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BUREAU OF AIR REGULATION

September 21, 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. 7901 6445 6623**

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

Dear Mr. Koerner:

Tampa Electric Company (TEC) has received the Department's request for additional information regarding the particulate matter emission factors and stack parameters for F.J. Gannon Station, and the requested data is enclosed.

TEC appreciates the opportunity to provide the additional information contained in this correspondence. 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\SKT275

Enclosure

c/enc: 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

TAMPA ELECTRIC COMPANY
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Table 1. F.J. Gannon and Bayside Power Station Stack Parameters

| Emission Source | Height (ft) | Height (m) | Diameter (ft) | Diameter (m) | Temperature (°F) | Temperature (K) | Velocity (ft/sec) | Velocity (m/sec) | Stack Area ($ft^2$) | Flow Rate ($ft^3$/min) |
|---|---|---|---|---|---|---|---|---|---|---|
| **F. J. Gannon Station (1973)** | | | | | | | | | | |
| Unit 1 | 200.0 | 61.0 | 14.1 | 4.30 | 309.0 | 427.0 | 26.5 | 8.1 | 156.15 | 248,271 |
| Unit 2 | 250.0 | 76.2 | 10.0 | 3.05 | 309.0 | 427.0 | 55.9 | 17.0 | 78.54 | 263,423 |
| Unit 3 | 250.0 | 76.2 | 10.6 | 3.23 | 266.0 | 403.2 | 65.5 | 20.0 | 88.25 | 346,812 |
| Unit 4 | 235.0 | 71.6 | 9.6 | 2.93 | 286.0 | 414.3 | 46.2 | 14.1 | 72.38 | 200,644 |
| Unit 5 | 230.0 | 70.1 | 14.6 | 4.45 | 288.0 | 415.4 | 56.7 | 17.3 | 167.42 | 569,547 |
| Unit 6 | 306.0 | 93.3 | 17.6 | 5.36 | 291.0 | 417.0 | 54.3 | 16.6 | 243.28 | 792,622 |
| **F. J. Gannon Station (1974)** | | | | | | | | | | |
| Unit 1 | 200.0 | 61.0 | 14.1 | 4.30 | 309.0 | 427.0 | 27.3 | 8.3 | 156.15 | 255,766 |
| Unit 2 | 250.0 | 76.2 | 10.0 | 3.05 | 309.0 | 427.0 | 56.1 | 17.1 | 78.54 | 264,365 |
| Unit 3 | 250.0 | 76.2 | 10.6 | 3.23 | 266.0 | 403.2 | 48.1 | 14.7 | 88.25 | 254,682 |
| Unit 4 | 235.0 | 71.6 | 9.6 | 2.93 | 286.0 | 414.3 | 48.2 | 14.7 | 72.38 | 209,330 |
| Unit 5 | 230.0 | 70.1 | 14.6 | 4.45 | 288.0 | 415.4 | 46.9 | 14.3 | 167.42 | 471,107 |
| Unit 6 | 306.0 | 93.3 | 17.6 | 5.36 | 291.0 | 417.0 | 52.7 | 16.1 | 243.28 | 769,267 |
| **Bayside Station** | | | | | | | | | | |
| CT1A - CT4B | 150.0 | 45.7 | 19.0 | 5.79 | 212.0 | 373.2 | 59.9 | 18.3 | 283.53 | 1,019,002 |
| (Per CT @ 100% Load, 59°F) | | | | | | | | | | |

Sources: ECT, 2001.
TEC, 2001.

