Engineering; B&W = Babcock & Wilcox; and FW = Foster Wheeler

[c]Type Control: LEA = Low Excess Air; BOOS = Burners-Out-Of-Service; BF = Biased Burner Firing; and Tuned = Boiler tuning.

[d]Short = Short-term test data, i.e., hours.

[e]UNK = Unknown.

[f]NO_x reductions are from lowering boiler oxygen levels from 5.0 percent to 3.5 percent.

[g]NO_x reductions are from lowering boiler oxygen levels from 4.5 percent to 3.5 percent.

approximately 40 percent and consisted of a combination of lowering the excess air, improving mill performance, optimizing burner tilt, and biasing the fuel and air.

A combination of BF and LEA on Crist 7 shows approximately 21 percent reduction in NO_X emissions. This unit had high uncontrolled NO_X emissions of 1.27 lb/MMBtu; therefore, the NO_X level was only reduced to 1.0 lb/MMBtu with BF and LEA. The baseline or uncontrolled NO_X level did not seem to influence the percent NO_X reduction; however, all these units are less than 20 years old and may be more amenable to changing operating conditions than older boilers that have smaller furnace volumes and outdated control systems and equipment.

5.1.2 Overfire Air

5.1.2.1 Process Description. Overfire air is a combustion control technique whereby a percentage of the total combustion air is diverted from the burners and injected through ports above the top burner level. The total amount of combustion air fed to the furnace remains unchanged. In the typical boiler shown in figure 5-1a, all the air and fuel are introduced into the furnace through the burners, which form the main combustion zone. For an OFA system such as in figure 5-1b, approximately 5 to 20 percent of the combustion air is injected above the main combustion zone to form the combustion completion zone.[8] Since OFA introduces combustion air at two different locations in the furnace, this combustion hardware modification is also called air staging.

Overfire air limits NO_X emissions by two mechanisms: (1) suppressing thermal NO_X formation by partially delaying and extending the combustion process, resulting in less intense combustion and cooler flame temperatures, and (2) suppressing fuel NO_X formation by lowering the concentration of air in the burner combustion zone where volatile fuel nitrogen is evolved.[8]

7.0 ENVIRONMENTAL AND ENERGY IMPACTS OF NO_x CONTROLS

This chapter presents the reported effects of combustion modifications and flue gas treatment controls on boiler performance and secondary emissions from new and retrofit fossil fuel-fired utility boilers. Since most of these effects are not routinely measured by utilities, there are limited data available to correlate boiler performance and secondary emissions with nitrogen oxides (NO_x) emissions or NO_x reduction. These effects are combustion-related and depend upon unit-specific factors such as furnace type and design, fuel type, and operating practices and restraints. As a result, the data in this chapter should be viewed as general information on the potential effects of NO_x controls, rather than a prediction of effects for specific boiler types.

The effects of combustion controls on coal-fired boilers, both new and retrofit applications, are given in section 7.1. The effects of combustion controls on natural gas- and oil-fired boilers are presented in section 7.2. The effects of flue gas treatment controls on conventional and fluidized bed combustion (FBC) boilers are given in section 7.3.

7.1 EFFECTS FROM COMBUSTION CONTROLS ON COAL-FIRED UTILITY BOILERS

Combustion NO_x controls suppress both thermal and fuel NO_x formation by reducing the peak flame temperature and by delaying mixing of fuel with the combustion air. This can result in a decrease of boiler efficiency and must be considered during the design of a NO_x control system for any new or retrofit application.

In coal-fired boilers, an increase in unburned carbon (UBC) indicates incomplete combustion and results in a reduction of boiler efficiency. The UBC can also change the properties of the fly ash and may affect the performance of the electrostatic precipitator. Higher UBC levels may make the flyash unsalable, thus increasing ash disposal costs for plants that currently sell the flyash to cement producers.

Other combustion efficiency indicators are carbon monoxide (CO) and total hydrocarbon (THC) emissions. An increase in CO emissions also signals incomplete combustion and can reduce boiler efficiency. Emissions of THC from coal-fired boilers are usually low and are rarely measured.

7.1.1 <u>Retrofit Applications</u>

7.1.1.1 <u>Carbon Monoxide Emissions</u>. The results from combustion modifications on coal-fired boilers are presented in table 7-1. Carbon monoxide emissions are presented for burners-out-of-service (BOOS), advanced overfire air (AOFA), low NO_x burners (LNB), LNB + AOFA, and reburn. For several of these applications, the data show increased CO emissions with retrofit combustion controls. For other units, however, the CO levels after application of controls were equal to or less than the initial levels.

For the only reported BOOS application, the CO emissions increased from 357 parts per million (ppm) to 392-608 ppm. The corresponding NO_x reduction was 30 to 33 percent.

While there were four units mentioned in section 5.1.2.3 that have NO_x emission data from retrofit AOFA, only one unit (Hammond 4) had corresponding CO emissions data. This unit is an opposed-wall unit firing bituminous coal. Data are presented for different loads prior to and after the retrofit of an AOFA system. The CO levels prior to the retrofit of AOFA range from 20 to 100 ppm over the load range. With the AOFA system, the CO levels decreased to an average of 15 ppm across the load range. The NO_x reduction was 10 to 25 percent across the load range. These data indicate a large decrease in CO; however, the CO levels were not routinely monitored

TABLE 7-1. SUMMARY OF CARBON MONOXIDE EMISSIONS FROM COAL-FIRED BOILERS WITH COMBUSTION NO_x CONTROLS

Utility	Unit (standard)[a]	Unit type[b]	Rated capacity (MW)	Control type[c] (vendor)[d]	Capacity tested	Carbon monoxide (ppm)		NO_x reduction (%)	Reference
						Uncontrolled	Control		
OPERATIONAL MODIFICATIONS, BITUMINOUS COAL									
Gulf Power Co.	Crist 7 (Pre)	Wall	500	BOOS	85	357	392-608	30-33	1
OVERFIRE AIR, BITUMINOUS COAL									
Georgia Power Co.	Hammond 4 (Pre)	Wall	500	AOFA (FW)	100 80 60	100 30 20	15 15 15	25 -- 10	2,3
LOW NO_x BURNERS, BITUMINOUS COAL									
Gulf Power Co.	Lansing Smith 2 (Pre)	Tan	190	LNCFS I (ABB-CE)	95 71 60	12 15 15	15 10 20	42 39 34	4,5
Ohio Edison Co.	Edgewater 4 (Pre)	Wall	105	XCL + SI (B&W)	100 78 63	16 16 16	100 130 170	39 43 42	6
Tennessee Valley Authority	Johnsonville 8 (Pre)	Wall	125	IFS (FW)	100	50	--	55	7,8
Board of Public Utilities	Quindaro 2 (Pre)	Wall	137	RO-II (ABB-CE)	90 70 55	-- -- --	50 50 95	-- -- --	9
Alabama Power Co.	Gaston 2 (Pre)	Wall	272	XCL (B&W)	100 68 50	60 -- --	60 50 --	50 46 43	10,11
Georgia Power Co.	Hammond 4 (Pre)	Wall	500	CF/SF (FW)	100 80 60	100 30 20	8 8 8	45 -- 50	2,3,12
Dayton Power & Light Co.	JM Stuart 4 (Pre)	Cell	610	LNCB (B&W)	100 75 56	26 17 20	35 28 10	55 54 47	13

TABLE 7-1. SUMMARY OF CARBON MONOXIDE EMISSIONS FROM COAL-FIRED BOILERS WITH COMBUSTION NO_x CONTROLS (CONTINUED)

Utility	Unit (standard)[a]	Unit type[b]	Rated capacity (MW)	Control type[c] (vendor)[d]	Capacity tested	Carbon monoxide (ppm)		NO_x reduction (%)	Reference
						Uncontrolled	Control		
LOW NO_x BURNERS, SUBBITUMINOUS COAL									
Board of Public Utilities	Quindaro 2 (Pre)	Wall	137	RO-II (ABB-CE)	80 70 55	-- -- --	70 70 50	-- -- --	9
Arizona Public Service Co.	Four Corners 4 (Pre)	Wall	818	CF/SF (FW)	105 69 49	53 35 30	86 33 41	57 29 6	14
Arizona Public Service. Co.	Four Corners 5 (Pre)	Wall	818	CF/SF (FW)	93	--	<50	50	14
LOW NO_x BURNERS + OVERFIRE AIR, BITUMINOUS COAL									
Public Service Co. of CO	Valmont 5 (Pre)	Tan	165	LNCFS II (ABB-CE)	91 75 50	<30 -- --	<30 -- --	52 26 27	15
Gulf Power Co.	Lansing Smith 2 (Pre)	Tan	190	LNCFS II (ABB-CE)	95 71 60	12 15 15	28 22 20	39 35 30	4,5,10
Public Service Co. of CO	Cherokee 4 (Pre)	Tan	350	LNCFS II (ABB-CE)	100 71 45	<30 -- --	<30 -- --	46 31 35	16
Gulf Power Co.	Lansing Smith 2 (Pre)	Tan	190	LNCFS III (ABB-CE)	95 71 60	12 15 15	45 25 22	48 47 39	4,5,10
Ohio Edison Co.	Sammis 6 (Pre)	Wall	630	DRB-XCL (B&W)	100 55	17.4-25.8 31.8	225-670 55		17
Public Service Co. of CO	Arapahoe 4 (Pre)	Roof	100	DRB-XCL + OFA (B&W)	100 80 60	48 42 39	38 21 12	66 71 63	18

TABLE 7-1. SUMMARY OF CARBON MONOXIDE EMISSIONS FROM COAL-FIRED BOILERS WITH COMBUSTION NO_x CONTROLS (CONCLUDED)

Utility	Unit (standard)[a]	Unit type[b]	Rated capacity (MW)	Control type[c] (vendor)[d]	Capacity tested	Carbon monoxide (ppm)		NO_x reduction (%)	Reference
						Uncontrolled	Control		
REBURN, BITUMINOUS COAL									
Illinois Power Co.	Hennepin 1 (Pre)	Tan	75	NGR (EERC)	100	2	2	63	19,20
Wisconsin Power and Light Co.	Nelson Dewey 2 (Pre)	Cyc	114	Coal Reburn (B&W)	100 75 50	60-70 40-70 80-94	90-110 80-100 80-100	53 50 36	21
Ohio Edison Co.	Niles 1 (Pre)	Cyc	125	NGR (EERC)	100 85 79 75	25-50 -- -- --	312 214 50 103	47 43 34 36	22

[a]Standard: Pre = Pre-NSPS

[b]Unit Type: Cell = Cell Burner; Cyc = Cyclone; Roof = Roof-fired; Tan = Tangentially-fired; and Wall = Wall-fired.

[c]Control Type: AOFA = Advanced Overfire Air; BOOS = Burners-out-of-service; CF/SF = Controlled Flow/Split Flame LNB; DRB-XCL = Dual Register Axial Control LNB; IFS = Internal Fuel Staged LNB; LNCB = Low NO_x Cell Burner; LNCFS, I, II, II = Low NO_x Concentric Firing System, Level I, II, III; NGR = Natural Gas Reburn; OFA = Overfire Air; RO-II = RO-II LNB; SI = Sorbent Injection for Sulfur Dioxide Control; and XCL = Axial Controlled LNB.

[d]Vendors: ABB-CE = Asea Brown Boveri-Combustion Engineering; B&W = Babcock & Wilcox; EERC = Energy and Environmental Research Corporation; and FW = Foster Wheeler.

-- = data not available.

prior to the retrofit and the decrease may be attributable to plant operating personnel taking action to reduce CO emissions after the retrofit.[2]

For the one tangential boiler with retrofit LNB (Lansing Smith 2), the uncontrolled CO emissions were 12 to 15 ppm while the CO emissions were 10 to 20 ppm with the Low NO_x Concentric Firing System (LNCFS) Level I which incorporates close-coupled OFA (CCOFA). The corresponding NO_x reduction was 34 to 42 percent across the load range.

For all but two of the wall-fired boilers firing bituminous coal with LNB, the reported uncontrolled CO emissions were 100 ppm or less and the controlled CO emissions were 60 ppm or less. However, for Edgewater 4, the CO increased from 16 ppm up to 100 to 170 ppm following retrofit of LNB. At reduced load, Quindaro 2 reported a CO level of 95 ppm with LNB. The CO level without LNB was not reported. The largest decrease in CO emissions was at the Hammond 4 unit. However, as previously discussed, the CO level was not routinely measured prior to the retrofit and the decrease may be attributable to plant operating personnel taking action to reduce the CO emissions after the retrofit. For the one cell-fired unit, J.M. Stuart 4, the CO emissions with LNB were slightly higher than uncontrolled levels at full-load and intermediate load. The CO emissions were less with LNB at low load. The corresponding NO_x reductions ranged from 47 to 55 percent.

The Four Corners 4 unit, which converted from cell firing to an opposed-wall circular firing configuration, showed a small increase in CO emissions with LNB when firing subbituminous coal. The corresponding NO_x reduction for Four Corners 4 ranged from 6 to 57 percent across the load range. Quindaro 2 was also tested on subbituminous coal and the CO ranged from 50-70 ppm across the load range.

There are four applications of LNB and AOFA on tangential boilers shown in table 7-1. The LNB represented are the LNCFS Levels II and III which incorporates separated OFA (SOFA) and a combination of SOFA and CCOFA, respectively. Three of these units (Valmont 5, Lansing Smith 2, and Cherokee 4) have the LNCFS II technology. For these units, the CO emissions for both uncontrolled and controlled conditions were less than 30 ppm. For the one unit employing LNCFS III technology (Lansing Smith 2), the CO emissions increased from uncontrolled levels of 12 to 15 ppm up to controlled levels of 22 to 45 ppm.

One wall-fired boiler, Sammis 6, was originally a cell-fired boiler and was retrofitted with LNB + OFA. At full-load, the CO increased to more than 225 ppm from baseline levels of 17-25 ppm. At reduced load, the CO also increased almost two-fold to 55 ppm. The reason for the large in CO at full-load was not reported. The NO_x reduction was approximately 65 percent. The one roof-fired boiler, Arapahoe 4, reported decreases in CO and ranged from 12-38 ppm with LNB + OFA. The NO_x reduction ranged from 63-71 percent across the load range.

For the tangentially-fired unit (Hennepin 1) with retrofit reburn, the CO emissions for both uncontrolled and controlled conditions were 2 ppm. Carbon monoxide data from two cyclone units with reburn are also given in table 7-1. One unit (Nelson Dewey 2), uses pulverized coal as the reburn fuel while the other unit (Niles 1), uses natural gas as the reburn fuel. The CO emissions for the cyclone boilers increased with the reburn system. For Nelson Dewey 2, the CO emissions were 60 to 94 ppm without reburn and 80 to 110 ppm with reburn. The corresponding NO_x reduction was 36 to 53 percent across the load range. For Niles 1, the CO emissions increased greatly from 25 to 50 to 312 ppm at full load. At lower loads, the CO emissions were still at elevated levels of 50 to 214 ppm. The corresponding NO_x reduction was 36 to 47 percent.

To summarize, the CO emissions may increase with retrofit combustion modifications. However, as shown in table 7-1, with few exceptions, the CO emissions were usually less than 100 ppm with retrofit combustion controls.

7.1.1.2 Unburned Carbon Emissions and Boiler Efficiency. Table 7-2 presents UBC and boiler efficiency data from 18 applications of retrofit combustion NO_x controls on coal-fired boilers. For Hammond 4, the AOFA resulted in an increase of UBC two or three times the uncontrolled level. Uncontrolled levels of UBC at Hammond 4 ranged from 2.3 percent at low load to 5.2 percent at full load. With the AOFA, the UBC levels increased to 7.1 percent at low load and 9.6 percent at full load. The boiler efficiency at low load decreased by 0.7 percentage points and by 0.4 percentage points at full load. The corresponding NO_x reduction with AOFA was 10 percent at low load and 25 percent at full load.

For the tangential unit with LNCFS I technology, Lansing Smith 2, the UBC levels range from 4.0 to 5.0 percent without LNB and 4.0 to 5.3 percent with LNB. The boiler efficiency with LNB decreased slightly to 89.6 percent.

The UBC from all of the wall-fired boilers increased with the retrofit of LNB and LNB with OFA. For Edgewater 4, the uncontrolled UBC levels increased from 2.7 to 3.2 percent to 6.6 to 9.0 percent with the LNB. The corresponding NO_x reduction was 39 to 43 percent across the load range. The boiler efficiency decreased by 1.3 percentages points at full load with the LNB.

For Gaston 2, the UBC increased from 5.3 to 6.3 percent at low load and 7.4 to 10.3 percent at full load. The corresponding NO_x reduction at Gaston 2 ranged from 43 to 50 percent across the load range. Boiler efficiency data were not available for this unit. For Hammond 4, the UBC increased from 2.3 to 5.8 percent at low load and 5.2 to 8.0 percent at full load with LNB. Increased UBC levels such as these could limit the sale of fly ash to cement producers that typically require UBC levels of 5 percent or less. The corresponding

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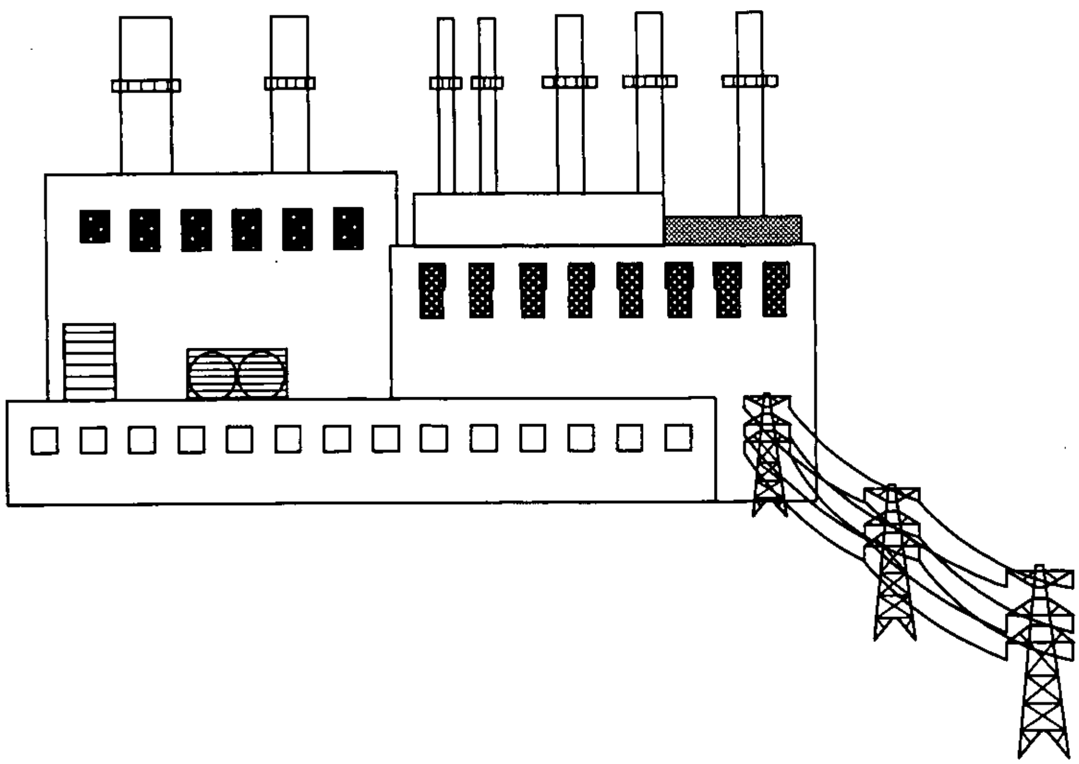
CORPORATE ENVIRONMENTAL SERVICES

AIR PROGRAMS REPORT

SOURCE EMISSION TEST
F. J. GANNON GENERATING STATION
BOILER NO. 5
AIRS #0570040
APRIL 7 and 8, 2000

CARBON MONOXIDE



REPORT CERTIFICATION

I have reviewed all data in this report, and hereby certify that the test report is authentic and accurate to the best of my knowledge.