Table 2. F.J. Gannon and Bayside Power Station PM Emission Rates

| Emission Source | 1973 PM (lb/hr) | 1973 PM (g/s) | 1974 PM (lb/hr) | 1974 PM (g/s) | 1975 PM (lb/hr) | 1975 PM (g/s) | 1976 PM (lb/hr) | 1976 PM (g/s) |
|---|---|---|---|---|---|---|---|---|
| **F. J. Gannon Station** | | | | | | | | |
| Unit 1 | 190 | 23.9 | 206 | 26.0 | 204 | 25.7 | 191 | 24.1 |
| Unit 2 | 220 | 27.7 | 107 | 13.5 | 99 | 12.5 | 214 | 27.0 |
| Unit 3 | 330 | 41.6 | 248 | 31.2 | 313 | 39.4 | 32 | 4.0 |
| Unit 4 | 464 | 58.5 | 568 | 71.6 | 56 | 7.1 | 84 | 10.6 |
| Unit 5 | 840 | 105.8 | 669 | 84.3 | 677 | 85.2 | 42 | 5.3 |
| Unit 6 | 2,170 | 273.4 | 44 | 5.5 | 38 | 4.8 | 51 | 6.4 |
| Totals | 4,214 | 531.0 | 1,842 | 232 | 1,387 | 175 | 614 | 77 |
| **Bayside Station (Future)** | | | | | | | | |
| CT1A - CT4B (Per CT @ 100% Load, 59°F) | 20.3 | 2.6 | N/A | N/A | N/A | N/A | N/A | N/A |
| Totals (11 CTs) | 223.30 | 28.1 | N/A | N/A | N/A | N/A | N/A | N/A |

Notes:

1. F.J. Gannon Station PM emissions based on EPA Reference Method 17 (front half only).
2. Bayside PM emissions based on EPA Reference Methods 201 and 202 (front and back half).

Sources: ECT, 2001.
TEC, 2001.

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September 10, 2001

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BUREAU OF AIR REGULATION

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. 7901 5518 4035**

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

Dear Mr. Koerner:

Tampa Electric Company (TEC) has received your requests for additional information dated August 20, 2001 addressing the proposed repowering of F.J. Gannon Station to Bayside Power Station. The original requests were sent via email to Mr. Tom Davis of ECT. TEC has noted that within the two requests, there are a total of five additional questions or requests by the Florida Department of Environmental Protection (FDEP). For your convenience, TEC has restated each point and provided a response below each specific issue.

**FDEP Issue 1**
**The application indicates the 1998 AP-42 emission factor as the reference for sulfuric acid mist emissions from the coal-fired units. What is the emission factor? Please note any assumptions.**

**TEC Response**
*The emission factor used for sulfuric acid mist for coal fired units varies depending on the sulfur content of the fuel. According to AP-42, in a coal fired unit, one can expect 0.7% of the fuel bound sulfur to be emitted as sulfur trioxide. As shown in Enclosure 1, this factor is used to calculate the sulfur trioxide formation resulting from coal combustion. Then, the stoichiometric relationship between sulfur trioxide, water and sulfuric acid mist is used to calculate the amount of sulfuric acid mist formed as a result of the reaction between sulfur trioxide and water. Finally, as mandated by the EPA Consent Decree, TEC calculated the emissions of sulfuric acid mist from Gannon Station had BACT level controls been applied to Units 3 through 6. These BACT level controls were assumed to be wet limestone flue gas desulfurization systems, which have the ability to remove approximately 35% of incoming sulfuric acid mist.*

**FDEP Issue 2**
**Cleve had sent a letter in July regarding the PSD increment for PM. I did not see the response for this item in your last submittal. Please let me know the status of this item.**

**TEC Response**
*TEC is currently performing the above referenced analysis, and will provide it to the Department upon completion.*

**FDEP Issue 3**
**Please submit the emission factors used to estimate past actual coal-firing emissions.**

**TEC Response**
*The requested emission factors are included as Enclosure 2.*

**FDEP Issue 4**
**Your most recent submittal indicates a net increase in VOC emissions of 21.5 TPY, which is below the 40 TPY PSD significant emission rate for VOC. However, based on TEC's annual operating reports, I estimate a 64.3 TPY increase. This makes the project subject to PSD for this pollutant, similar to the Bayside Units 1 and 2 project. Therefore, the Department will be making a BACT determination for VOC emissions. Please submit a proposal for BACT controls.**

**TEC Response**
*In our August 10, 2001 response to the Department's July 17, 2001 incompleteness letter TEC inadvertently used VOC emission factors applicable to cyclone fired boilers for all four Gannon boilers in the revised PSD netting analysis. Gannon Units 5 and 6 are Riley Stoker turbo, wet bottom fired units, and the VOC emission factor for these units differs from that used for Units 3 and 4. As such, the netting analysis has been adjusted to use the correct VOC emission factor for Gannon Units 5 and 6 as well as only natural gas firing for Bayside Units 1 and 2.*

*Based on the adjusted netting analysis, TEC calculates a net increase in VOC emissions of 56.8 tons per year. This differs from the values submitted by TEC in annual operating reports because the VOC emission factors for PC- fired, wet bottom boilers changed from 0.07 lb VOC/ton coal to 0.04 lb VOC/ton coal in 1998. TEC believes that it is appropriate to use the most recent emission factors for the purpose of performing this netting analysis.*

*Since this project results in a net increase of 56.8 tons of VOC emissions per year, TEC has enclosed a BACT analysis for VOC emissions (Enclosure 3). Based on this analysis, TEC has concluded that firing natural gas and good combustion practice is BACT for this project. This is consistent with other recently issued permits for similar facilities by FDEP.*

**FDEP Issue 5**
**There were discussions near the end of the last project indicating that TEC may not fire oil at all for this project. The current application for Bayside Units 3 and 4 indicates that these units will fire only natural gas. Please indicate whether or not Bayside Units 1 and 2 will fire distillate oil as a backup fuel.**

**TEC Response**
*Although the Bayside Units 1 and 2 were designed with provisions to fire distillate oil as a backup fuel, TEC is requesting to remove the oil firing permit conditions from the Bayside 1 and 2 Air Construction permit. Although these units have been designed to accommodate future oil firing, TEC has elected to fire natural gas as the only fuel. If the decision is made to fire distillate oil in Bayside Units 1 and 2 in the future, TEC will apply for a modification of the appropriate permits at that time.*

TEC appreciates the opportunity to provide the additional information contained in this correspondence. 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\SKT273

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

# Enclosure 1

## TECO F.J. Gannon Station
## Derivation of $H_2SO_4$ Emission Rates

**Procedure References:**

Coal: Per AP-42 (9/98), Section 1.1, Table 1.1-3, Footnote b, 0.7% of fuel sulfur is emitted as $SO_3$.

No. 2 Oil: Per AP-42 (9/98), Section 1.3, Table 1.3-1, boilers <100 MMBtu/hr (oil-firing), $SO_3$ emission factor is (2 x %S) lb $SO_3$ / 1,000 gallons oil.

Retroactive BACT control efficiency for $H_2SO_4$ = 35%

$SO_3 + H_2O = H_2SO_4$
(one mole of $SO_3$ and one mole of $H_2O$ react to form one mole of $H_2SO_4$)

**$H_2SO_4$ Calculation Equations:**

Coal:
(lb S / 100 lb coal) x (ton coal / yr ) x (2000 lb coal / ton coal) x (0.7 lb $SO_3$ / 100 lb S)
x (1 lb-mole $H_2SO_4$ / 1 lb-mole $SO_3$) x (lb-mole $SO_3$ /80 lb $SO_3$)
x (98 lb $H_2SO_4$ / lb-mole $H_2SO_4$) x (ton $H_2SO_4$ / 2000 lb $H_2SO_4$)
x (1 – (Retroactive BACT Control Efficiency / 100))

Oil:
(2 lb $SO_3$ / 1,000 gallon oil) x (% S oil) x (gallon oil / yr)
x (1 lb-mole $H_2SO_4$ / 1 lb-mole $SO_3$) x (lb-mole $SO_3$ /80 lb $SO_3$)
x (98 lb $H_2SO_4$ / lb-mole $H_2SO_4$) x (ton $H_2SO_4$ / 2000 lb $H_2SO_4$)
x (1 – (Retroactive BACT Control Efficiency / 100))

**Example: 1996, Unit 3**

Coal Usage: 298,202 ton/yr
Coal Sulfur Content: 1.12 weight percent sulfur
No. 2 Oil Usage: 311,000 gal/yr
No. 2 Oil Sulfur Content: 0.030 weight percent sulfur