Date 5/1/2000 Signature

Quality Control/Quality Assurance Coordinator
Senior Environmental Technician
Air Services and Auditing
Corporate Environmental Services
Tampa Electric Company

The sampling and analysis performed for this report were carried out under my direction and, and I hereby certify that this test report is authentic and accurate.

Date 5/1/00 Signature

Test Team Leader
Senior Environmental Technician
Air Services and Auditing
Corporate Environmental Services
Tampa Electric Company

I have reviewed the testing details and results in this report, and hereby certify that the test report is authentic and accurate to the best of my knowledge.

Date 5-2-00 Signature

Administrator
Air Services and Auditing
Corporate Environmental Services
Tampa Electric Company

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1.0 SUMMARY OF RESULTS

On April 7 and 8, 2000, Corporate Environmental Services, Air Services and Auditing group of Tampa Electric Company, performed source emission tests at the F.J. Gannon Station, Boiler number 5, Airs # 0570040. Testing was conducted according to procedures stipulated by the Florida Department of Environmental Protection (FDEP) for fossil fuel steam generators, 40CFR60.

The Carbon Monoxide emission rate was derived from three test runs. The calculated average of CO was 0.295 lbs/MMBtu (lb/10^6 Btu) based on Oxygen content of the flue gas (O_2 F-factor).

During the tests on April 7 and 8, 2000, the boiler was operated at an average heat input rate of 2082 x 10^6 Btu/hr and an average load of 220 megawatts. The average quantity of fuel burned was 82 tons per hour. Details of boiler operations are included in Appendix C.

2.0 SOURCE DESCRIPTION/TEST PROCEDURES

F.J. Gannon Generating Station is located on Port Sutton Road, Tampa, Florida at UTM coordinates East 360.1 North 3087.5. Unit No. 1 source sampling location consists of a circular stack 12 feet in diameter with four sample ports located 90E apart on the stack circumference. A diagram of the stack sampling location is included in Figure 1 along with other pertinent information on the test site.

An electrostatic precipitator for the control of flyash emissions services boiler No. 1. Appendix C details the operational parameters of the electrostatic precipitator during the test period.

Carbon Monoxide sampling was performed according to U.S. EPA Method 10 - "Determination of Carbon Monoxide Emissions from Stationary Sources". Sampling was performed using the equipment depicted in Figure 2. Oxygen gas sampling was performed according to U.S. EPA Method 3A - "Determination of Oxygen and Carbon Monoxide Concentrations in Emissions from Stationary Sources "(Instrumental Analyzer Procedures)". Sampling was performed using the equipment depicted in Figure 2.

3.0 TCEMS Description

The following discussion briefly outlines the operation principles of Tampa Electric Company's Continuous Emissions Monitoring System (TCEMS). Additional information on instrument operation may be found in the individual instrument manuals provided by the manufacturers. A schematic of the TCEMS set-up is presented in Figure 2.

Servomex Model 1400 B O_2 Analyzer

The Servomex 1400B oxygen analyzer measures the paramagnetic susceptibility of the sample gas by means of a magneto-dynamic type measuring cell.

Thermo Environmental Instruments Model 48-H Gas Filter Correlation CO Analyzer High Range

Gas Filter Correlation (GFC) spectroscopy is based upon comparison of the detailed structure of the infrared absorption spectrum of the measured gas to that of other gases also present in the sample being analyzed. The technique is implemented by using a high concentration sample of the measured gas, i.e., CO, as a filter for the infrared radiation transmitted through the analyzer, hence the term GFC.

Radiation from an IR source is chopped and then passed through a gas filter alternating between CO and N_2 due to rotation of the filter wheel. The radiation then passes through a narrow bandpass interference filter and enters a multiple optical pass cell where absorption by the sample gas occurs. The IR radiation then exits the sample cell and falls on an IR detector.

The CO gas filter acts to produce a reference beam which cannot be further attenuated by CO in the sample cell. The N_2 side of the filter wheel is transparent to the IR radiation and therefore produces a measurement beam which can be absorbed by CO in the cell. The chopped detector signal is modulated by the alternation between the two gas filters with an amplitude related to the concentration of CO in the sample cell. Other gases do not cause modulation of the detector signal since they absorb the reference and measure beams equally. Thus the GFC system responds specifically to CO.

Data Acquisition System

The data acquisition system (DAS) developed by Entropy Environmentalists Inc., uses a portable personal computer with an internal 32 bit analog-to-digital converter with an external 16 channel multiplexer. In addition to providing an instantaneous display of analyzer responses, the DAS can average data, calculate emission rates, and document analyzer calibrations. The test results and calibrations are stored on the hard disk and printed on a dot matrix printer.

TCEMS Sample Handling System

The extractive monitors utilized in the TCEMS require that the effluent stream be conditioned to eliminate any possible interference (i.e., water vapor and particulate matter), before being transported and injected into each analyzer. Figure 2 depicts a schematic of the entire sample handling system. The major components of this system are listed below:

- Gas transport tubing
- Moisture removal system
- Sampling pump

Gas Transport Tubing

Two separate 1/4 inch O.D. Teflon tubes were used for the sample gas transport.

Moisture Removal System

The moisture removal system was comprised of an ice bath condenser, constructed of a 30-foot section of 3/8 inch O.D. Teflon tubing, wrapped in a 12-inch coil. Effluent travels through this coil and then passes, in series, through two stainless steel moisture traps where the condensate drops out and is removed via a condensate discharge pump. With the exception of the discharge pump, the entire assembly is chilled in an ice bath.

Sampling Pump

The Thomas Model 2107CE20-TFE pump is used to transport the effluent sample through the conditioning system to the analyzers. All internal parts of the pump that come into contact with the gas sample are constructed of 316 stainless steel or Teflon.

3.0 TEST RESULTS

TEST SUMMARY
CARBON MONOXIDE TEST RESULTS

PLANT:	F. J. GANNON STATION
SAMPLING LOCATION:	BOILER NO. 5
DATE:	April 7 and 8, 2000

USEPA Method 10

RUN NO.	ppm CO	Oxygen %	lbs. CO /MM Btu
1	117.3	13.52	0.222
2	158.9	12.36	0.259
3	243.4	12.49	0.404
Averages	173.2	12.79	0.295

SOURCE SAMPLING NOMENCLATURE

A	=	Absorbance of sample.
A_n	=	Cross-sectional area of nozzle, m5 (ft5).
A_s	=	Cross-sectional area of stack, m5 (ft5).
B_{ws}	=	Water vapor in the gas steam, proportion by volume.
C	=	Concentration of particulate matter, (lbs/dscf), Method 5,17.
C	=	Concentration of NO_x, as NO_2, basis, corrected to standard conditions, mg/dscm (lbs/dscf), Method 7.
C_a	=	Concentration of acetone blank residue, mg/g.
$CH_2 SO_4$	=	Sulfuric acid (including SO_3) concentration, g/dscm (lbs/dscf).
C_p	=	Pitot tube coefficient, dimensionless.
c_s	=	Concentration of stack gas particulates, dry basis corrected to standard conditions, g/dscm (lbs/dscf).
CSO_2	=	Sulfur dioxide concentration, mg/dscm (lbs/dscf).
E	=	Pollutant emissions, lbs/10^6 Btu.
EM	=	Particulate emission rate, lbs/hr.
F	=	Factor ratio of generated flue gases to calorific value of fuel, Method 5,17.
F	=	Dilution factor (i.e., 25/5, 25/10, etc.) required only if sample dilution was needed to reduce the absorbance to the range of calibration, Method 7.
FDA	=	Fraction of dry air.
I	=	Percent of isokinetic sampling, %.
K_c	=	Spectrophotometer calibration factor.
K_p	=	Pitot tube constant,

$$34.97 m/\sec\left[\frac{(g/g\text{-}mole)(mmHg)}{(°K)(mmH20)}\right]1/2$$

Metric

$$85.49 ft / \sec \left[\frac{(lb / lb\text{-}mole)('' Hg)}{(^\circ K)(mmH2O)} \right] 1/2$$

English

L_a = Maximum acceptable leakage rate for either a pretest leak check or a leak check following a component change; equal to 0.00057 m^3/min (0.02 ft^3/min) or 4% of the average sampling rate, whichever is less.

L_i = Individual leakage rate observed during the leak check conducted prior to the "ith" component change (i = 1, 2, 3,...n), m^3/min (ft/min).

L_p = Leakage rate observed during the post test leak check, m^3/min (ft^3/min).

m = Mass of NO_x as NO_2 in gas sample, :g.

m_a = Mass of acetone residue after evaporation, mg.

M_d = Molecular weight of stack gas, dry basis, g/g-mole (lb/lb-mole).

m_f = Filter weight gain, mg.

m_n = Total amount of particulates collected, mg.

M_s = Molecular weight of stack gas, wet basis, g/g-mole (lb/lb-mole), or $M_d(1 - B_{ws}) = 18.0\ B_{ws}$.

M_w = Molecular weight of water, 18.0 g/g-mole (18.0 lb/lb-mole).

N = Normality of $Ba(ClO_4)_2 \cong 3H_2O$ titrant, g-eq/l.

N = Normality of barium perchlorate titrant, meq/ml.

P_a = Density of acetone, mg/ml (see bottle label).

P_{bar} = Barometric pressure at sampling site, mm Hg (in. Hg).

P_f = Final absolute pressure of flask, mm Hg (in. Hg).

P_g = Stack static pressure, mm Hg (in. Hg).

P_i = Initial absolute pressure of flask, mm Hg (in. Hg).

P_s = Absolute stack pressure, 760 mm Hg (29.92 in. Hg).

P_w = Density of water, 0.9982 g/ml (0.0022 lb/ml).

Q_s = Volumetric flow rate, actual cubic feet per min, acf/min.

Q_{std} = Dry volumetric stack gas flow rate corrected to standard conditions dsm^3/hr (dscf/hr).

R = Ideal gas constant, 0.06236 (mm Hg - m^3)/(EK - g - mole) for metric units and 21.85 (in. Hg - ft^3)(ER - 1b - mole) for English units.

S.V.P. = Saturated vapor pressure of water at average stack temperature mm Hg (in. Hg).

T_f = Final absolute temperature of flask, K (ER).

T_i = Initial absolute temperature of flask, K (ER).

T_m = Absolute average dry gas meter temperature, K (ER).

t_s = Stack temperature, EC (EF).

T_s = Absolute stack temperature, K (ER), or 273 + t_s for metric system or 460 + t_s for English system.

T_{std} = Standard absolute temperature, 293K (528ER).

V_a = Volume of acetone blank, ml, (Method 5,17).

V_a = Volume of sample aliquot titrated, ml, (Method 6).

V_a = Volume of absorbing solution, 25 ml, (Method 7).

V_a = Volume of sample aliquot titrated, 100 ml for H_2SO_4 and 10ml for SO_2 (Method 8).

V_{aw} = Volume of acetone used in wash, ml.

V_f = Final volume of condenser water, ml.

V_f = Volume of flask and valve, ml.

V_i = Initial volume of condenser water, ml.

V_{ic} = Total volumes of liquid and silica gel collected in impingers, ml.

V_m = Dry gas volume measured by dry gas meter, scm (dcf).

$V_{m(std)}$ = Volume of gas sample measured by the dry gas meter and corrected to standard condition, dscm (dscf).

v_s = Average stack gas velocity calculated by Method 2, m/sec (ft/sec).

V_{sc} = Sample volume at standard conditions (dry basis), ml.

V_{soln} = Total volume of solution in which the sulfur dioxide sample is contained, 100 ml, (method 6).

V_{soln} = Total volume of solution in which the H_2SO_4 or SO_2 sample is contained, 250 ml or 1000 ml, respectively, (Method 8).

V_t = Volume of $Ba(ClO_4)_2{\cong}3H_2O$ titrant used for the sample, ml, (Method 8).

V_t = Volume of barium perchlorate titrant used for the sample (average of replicate titrations), ml, (Method 6).

V_{tb} = Volume of barium perchlorate titrant used for the blank, ml.

$V_{w(std)}$ = Volume of water vapor in the gas sample, corrected to standard conditions, scm (scf).

$V_{wc(std)}$ = Volume of condensed water vapor, corrected to standard conditions,

sm^3(scf).

$V_{wsg(std)}$ = Volume of water vapor collected in silica gel, corrected to standard conditions, sm^3 (scf).

W_a = Weight of acetone wash residue, mg.

W_f = Final weight of silica gel or silica gel plus impinger, g.

W_i = Initial weight of silica gel or silica gel plus impinger, g.

Y = Dry gas meter calibration factor.

)H = Average pressure differential across the orifice meter, mm (in) H_2O.

)H@ = Measurement of pressure differential across the orifice meter, mm (in.) H_2O.

)p = Average velocity head of stack gas, mm (in.) H_2O.

$)V_m$ = Incremental volume measured by dry gas meter at each traverse point, dm^3 (dcf).

%CO = Percent CO by volume (dry basis), average of three CO values.

$\%CO_2$ = Percent CO_2 by volume (dry basis), average of three analyses.

%EA = Percent excess air, %.

$\%N_2$ = Percent N_2 by volume (dry basis), average of three N_2 values.

$\%O_2$ = Percent O_2 by volume (dry basis), average of three O_2 values.

0.262 = Ratio of O_2 to N_2 in air, v/v.

2 = 50/25, the aliquot factor, (Method 7).

13.6 = Specific gravity of mercury (Hg).

18.0 = Molecular weight of water, g/g-mole (lb/lb-mole).

32.03 = Equivalent weight of sulfur dioxide.

60 = Seconds per minute (sec/min).

100 = Conversion to percent, %.

3600 = Conversion factor, (sec/hr).

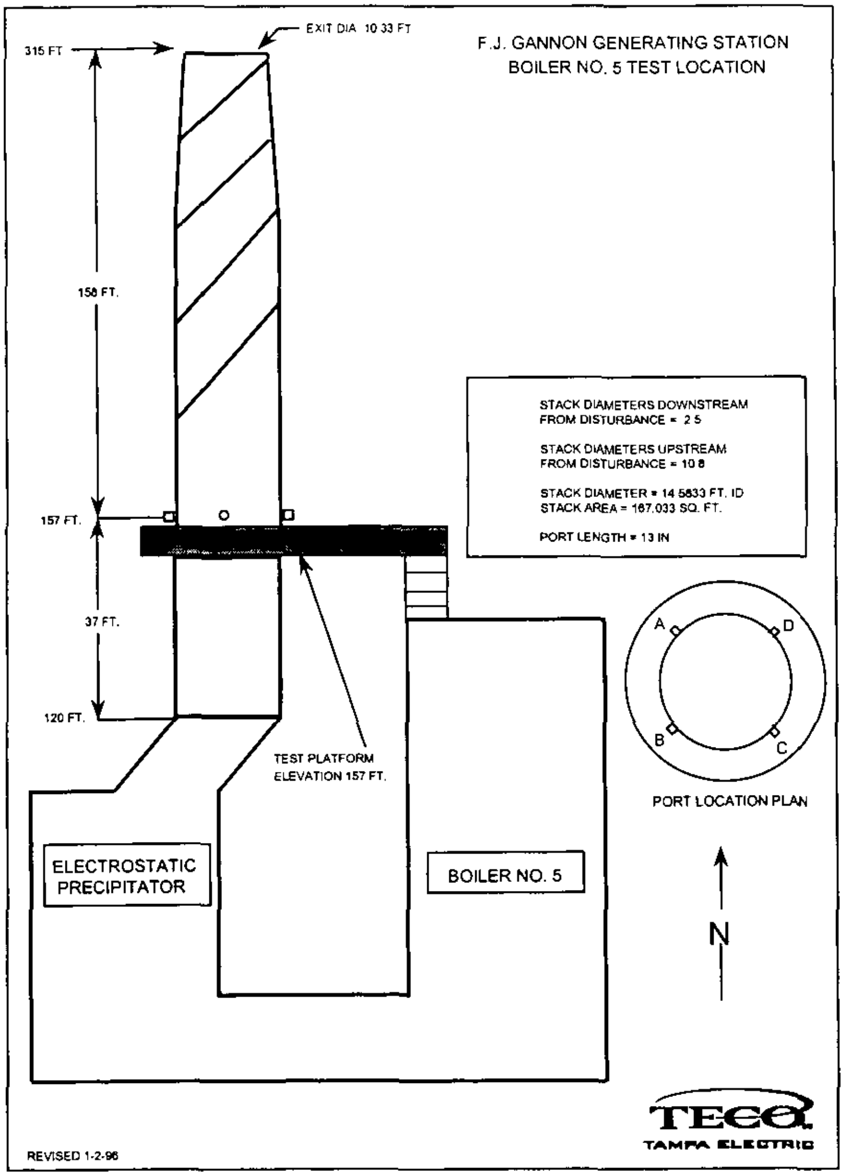
2 = Total sampling time, min.

2_I = Interval of sampling time from beginning of a run until first component change, min.

2_i = Interval of sampling time between two successive component changes, beginning with first and second changes, min.

2_p = Interval of sampling time from final (nth) component change until the end of the sampling run, min.

4.0 FIGURES



EXIT DIA 10 33 FT
F.J. GANNON GENERATING STATION
BOILER NO. 5 TEST LOCATION
315 FT
158 FT.
157 FT.
37 FT.
120 FT.
STACK DIAMETERS DOWNSTREAM
FROM DISTURBANCE = 2 5
STACK DIAMETERS UPSTREAM
FROM DISTURBANCE = 10 8
STACK DIAMETER = 14 5833 FT. ID
STACK AREA = 167.033 SQ. FT.
PORT LENGTH = 13 IN
A
D
B
C
PORT LOCATION PLAN
TEST PLATFORM
ELEVATION 157 FT.
ELECTROSTATIC
PRECIPITATOR
BOILER NO. 5
N
TECO
TAMPA ELECTRIC
REVISED 1-2-96

FIGURE 1

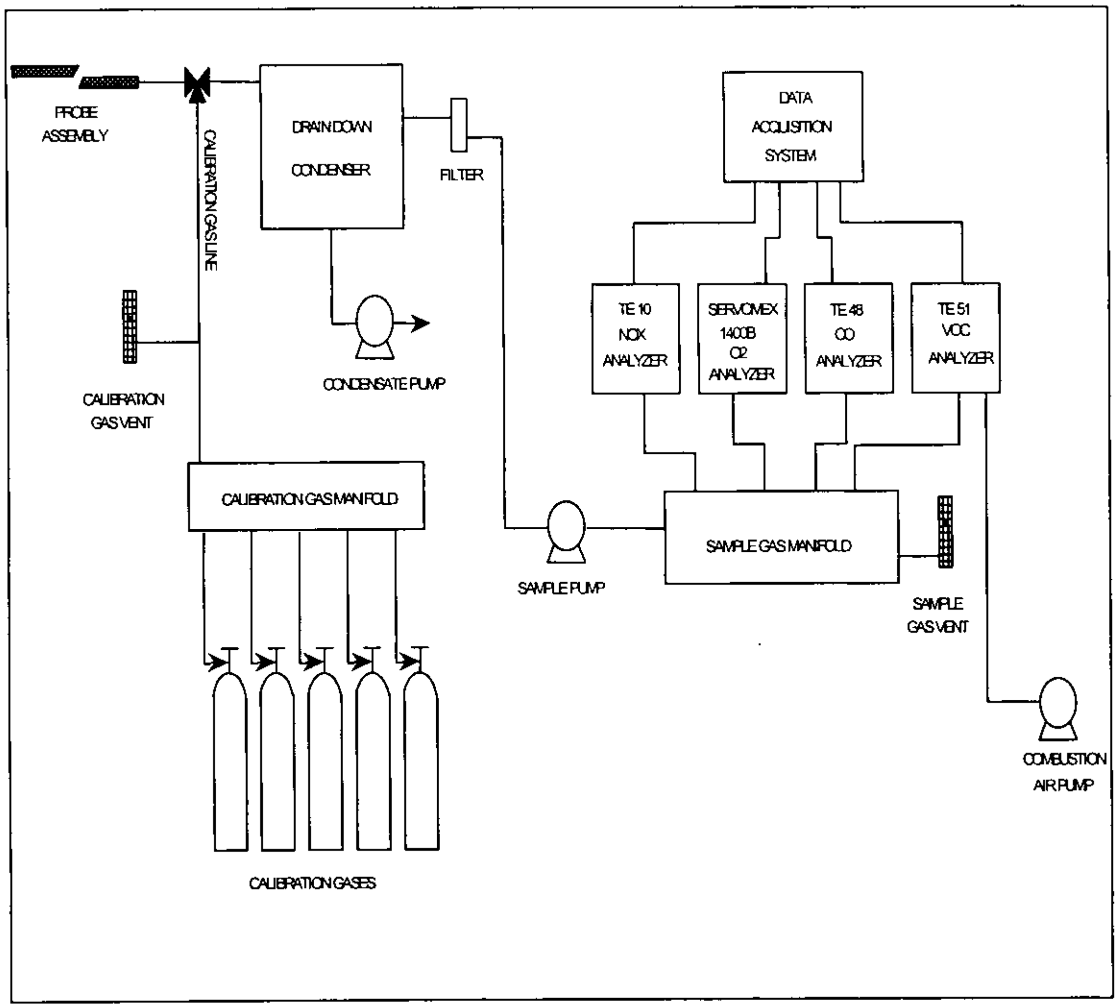


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FIGURE 2
Carbon Monoxide and Nitrogen Oxide Sampling Trains