Coal:
(1.12 lb S / 100 lb coal) x (298,202 ton coal / yr ) x (2000 lb coal / ton coal)
x (0.7 lb $SO_3$ / 100 lb S) x (1 lb-mole $H_2SO_4$ / 1 lb-mole $SO_3$)
x (lb-mole $SO_3$ /80 lb $SO_3$) x (98 lb $H_2SO_4$ / lb-mole $H_2SO_4$)
x (ton $H_2SO_4$ / 2000 lb $H_2SO_4$) x (1 – (35 / 100))
= 18.62 ton/yr $H_2SO_4$

Oil:
(2 lb $SO_3$ / 1,000 gallon oil) x (0.030 S oil) x (311,000 gallon oil / yr)
x (1 lb-mole $H_2SO_4$ / 1 lb-mole $SO_3$) x (lb-mole $SO_3$ /80 lb $SO_3$)
x (98 lb $H_2SO_4$ / lb-mole $H_2SO_4$) x (ton $H_2SO_4$ / 2000 lb $H_2SO_4$)
x (1 – (35 / 100))
= 0.074 ton/yr $H_2SO_4$

**Total = 18.62 (coal) + 0.074 (oil) = 18.69 ton/yr $H_2SO_4$**

# Enclosure 2

## TECO F.J. Gannon Station
## Derivation of Actual Coal-Firing Emission Rates

**Procedure References:**

Tampa Electric Company 1996 – 2000 Annual Operating Reports (AORs)

VOC Emission Factors:
Coal: Per AP-42 (9/98), Section 1.1, Table 1.1-19, TNMOC emission factor is 0.11 lb TNMOC / ton coal for cyclone furnaces (Units 3 & 4)
Coal: Per AP-42 (9/98), Section 1.1, Table 1.1-19, TNMOC emission factor is 0.04 lb TNMOC / ton coal for PC-fired, wet bottom furnaces (Units 5 & 6)
No. 2 Oil: Per AP-42 (9/98), Section 1.3, Table 1.3-3, Distillate fuel oil, NMTOC emission factor is 0.2 lb NMTOC / 1,000 gallons oil.

Retroactive BACT emission rate for $NO_x$ = 0.10 lb $NO_x$ / MMBtu

Retroactive BACT emission rate for $PM/PM_{10}$ = 0.010 lb $PM/PM_{10}$ / MMBtu

Retroactive BACT control efficiency $SO_2$ = 95.0 lb %

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**$NO_x$ Calculation:**

(Annual Heat Input [MMBtu/yr] From AOR) x (0.10 lb $NO_x$ / MMBtu)

**Example: 2000, Unit 5**

Coal Usage: 418,667 ton/yr
Coal Heat Content: 24 MMBtu/ton
No. 2 Oil Usage: 101,569,000 gal/yr
No. 2 Oil Heat Content: 138,000 Btu/gal

Heat Input Coal:
(418,667 ton coal) x (24 MMBtu / ton coal)
= 10,048,008 MMBtu/yr

Heat Input Oil:
(10,156,900 gallon oil) x (138,000 Btu / gal) x (MMBtu / 1,000,000)
= 1,401,652 MMBtu/hr

**Total Annual Heat Input = 10,048,008 (coal) + 1,401,652 (oil) = 11,449,660 MMBtu/yr**

$NO_x$ = (11,449,660 MMBtu/yr) x (0.10 lb $NO_x$ / MMBtu) x (1 ton / 2,000 lb)

**$NO_x$ = 572.5 ton/yr**

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TECO F.J. Gannon Station
Derivation of Actual Coal-Firing Emission Rates

**$PM/PM_{10}$ Calculations:**

(Annual Heat Input [MMBtu/yr] From AOR) x (0.010 lb $NO_x$ / MMBtu)

**Example: 1999, Unit 4**

Coal Usage: 409,995 ton/yr
Coal Heat Content: 20 MMBtu/ton
No. 2 Oil Usage: 397,000 gal/yr
No. 2 Oil Heat Content: 138,000 Btu/gal

Heat Input Coal:
(409,995 ton coal) x (20 MMBtu / ton coal)
= 8,199,900 MMBtu/yr

Heat Input Oil:
(397,000 gallon oil) x (138,000 Btu / gal) x (MMBtu / 1,000,000)
= 54,786 MMBtu/hr

**Total Annual Heat Input = 8,199,900 (coal) + 54,786 (oil) = 8,254,686 MMBtu/yr**

$PM/PM_{10}$ = (8,254,686 MMBtu/yr) x (0.010 lb $NO_x$ / MMBtu) x (1 ton / 2,000 lb)

**$PM/PM_{10}$ = 41.2 ton/yr**

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**$SO_2$ Calculation:**

(Annual Emissions [ton/yr] From AOR) x (x (1 – (Retroactive BACT Control Efficiency / 100))

**Example: 1996, Unit 3**

Coal – $SO_2$: 6,400 ton/yr
Oil – $SO_2$: 6.5 ton/yr

$SO_2$ = (6,400 + 6.5 ton/yr $SO_2$) x (1 – (95 / 100))
$SO_2$ = (6,406.5 ton/yr $SO_2$) x (0.05)

**$SO_2$ = 320.3 ton/yr**

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**CO Calculation:**

(Annual Emissions [ton/yr] From AOR)

**Example: 1997, Unit 4**

Coal – CO: 142 ton/yr
Oil – CO: 1 ton/yr

CO = (142 + 1 ton/yr CO)

**CO = 143 ton/yr**

**TECO F.J. Gannon Station**
**Derivation of Actual Coal-Firing Emission Rates**

**VOC Calculation:**

Coal:
(0.11 lb VOC / ton coal) x (ton coal / yr) x (ton VOC / 2000 lb VOC)

Oil:
(0.2 lb VOC / 1,000 gallon oil) x (gallon oil / yr) x (ton VOC / 2000 lb VOC)

**Example: 1998, Unit 4**

Coal Usage: 486,831 ton/yr
No. 2 Oil Usage: 598,990 gal/yr

Coal VOC = (486,831 ton/yr) x (0.11 lb VOC / ton coal) x (1 ton / 2,000 lb)
Coal VOC = 26.7 ton/yr

Oil VOC = (598,831 gallon oil/yr) x (0.2 lb VOC / 1,000 gallon oil) x (1 ton / 2,000 lb)
Oil VOC = 0.06 ton/yr