USEPA METHODS 3A, 10, 20, 25 CEM SYSTEM LAYOUT

A. GAS CALCULATIONS

A-1 CARBON MONOXIDE CALCULATIONS
A-2 OXYGEN CALCULATIONS

A-1 CARBON MONOXIDE CALCULATIONS

CALCULATION OF AVERAGE CARBON MONOXIDE CONCENTRATION

RUN: 1

SOURCE: F.J. GANNON STATION BOILER 5

TEST DATE: 4/7/00

GAS VALUE	INITIAL CAL	FINAL CAL	MEAN CAL
0.00 ppm CO	3.30	2.20	2.75
150.00 ppm CO	146.00	142.20	144.10

$\bar{C}$ = 113.3 ppm CO

02= 13.52

EMISSION RATE = (ppm CO) (9190) (0.7263E-07) [20.9/(20.9 - %02)]

CORRECTED RESULTS

117.3 ppm CO

0.222 lb/MMBtu

Corrected Conc. = Cma(C - $\bar{C}$o)/(Cm - Co)

Where: $\bar{C}$ = mean reference measurement
Co = mean zero calibration response
Cm = mean mid or upscale calibration gas response
Cma = actual mid or upscale calibration gas concentration

CALCULATION OF AVERAGE CARBON MONOXIDE CONCENTRATION

RUN: 2

SOURCE: F.J. GANNON STATION BOILER 5

TEST DATE: 4/7/00

GAS VALUE	INITIAL CAL	FINAL CAL	MEAN CAL
0.00 ppm CO	2.20	1.80	2.00
150.00 ppm CO	142.20	150.20	146.20

$\bar{C}$ = 154.8 ppm CO

02= 12.36

EMISSION RATE = (ppm CO) (9190) (0.7263E-07) [20.9/(20.9 - %02)]

CORRECTED RESULTS

158.9 ppm CO

0.259 lb/MMBtu

Corrected Conc. = Cma(C - $\bar{Co}$)/(Cm - Co)

Where: $\bar{C}$ = mean reference measurement
Co = mean zero calibration response
Cm = mean mid or upscale calibration gas response
Cma = actual mid or upscale calibration gas concentration

CALCULATION OF AVERAGE CARBON MONOXIDE CONCENTRATION

RUN: 3

SOURCE: F.J. GANNON STATION BOILER 5

TEST DATE: 4/7/00

GAS VALUE	INITIAL CAL	FINAL CAL	MEAN CAL
0.00 ppm CO	1.80	2.20	2.00
150.00 ppm CO	150.20	143.10	146.65

$\bar{C}$ = 236.7 ppm CO

02= 12.49

EMISSION RATE = (ppm CO) (9190) (0.7263E-07) [20.9/(20.9 - %02)]

CORRECTED RESULTS

243.4 ppm CO

0.404 lb/MMBtu

Corrected Conc. = Cma($\bar{C}$ - Co)/(Cm - Co)

Where: $\bar{C}$ = mean reference measurement
Co = mean zero calibration response
Cm = mean mid or upscale calibration gas response
Cma = actual mid or upscale calibration gas concentration

A-2 OXYGEN CALCULATIONS

CALCULATION OF AVERAGE OXYGEN CONCENTRATION

RUN: 1

SOURCE: F.J. GANNON STATION BOILER 5

TEST DATE: 4/7/00

GAS VALUE	INITIAL CAL	FINAL CAL	MEAN CAL
0.00 % Oxygen	0.06	0.23	0.15
11.96 % Oxygen	12.13	12.13	12.13

$\bar{C}$ = 13.52

CORRECTED RESULTS

13.3 % Oxygen

Corrected Conc. = $Cma(\bar{C} - Co)/(Cm - Co)$

Where: $\bar{C}$ = mean reference measurement
Co = mean zero calibration response
Cm = mean mid or upscale calibration gas response
Cma = actual mid or upscale calibration gas concentration

CALCULATION OF AVERAGE OXYGEN CONCENTRATION

RUN: 2

SOURCE: F.J. GANNON STATION BOILER 5

TEST DATE: 4/7/00

GAS VALUE	INITIAL CAL	FINAL CAL	MEAN CAL
0.00 % Oxygen	0.23	-1.35	-0.56
11.96 % Oxygen	12.13	11.93	12.03

$\bar{C}$ = 12.36

CORRECTED RESULTS

12.3 % Oxygen

Corrected Conc. = $Cma(\bar{C} - Co)/(Cm - Co)$

Where: $\bar{C}$ = mean reference measurement
Co = mean zero calibration response
Cm = mean mid or upscale calibration gas response
Cma = actual mid or upscale calibration gas concentration

CALCULATION OF AVERAGE OXYGEN CONCENTRATION

RUN: 3

SOURCE: F.J. GANNON STATION BOILER 5

TEST DATE: 4/7/00

GAS VALUE	INITIAL CAL	FINAL CAL	MEAN CAL
0.00 % Oxygen	-1.35	-0.11	-0.73
11.96 % Oxygen	11.93	12.05	11.99

$\bar{C}$ = 14.42

CORRECTED RESULTS

14.2 % Oxygen

Corrected Conc. = Cma($\bar{C}$ - Co)/(Cm - Co)

Where: $\bar{C}$ = mean reference measurement
Co = mean zero calibration response
Cm = mean mid or upscale calibration gas response
Cma = actual mid or upscale calibration gas concentration

B. UNCORRECTED REFERENCE METHOD DATA

F.J. GANNON BOILER 5 COMPLIANCE TEST 04-07-2000

TIME	CHAN 2 STACK %CO2	CHAN 1 STACK ppmSO2	CHAN 4 STACK ppmCO	CHAN 3 STACK %O2	STACK lb SO2 MM-BTU	STACK lb CO MM-BTU
09:24	14.28	889.3	128.3	13.08	1.861	0.378
09:25	14.31	891.9	169.4	13.11	1.862	0.322
09:26	14.30	890.4	114.5	13.18	1.857	0.220
09:27	14.27	883.1	125.6	13.18	1.849	0.241
09:28	14.35	885.6	171.6	13.11	1.847	0.327
09:29	14.52	896.3	177.5	13.25	1.845	0.346
09:30	14.55	897.5	287.2	13.17	1.843	0.552
09:31	14.58	901.3	151.4	13.42	1.848	0.301
09:32	14.44	895.2	181.2	13.35	1.852	0.357
09:33	14.46	899.0	134.3	13.46	1.858	0.268
09:34	14.45	897.9	88.7	13.47	1.857	0.177
09:35	14.31	886.3	134.0	13.58	1.850	0.272
09:36	14.19	879.2	192.1	13.52	1.851	0.389
09:37	14.25	881.8	160.5	13.52	1.849	0.324
09:38	14.14	875.1	112.8	13.47	1.850	0.225
09:39	14.17	873.6	88.1	13.51	1.842	0.177
09:40	14.27	877.8	69.7	13.51	1.838	0.140
09:41	14.22	870.2	64.8	13.48	1.829	0.129
09:42	14.17	871.6	95.5	13.53	1.839	0.192
09:43	14.23	879.2	67.2	13.41	1.846	0.133
09:44	14.12	870.8	62.2	13.48	1.843	0.124
09:45	14.16	872.1	72.6	13.44	1.841	0.145
09:46	14.12	868.0	116.5	13.45	1.836	0.232
09:47	14.21	873.8	94.6	13.33	1.838	0.185
09:48	14.11	869.6	94.9	13.41	1.841	0.188
09:49	14.22	875.1	87.7	13.33	1.839	0.172
09:50	14.26	877.4	91.7	13.56	1.838	0.186
09:51	14.24	877.1	114.5	13.40	1.840	0.227
09:52	14.16	870.7	74.0	13.52	1.838	0.149
09:53	14.17	870.2	104.7	13.45	1.835	0.208
09:54	14.15	868.4	87.1	13.56	1.834	0.176
09:55	14.25	877.1	66.8	13.56	1.839	0.135
09:56	14.20	872.9	58.0	13.63	1.837	0.119
09:57	14.05	865.8	55.1	13.56	1.841	0.112
09:58	14.06	864.3	64.9	13.69	1.837	0.134
09:59	14.15	870.2	90.5	13.62	1.837	0.185
10:00	14.18	870.6	84.8	13.62	1.834	0.174
10:01	14.21	872.7	63.0	13.72	1.836	0.130
10:02	14.18	871.0	65.5	13.64	1.835	0.134
10:03	14.15	869.0	76.6	13.67	1.835	0.157
10:04	14.27	876.7	96.6	13.63	1.836	0.197
10:05	14.27	876.2	87.7	13.73	1.835	0.182
10:06	14.32	880.3	133.6	13.76	1.837	0.278
10:07	14.36	881.4	154.6	13.64	1.834	0.316
10:08	14.33	880.9	132.1	13.70	1.836	0.273
10:09	14.46	891.4	84.5	13.74	1.842	0.175
10:10	14.33	881.3	103.8	13.71	1.837	0.214
10:11	14.44	889.8	71.1	13.79	1.841	0.148
10:12	14.40	884.9	127.5	13.51	1.836	0.256
10:13	14.45	892.6	109.8	13.53	1.846	0.221
10:14	14.44	894.6	107.6	13.51	1.851	0.216
10:15	14.28	885.5	129.0	13.52	1.853	0.259
10:16	14.42	894.3	81.9	13.49	1.853	0.164
10:17	14.43	895.1	110.8	13.64	1.853	0.226
10:18	14.53	901.8	115.7	13.54	1.855	0.233

F.J. GANNON BOILER 5 COMPLIANCE TEST 04-07-2000

TIME	CHAN 2 STACK %CO2	CHAN 1 STACK ppmSO2	CHAN 4 STACK ppmCO	CHAN 3 STACK %O2	STACK lb SO2 MM-BTU	STACK lb CO MM-BTU
10:19	14.48	900.7	117.0	13.87	1.858	0.248
10:20	14.46	897.0	199.4	13.79	1.854	0.418
10:21	14.44	894.2	91.6	13.80	1.850	0.192
10:22	14.49	896.3	163.4	13.77	1.848	0.339
10:23	14.48	893.9	172.0	13.66	1.845	0.354

AVERAGE VALUES FOR THE LAST HOUR: 60 MINUTES OF VALID DATA

10:23	14.30	882.3	113.3	13.52	1.844	0.228

COMMENTS: END RUN ONE

F.J. GANNON BOILER 5 COMPLIANCE TEST 04-07-2000

TIME	CHAN 2 STACK %CO2	CHAN 1 STACK ppmSO2	CHAN 4 STACK ppmCO	CHAN 3 STACK %O2	STACK lb SO2 MM-BTU	STACK lb CO MM-BTU
10:57	14.67	913.2	227.1	11.73	1.860	0.368
10:58	14.65	907.9	344.9	11.68	1.852	0.556
10:59	14.75	915.0	376.9	11.88	1.854	0.619
11:00	14.73	915.9	211.1	11.82	1.858	0.345
11:01	14.61	906.5	267.7	11.94	1.854	0.444
11:02	14.63	910.2	471.5	11.85	1.859	0.774
11:03	14.68	917.2	314.3	11.93	1.866	0.521
11:04	14.71	918.3	201.6	12.26	1.865	0.345
11:05	14.61	907.4	100.6	12.24	1.855	0.173
11:06	14.35	885.9	111.0	12.35	1.844	0.193
11:07	14.29	881.8	206.2	12.20	1.844	0.352
11:08	14.24	881.1	149.7	12.55	1.849	0.266
11:09	14.24	882.2	229.2	12.28	1.851	0.394
11:10	14.30	888.9	327.7	12.11	1.857	0.553
11:11	14.33	895.2	431.5	12.09	1.866	0.727
11:12	14.49	911.6	483.7	12.10	1.880	0.816
11:13	14.53	919.4	324.3	12.05	1.891	0.544
11:14	14.59	920.2	187.8	12.14	1.883	0.318
11:15	14.62	916.8	118.7	12.18	1.874	0.202
11:16	14.47	902.9	146.6	12.09	1.864	0.247
11:17	14.42	899.0	183.7	11.83	1.863	0.301
11:18	14.40	900.4	145.1	12.01	1.868	0.242
11:19	14.38	897.0	97.5	12.13	1.864	0.165
11:20	14.31	891.8	102.4	12.25	1.862	0.176
11:21	14.31	891.8	119.0	12.16	1.862	0.202
11:22	14.30	893.5	98.2	11.93	1.867	0.162
11:23	14.32	889.5	120.6	12.06	1.856	0.203
11:24	14.36	888.5	98.1	12.19	1.849	0.167
11:25	14.27	884.0	133.3	12.25	1.851	0.229
11:26	14.25	883.2	123.0	12.24	1.852	0.211
11:27	14.21	882.5	84.7	12.41	1.856	0.148
11:28	14.14	876.0	126.2	12.36	1.851	0.220
11:29	14.14	874.5	173.2	12.37	1.848	0.302
11:30	14.22	879.9	96.3	12.46	1.849	0.169
11:31	14.30	879.2	106.9	12.39	1.837	0.187
11:32	14.26	875.4	90.4	12.43	1.834	0.159
11:33	14.25	875.0	120.0	12.45	1.835	0.211
11:34	14.20	871.5	96.5	12.63	1.834	0.173
11:35	14.23	873.0	75.2	12.56	1.833	0.134
11:36	14.20	868.6	78.9	12.63	1.828	0.142
11:37	14.27	872.8	109.9	12.71	1.828	0.200
11:38	14.26	873.2	94.9	12.85	1.830	0.175
11:39	14.30	876.0	94.1	12.56	1.830	0.168
11:40	14.33	876.1	72.6	12.69	1.827	0.131
11:41	14.31	875.6	162.7	12.75	1.828	0.296
11:42	14.28	875.5	95.4	12.67	1.833	0.172
11:43	14.26	873.2	95.1	12.85	1.830	0.177
11:44	14.22	872.3	106.1	12.80	1.833	0.195
11:45	14.18	868.0	118.2	12.78	1.829	0.216
11:46	14.21	869.1	80.6	12.85	1.828	0.149
11:47	14.27	872.7	81.7	12.60	1.828	0.146
11:48	14.32	875.8	76.8	12.57	1.827	0.137
11:49	14.32	874.8	96.9	12.57	1.825	0.173
11:50	14.29	874.1	72.5	12.63	1.828	0.130
11:51	14.20	870.0	64.4	12.90	1.830	0.119

F.J. GANNON BOILER 5 COMPLIANCE TEST 04-07-2000

	CHAN 2	CHAN 1	CHAN 4	CHAN 3	STACK	STACK
	STACK	STACK	STACK	STACK	lb SO2	lb CO
TIME	%CO2	ppmSO2	ppmCO	%O2	MM-BTU	MM-BTU
11:52	14.22	870.3	86.4	12.60	1.829	0.155
11:53	14.22	870.8	62.0	12.74	1.830	0.113
11:54	14.29	877.3	75.8	12.82	1.835	0.139
11:55	14.22	871.6	69.4	12.86	1.832	0.128
11:56	14.18	865.5	70.8	12.80	1.824	0.130

AVERAGE VALUES FOR THE LAST HOUR: 60 MINUTES OF VALID DATA

11:56	14.35	887.1	154.8	12.36	1.847	0.265

COMMENTS: END RUN TWO

F J CANNON BOILER 5 COMPLIANCE TEST 04-07-2000

TIME	CHAN 2 STACK %CO2	CHAN 1 STACK ppmSO2	CHAN 4 STACK ppmCO	CHAN 3 STACK %O2	STACK lb SO2 MM-BTU	STACK lb CO MM-BTU
12:26	14.20	872.2	92.5	12.34	1.835	0.160
12:27	14.41	885.2	281.1	12.39	1.836	0.489
12:28	14.55	897.5	146.4	12.48	1.843	0.259
12:29	14.43	890.0	125.1	12.40	1.843	0.218
12:30	14.34	884.6	177.6	12.62	1.843	0.319
12:31	14.43	890.9	85.9	12.57	1.845	0.153
12:32	14.29	880.0	180.4	12.51	1.840	0.319
12:33	14.40	888.4	183.4	12.56	1.844	0.327
12:34	14.42	892.2	159.5	12.69	1.848	0.289
12:35	14.45	891.5	181.1	12.67	1.844	0.327
12:36	14.46	891.3	128.2	12.72	1.841	0.233
12:37	14.43	889.8	105.8	12.69	1.843	0.191
12:38	14.33	884.7	134.4	12.65	1.844	0.242
12:39	14.34	884.8	174.1	12.74	1.844	0.316
12:40	14.46	894.7	206.8	12.61	1.849	0.373
12:41	14.40	891.7	270.8	12.57	1.850	0.478
12:42	14.25	884.5	331.0	12.76	1.855	0.600
12:43	14.45	898.6	362.8	12.54	1.858	0.646
12:44	14.37	890.8	257.5	12.56	1.852	0.460
12:45	14.45	900.1	236.1	12.74	1.861	0.428
12:46	14.51	899.0	285.1	12.55	1.851	0.507
12:47	14.37	890.4	175.3	12.75	1.852	0.320
12:48	14.40	892.1	363.9	12.57	1.851	0.650
12:49	14.44	894.1	274.2	12.63	1.851	0.491
12:50	14.40	894.3	368.4	12.61	1.856	0.659
12:51	14.50	902.4	263.7	12.62	1.860	0.473
12:52	14.53	901.7	172.3	12.68	1.854	0.311
12:53	14.57	902.3	117.2	12.59	1.850	0.210
12:54	14.56	898.8	320.3	12.30	1.844	0.555
12:55	14.48	898.5	302.2	12.40	1.854	0.529
12:56	14.50	903.0	273.6	12.42	1.860	0.479
12:57	14.55	902.7	330.8	12.52	1.853	0.585
12:58	14.52	900.7	187.6	12.60	1.853	0.335
12:59	14.41	891.4	254.5	12.52	1.848	0.451
13:00	14.41	891.2	224.8	12.64	1.848	0.405
13:01	14.45	896.7	239.3	12.30	1.854	0.415
13:02	14.47	895.7	412.2	12.24	1.850	0.709
13:03	14.59	903.4	141.0	12.39	1.850	0.245
13:04	14.47	897.1	113.2	12.30	1.852	0.195
13:05	14.35	885.9	106.0	12.51	1.845	0.188
13:06	14.35	886.5	101.8	12.34	1.846	0.176
13:07	14.33	883.7	100.5	12.50	1.843	0.178
13:08	14.32	884.5	326.8	12.34	1.846	0.570
13:09	14.42	894.4	285.7	12.42	1.853	0.504
13:10	14.45	899.0	348.4	12.18	1.859	0.594
13:11	14.47	901.2	328.6	12.29	1.861	0.567
13:12	14.58	908.7	186.5	12.32	1.862	0.323
13:13	14.53	901.7	302.1	12.25	1.854	0.518
13:14	14.45	897.2	174.3	12.30	1.855	0.301
13:15	14.42	895.8	375.7	12.42	1.856	0.656
13:16	14.41	895.3	332.2	12.26	1.856	0.570
13:17	14.29	890.0	354.6	12.41	1.861	0.620
13:18	14.50	905.6	233.9	12.46	1.867	0.409
13:19	14.52	901.7	271.7	12.39	1.855	0.478
13:20	14.37	889.9	208.5	12.39	1.851	0.363

T.J. GANNON BOILER 5 COMPLIANCE TEST 04-07-2000

TIME	CHAN 2 STACK %CO2	CHAN 1 STACK ppmSO2	CHAN 4 STACK ppmCO	CHAN 3 STACK %O2	STACK lb SO2 MM-BTU	STACK lb CO MM-BTU
13:21	14.27	884.5	368.4	12.52	1.851	0.651
13:22	14.28	889.0	419.0	12.40	1.861	0.734
13:23	14.23	888.6	252.7	12.58	1.865	0.449
13:24	14.37	898.8	290.1	12.54	1.869	0.517
13:25	14.31	891.7	191.6	12.41	1.862	0.335

AVERAGE VALUES FOR THE LAST HOUR: 60 MINUTES OF VALID DATA

13:25	14.42	893.5	236.7	12.49	1.851	0.417

COMMENTS: END RUN THREE

C. BOILER OPERATIONAL DATA

F. J. GANNON GENERATING STATION HEAT INPUT CALCULATIONS

F. J. GANNON STATION BOILER NO. 5 ANNUAL COMPLIANCE TEST April 7 & 8, 2000	
March Gross Heat Rate =	9.478 X10^6 Btu/MWH
BOILER NO. 5 SOURCE TEST HEAT INPUT CALCULATIONS	
Final MWH (781099) - Initial MWH(780183) =	916 MWH
Time =	4.17 Hours
Average MW = 916MWH) 4.17 H =	219.7 MW
9.478X 10^6 Btu/MWH X 916 MWH)4.17 H =	2082 X 10^6 MMBtu/H

COMPLIANCE TEST DATA
F. J. GANNON STATION

BOILER NO. 5 TEST DATE April 7, 2000

UNIT LOAD (MW) 215 MW

BASE LOADED (TIME) 1900

TEST DATA

MEGAWATTS INTEGRATOR				INITIALS
BEGIN MWH	780183	BEGIN SAMPLING	2058	EB
END MWH	781099	END SAMPLING	0108	EB

SOOTBLOWING

RUN	BEGIN TIME	END TIME	INITIALS
1SB	2058	2206	EB/
2SB	2234	2339	EB/
3SB	0004		EB/

FLYASH REINJECTION

RUN	REINJECTION (Y/N)	% REINJECTION	INITIALS
1SB	yes	100%	EB/ WK
2SB	yes	100%	EB/ WK
3SB	yes	100%	EB/ WK

MCD\COMPFORM.WP

D. FUEL ANALYSIS

TECO
TAMPA ELECTRIC

Corporate Environmental Laboratory Services

5012 Causeway Blvd · Tampa Fl. 33619 · Ph (813)630-7378 · Fax (813)630-7360 · CompQAP #910140G · DOH #E54272

Tuesday, April 25, 2000

Report For: David Smith, Air Programs, CES

Sample Information

Sample ID: **AA54325**
Location Code: GN-STK-5
Location Description: Gannon, Stack Test - Unit 5

Lab Submittal Date: 04/10/2000
Sample Collection Date: 04/08/2000
Sample Collector: R.DECECIO

Laboratory Results

Coal Analysis - As Received	Result	Units	Lower Limit	Upper Limit	Violation
Ash, as Received	8.63	%			
BTU, as Received	12691	BTU/Lb			
Sulfur, as Received	1.15	%			

Coal Analysis - Dry Basis	Result	Units	Lower Limit	Upper Limit	Violation
Ash, Dry Basis	9.24	%			
BTU, Dry Basis	13583	BTU/Lb.			
Sulfur, Dry Basis	1.23	%			

Coal Analysis - Miscellaneous	Result	Units	Lower Limit	Upper Limit	Violation
BTU, Moisture-Ash Free	14966	BTU/Lb.			
Pounds SO2 / Million BTU	1.72	Lbs. SO2/MMBTU		2.4	
Total Moisture	6.57	%			

Comments:

Gannon ID# S-6488
Quality Control Values of Knowns
Sulfur
ID:NIST 2683 b True Value: 1.88 % CES Value: 1.86%
BTU
ID:AR 1722 True Value: 14667BTU/ Lb+/-70 CES Value: 14616 Lbs./BTU

TAMPA ELECTRIC
A TECO ENERGY COMPANY

CORPORATE ENVIRONMENTAL SERVICES
ANALYSIS REQUEST & CHAIN OF CUSTODY

5012 CAUSEWAY BLVD.
TAMPA, FLORIDA 33619
PHONE: 813/228-4111

☐ AIR LAB
☑ FUEL LAB
☐ WATER LAB

CLIENT NAME	TELEPHONE
CINDY BARRINGER	35-397

SAMPLER(S) NAME(S): Ron Di Cocco

PAGE ___ OF ___

☐ STANDARD TAT
☐ RUSH TAT

SAMPLING DATE	SAMPLING TIME	SAMPLING IDENTIFICATION	MATRIX TYPE	COAL SAMPLE	MATRIX TYPE	MATRIX TYPE	60 Mesh Residual Moisture ASTM D 3173	Total Moisture ASTM D 3302	Percent Sulfur ASTM D 4239	BTU ASTM 240	COMMENTS
4-8-00	1100	#5 UNIT STACK TEST S-6488 (GANNON)		✓							

NUMBER OF CONTAINERS SUBMITTED

RELINQUISHED BY: (SIGNATURE)	DATE	TIME	RECEIVED BY: (SIGNATURE)	DATE	TIME
Larry Kauleisen	4/10/00	8:07	Elena Buitia	4/10/00	8:07
Elena Buitia	4/10/00	1:15	David A Smith	4/10/00	1:15
Brian Rodgy	4/10/00	1520	Cristina Stefanovic	04/10/00	15:20

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E. TCEMS CALIBRATION DATA

E-1 INITIAL/FINAL TCEMS CALIBRATIONS

E-2 SYSTEM BIAS TESTS

E-3 SYSTEM BIAS AND DRIFT CALCULATIONS

E-1 INITIAL/FINAL TCEMS CALIBRATIONS

CALIBRATION SUMMARY

SOURCE: F.J. GANNON BOILER 5 COMPLIANCE TEST

REASON: INITIAL DAILY CAL

DATE : 04-07-2000 TIME: 20:50 - 21:18

A/D CHAN	MONITOR DESCRIPTION	UNITS	GAS VALUE	MONITOR RESPONSE
2	STACK	%CO2	0.00	0.14
2	STACK	%CO2	9.97	10.04
2	STACK	%CO2	17.95	17.93
1	STACK	ppmSO2	0.0	5.9
1	STACK	ppmSO2	693.4	668.2
1	STACK	ppmSO2	1239.0	1234.3
4	STACK	ppmCO	0.0	3.3
4	STACK	ppmCO	150.0	146.0
4	STACK	ppmCO	301.2	304.3
3	STACK	%O2	0.00	0.06
3	STACK	%O2	11.96	12.13
3	STACK	%O2	20.90	20.93

CONTINUOUS EMISSIONS MONITORING SET-UP

SOURCE: F.J. GANNON BOILER 5 COMPLIANCE TEST

DATE: 04-07-2000 TIME: 21:22

A/D CHAN	DESCRIP	UNITS	SPAN	INPUT VOLTAGE	ZERO OFFSET
2	STACK	%CO2	20	5.00 V	20%
1	STACK	ppmSO2	1350	10.00 V	0%
4	STACK	ppmCO	500	1.00 V	0%
3	STACK	%O2	25	1.00 V	0%

AVERAGING PERIODS: ONE HOUR,

EMISSION RATE 1: lb SO2/MMBTU STACK

E = (ppm SO2) (1800) (0.1660E-06) (100/%CO2)

ppm SO2 from A/D Channel 1
%CO2 from A/D Channel 2

EMISSION RATE 2: lb CO /MMBTU STACK

E = (ppm CO) (9780) (0.7263E-07) [20.9/(20.9 - %O2)]

ppm CO from A/D Channel 4
%O2 from A/D Channel 3

E-2 SYSTEM BIAS TESTS

CALIBRATION SUMMARY

SOURCE: F.J. GANNON BOILER 5 COMPLIANCE TEST

REASON: RUN ONE BIAS CAL

DATE : 04-07-2000 TIME: 10:27 - 10:37

A/D CHAN	MONITOR DESCRIPTION	UNITS	GAS VALUE	MONITOR RESPONSE
2	STACK	%CO2	0.00	0.20
2	STACK	%CO2	9.97	9.85
1	STACK	ppmSO2	0.0	7.2
1	STACK	ppmSO2	693.4	680.4
4	STACK	ppmCO	0.0	2.2
4	STACK	ppmCO	150.0	142.2
3	STACK	%O2	0.00	0.23
3	STACK	%O2	11.96	12.13

CALIBRATION SUMMARY

SOURCE: F.J. GANNON BOILER 5 COMPLIANCE TEST

REASON: RUN TWO BIAS CAL

DATE : 04-07-2000 TIME: 11:56 - 12:07

A/D CHAN	MONITOR DESCRIPTION	UNITS	GAS VALUE	MONITOR RESPONSE
2	STACK	%CO2	0.00	0.12
2	STACK	%CO2	9.97	9.76
1	STACK	ppmSO2	0.0	5.9
1	STACK	ppmSO2	693.4	686.5
4	STACK	ppmCO	0.0	1.8
4	STACK	ppmCO	150.0	150.2
3	STACK	%O2	0.00	-1.35
3	STACK	%O2	11.96	11.93

CALIBRATION SUMMARY

SOURCE: F.J. GANNON BOILER 5 COMPLIANCE TEST

REASON: RUN THREE BIAS CAL

DATE : 04-07-2000 TIME: 13:27 - 13:38

A/D CHAN	MONITOR DESCRIPTION	UNITS	GAS VALUE	MONITOR RESPONSE
2	STACK	%CO2	0.00	0.15
2	STACK	%CO2	9.97	9.79
1	STACK	ppmSO2	0.0	7.3
1	STACK	ppmSO2	693.4	692.9
4	STACK	ppmCO	0.0	2.2
4	STACK	ppmCO	150.0	143.1
3	STACK	%O2	0.00	-0.11
3	STACK	%O2	11.96	12.05

E-3 SYSTEM BIAS AND DRIFT CALCULATIONS

SYSTEM CALIBRATION BIAS AND DRIFT CALCULATIONS

SOURCE: F.J. GANNON STATION BOILER 5

TEST DATE: 4/7/00

RUN NUMBER: 1

SPAN VALUE: 500 ppm CO

	------INITIAL VALUES------			------FINAL VALUES------		
	ANALYZER CAL. RESPONSE	SYSTEM CAL. RESPONSE	SYSTEM CAL. BIAS (% OF SPAN)	SYSTEM CAL. RESPONSE	SYSTEM CAL. BIAS (% OF SPAN)	DRIFT (% OF SPAN)
CO ZERO GAS	3.30	3.30	0.00	2.20	-0.22	-0.22
CO UP-SCALE	146.00	146.00	0.00	142.20	-0.76	-0.76

$$\text{SYSTEM CAL. BIAS} = \frac{\text{SYSTEM CAL. RESPONSE - ANALYZER CAL. RESPONSE}}{\text{SPAN}} \text{ X 100}$$

$$\text{DRIFT} = \frac{\text{FINAL SYSTEM CAL. RESPONSE - INITIAL CAL. RESPONSE}}{\text{SPAN}} \text{ X 100}$$

SYSTEM CALIBRATION BIAS AND DRIFT CALCULATIONS

SOURCE: F.J. GANNON STATION BOILER 5

TEST DATE: 4/7/00

RUN NUMBER: 1

SPAN VALUE: 25 % Oxygen

	------INITIAL VALUES------			------FINAL VALUES------		
	ANALYZER CAL. RESPONSE	SYSTEM CAL. RESPONSE	SYSTEM CAL. BIAS (% OF SPAN)	SYSTEM CAL. RESPONSE	SYSTEM CAL. BIAS (% OF SPAN)	DRIFT (% OF SPAN)
O2 ZERO GAS	0.06	0.06	0.00	0.23	0.68	0.68
O2 UP-SCALE	12.13	12.13	0.00	12.13	0.00	0.00

$$\text{SYSTEM CAL. BIAS} = \frac{\text{SYSTEM CAL. RESPONSE - ANALYZER CAL. RESPONSE}}{\text{SPAN}} \text{ X 100}$$

$$\text{DRIFT} = \frac{\text{FINAL SYSTEM CAL. RESPONSE - INITIAL CAL. RESPONSE}}{\text{SPAN}} \text{ X 100}$$

SYSTEM CALIBRATION BIAS AND DRIFT CALCULATIONS

SOURCE: F.J. GANNON STATION BOILER 5

TEST DATE: 4/7/00

RUN NUMBER: 2

SPAN VALUE: 500 ppm CO

	------INITIAL VALUES------			------FINAL VALUES------		
	ANALYZER CAL. RESPONSE	SYSTEM CAL. RESPONSE	SYSTEM CAL. BIAS (% OF SPAN)	SYSTEM CAL. RESPONSE	SYSTEM CAL. BIAS (% OF SPAN)	DRIFT (% OF SPAN)
CO ZERO GAS	3.30	2.20	-0.22	1.80	-0.30	-0.08
CO UP-SCALE	146.00	142.20	-0.76	150.20	0.84	1.60

$$\text{SYSTEM CAL. BIAS} = \frac{\text{SYSTEM CAL. RESPONSE - ANALYZER CAL. RESPONSE}}{\text{SPAN}} \times 100$$

$$\text{DRIFT} = \frac{\text{FINAL SYSTEM CAL. RESPONSE - INITIAL CAL. RESPONSE}}{\text{SPAN}} \times 100$$

SYSTEM CALIBRATION BIAS AND DRIFT CALCULATIONS

SOURCE: F.J. GANNON STATION BOILER 5

TEST DATE: 4/7/00

RUN NUMBER: 2

SPAN VALUE: 25 % Oxygen

	------INITIAL VALUES------			------FINAL VALUES------		
	ANALYZER CAL. RESPONSE	SYSTEM CAL. RESPONSE	SYSTEM CAL. BIAS (% OF SPAN)	SYSTEM CAL. RESPONSE	SYSTEM CAL. BIAS (% OF SPAN)	DRIFT (% OF SPAN)
O2 ZERO GAS	0.06	0.23	0.68	-1.35	-5.64	-6.32
O2 UP-SCALE	12.13	12.13	0.00	11.93	-0.80	-0.80

$$\text{SYSTEM CAL. BIAS} = \frac{\text{SYSTEM CAL. RESPONSE - ANALYZER CAL. RESPONSE}}{\text{SPAN}} \times 100$$

$$\text{DRIFT} = \frac{\text{FINAL SYSTEM CAL. RESPONSE - INITIAL CAL. RESPONSE}}{\text{SPAN}} \times 100$$

SYSTEM CALIBRATION BIAS AND DRIFT CALCULATIONS

SOURCE: F.J. GANNON STATION BOILER 5

TEST DATE: 4/7/00

RUN NUMBER: 3

SPAN VALUE: 500 ppm CO

	INITIAL VALUES			FINAL VALUES		
	ANALYZER CAL. RESPONSE	SYSTEM CAL. RESPONSE	SYSTEM CAL. BIAS (% OF SPAN)	SYSTEM CAL. RESPONSE	SYSTEM CAL. BIAS (% OF SPAN)	DRIFT (% OF SPAN)
CO ZERO GAS	3.30	1.80	-0.30	2.20	-0.22	0.08
CO UP-SCALE	146.00	150.20	0.84	143.10	-0.58	-1.42

$$\text{SYSTEM CAL. BIAS} = \frac{\text{SYSTEM CAL. RESPONSE - ANALYZER CAL. RESPONSE}}{\text{SPAN}} \times 100$$

$$\text{DRIFT} = \frac{\text{FINAL SYSTEM CAL. RESPONSE - INITIAL CAL. RESPONSE}}{\text{SPAN}} \times 100$$

SYSTEM CALIBRATION BIAS AND DRIFT CALCULATIONS

SOURCE: F.J. GANNON STATION BOILER 5

TEST DATE: 4/7/00

RUN NUMBER: 3

SPAN VALUE: 25 % Oxygen

	------INITIAL VALUES------			------FINAL VALUES------		
	ANALYZER CAL. RESPONSE	SYSTEM CAL. RESPONSE	SYSTEM CAL. BIAS (% OF SPAN)	SYSTEM CAL. RESPONSE	SYSTEM CAL. BIAS (% OF SPAN)	DRIFT (% OF SPAN)
O2 ZERO GAS	0.06	-1.35	-5.64	-0.11	-0.68	4.96
O2 UP-SCALE	12.13	11.93	-0.80	12.05	-0.32	0.48

$$\text{SYSTEM CAL. BIAS} = \frac{\text{SYSTEM CAL. RESPONSE - ANALYZER CAL. RESPONSE}}{\text{SPAN}} \times 100$$

$$\text{DRIFT} = \frac{\text{FINAL SYSTEM CAL. RESPONSE - INITIAL CAL. RESPONSE}}{\text{SPAN}} \times 100$$

F. CALIBRATION GAS CERTIFICATES OF ANALYSIS

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RATA CLASS

Dual-Analyzed Calibration Standard

Scott Specialty Gases

1750 EAST CLUB BLVD,DURHAM,NC 27704

Phone: 919-220-0803 Fax: 919-220-0808

CERTIFICATE OF ACCURACY: EPA Protocol Gas

Assay Laboratory

SCOTT SPECIALTY GASES
1750 EAST CLUB BLVD
DURHAM,NC 27704

P.O. No.: N31923
Project No.: 12-33126-001

Customer

TAMPA ELECTRIC CO
RAY MCDARBY
5010 CAUSEWAY BLVD
TAMPA FL 33619

ANALYTICAL INFORMATION

This certification was performed according to EPA Traceability Protocol For Assay & Certification of Gaseous Calibration Standards; Procedure #G1; September, 1997.

Cylinder Number: ALM020393 **Certification Date:** 3/11/99 **Exp. Date:** 3/11/2002
Cylinder Pressure*:** 2015 PSIG

COMPONENT	CERTIFIED CONCENTRATION	ANALYTICAL ACCURACY**	TRACEABILITY
OXYGEN	11.96 %	+/- 1%	NIST
NITROGEN	BALANCE		

*** Do not use when cylinder pressure is below 150 psig.

** Analytical accuracy is inclusive of usual known error sources which at least include precision of the measurement processes.
Product certified as +/- 1% analytical accuracy is directly traceable to NIST standards.

REFERENCE STANDARD

TYPE/SRM NO.	EXPIRATION DATE	CYLINDER NUMBER	CONCENTRATION	COMPONENT
NTRM 2658	1/02/01	ALM031884	9.680 %	OXYGEN

INSTRUMENTATION

INSTRUMENT/MODEL/SERIAL#	DATE LAST CALIBRATED	ANALYTICAL PRINCIPLE
VARIAN/3400/16804-02	02/22/99	GC / TCD

ANALYZER READINGS

(Z = Zero Gas R = Reference Gas T = Test Gas r = Correlation Coefficient)

First Triad Analysis / **Second Triad Analysis** / **Calibration Curve**

OXYGEN

First Triad Analysis:

Date: 03/11/99	Response Unit: AREA	
Z1 = 0.0000	R1 = 247696	T1 = 306452
R2 = 248148	Z2 = 0.0000	T2 = 306564
Z3 = 0.0000	T3 = 306567	R3 = 248251
Avg. Concentration:	11.96 %	

Calibration Curve:

Concentration = A + Bx + Cx2 + Dx3 + Ex4
r = 0.99999

Constants:	A = 0.00
B = 1.00	C = 0.00
D = 0.00	E = 0.00

Special Notes:

APPROVED BY: B. M. Becton
B.M. BECTON

Scott Specialty Gases

Shipped From: 1750 EAST CLUB BLVD
DURHAM NC 27704
Phone: 919-220-0803 Fax: 919-220-0808

CERTIFICATE OF ANALYSIS

TAMPA ELECTRIC CO
RAY MCDARBY
5010 CAUSEWAY BLVD

TAMPA FL 33619

PROJECT #: 12-32332-003
PO#: E-N31293
ITEM #: 1202RCOC AL
DATE: 1/29/99

CYLINDER #: ALM007103
FILL PRESSURE: 1046 PSIG

ANALYTICAL ACCURACY: +/- 1%
PRODUCT EXPIRATION: 1/29/2002

RECERTIFICATION

COMPONENT	ANALYSIS
CARBON MONOXIDE	150.0 PPM
NITROGEN	BALANCE

ANALYST: B.M. Becton
B.M. BECTON

CCS MHTC Y

Scott Specialty Gases

1750 EAST CLUB BLVD,DURHAM,NC 27704 Phone: 919-220-0803 Fax: 919-220-0808

CERTIFICATE OF ANALYSIS: Interference-Free™ EPA Protocol Gas

Customer	Assay Laboratory	
TAMPA ELECTRIC CO		Project No.: 12-29539-001
	SCOTT SPECIALTY GASES	P.O. No.: E-N31293
5010 CAUSEWAY BLVD	1750 EAST CLUB BLVD	
	DURHAM,NC 27704	
TAMPA,FL 33619		

ANALYTICAL INFORMATION

This certification was performed according to EPA Traceability Protocol For Assay & Certification of Gaseous Calibration Standards; Procedure #G1; September, 1993.

Cylinder Number: ALM065138 **Certification Date:** 7/17/98 **Exp. Date:** 7/17/2001
Cylinder Pressure*:** 1818 PSIG

COMPONENT	CERTIFIED CONCENTRATION		ANALYTICAL ACCURACY**
CARBON MONOXIDE	301.2	PPM	+/- 1% NIST Traceable
NITROGEN		BALANCE	

*** Do not use when cylinder pressure is below 150 psig.

** Analytical accuracy is inclusive of usual known error sources which at least include precision of the measurement processes. Product certified as +/- 1% analytical accuracy is directly traceable to NIST standards.

REFERENCE STANDARD

TYPE/SRM NO.	EXPIRATION DATE	CYLINDER NUMBER	CONCENTRATION	COMPONENT
NTRM2636	1/08/01	ALM034285	244.2 PPM	CO/N2

INSTRUMENTATION

INSTRUMENT/MODEL/SERIAL#	LAST DATE CALIBRATED	ANALYTICAL PRINCIPLE
FTIR System/8220/AAB9400252	06/18/98	Scott Enhanced FTIR

ANALYZER READINGS

(Z=Zero Gas R=Reference Gas T=Test Gas r=Correlation Coefficient)

First Triad Analysis **Second Triad Analysis** **Calibration Curve**

CARBON MONOXIDE

Date: 07/10/98	Response Unit: PPM	
Z1=0.0495	R1=243.81	T1=300.89
R2=244.34	Z2=0.0524	T2=301.39
Z3=0.0735	T3=301.15	R3=244.44
Avg. Concentration:	301.1	PPM

Date: 07/17/98	Response Unit: PPM	
Z1=0.0187	R1=244.11	T1=301.40
R2=244.09	Z2=0.0229	T2=301.12
Z3=-0.014	T3=301.46	R3=244.40
Avg. Concentration:	301.3	PPM

Concentration=A+Bx+Cx2+Dx3+Ex4	
r=0.999990	
Constants:	A=0.000000
B=1.000000	C=0.000000
D=0.000000	E=0.000000

Special Notes:

ANALYST: B. M. Becton
B.M. Becton

G. TEST PARTICIPANTS

TEST PARTICIPANTS

Corporate Environmental Services

Robert Barthelette, Jr	Environmental Technician
Craig Coronado	Environmental Technician
David Smith	Sr. Environmental Technician
Tom Toombs	Environmental Technician

F. J. Gannon Generating Station

Elena Beitia	Operations Engineer

Question 6.a. Attachments

Date: 7/28/00 5:25 PM
Sender: ALAN THELEN
To: DEBRA A LUKASIEWICZ
Priority: Normal
Subject: Re: Bayside - CO/VOC Catalyst Info Needs for Air Permit

----

Pls file under HRSG

Al

Forward Header

Subject: Re: Bayside - CO/VOC Catalyst Info Needs for Air Permit
Author: philip.a.stepczyk@us.abb.com at nxmime
Date: 7/10/00 10:35 AM

Alan,

I apologize for the delay in responding.

The total estimated cost for the six (6) CO/VOC catalysts is
Three Million Three
Hundred Thirty Five Thousand Dollars, ($3,335,000).

The total estimated cost for the six spool pieces to accommodate
the future
installation of the CO/VOC catalysts is Five Hundred Thousand
Dollars, ($
500,000).

With regards to the additional support steel to support future
expansion of the
SCR catalysts by two (2) rows, the estimated cost for six (6)
units is One
Hundred Thirty Eight Thousand Dollars, ($ 138,000)

We are continuing to work to obtain the balance of information
requested.

Regards,

Phil

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Table 4-2. Economic Cost Factors

Factor	Units	Value
Interest rate	%	7.0*
Control system life	Years	15
Oxidation catalyst life	Years	5
VOC control efficiency	%	50*
Electricity cost	$/kwh	0.030*
Labor costs (base rates)	$/hour	
Operator		22.00
Maintenance		22.00

* Per FDEP request.

Sources: ECT, 2000.
TEC, 2000.

Table 4-3. Capital Costs for Oxidation Catalyst System, Seven CTs

Item	Dollars		OAQPS Factor
Direct Costs			
Purchased equipment	4,474,120		A
Sales tax	268,447		0.06 x A
Freight	223,706		0.05 x A
Instrumentation	447,412		0.10 x A
Subtotal Purchased Equipment Cost	**5,413,685**		**B**
Installation			
Foundations and supports	433,095		0.08 x B
Handling and erection	757,916		0.14 x B
Electrical	216,547		0.04 x B
Piping	108,274		0.02 x B
Insulation for ductwork	54,137		0.01 x B
Painting	54,137		0.01 x B
Subtotal Installation Cost	**1,624,106**		
Subtotal Direct Costs	**7,037,791**		
Indirect Costs			
Engineering	541,369		0.10 x B
Construction and field expenses	270,684		0.05 x B
Contractor fees	541,369		0.10 x B
Startup	108,274		0.02 x B
Performance test	54,137		0.01 x B
Contingency	162,411		0.03 x B
Subtotal Indirect Costs	**1,678,242**		
TOTAL CAPITAL INVESTMENT	**8,716,033**	(TCI)	

Source: Alstom Power Inc., 2000.
ECT, 2000.
S&L, 2000.

Table 4-4. Annual Operating Costs for Oxidation Catalyst System, Seven CTs

Item	Dollars		Basis
Direct Costs			
Catalyst costs			
Replacement (materials and labor)	4,326,191		
Credit for used catalyst	(583,622)		15% credit
Subtotal Catalyst Costs	3,742,570		
Annualized Catalyst Costs	**912,778**		5 yr @ 7.0%
Energy Penalties			
Turbine backpressure	610,747		0.2% penalty
Subtotal Direct Costs	**1,523,525**	(TDC)	
Indirect Costs			
Administrative charges	174,321		0.02 x TCI
Property taxes	87,160		0.01 x TCI
Insurance	87,160		0.01 x TCI
Capital recovery	481,981		15 yr @ 7.0%
Subtotal Indirect Costs	**830,622**		
TOTAL ANNUAL COST	**2,354,147**		

Sources: Alstom Power Inc., 2000.
ECT, 2000.
S&L, 2000.
TEC, 2000.

Table 4-5. Summary of VOC BACT Analysis

Control Option	Emission Impacts: Emission Rates (lb/hr)	Emission Impacts: Emission Rates (tpy)	Emission Impacts: Emission Reduction (tpy)	Economic Impacts: Installed Capital Cost ($)	Economic Impacts: Total Annualized Cost ($/yr)	Economic Impacts: Cost Effectiveness Over Baseline ($/ton)	Energy Impacts: Increase Over Baseline (MMBtu/yr)	Environmental Impacts: Toxic Impact (Y/N)	Environmental Impacts: Adverse Envir. Impact (Y/N)
Oxidation catalyst	11.4	49.8	49.8	8,716,033	2,354,147	47,251	69,465	N	Y
Baseline	22.7	99.6	N/A	N/A	N/A	N/A	N/A	N/A	N/A

Basis: Seven GE PG7241 (FA) CTs, 100-percent load, natural gas-firing for 7,884 hr/yr, and fuel oil-firing for 876 hr/yr.

Sources: ECT, 2000.
GE, 2000.
TEC, 2000

Question 6.c. Attachment

Department of
Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

August 22, 2000

RECEIVED
AUG 28 2000
ENVIRONMENTAL AFFAIRS

Mr. Jamie Hunter
Tampa Electric Company
PO Box 111
Tampa, Florida 33601-0111

Re: Gannon/Bayside Station
New Fuel Oil Storage Tank

Dear Mr. Hunter:

We have reviewed your letters of July 27 and August 15 regarding installation of a new fuel oil storage tank at the Gannon Station. You requested concurrence that the installation did not require an air construction permit pursuant to the exemption criteria of Rule 62-210.300(3)(b)1, F.A.C. Pursuant to your description, the tank will have a nominal capacity of 8 million gallons and will be used to store new number 2 fuel oil to serve the existing requirements of the Gannon Station and the requirements of the future Bayside Station as the Gannon steam units are phased out of service. It will replace the existing 300,000 gallon fuel tank.

Given the facts presented in your letters, and evaluating this project as an isolated project, the Department agrees that no air construction permit is required for Tampa Electric Company to proceed with construction of this new fuel oil storage tank. As mentioned previously, emissions associated with the new tank will need to be evaluated during preconstruction review of the planned Bayside re-powering project. The change will also need to be reflected in the facility's Title V permit.

Please contact me at 850-921-9519 if you have any questions about the above.

Sincerely,

Joseph Kahn, P.E.
New Source Review Section

/jk

cc: Bill Thomas, P.E., DEP SWD
Jerry Campbell, Hillsborough County EPC

Question 10.b. Attachment

Attachment for Question 10.b.

TEC's draft startup schedule does not have a specific time period designated "shakedown", "commercial startup", or "initial power generation". TEC has listed below estimated dates that should provide the Department with the information requested.

Activity	**Bayside Unit 1**	**Bayside Unit 2**
Start of Construction	April 1, 2000	April 1, 2000
First Firing of a Unit's CT	March 16, 2003	March 14, 2004
Initial Performance Testing	With in 60 days of attainment of maximum production rate	Within 60 days of attainment of maximum production rate

Question 11.a. Attachment

Gail S. Dreggors
P. O. Box 111, Tampa, Florida 33601
(813) 228-4293
(813) 228-4811 (fax)

TECO Energy, Inc.

Fax

To:	Greg Nelson	From:	Gail S. Dreggors
Fax:	46881	Pages:	6
Phone:		Date:	10/18/00
Re:		CC:	

Urgent For Review Please Comment Please Reply Please Recycle

● Comments:

letters you requested

SHEILA M. MCDEVITT
VICE PRESIDENT-
GENERAL COUNSEL

April 26, 2000

Ms. Teri L. Donaldson, General Counsel
Florida Dept. of Environmental Protection
3900 Commonwealth Blvd.
MS #35
Tallahassee, Florida 32399-3000

Dear Ms. Donaldson:

I am in receipt of your letter dated April 20, 2000, and I appreciate your agreeing to allow us the flexibility requested with respect to the repowering of units at Gannon station. We will proceed as described in my communications to you.

I note that you have agreed to extend the date of determination of commercial viability of the zero ammonia NOx control technology through July, 2000. However, since Tampa Electric proceeded in the belief that May 1, 2000 was the deadline (not hearing to the contrary from you) we have provided the information that was available to us. I'm not sure what more information we can provide or what is expected of us. Therefore, I would hope someone from the Department would contact Greg Nelson or Patrick Shell in order to communicate any further expectations. In any event, performance by Tampa Electric is totally predicated upon the regulatory approval, and I attempted to communicate to you that it is unlikely that there will be such approval.

Accordingly, I would appreciate some rational discussion with respect to the other issues raised in the letter. I guess I must have been in a different meeting than you; but I believed that you had agreed to the $6 million dollar figure. As I am sure you are aware, Tampa Electric will have to install the SCR anyway in order to meet schedule and achieve environmental compliance.

Sincerely yours,

SMMcD/mlc
Cc: Spence Autry
Greg Nelson
Patrick Shell

TECO ENERGY, INC.
702 N. FRANKLIN ST. TAMPA, FL 33602
P.O. BOX 111 TAMPA, FL 33601-0111
813-228-1804 FAX 813-228-1328/228-4811
SMMCDEVITT@TECOENERGY.COM

Department of
Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

copy to:
Spence Autry
Chuck Black
Greg Nelson
4/20/00

April 20, 2000

Sheila M. McDeVitt — NO Title
702 N. Franklin Street
Tampa, Florida 33602

RE: TECO

Dear Mr. McDeVitt,

I write in reply to your letter of April 19, 2000. With regard to the repowering of Gannon, we are prepared to accept the approach described in paragraph 1 of your letter. Thank you for keeping us advised.

With regard to the zero ammonia control technology issue, we will extend determination of commercial viability through and including July, 2000. We cannot agree, however, to lower the potential expenditure from $8 million to $ 6 million. Thank you for providing to the Air Division the information referenced in paragraph 2 of your letter. As you may know, the Air Division received this information only two days ago. We will review it and contact you to discuss our concerns.

I hope this letter addresses your most immediate questions. We will contact you regarding the remaining issues at the earliest possible opportunity. Thank you for your patience.

Sincerely,

Teri L. Donaldson
General Counsel

TLD/yw

SHEILA M. MCDEVITT
VICE PRESIDENT-
GENERAL COUNSEL

April 19, 2000

Ms. Teri Donaldson, General Counsel
Florida Dept. of Environmental Protection
3900 Commonwealth Blvd.
MS #35
Tallahassee, Florida 32399-3000

Re: Tampa Electric Company
Consent Final Judgment

Dear Teri:

This letter again follows up on the letter and enclosures I forwarded to you on March 21, 2000 suggesting some conforming changes to the Consent Final Judgment relative to the Consent Decree entered into with the United States. Among those suggestions were two of significant to which I wish you would direct your attention.

1. As you know, we are attempting to meet the deadlines required by both the Consent Final Judgment and the Consent Decree with respect to the repowering of Gannon Station by 2003 and 2004. As I indicated in my letter to you of March 21, 2000, between the entry of the Consent Final Judgment and lodging the Consent Decree, the engineers have developed a more optimum scenario for repowering Gannon Station. In other words, Units 3, 4 & 5 at Gannon which are called out in the Consent Final Judgment are not the units which will be repowered. Now the intention is to repower a different configuration which would also include 6; however, the number of megawatts would be substantially the same and the reductions would occur in approximately the same increments. Because we are well into the engineering and the expenditure of significant dollars, I would hope that the DEP could at least provide a waiver of the requirement to

TECO ENERGY, INC.
702 N. FRANKLIN ST. TAMPA, FL 33602
P.O. BOX 111 TAMPA, FL 33601-0111
813-228-1604 FAX 813-228-1328/228-4811
SMMCDEVITT@TECOENERGY.COM

specifically repower those units identified and let us proceed since I have not had any response to my communication of March 21st.

2. As we discussed several times, the Consent Final Judgment requires that the commercial viability of the "zero ammonia" control technology be determined by the DEP no later than May, 2000. Since it is now April 19, 2000, and the DEP has still not responded to the request that that date be adjusted along with a reduction in the capital cost differential from $8 million to $6 million dollars. Tampa Electric has provided to your Air Division the information we were able to assimilate with respect to the availability of the technologies and the respective capital costs. We have also provided the additional O&M costs as we understand them. Regardless of whether the dollar value was reduced to $6 million the incremental capital cost seems to exceed the requirements of the Consent Final Judgment by 3 times. Accordingly, I would hope that we could move forward by May 1 to dispose of this particular requirement.

There are several other suggested changes which were provided in the March 21 communication, but the two I mentioned are those most important. It seems that some of the suggestions would be to the benefit of DEP and if you are so inclined to agree to them that would suit me fine.

I am leaving for Chicago where the Gannon repowering team is currently located and actively engaged in the engineering and procurement phase of this project. We are proceeding under the assumption that DEP will be reasonable in connection with the change in the designated units required to be repowered and with respect to the use of the "zero ammonia" NOx technology. It is important for us to be able to proceed with the development of this project since we are on a very tight time frame in order to meet the in service dates called out by both the Consent Final Judgment and the Consent Decree. I have attempted to contact you by telephone, fax, and mail and have

Page 3
Ms. Teri Donaldson
April 19, 2000

been unsuccessful with those efforts. I would appreciate the courtesy of a response at least letting me know when I can expect to have a discussion regarding these issues.

Sincerely yours,

SMMcD/gsd
Cc: Spence Autry
bcc: Virginia Wetherell

Question 13.a. Attachment

6.0 AMBIENT IMPACT ANALYSIS RESULTS

The refined ISCST3 model was used to model each of the 12 Bayside Units 1 and 2 operating scenarios during fuel oil-firing. These operating scenarios include three loads (50, 75, and 100 percent) and four ambient temperatures (18, 59, 72, and 93°F). ISCST3 model results for each year of meteorology evaluated (1992 through 1996) for SO_2, NO_2, PM/PM_{10}, and CO impacts during distillate fuel oil-firing are summarized on Table 6-1.

Maximum highest, second highest (HSH) 3- and 24-hour SO_2 impacts are projected to be 320.2 and 85.1 $\mu g/m^3$, respectively. The 3-hour HSH SO_2 impact is 24.6 percent of the Federal and Florida 3-hour average Ambient Air Quality Standard (AAQS) of 1,300 $\mu g/m^3$. The 24-hour HSH SO_2 impact is 23.3 and 32.7 percent of the Federal and Florida 24-hour average AAQS of 365 and 260 $\mu g/m^3$, respectively. Maximum annual average SO_2 impact is projected to be 5.2 $\mu g/m^3$. This impact is 6.5 and 8.7 percent of the Federal and Florida annual average AAQS of 80 and 60 $\mu g/m^3$, respectively.

Maximum annual average NO_2 impact is projected to be 4.8 $\mu g/m^3$. This impact is 4.8 percent of the Federal and Florida annual average AAQS of 100 $\mu g/m^3$.

Maximum highest, second highest (HSH) 24-hour PM/PM_{10} impact is projected to be 53.6 $\mu g/m^3$. This impact is 35.7 percent of the 24-hour Federal and Florida AAQS of 150 $\mu g/m^3$. Maximum annual average PM/PM_{10} impact is projected to be 3.9 $\mu g/m^3$. This impact is 7.7 percent of the Federal and Florida annual average AAQS of 50 $\mu g/m^3$.

Maximum highest, second highest (HSH) 1- and 8-hour CO impacts are projected to be 408.4 and 134.0 $\mu g/m^3$, respectively. These impacts are 1.0 and 1.3 percent of the Federal and Florida 1- and 8-hour average AAQS of 40,000 and 10,000 $\mu g/m^3$, respectively.

The air quality impacts described above reflect the operation of Bayside Units 1 and 2 assuming all units are fired with back-up distillate fuel oil. Air quality impacts during use of the primary fuel, natural gas, are considerably lower. For example, the maximum highest, second highest (HSH) 3- and 24-hour SO_2 impacts during natural gas-firing are projected to be 40.3 and 10.8 μg/m^3, respectively. The 3-hour HSH SO_2 impact is 3.1 percent of the Federal and Florida 3-hour average Ambient Air Quality Standard (AAQS) of 1,300 μg/m^3. The 24-hour HSH SO_2 impact is 3.0 and 4.2 percent of the Federal and Florida 24-hour average AAQS of 365 and 260 μg/m^3, respectively. Maximum annual average SO_2 impact is projected to be 0.8 μg/m^3. This impact is 1.0 and 1.4 percent of the Federal and Florida annual average AAQS of 80 and 60 μg/m^3, respectively. ISCST3 model results for each year of meteorology evaluated (1992 through 1996) for SO_2, NO_2, PM/PM_{10}, and CO impacts during natural gas-firing are summarized on Table 6-2.

In response to the Department's October 19, 2000 e-mail, an assessment of SO_2 ambient air quality impacts resulting from Interim Case 1 (Bayside Unit 1 and Gannon Units 1, 2, 3, 4, and 6 in operation) was also conducted. This analysis evaluated the SO_2 air quality impacts resulting from the operation of Bayside Unit 1 (during back-up low sulfur distillate fuel oil-firing, Case 4) and Gannon Units 1-4 and 6 at a station-wide SO_2 emission rate of 8.3 tons per hour, 24-hour average. Gannon Units 1-4 and Unit 6 were modeled at SO_2 emission rates of 1.64 and 1.80 lb SO_2/MMBtu, respectively. The results of this assessment are provided on Table 6-3.

The dispersion model results shown on Tables 6-1 through 6-3 provide reasonable assurance that operation of the Bayside Units 1 and 2 will not contribute to any exceedances of an AAQS. Following installation of Bayside Units 1 and 2 and cessation of Gannon coal-fired operations, the HSH 24-hour average SO_2 impact will be only 4.2 per cent of the Florida AAQS during natural gas-firing (the primary fuel for Bayside Power Station) and only 32.7 percent of the Florida AAQS during back-up distillate fuel oil-firing.

Table 6-3. Bayside/ F.J. Gannon Stations SO_2 Air Quality Impact Analysis Summary
Interim Case 1 (Bayside Unit 1 and Gannon Units 1-4 and 6)

SO_2 Impacts	1992	1993	1994	1995	1996
Annual Average SO_2 Impacts					
ISCST3 Impact ($\mu g/m^3$)	15.2	14.8	11.5	11.6	13.7
Florida AAQS ($\mu g/m^3$)	60	60	60	60	60
Exceed Florida AAQS (Y/N)	N	N	N	N	N
Percent of Florida AAQS (%)	25.3	24.7	19.1	19.4	22.8
Receptor UTM Easting (m)	360,306.0	360,306.0	359,601.6	360,244.4	360,244.4
Receptor UTM Northing (m)	3,087,197.5	3,087,197.5	3,087,136.0	3,087,136.0	3,087,136.0
HSH 24-Hour SO_2 Impacts					
ISCST3 Impact ($\mu g/m^3$)	222.3	218.8	216.0	175.3	257.8
Florida AAQS ($\mu g/m^3$)	260	260	260	260	260
Exceed Florida AAQS (Y/N)	N	N	N	N	N
Percent of Florida AAQS (%)	85.5	84.2	83.1	67.4	99.1
Receptor UTM Easting (m)	360,356.0	360,244.4	360,306.0	360,244.4	359,601.6
Receptor UTM Northing (m)	3,087,269.0	3,087,136.0	3,087,197.5	3,087,136.0	3,087,136.0
HSH 3-Hour SO_2 Impacts					
ISCST3 Impact ($\mu g/m^3$)	590.0	543.9	543.2	510.9	583.8
Florida AAQS ($\mu g/m^3$)	1,300	1,300	1,300	1,300	1,300
Exceed Florida AAQS (Y/N)	N	N	N	N	N
Percent of Florida AAQS (%)	45.4	41.8	41.8	39.3	44.9
Receptor UTM Easting (m)	359,601.6	360,306.0	359,601.6	359,601.6	359,540.0
Receptor UTM Northing (m)	3,087,136.0	3,087,197.5	3,087,136.0	3,087,136.0	3,087,197.5

Source: ECT, 2000.

	Case 1 (100% Load, 18°F Ambient)					Case 2 (75% Load, 18°F Ambient)					Case 3 (50% Load, 18°F Ambient)					Case 4 (100% Load, 59°F Ambient)				
	1992	1993	1994	1995	1996	1992	1993	1994	1995	1996	1992	1993	1994	1995	1996	1992	1993	1994	1995	1996
Nominal 10 g/s Impacts:																				
HSH, 1-Hour (μg/m^3)	263.5	264.3	289 9	215.4	260.7	323.4	335.9	335.1	297.1	331.1	367.3	375.1	377.1	360.8	369.4	290.4	293.2	305.0	257.4	289.6
HSH, 3-Hour (μg/m^3)	123.2	114.1	122.3	117.2	130.1	161.4	171.3	157.8	128.1	168.6	207.9	193.0	192.4	141.3	176.4	134.6	134.3	134.0	122.4	149.4
HSH, 8-Hour (μg/m^3)	77.5	78.5	75.7	47.2	98.5	100.5	100.5	98.4	67.7	115.0	95.3	113 9	111.3	92.9	133.4	88.2	85.0	85.6	52.9	109.2
HSH, 24-Hour (μg/m^3)	43.8	30.6	43.1	19.1	60.6	63.0	49.6	51.5	30.4	78.4	68.6	57.1	55.4	42.9	88.1	51.7	39.8	46.8	22.2	68.8
Annual (μg/m^3)	2.0	1.4	1.4	0.8	1.2	3.9	3.2	2.6	1.8	2.3	5.7	4.8	3.6	2.6	3.4	2.6	2.0	1.7	1.1	1.5
SO_2																				
Emission Rate (g/s)	13.17	13.17	13.17	13.17	13.17	10.62	10.62	10.62	10.62	10.62	8.43	8.43	8.43	8.43	8.43	12.38	12.38	12.38	12.38	12.38
HSH, 3-Hour (μg/m^3)	162.3	150.3	161.0	154.3	171.3	171.4	182.0	167.5	315.5	179.0	175.2	162.7	162.2	304.2	148.7	166.7	166.3	165.9	151.5	184.9
HSH, 24-Hour (μg/m^3)	57.7	40.3	56.8	25.2	79.8	66.9	52.7	54.7	32.3	83.2	57.9	48.1	46.7	36.2	74.3	64.0	49.3	58.0	27.5	85.1
Annual (μg/m^3)	2.7	1.9	1.8	1.0	1.6	4.1	3.4	2.8	1.9	2.5	4.8	4.1	3.1	2.2	2.9	3.2	2.4	2.2	1.3	1.9
NO_2																				
Emission Rate (g/s)	16.67	16.67	16.67	16.67	16.67	13.31	13.31	13.31	13.31	13.31	10.47	10.47	10.47	10.47	10.47	15.65	15.65	15.65	15.65	15 65
Tier 2 Annual (μg/m^3)	2.5	1.8	1.7	1 0	1.5	3.9	3.2	2.6	1.8	2.3	4.5	3.8	2.9	2.1	2.7	3.0	2.3	2.1	1.3	1.8
PM/PM_{10}																				
Emission Rate (g/s)	6.78	6.78	6.78	6.78	6.78	6.30	6.30	6.30	6.30	6.30	5.88	5.88	5.88	5.88	5.88	6.63	6.63	6.63	6.63	6.63
HSH, 24-Hour (μg/m^3)	29.7	20.7	29.2	13.0	41.1	39.7	31.2	32.5	19.1	49.4	40.4	33.6	32.6	25.2	51.8	34.3	26.4	31.0	14.7	45.6
Annual (μg/m^3)	1.4	1.0	0.9	0.5	0.8	2.5	2.0	1.6	1.1	1.5	3.4	2.8	2.1	1.5	2.0	1.7	1.3	1.2	0.7	1.0
CO																				
Emission Rate (g/s)	8.82	8.82	8.82	8.82	8.82	8.14	8.14	8.14	8.14	8.14	9.34	9.34	9.34	9.34	9.34	8.13	8.13	8.13	8.13	8.13
HSH, 1-Hour (μg/m^3)	232.4	233.1	255.7	190.0	229.9	263.3	273.5	272.8	241.8	269.5	343.1	350.3	352.2	337.0	345.0	236.1	238.4	248.0	209.3	235.4
HSH, 8-Hour (μg/m^3)	68.3	69.3	66.7	41.7	86.9	81.8	81.8	80.1	55.1	93.6	89.0	106.4	104.0	86.8	124.6	71.7	69.1	69.6	43.0	88.8

	Case 5 (75% Load, 59°F Ambient)					Case 6 (50% Load, 59°F Ambient)					Case 7 (100% Load, 72°F Ambient)					Case 8 (75% Load, 72°F Ambient)				
	1992	1993	1994	1995	1996	1992	1993	1994	1995	1996	1992	1993	1994	1995	1996	1992	1993	1994	1995	1996
Nominal 10 g/s Impacts:																				
HSH, 1-Hour (μg/m³)	336.3	350.6	351.8	317.3	344.3	384.6	388.2	392.4	382.1	382.2	294.2	298.1	307.9	264.6	294 5	338.6	352.9	354.5	322.0	346.7
HSH, 3-Hour (μg/m³)	182.0	185.9	169.4	135.4	174.2	229.0	208.5	203.8	155.0	183.4	136.5	138.0	136.7	123.2	151.3	185.9	170.7	171.9	136.8	175.0
HSH, 8-Hour (μg/m³)	105.2	114.3	102 8	75.9	120.8	101.3	120.2	116.2	102.5	139.6	89.6	85.8	87.1	53.8	110.9	106.0	116.9	103.6	77.7	121.8
HSH, 24-Hour (μg/m³)	67.4	52.1	56.6	35.2	82.8	73.0	59.9	58.6	45.9	92.4	53.0	41.7	47.4	22.7	70.1	68.8	52.6	58.5	36.1	83.6
Annual (μg/m³)	4.4	3.7	2.9	2.0	2.6	6.5	5.5	4.1	3.0	3.9	2.7	2.0	1.8	1.1	1.6	4.6	3.8	3.0	2.1	2.7
SO_2																				
Emission Rate (g/s)	10.00	10.00	10.00	10.00	10.00	7.97	7.97	7.97	7.97	7.97	12.10	12.10	12.10	12.10	12.10	9.75	9.75	9.75	9.75	9.75
HSH, 3-Hour (μg/m³)	182.0	185.9	169.4	135.4	174.2	182.5	166.2	162.5	304.6	146.1	165.2	166.9	165.5	320.2	183.0	181.2	166.5	167.6	313.9	170.6
HSH, 24-Hour (μg/m³)	67.4	52.1	56.6	35.2	82.8	58.2	47.7	46.7	36.6	73.6	64.1	50.5	57.3	27.5	84.8	67.1	51.3	57.1	35.2	81.5
Annual (μg/m³)	4.4	3.7	2.9	2.0	2.6	5.2	4.4	3.3	2.4	3.1	3.2	2.5	2.2	1.3	1.9	4.4	3.7	2.9	2.0	2.6
NO_2																				
Emission Rate (g/s)	12.52	12.52	12.52	12.52	12.52	9.9	9.89	9.89	9.89	9.89	15.32	15.32	15.32	15.32	15.32	12.21	12.21	12.21	12.21	12.21
Tier 2 Annual (μg/m³)	4.2	3.5	2.8	1.9	2.5	4.8	4.1	3.1	2.3	2.9	3.1	2.3	2.1	1.3	1.8	4 2	3.5	2.7	1.9	2.5
PM/PM_{10}																				
Emission Rate (g/s)	6.19	6.19	6.19	6 19	6.19	5.80	5.80	5.80	5.80	5.80	6.58	6.58	6.58	6.58	6.58	6.14	6.14	6.14	6.14	6.14
HSH, 24-Hour (μg/m³)	41.7	32.3	35.1	21.8	51.3	42.3	34.7	34.0	26.6	53.6	34.8	27.5	31.2	15.0	46.1	42.3	32.3	35.9	22.2	51.3
Annual (μg/m³)	2.7	2.3	1 8	1 2	1.6	3.8	3.2	2.4	1.8	2.2	1.8	1.3	1.2	0.7	1.0	2.8	2.3	1.8	1.3	1.7
CO																				
Emission Rate (g/s)	7.47	7.47	7.47	7.47	7.47	9.00	9.00	9.00	9.00	9.00	7.88	7.88	7.88	7.88	7.88	7.32	7.32	7.32	7.32	7.32
HSH, 1-Hour (μg/m³)	251.3	261.9	262.8	237.0	257.2	346.2	349.4	353.1	343.9	344.0	231.8	234.9	242.6	208.5	232.1	247.9	258.3	259.5	235.7	253.8
HSH, 8-Hour (μg/m³)	78.6	85.4	76.8	101.1	90.3	91.2	108.2	104.6	92.2	125.6	70.6	67.6	68.6	97.1	87.4	77.6	85.6	75.8	56.9	89.2

	Case 9 (50% Load, 72°F Ambient)					Case 10 (100% Load, 93°F Ambient)					Case 11 (75% Load, 93°F Ambient)					Case 12 (50% Load, 93°F Ambient)					Maximums
	1992	1993	1994	1995	1996	1992	1993	1994	1995	1996	1992	1993	1994	1995	1996	1992	1993	1994	1995	1996	
Nominal 10 g/s Impacts:																					
HSH, 1-Hour ($\mu g/m^3$)	386.1	389.7	394.0	384.3	383.6	300.4	306.0	312.3	272.5	302.5	345.6	358.6	360.2	333.5	352.6	391.3	394.2	398.9	390.7	387.9	398.9
HSH, 3-Hour ($\mu g/m^3$)	230.1	211.7	205.0	156.8	184.1	139.6	146.0	141.4	124.6	154.5	195.6	177.3	178.0	140.2	176.9	233.4	215.0	208.4	161.8	186.5	233.4
HSH, 8-Hour ($\mu g/m^3$)	102.0	120.9	116.8	103.5	128.9	92.0	87.3	89.5	56.4	113.8	108.0	121.9	105.5	82.1	124.4	100.8	122.9	118.5	107.7	130.8	139.6
HSH, 24-Hour ($\mu g/m^3$)	73.4	60.2	58.9	46.2	89.1	55.1	46.3	48.3	24.0	72.6	70.8	53.9	59.4	38.6	85.6	68.5	61.1	60.5	48.1	86.6	92.4
Annual ($\mu g/m^3$)	6.6	5.6	4.2	3.1	3.9	3.0	2.4	2.0	1.3	1.8	4.9	4.1	3.2	2.3	2.9	6.8	5.8	4.3	3.2	4.0	6.8
SO_2																					
Emission Rate (g/s)	7.75	7.75	7.75	7.75	7.75	11.70	11.70	11.70	11.70	11.70	9.25	9.25	9.25	9.25	9.25	7.35	7.35	7.35	7.35	7.35	13.2
HSH, 3-Hour ($\mu g/m^3$)	178.3	164.1	158.9	297.8	142.7	163.4	170.8	165.4	145.8	180.8	180.9	164.0	164.6	308.5	163.7	171.6	158.0	153.2	287.2	137.1	320.2
HSH, 24-Hour ($\mu g/m^3$)	56.9	46.7	45.6	35.8	69.0	64.5	54.2	56.5	28.1	84.9	65.5	49.8	55.0	35.7	79.1	50.3	44.9	44.5	35.4	63.7	85.1
Annual ($\mu g/m^3$)	5.1	4.3	3.2	2.4	3.0	3.5	2.8	2.4	1.5	2.1	4.5	3.8	3.0	2.1	2.7	5.0	4.3	3.2	2.4	3.0	5.2
NO_2																					
Emission Rate (g/s)	9.61	9.61	9.61	9.61	9.61	14.82	14.82	14.82	14.82	14.82	11.58	11.58	11.58	11.58	11.58	9.10	9.10	9.10	9.10	9.10	16.7
Tier 2 Annual ($\mu g/m^3$)	4.8	4.0	3.0	2.2	2.8	3.3	2.6	2.3	1.4	2.0	4.3	3.6	2.8	2.0	2.5	4.7	4.0	2.9	2.2	2.8	4.8
PM/PM_{10}																					
Emission Rate (g/s)	5.76	5.76	5.76	5.76	5.76	6.50	6.50	6.50	6.50	6.50	6.04	6.04	6.04	6.04	6.04	5.68	5.68	5.68	5.68	5.68	6.8
HSH, 24-Hour ($\mu g/m^3$)	42.3	34.7	33.9	26.6	51.3	35.8	30.1	31.4	15.6	47.2	42.8	32.5	35.9	23.3	51.7	38.9	34.7	34.4	27.3	49.2	53.6
Annual ($\mu g/m^3$)	3.8	3.2	2.4	1.8	2.2	1.9	1.5	1.3	0.8	1.2	3.0	2.5	1.9	1.4	1.8	3.9	3.3	2.4	1.8	2.3	3.9
CO																					
Emission Rate (g/s)	9.40	9.40	9.40	9.40	9.40	7.61	7.61	7.61	7.61	7.61	7.07	7.07	7.07	7.07	7.07	10.24	10.24	10.24	10.24	10.24	10.2
HSH, 1-Hour ($\mu g/m^3$)	362.9	366.3	370.4	361.2	360.6	228.6	232.9	237.6	207.4	230.2	244.3	253.6	254.7	235.8	249.3	400.7	403.6	408.4	400.1	397.2	408.4
HSH, 8-Hour ($\mu g/m^3$)	95.9	113.6	109.8	97.2	121.2	70.0	66.4	68.1	42.9	86.6	76.3	86.2	74.6	58.1	87.9	103.2	125.8	121.3	110.3	134.0	134.0

	Project Impact	Case No	Year	Florida AAQS	Federal NAAQS	% of AAQS Florida	% of AAQS Federal
SO_2							
HSH, 3-Hour ($\mu g/m^3$)	320.2	7	1995	1,300	1,300	24.6	24.6
HSH, 24-Hour ($\mu g/m^3$)	85.1	4	1996	260	365	32.7	23.3
Annual ($\mu g/m^3$)	5.2	6	1992	60	80	8.7	6.5
NO_2							
Annual ($\mu g/m^3$)	4.8	6	1992	100	100	4.8	4.8
PM_{10}							
HSH, 24-Hour ($\mu g/m^3$)	53.6	6	1996	150	150	35.7	35.7
Annual ($\mu g/m^3$)	3.9	12	1992	50	50	7.7	7.7
CO							
HSH, 1-Hour ($\mu g/m^3$)	408.4	12	1994	40,000	40,000	1.0	1.0
HSH, 8-Hour ($\mu g/m^3$)	134.0	12	1996	10,000	10,000	1.3	1.3

Source: ECT, 2000.

Table 6-2. Air Quality Impact Analysis Summary
Natural Gas-Firing (Page 1 of 3)

	Case 1 (100% Load, 18°F Ambient)					Case 2 (75% Load, 18°F Ambient)					Case 3 (50% Load, 18°F Ambient)					Case 4 (100% Load, 59°F Ambient)				
	1992	1993	1994	1995	1996	1992	1993	1994	1995	1996	1992	1993	1994	1995	1996	1992	1993	1994	1995	1996
Nominal 10 g/s Impacts:																				
HSH, 1-Hour ($\mu g/m^3$)	307.0	313.6	317.9	280.5	309.2	373.3	378.0	384.1	369.7	370.1	448.6	462.3	447.6	440.0	440.7	335.0	349.1	350.8	311.2	340.2
HSH, 3-Hour ($\mu g/m^3$)	143.2	152.4	149.7	127.2	159.4	211.8	201.1	198.0	154.2	186.6	258.7	249.5	226.1	193.5	230.9	174.0	185.5	170.8	128.2	176.3
HSH, 8-Hour ($\mu g/m^3$)	96.3	89.1	92.2	58.8	118.5	116.8	133.5	112.3	98.7	134.6	146.4	139.5	128.9	144.7	147.3	107.3	112.1	102.4	75.4	131.8
HSH, 24-Hour ($\mu g/m^3$)	58.3	48.7	51.0	25.0	75.6	78.6	58.0	61.9	46.9	92.9	84.2	71.4	80.0	59.2	97.5	68.3	51.5	56.6	34.4	85.9
Annual ($\mu g/m^3$)	3.1	2.4	2.1	1.3	1.9	6.0	5.1	3.9	2.8	3.6	9.3	8.1	5.8	4.5	5.6	4.4	3.6	2.9	2.0	2.6
SO_2																				
Emission Rate (g/s)	1.35	1.35	1.35	1.35	1.35	1.09	1.09	1.09	1.09	1.09	0.88	0.88	0.88	0.88	0.88	1.26	1.26	1.26	1.26	1.26
HSH, 3-Hour ($\mu g/m^3$)	19.3	20.6	20.2	17.2	21.5	23.1	21.9	21.6	40.3	20.3	22.8	22.0	19.9	38.7	20.3	21.9	23.4	21.5	16.2	22.2
HSH, 24-Hour ($\mu g/m^3$)	7.9	6.6	6.9	3.4	10.2	8.6	6.3	6.7	5.1	10.1	7.4	6.3	7.0	5.2	8.6	8.6	6.5	7.1	4.3	10.8
Annual ($\mu g/m^3$)	0.4	0.3	0.3	0.2	0.3	0.7	0.6	0.4	0.3	0.4	0.8	0.7	0.5	0.4	0.5	0.5	0.5	0.4	0.2	0.3
NO_2																				
Emission Rate (g/s)	3.11	3.11	3.11	3.11	3.11	2.51	2.51	2.51	2.51	2.51	1.99	1.99	1.99	1.99	1.99	2.91	2.91	2.91	2.91	2.91
Tier 2 Annual ($\mu g/m^3$)	0.7	0.6	0.5	0.3	0.4	1.1	1.0	0.7	0.5	0.7	1.4	1.2	0.9	0.7	0.8	0.9	0.8	0.6	0.4	0.6
PM/PM_{10}																				
Emission Rate (g/s)	2.58	2.58	2.58	2.58	2.58	2.52	2.52	2.52	2.52	2.52	2.47	2.47	2.47	2.47	2.47	2.56	2.56	2.56	2.56	2.56
HSH, 24-Hour ($\mu g/m^3$)	15.1	12.6	13.2	6.4	19.5	19.8	14.6	15.6	11.8	23.4	20.8	17.6	19.8	14.6	24.1	17.5	13.2	14.5	8.8	22.0
Annual ($\mu g/m^3$)	0.8	0.6	0.5	0.3	0.5	1.5	1.3	1.0	0.7	0.9	2.3	2.0	1.4	1.1	1.4	1.1	0.9	0.7	0.5	0.7
CO																				
Emission Rate (g/s)	3.92	3.92	3.92	3.92	3.92	3.10	3.10	3.10	3.10	3.10	2.57	2.57	2.57	2.57	2.57	3.62	3.62	3.62	3.62	3.62
HSH, 1-Hour ($\mu g/m^3$)	120.3	122.9	124.6	110.0	121.2	115.7	117.2	119.1	114.6	114.7	115.3	118.8	115.0	113.1	113.3	121.3	126.4	127.0	112.6	123.1
HSH, 8-Hour ($\mu g/m^3$)	37.8	34.9	36.1	23.0	46.5	36.2	41.4	34.8	30.6	41.7	37.6	35.9	33.1	37.2	37.9	38.8	40.6	37.1	27.3	47.7

Table 6-2. Air Quality Impact Analysis Summary
Natural Gas-Firing (Page 2 of 3)

	Case 5 (75% Load, 59°F Ambient)					Case 6 (50% Load, 59°F Ambient)					Case 7 (100% Load, 72°F Ambient)					Case 8 (75% Load, 72°F Ambient)				
	1992	1993	1994	1995	1996	1992	1993	1994	1995	1996	1992	1993	1994	1995	1996	1992	1993	1994	1995	1996
Nominal 10 g/s Impacts:																				
HSH, 1-Hour (μg/m^3)	386.3	392.1	394.8	387.1	380.8	448.0	464.2	450.6	440.2	439.7	337.1	351.2	353.3	315.6	342.5	388.8	395.1	396.5	390.2	383.0
HSH, 3-Hour (μg/m^3)	218.6	212.2	216.9	162.4	187.8	259.1	248.8	226.1	192.1	232.3	177.9	187.6	171.7	129.1	177.2	219.7	214.1	220.6	163.4	188.4
HSH, 8-Hour (μg/m^3)	120.9	138.8	116.2	106.4	139.3	146.1	139.4	128.0	144.5	148.9	107.8	114.4	103.1	77.0	132.6	121.6	139.7	116.9	107.7	140.1
HSH, 24-Hour (μg/m^3)	82.2	60.2	64.1	50.4	96.3	84.3	71.3	79.8	59.2	98.0	68.8	52.0	56.9	35.2	86.6	82.8	60.7	64.4	50.8	96.9
Annual (μg/m^3)	6.7	5.7	4.3	3.2	4.0	9.3	8.0	5.8	4.5	5.6	4.4	3.7	2.9	2.0	2.6	6.8	5.8	4.4	3.2	4.0
SO_2																				
Emission Rate (g/s)	1.03	1.03	1.03	1.03	1.03	0.82	0.82	0.82	0.82	0.82	1.23	1.23	1.23	1.23	1.23	1.00	1.00	1.00	1.00	1.00
HSH, 3-Hour (μg/m^3)	22.5	21.9	22.3	16.7	19.3	21.2	20.4	18.5	36.1	19.0	21.9	23.1	21.1	38.8	21.8	22.0	21.4	22.1	39.0	18.8
HSH, 24-Hour (μg/m^3)	8.5	6.2	6.6	5.2	9.9	6.9	5.8	6.5	4.9	8.0	8.5	6.4	7.0	4.3	10.6	8.3	6.1	6.4	5.1	9.7
Annual (μg/m^3)	0.7	0.6	0.4	0.3	0.4	0.8	0.7	0.5	0.4	0.5	0.5	0.5	0.4	0.2	0.3	0.7	0.6	0.4	0.3	0.4
NO_2																				
Emission Rate (g/s)	2.36	2.36	2.36	2.36	2.36	1.86	1.86	1.86	1.86	1.86	2.85	2.85	2.85	2.85	2.85	2.29	2.29	2.29	2.29	2.29
Tier 2 Annual (μg/m^3)	1.2	1.0	0.8	0.6	0.7	1.3	1.1	0.8	0.6	0.8	0.9	0.8	0.6	0.4	0.6	1.2	1.0	0.7	0.6	0.7
PM/PM_{10}																				
Emission Rate (g/s)	2.51	2.51	2.51	2.51	2.51	2.46	2.46	2.46	2.46	2.46	2.56	2.56	2.56	2.56	2.56	2.49	2.49	2.49	2.49	2.49
HSH, 24-Hour (μg/m^3)	20.6	15.1	16.1	12.7	24.2	20.7	17.5	19.6	14.6	24.1	17.6	13.3	14.6	9.0	22.2	20.6	15.1	16.0	12.7	24.1
Annual (μg/m^3)	1.7	1.4	1.1	0.8	1.0	2.3	2.0	1.4	1.1	1.4	1.1	0.9	0.7	0.5	0.7	1.7	1.4	1.1	0.8	1.0
CO																				
Emission Rate (g/s)	2.96	2.96	2.96	2.96	2.96	2.46	2.46	2.46	2.46	2.46	3.50	3.50	3.50	3.50	3.50	2.87	2.87	2.87	2.87	2.87
HSH, 1-Hour (μg/m^3)	114.3	116.1	116.8	114.6	112.7	110.2	114.2	110.8	108.3	108.2	118.0	122.9	123.7	110.5	119.9	111.6	113.4	113.8	112.0	109.9
HSH, 8-Hour (μg/m^3)	35.8	41.1	34.4	48.1	41.2	35.9	34.3	31.5	35.6	36.6	37.7	40.0	36.1	45.2	46.4	34.9	40.1	33.6	30.9	40.2

Table 6-2. Air Quality Impact Analysis Summary
Natural Gas-Firing (Page 3 of 3)

	Case 9 (50% Load, 72°F Ambient)					Case 10 (100% Load, 93°F Ambient)					Case 11 (75% Load, 93°F Ambient)					Case 12 (50% Load, 93°F Ambient)					Maximums
	1992	1993	1994	1995	1996	1992	1993	1994	1995	1996	1992	1993	1994	1995	1996	1992	1993	1994	1995	1996	
Nominal 10 g/s impacts:																					
HSH, 1-Hour (μg/m³)	449.2	467.6	454.2	441.4	442.1	341.6	355.8	358.1	324.8	347.3	396.2	404.2	403.4	399.5	389.4	453.7	**479.5**	466.1	445.9	453.0	**479.5**
HSH, 3-Hour (μg/m³)	259.8	235.5	226.8	192.7	234.6	185.5	192.7	174.5	131.8	179.6	224.4	220.1	231.8	169.1	190.3	**262.4**	238.4	229.5	198.8	239.1	**262.4**
HSH, 8-Hour (μg/m³)	146.4	139.8	128.4	143.3	149.3	109.3	119.5	104.6	80.5	134.6	124.0	142.6	119.4	112.6	145.4	147.7	141.2	135.3	145.0	**150.9**	**150.9**
HSH, 24-Hour (μg/m³)	84.9	71.6	80.5	59.6	98.2	70.3	52.9	58.0	37.1	88.1	84.7	62.1	67.0	52.3	**99.6**	87.0	73.1	82.2	61.1	99.2	**99.6**
Annual (μg/m³)	9.3	8.0	5.8	4.5	5.6	4.7	3.9	3.1	2.1	2.8	7.2	6.2	4.6	3.5	4.3	**9.5**	8.3	6.0	4.7	5.7	**9.5**
SO_2																					
Emission Rate (g/s)	0.80	0.80	0.80	0.80	0.80	1.19	1.19	1.19	1.19	1.19	0.95	0.95	0.95	0.95	0.95	0.76	0.76	0.76	0.76	0.76	**1.4**
HSH, 3-Hour (μg/m³)	20.8	18.8	18.1	35.3	18.8	22.1	22.9	20.8	15.7	21.4	21.3	20.9	22.0	38.0	18.1	19.9	18.1	17.4	33.9	18.2	**40.3**
HSH, 24-Hour (μg/m³)	6.8	5.7	6.4	4.8	7.9	8.4	6.3	6.9	4.4	10.5	8.0	5.9	6.4	5.0	9.5	6.6	5.6	6.2	4.6	7.5	**10.8**
Annual (μg/m³)	0.7	0.6	0.5	0.4	0.4	0.6	0.5	0.4	0.3	0.3	0.7	0.6	0.4	0.3	0.4	0.7	0.6	0.5	0.4	0.4	**0.8**
NO_2																					
Emission Rate (g/s)	1.81	1.81	1.81	1.81	1.81	2.76	2.76	2.76	2.76	2.76	2.17	2.17	2.17	2.17	2.17	1.73	1.73	1.73	1.73	1.73	**3.1**
Tier 2 Annual (μg/m³)	1.3	1.1	0.8	0.6	0.8	1.0	0.8	0.6	0.4	0.6	1.2	1.0	0.8	0.6	0.7	1.2	1.1	0.8	0.6	0.7	**1.4**
PM/PM_{10}																					
Emission Rate (g/s)	2.46	2.46	2.46	2.46	2.46	2.55	2.55	2.55	2.55	2.55	2.48	2.48	2.48	2.48	2.48	2.44	2.44	2.44	2.44	2.44	**2.6**
HSH, 24-Hour (μg/m³)	20.9	17.6	19.8	14.7	24.2	17.9	13.5	14.8	9.5	22.5	21.0	15.4	16.6	13.0	**24.7**	21.2	17.8	20.1	14.9	24.2	**24.7**
Annual (μg/m³)	2.3	2.0	1.4	1.1	1.4	1.2	1.0	0.8	0.5	0.7	1.8	1.5	1.1	0.9	1.1	**2.3**	2.0	1.5	1.1	1.4	**2.3**
CO																					
Emission Rate (g/s)	2.41	2.41	2.41	2.41	2.41	3.39	3.39	3.39	3.39	3.39	2.76	2.76	2.76	2.76	2.76	2.34	2.34	2.34	2.34	2.34	**3.9**
HSH, 1-Hour (μg/m³)	108.3	112.7	109.5	106.4	106.5	115.8	120.6	121.4	110.1	117.7	109.4	111.6	111.3	110.3	107.5	106.2	112.2	109.1	104.3	106.0	**127.0**
HSH, 8-Hour (μg/m³)	35.3	33.7	31.0	34.5	36.0	37.0	40.5	35.5	27.3	45.6	34.2	39.4	33.0	31.1	40.1	34.6	33.0	31.7	33.9	35.3	**48.1**

	Project Impact	Case No.	Year	Florida AAQS	Federal NAAQS	% of AAQS Florida	% of AAQS Federal
SO_2							
HSH, 3-Hour (μg/m³)	40.3	2	1995	1,300	1,300	3.1	3.1
HSH, 24-Hour (μg/m³)	10.8	4	1996	260	365	4.2	3.0
Annual (μg/m³)	0.8	3	1992	60	80	1.4	1.0
NO_2							
Annual (μg/m³)	1.4	3	1992	100	100	1.4	1.4
PM_{10}							
HSH, 24-Hour (μg/m³)	24.7	11	1996	150	150	16.5	16.5
Annual (μg/m³)	2.3	12	1992	50	50	4.7	4.7
CO							
HSH, 1-Hour (μg/m³)	127.0	4	1994	40,000	40,000	0.3	0.3
HSH, 8-Hour (μg/m³)	48.1	5	1995	10,000	10,000	0.5	0.5

Source: ECT, 2000.

FLORIDA

Department of Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

October 16, 2000

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Karen Sheffield, General Manager
Bayside Power Station, Tampa Electric Company
Port Sutton Road
Tampa, FL 33619

Re: Request for Additional Information
Project No. 0570040-013-AC (PSD-FL-301)
Bayside Power Station (Gannon Repowering Project)

Dear Ms. Sheffield:

On September 21, 2000, the Department received an application from the Tampa Electric Company (TEC) with sufficient fee for a PSD air permit to construct seven new combined cycle combustion turbine/electrical generator/HRSG sets. The stated purpose of the project is to repower the existing steam turbines for Units 5 and 6 at the Gannon Station located in Hillsborough County. The repowered electrical generating plant will be known as the Bayside Power Station. The application is incomplete. In order to continue processing your application, the Department will need the additional information requested below. Should your response to any of these items require new calculations, please submit the new calculations, assumptions, reference material and appropriate revised pages of the application form.

1. Netting Analysis: Attachment D of the PSD permit application provides a netting analysis that summarizes the actual emissions decreases from the shut down of Gannon Units 5 and 6 and the potential emissions increases from operation of the new Bayside Units. Previous EPA guidance suggests that emissions decreases needed to meet regulatory requirements should not be included in calculating net emissions increases for a project. Please explain TEC's understanding of the DEP/TEC Consent Final Judgement related to the issue of netting. Note that the remaining questions presume netting.

2. Gas Turbines / HRSGs

    a. Please identify the model of dry low NOx combustor that will be installed on each General Electric Model PG 7241(FA) gas turbine. Is this the latest version?

    b. Please identify the automated gas turbine control system that will be installed with each unit. Describe how this system will interact with the SCR and SCONOx™ control systems to reduce NOx emissions.

    c. Is the evaporative cooler a high-pressure direct spray system? Please describe the system and identify the manufacturer, model, designed cooling reduction (°F), operating pressure, and water consumption rate.

    d. Will this project include natural gas fuel heaters or cooling towers? If so, please provide the information required on the permit application form for these emissions units.

    e. Is each Heat Recovery Steam Generator (HRSG) identical? What is the designed maximum steam production rate (lb/hour), steam temperature (° F), and steam pressure (psig) for each HRSG? What are the current existing maximum and design capacities of the steam turbines for Gannon Units 5 and 6?

    f. The application established maximum mass emission rates at an ambient temperature of 17° F. Based 48 years of data from the www.weatherbase.com Internet web site, the lowest "average daily" temperatures in Tampa occurred during the months of January (61° F), February (62° F), and December (62° F). The average "low temperatures" for these months are January (50° F), February (52° F), and December (52° F). The "lowest recorded temperatures below 32° F" occur in January (21° F), February (24° F), March (29° F), November (23°

F), and December (18° F). The "average number of days below 32° F" is one each for the months of January, February, and December. Please revise the mass emission rates for the Model PG7241(FA) to reflect a more reasonable "low temperature" of 32° F for the Tampa area. Permit conditions for gas turbines typically allow adjustment of the mass emission rate for compressor inlet temperature, if necessary. Otherwise, the Department is considering mass emission rates based on a compressor inlet temperature of 59° F or other available information.

g. Please provide the "Emissions Performance Estimates" from General Electric for the proposed Model PG 7241(FA) gas turbine. This specification sheet identifies the emission rates for CO, NOx, PM/PM_{10}, SO_2, and VOC in terms of ppmvd and lb/hour as estimated by the manufacturer. In addition to the emission rates, these performance specification sheets should also include the unit performance, load conditions, power generation, heat input, fuel consumption, stack conditions, compressor inlet temperature, and fuel type. Specifically, the Department requests "Emissions Performance Estimate" data sheets from General Electric for:

- Gas firing at 100% base load with an inlet compressor temperature of 59° F;
- Gas firing at 100% base load with an inlet compressor temperature of 32° F;
- Oil firing at 100% base load with an inlet compressor temperature of 59° F; and
- Oil firing at 100% base load with an inlet compressor temperature of 32° F.
- Oil firing at 50% base load with an inlet compressor temperature of 93° F.

If necessary, the Department will provide an example from a similar project.

3. Proposed Control Equipment

a. Does the proposed Selective Catalytic Reduction (SCR) system include a NOx emissions monitor prior to the ammonia injection grid to measure uncontrolled NOx emissions? Please identify and describe the automated control system that will be used to adjust the ammonia injection rates based on uncontrolled NOx emissions. What are the input parameters to this system? How will the ammonia slip concentration be determined? What is the proposed test method and frequency for the determination of ammonia slip? For similar combined cycle projects, maximum ammonia slip has been limited to 5 ppm. Please comment.

b. The DEP/TEC Consent Final Judgement requires an evaluation of zero ammonia NOx control technologies. (Question No. 11 summarizes these issues.) The PSD permit application identifies SCONOx™ as such a technology. Please indicate which Emission Unit the SCONOx™ system would be installed on, provide a process flow diagram, and identify emission levels for all pollutants from the combined cycle unit controlled with a SCONOx™ system.

Please note that the issue concerning the evaluation of zero ammonia technologies must be resolved before the Department will deem the Bayside PSD permit application complete.

c. For each NOx control system, describe any unique performance or operating conditions related to startups, shutdowns, or maintenance requirements.

4. Operation

a. The application requests continuous operation (8760) for each gas turbine unit with up to 876 hours f operation per unit when firing low sulfur distillate oil. No other methods of operation are requested. Is this correct?

5. BACT Determination for CO

A review of the Annual Operation Reports filed by TEC with the Department indicates the following inconsistency with information submitted as part of the application (Attachment D, Tables 1 – 3):

Gannon	1997		1998		1999		2-Year Average	
Unit	AOR	App.	AOR	App.	AOR	App.	AOR	App.
5	---	---	140.00	2083.40	136.38	2027.50	138.19	2055.5
6	278.00	3446.30	216.00	3221.90	---	---	247.00	3334.1
						Totals	385.19	5389.60

Note: An equipment explosion affected operation of Unit No. 6 in 1999. Therefore, 1997 and 1998 data was used to establish actual emissions representative of "normal operation".

a. The application briefly notes that CO emissions were based on tests conducted in April of 2000. Neither the Department's Southwest District Office nor the Air Quality Division of the Hillsborough County Environmental Protection Commission have any records related to these emission performance tests. There is no information on record of the test methods, duration, number of tests, performance conditions, levels of other pollutants during these tests, or submittal of a test report. The Department is interested in TEC's rationale for, and the support of, the submitted values. However, TEC is required to submit a top-down BACT analysis for the control of carbon monoxide based upon the Department's records and ensuing conclusion regarding the applicability of BACT. When evaluating the oxidation catalyst, please include the items listed below under "Proposed VOC BACT". Note that a CO control efficiency of at least 90% would be expected.

b. Please identify the controlled CO emission levels from a combined cycle unit controlled by a SCONOx™ system.

6. <u>Proposed VOC BACT</u>

a. With regard to the oxidation catalyst cost analysis, please provide:

- Vendor quotes for the oxidation catalyst system, replacement catalyst, and instrumentation.
- Supporting documentation for a VOC control efficiency of only 33% or revise the cost analysis based on a VOC control efficiency of at least 50%.
- Supporting documentation showing a cost of $0.04/kwh for TEC to generate electricity, otherwise revise the energy penalty accordingly. (The Department believes the actual cost for TEC to be lower than the stated cost.)
- A revised cost analysis using a 7% interest rate or provide substantial detail for the assumed interest rate of 9.55%. (TEC's parent company, TECO Energy, Inc., states in its annual report issuance of fixed rate bonds with interest rates of 6% to 8% for terms of over 20 years. It appears that Tampa Electric can issue tax-exempt bonds, which usually carry a lower interest rate than comparable corporate bonds. It is also noted that the federal 30-year bond rate is less than 5.9%.)
- A revised cost analysis if the contracted package for the HRSG that will be supplied by Alstom Power already includes the spool piece for an oxidation catalyst. (Costs estimated for foundations, supports, handling, erection, engineering, construction field expenses, and contractor fees appear excessive and/or unnecessary.)

b. The application (Table 4-5) indicates that TEC rejects the oxidation catalyst based on high costs and the adverse environmental impacts related to collateral increases of sulfuric acid mist emissions (SAM). The Department will review the revised cost analysis, but notes that natural gas and low sulfur distillate oil contain minimal amounts of sulfur. The application does not discuss the amount and consequences of additional SAM emissions. In addition, the Department would expect an oxidation catalyst to result in a significant reduction of hazardous air pollutants for which this project appears to be major. Therefore, the Department disagrees that the addition of an oxidation catalyst would result in net adverse environmental impacts. Please comment.

c. Please complete the appropriate emissions unit pages of the permit application form for the distillate oil tank. The Department previously allowed construction of this tank contingent on TEC including it as part of the BACT analysis in the application to repower the Gannon Station. Also, please propose a VOC BACT for this emissions unit.

7. <u>MACT Determination for Hazardous Air Pollutants (HAPs)</u>

a. The application (Page 1-5) indicates that this project will NOT be a major source of hazardous air pollutants (HAPs) because potential emissions are less than 10 TPY of any individual HAP and 25 TPY for all HAPs. However, the supporting documentation (Attachment C, Table 7) shows total potential HAP emissions for Bayside Units 1 and 2 combined will be 27.87 TPY, which is greater than the 25 TPY threshold for total HAPs. Projects that are major for HAP emissions are required to obtain case-by-case MACT determinations until EPA promulgates a final NESHAP for gas turbines. Please submit a technical review and proposal for MACT.

The Department notes that EPA issued a December 30, 1999 memorandum entitled, "Hazardous Air Pollutant (HAP) Emission Control Technology for New Stationary Combustion Turbines". This guidance discusses the use of an oxidation catalyst for the control of HAP emissions.

b. The HAP emission calculations (Attachment C) were based on selected test rates from data used to compile EPA's recent AP-42 update for gas turbines. TEC believes the selected rates are more representative of large frame-type gas turbines. Please provide specific HAP emission rates for the Model PG7241(FA) from General Electric and revise the potential emissions calculations accordingly.

8. Emissions Standards Proposed in the Application

a. Please comment on the following items:

- CEMS have been required to demonstrate compliance with CO emission standards for similar combined cycle projects currently under review by the Department (e.g. Calpine, FPC).
- For similar combined cycle projects, compliance with a NOx emission standard for gas firing of 3.5 ppmvd corrected to 15% oxygen has been based on CEMS data for both a 3-hour rolling average as well as a 24-hour block average of actual operating hours.
- For recent gas turbine projects, annual tests for volatile organic compounds and particulate matter have been required to demonstrate compliance with the applicable emission standards.
- EPA Region 4 has recently recommended testing for selected emissions of hazardous air pollutants, such as formaldehyde.

b. The application states that maximum CO emissions (30.3 ppmvd @ 15% oxygen) occur at 50% base load when firing oil with a compressor inlet temperature of 93° F. Please provide supporting documentation from General Electric.

c. Is TEC proposing an Alternate Monitoring Plan to demonstrate compliance with the NSPS Subpart GG monitoring requirements for NOx and SO_2?

9. Excess Emissions

The application (Page 2-8) requests the following periods of permitted excess emissions:

- *Typical Operation*: Up to 2 hours in any 24-hour period due to startup, shutdown, or unavoidable malfunction.
- *CT Warm Startup*: Up to 3 hours in any 24-hour period when the CT/HRSG has been down for more than 2 hours and less than or equal to 24 hours.
- *CT Cold Startup*: Up to 4 hours in any 24-hour period when the CT/HRSG has been down for more than 24 hours.
- *Steam Turbine Cold Startup*: Up to 18 hours of excess emissions resulting from the cold startup of the repowered steam turbines due to metal temperature limitations.

a. Please describe the warm and cold startups of the CT/HRSG units and the associated excess emissions. Please provide supporting documentation to include the duration of each startup and the quantity and duration of excess emissions. How many warm and cold CT/HRSG startups are predicted for each year?

b. Please describe the process of bringing the repowered steam turbines back on-line during a cold startup and define "cold startup" for this equipment. Please provide data that indicates the exhaust gas emissions from the gas turbines will be in excess of the proposed standards for the entire 18-hour cold startup of a steam turbine. Please identify any startup methods that could be used to minimize damage to the steam turbine while allowing the gas turbines to achieve steady-state operation and avoid excess emissions. For example, is it possible to operate a single gas turbine at 75% load to gradually heat up the repowered steam turbine? Is it possible to use steam from the other Bayside Unit to gradually heat up the repowered steam turbine? How many cold startups of each steam turbine are predicted for each year?

c. For each requested period of excess emissions, what is the duration (hours), amount (ppmvd and lb/hour), frequency (incidents per year), and resulting annual emissions (tons per year).

d. Note that the permit can only allow excess emissions for pollutants for which the compliance status would be known. For this project, compliance should be readily identifiable for CO (CEMS), NOx (CEMS), and visible emissions (EPA Method 9 observation). Please comment.

10. Repowering - Bayside Startup and Gannon Shutdown

a. As stated in the application (Attachment D), the actual emissions decreases from the Gannon Units must take place on or before the date that emissions from the modification project (new Bayside Units) first occur and must be federally enforceable on and after the date the Department issues a permit for the modification project. However, the Project Summary indicates that each Gannon Unit will be shut down after installation and "commercial startup" of the corresponding Bayside Unit. Please define "commercial startup" in specific terms.

b. For each new combined cycle unit, please provide an estimated schedule for the start of construction, the completion of construction, the shakedown period, the initial performance testing, "commercial startup", and initial power generation. Also, please indicate when each of the six coal-fired Gannon Units will be shut down.

c. Gannon Units that are not being repowered are required to be shutdown between January 1, 2003 and December 31, 2004. It is expected that any permit issued for this project would be conditioned to require:

- Permanent shutdown of the Gannon Units within this time frame.
- A reduction in the current annual "heat input" limit on the Gannon coal yard by an amount equivalent to that for Gannon Unit 5 when shutdown.
- A reduction in the current annual "heat input" limit on the Gannon coal yard by an amount equivalent to that for Gannon Unit 6 when shutdown.
- Permanent shutdown of all coal-fired Gannon units when both Bayside Units are operational.

Otherwise, allowing the remaining Gannon Units 1 – 4 to fire additional coal could cause actual emissions increases and trigger additional PSD requirements. Please comment.

11. Requirements of the DEP/TEC Consent Final Judgement

Paraphrasing Section V of the DEP/TEC Consent Final Judgement (CFJ), this agreement requires the following for the Gannon Station:

CFJ Section V, A: TEC shall shut down coal-fired Units 1, 2, and 6 at Gannon Station and repower Units 3, 4, and 5 to be phased-in between January 1, 2003 and December 31, 2004. The repowered units shall fire gas and meet a NOx emission rate of 3.5 ppm.

a. The application indicates that the steam boilers for Gannon Units 5 and 6 will be shutdown and the steam turbines for Gannon Units 5 and 6 will be repowered with steam from Bayside Units 1 and 2. How does this comply with the requirements of the CFJ to repower Gannon Units 3, 4, and 5?

b. The CFJ requires the shutdown of Gannon Units 1, 2, and 6. The application does not appear to discuss the future status of any Gannon units that are not being repowered. The Department understands that the steam boilers for any repowered Gannon units must be permanently shut down prior to operation of any corresponding Bayside Unit. The steam boilers for the remaining Gannon units must be shut down between January 1, 2003 and December 31, 2004. In addition, all coal-fired Gannon Units must be permanently shutdown when both Bayside Units are operational. These emissions decreases will not be available for any future projects at the Bayside Station. Please comment.

c. In several places, the application indicates that Gannon Units 5 and 6 will "... permanently cease coal-fired operation." The Department understands this to mean that the steam boilers for Gannon Units 5 and 6 will be permanently shutdown and rendered incapable of operation prior to beginning operations of the corresponding Bayside Unit. Please comment.

d. The application requests 876 hours per year of very low sulfur distillate oil firing as a backup fuel with an emission standard of 16.4 ppmvd corrected to 15% oxygen. How does this meet the requirements of the CFJ to repower with *gas-fired* units meeting a NOx emissions standard of *3.5 ppm*?

CFJ Section V, B: TEC must evaluate "zero ammonia" NOx control technologies for the Gannon facility. If the capital cost differential above Selective Catalytic Reduction (SCR) does not exceed $8 million and TEC obtains acceptable performance guarantees and remedies from the manufacturer, TEC shall install such technology on one repowered unit no later than December 31, 2004. Otherwise, TEC shall spend up to $8 million to demonstrate alternative commercially viable NOx control technologies for natural gas or coal-fired generating units.

e. SCONOx™ is identified as a commercially viable "zero ammonia" NOx control technology and is available for large frame-type units from Alstom Power. Please describe the progress to date on obtaining capital cost estimates, manufacturer performance guarantees and remedies (in accordance with generally recognized industry standards), and all other information necessary for the Department to conclude the required evaluation.

   Please note that the issue of evaluating "zero ammonia" NOx control technologies must be resolved before the Department will deem the Bayside PSD permit application complete.

f. The Department expects that any permit issued for the proposed Bayside project will comport with the Consent Final Judgement. Please comment.

12. Requirements of the EPA/TEC Consent Decree

   a. The Department notes that TEC has signed a separate Consent Decree with the U.S. Environmental Protection Agency. The conditions of the order vary from the requirements of the Department's Consent Final Judgement. EPA Region 4 is currently reviewing the permit application for purposes of PSD as well as compliance with the federal order. When received, the Department will forward any questions from EPA to TEC for comment.

13. Air Quality Analysis

   a. Please review Table 6-1 on pages 6-2, 6-3, and 6-4. The data presented in these tables does not appear consistent with the data provided in the electronic modeling files. Also, please revise the AAQS modeling analysis to include impacts from nearby major sources.

   b. Please provide an additional modeling analysis for SO_2 that demonstrates compliance with the AAQS for the following case: Bayside Unit 1 is on-line, repowered Gannon Unit 5 is permanently shut down, and the remaining Gannon Units are on-line. This new analysis should also include impacts from nearby major sources.

14. Miscellaneous

   a. The application does not indicate whether or not the application for an Acid Rain permit has been submitted. The new Bayside Units will be subject to the Acid Rain (Title IV) provisions. You are notified that an application for a Title IV Acid Rain Permit must be submitted at least 24 months before the date on which a new unit begins serving an electrical generator greater than 25 MW. The application must be submitted to the Region 4 office of the U.S. Environmental Protection Agency in Atlanta, Georgia with a copy to the Department's Bureau of Air Regulation in Tallahassee.

   b. Please be aware that the anhydrous ammonia storage tanks will require an update of the current Risk Management Plan for this site.

The Department will resume processing your application after receipt of the requested information. Rule 62-4.050(3), F.A.C. requires that all applications for a Department permit must be certified by a professional engineer registered in the State of Florida. This requirement also applies to responses to Department requests for additional information of an engineering nature. For material changes to the application, please submit a new certification statement by the authorized representative or responsible official. Rule 62-4.055(1), F.A.C. now requires permit applicants to response to requests for information within 90 days. If there are any questions, please contact me at 850/414-7268. Questions regarding the air quality analysis should be directed to the project meteorologist, Chris Carlson, at 850/921-9537.

Sincerely,

Jeffery F. Koerner

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

AAL/jfk

Mr. Patrick Shell, TEC
Mr. Shannon Todd, TEC
Mr. Thomas Davis, ECT
Mr. Jerry Kissel, SWD
Mr. Jerry Campbell, EPCHC
Mr. John Bunyak, NPS
Mr. Gregg Worley, EPA Region 4
Ms. Katy Forney, EPA Region 4

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

7099 3400 0000 1453 1613

Article Sent To:

Karen Sheffield, General Mgr.

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

TEC/Bayside Power Stat.

Postmark Here

Name (Please Print Clearly) (to be completed by mailer)
Karen Sheffield, Gen. Mgr.
Street, Apt. No.; or PO Box No.
Port Sutton Rd.
City, State, ZIP+4
Tampa, FL 33619

PS Form 3800, July 1999 — See Reverse for Instructions

SENDER: *COMPLETE THIS SECTION*

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

1. Article Addressed to:

Karen Sheffield, General Mgr.
Bayside Power Station
Tampa Electric Company
Port Sutton Road
Tampa, FL 33619

COMPLETE THIS SECTION ON DELIVERY

A. Received by *(Please Print Clearly)*
B. Date of Delivery 10/20

C. Signature
X [signature] ☐ Agent ☐ Addressee

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

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☐ Registered ☐ Return Receipt for Merchandise
☐ Insured Mail ☐ C.O.D.

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

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

ECT

Environmental Consulting & Technology, Inc.

RECEIVED

OCT 02 2000

BUREAU OF AIR REGULATION

September 29, 2000
ECT No. 991060-0100-1100

Mr. A. A. Linero, P.E.
Administrator, New Source Review Section
Division of Air Resources Management
Florida Department of Environmental Protection
2600 Blair Stone Road, MS # 5505
Tallahassee, Florida 32399-2400

Re: Tampa Electric Company
Bayside Power Station

Dear Mr. Fancy:

On behalf of Tampa Electric Company (TEC), please find enclosed a revised Page 7 of the FDEP Construction Permit Application for the Bayside Power Station project. This revision updates the Facility Contact information. Elena Baritta

Please contact Shannon Todd of TEC at 813/641-5125 or the undersigned at 352/332-6230, Ext.351, if there are any questions.

Sincerely,

ENVIRONMENTAL CONSULTING & TECHNOLOGY, INC.

Thomas W. Davis

Thomas W. Davis, P.E.
Principal Engineer

Enclosure

cc: Mr. Shannon Todd, TEC

3701 Northwest
98TH Street
Gainesville, FL
32606

(352)
332-0444

FAX (352)
332-6722

II. FACILITY INFORMATION

A. GENERAL FACILITY INFORMATION

Facility Location and Type

1. Facility UTM Coordinates: Zone: **17** East (km): **360.00** North (km): **3,087.50**			
2. Facility Latitude/Longitude: Latitude (DD/MM/SS): Longitude (DD/MM/SS):			
3. Governmental Facility Code: **0**	4. Facility Status Code: **A**	5. Facility Major Group SIC Code: **49**	6. Facility SIC(s): **4911**
7. Facility Comment (limit to 500 characters):			

Facility Contact

1. Name and Title of Facility Contact: **Elena Beitia, Environmental Coordinator**
2. Facility Contact Mailing Address: Organization/Firm: **Tampa Electric Company** Street Address: **Port Sutton Road** City: **Tampa** State: **FL** Zip Code: **33619**
3. Facility Contact Telephone Numbers: Telephone: **(813) 641-5595** Fax: **(813) 641-5566**

ECT

Environmental Consulting & Technology, Inc.

RECEIVED
OCT 02 2000
BUREAU OF AIR REGULATION

September 29, 2000
ECT No. 991060-0100-1100

Mr. C. H. Fancy, P.E.
Chief, Bureau of Air Regulation
Division of Air Resources Management
Florida Department of Environmental Protection
2600 Blair Stone Road, MS # 5505
Tallahassee, Florida 32399-2400

Re: Tampa Electric Company
Bayside Power Station

Dear Mr. Fancy:

On behalf of Tampa Electric Company (TEC), please find enclosed six copies of a revised Page 7 of the FDEP Construction Permit Application for the Bayside Power Station project. This revision updates the Facility Contact information.

Please contact Shannon Todd of TEC at 813/641-5125 or the undersigned at 352/332-6230, Ext.351, if there are any questions.

Sincerely,

ENVIRONMENTAL CONSULTING & TECHNOLOGY, INC.

Thomas W. Davis

Thomas W. Davis, P.E.
Principal Engineer

Enclosures

cc: Mr. Shannon Todd, TEC

3701 Northwest 98TH Street Gainesville, FL 32606

(352) 332-0444

FAX (352) 332-6722

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3. Facility Contact Telephone Numbers: Telephone: **(813) 641-5595** Fax: **(813) 641-5566**

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2. Facility Contact Mailing Address: Organization/Firm: **Tampa Electric Company** Street Address: **Port Sutton Road** City: **Tampa** State: **FL** Zip Code: **33619**
3. Facility Contact Telephone Numbers: Telephone: **(813) 641-5595** Fax: **(813) 641-5566**

Department of Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

September 27, 2000

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

RE: Tampa Electric Company
F. J. Gannon/Bayside Power Station
PSD-FL-301
Facility ID No. 0570040-013-AC

Dear Mr. Bunyak:

Enclosed for your review and comment is an application for construction of a PSD source. The applicant, Tampa Electric Company, proposes to repower its existing F. J. Gannon Station in Hillsborough County, Florida.

Your comments may be forwarded to my attention at the letterhead address or faxed to the Bureau of Air Regulation at 850/922-6979. If you have any questions, please contact the project engineer, Jeff Koerner at 850/414-7268.

Sincerely,

Patty Adams

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

AAL/jka

Enclosures

cc: J. Koerner

FLORIDA

Department of
Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

September 27, 2000

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

RE: Tampa Electric Company
F. J. Gannon/Bayside Power Station
PSD-FL-301
Facility ID No. 0570040-013-AC

Dear Mr. Worley:

Enclosed for your review and comment is an application for construction of a PSD source. The applicant, Tampa Electric Company, proposes to repower its existing F. J. Gannon Station in Hillsborough County, Florida.

Your comments may be forwarded to my attention at the letterhead address or faxed to the Bureau of Air Regulation at 850/922-6979. If you have any questions, please contact the project engineer, Jeff Koerner at 850/414-7268.

Sincerely,

Patty Adams

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

AAL/jka

Enclosures

TAMPA ELECTRIC

RECEIVED
SEP 21 2000
BUREAU OF AIR REGULATION

September 20, 2000

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

Via Fed Ex
Airbill No. 7918 5340 7932

Re: Bayside Power Station Air Construction Permit Application

Dear Mr. Fancy:

Please find enclosed six signed, sealed copies of the Bayside Power Station Air Construction Permit Application. If you have questions, please contact Shannon Todd or me at (813) 641-5125.

Sincerely,

Karen A. Sheffield

Karen A. Sheffield
General Manager
Gannon Station

EP\gm\SKT200

Enclosure

c/enc: Mr. Alvaro Linero -FDEP
Mr. Jerry Kissel - FDEP SW
Ms. Alice Harman - EPCHC
G. Koerner
C. Carlson
EPA
NPS

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

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

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