**Total VOC = 26.7 (coal) + 0.06 (oil) = 26.8 ton/yr**

# Enclosure 3

**REVISED PSD NETTING ANALYSIS**

**GANNON UNITS 3 – 6 / BAYSIDE UNITS 1 – 4**

**(ADJUSTED FOR RETROACTIVE BACT)**

## Table 3. Bayside Station Units 1, 2, 3 and 4 Netting Analysis - F.J. Gannnon Station Unit 5 Historical Emissions

Revised 8/23/01

| | 1996 | 1997 | 1998 | 1999 | 2000 | 96 - 00, 5 Yr Avg | 98, 99 Avg |
|---|---|---|---|---|---|---|---|
| Coal Usage (tons) | 574,584 | 450,802 | 556,487 | 541,559 | 418,667 | 508,420 | 549,023 |
| Wt % Ash | 7.47 | 8.26 | 8.15 | 7.58 | 6.95 | 7.68 | 7.87 |
| Heat Content ($10^6$ Btu/ton) | 24.65 | 23.96 | 24.00 | 24.00 | 24.00 | 24.12 | 24.00 |
| Wt % S | 1.19 | 1.16 | 1.21 | 1.17 | 1.22 | 1.19 | 1.19 |
| Oil Usage ($10^3$ gal) | 311.0 | 600.9 | 599.0 | 397.0 | 10,156.9 | 2,413.0 | 498.0 |
| Heat Content ($10^6$ Btu/$10^3$ gal) | 138.556 | 137.989 | 138.551 | 138.000 | 138.000 | 138.219 | 138.276 |
| Wt % S | 0.30 | 0.15 | 0.28 | 0.41 | 0.42 | 0.31 | 0.35 |
| Total Heat Input ($10^6$ Btu/yr) | 14,208,885 | 10,884,135 | 13,438,679 | 13,052,202 | 11,449,660 | 12,606,712 | 13,245,440 |
| $NO_x$ (a) | 710.4 | 544.2 | 671.9 | 652.6 | 572.5 | 630.3 | 662.3 |
| CO AOR | 173.0 | 135.0 | 140.0 | 136.4 | 105.7 | 138.0 | 138.2 |
| $SO_2$ (b) | 648.4 | 537.7 | 685.1 | 630.1 | 538.6 | 608.0 | 657.6 |
| $H_2SO_4$ (c) AP-42 (1998) | 38.2 | 29.2 | 37.7 | 35.4 | 31.9 | 34.5 | 36.6 |
| $PM_{10}$ (d) | 71.0 | 54.4 | 67.2 | 65.3 | 57.2 | 63.0 | 66.2 |
| PM (d) | 71.0 | 54.4 | 67.2 | 65.3 | 57.2 | 63.0 | 66.2 |
| Pb AOR | 3.8 | 3.0 | 3.7 | 3.6 | 0.1 | 2.8 | 3.4 |
| VOC AP-42 (1998) | 11.5 | 9.1 | 11.2 | 10.9 | 9.4 | 10.4 | 10.3 |

(a) Actual emissions based on 0.10 lb/MMBtu emission rate per EPA/TEC Consent Decree.
(b) Actual emissions reduced by 95% per EPA/TEC Consent Decree.
(c) Actual emissions reduced by 35% to reflect retroactive BACT.
(d) Actual emissions based on 0.010 lb/MMBtu emission rate per EPA/TEC Consent Decree.

Sources: ECT, 2001.
TEC, 2001.

## Table 4. Bayside Station Units 1, 2, 3 and 4
## Netting Analysis - F.J. Gannnon Station Unit 6 Historical Emissions

Revised 8/23/01

| | 1996 | 1997 | 1998 | 1999 | 2000 | 96 - 00, 5 Yr Avg | 97, 98 Avg |
|---|---|---|---|---|---|---|---|
| Coal Usage (tons) | 892,742 | 920,526 | 860,597 | 693,039 | 391,079 | 751,597 | 890,562 |
| Wt % Ash | 7.48 | 8.79 | 8.41 | 7.28 | 7.18 | 7.83 | 8.60 |
| Heat Content ($10^6$ Btu/ton) | 24.85 | 24.28 | 24.01 | 24.00 | 16.00 | 22.63 | 24.15 |
| Wt % S | 1.19 | 1.18 | 1.22 | 1.13 | 1.10 | 1.16 | 1.20 |
| Oil Usage ($10^3$ gal) | 311.0 | 639.9 | 599.0 | 362.0 | 6,587.5 | 1,699.9 | 619.4 |
| Heat Content ($10^6$ Btu/$10^3$ gal) | 138.556 | 137.989 | 138.551 | 138.000 | 138.000 | 138.219 | 138.270 |
| Wt % S | 0.30 | 0.15 | 0.28 | 0.41 | 0.42 | 0.31 | 0.22 |
| Total Heat Input ($10^6$ Btu/yr) | 22,229,515 | 22,438,664 | 20,745,925 | 16,682,892 | 7,166,339 | 17,852,667 | 21,592,294 |
| $NO_x$ [a] | 1,111.5 | 1,121.9 | 1,037.3 | 834.1 | 358.3 | 892.6 | 1,079.6 |
| CO AOR | 269.0 | 278.0 | 216.0 | 174.2 | 98.5 | 207.1 | 247.0 |
| $SO_2$ [b] | 1,015.4 | 1,141.5 | 1,185.2 | 801.5 | 465.5 | 921.8 | 1,163.3 |
| $H_2SO_4$ [c] AP-42 (1998) | 59.3 | 60.6 | 58.7 | 43.8 | 26.2 | 49.7 | 59.6 |
| $PM_{10}$ [d] | 111.1 | 112.2 | 103.7 | 83.4 | 35.8 | 89.3 | 108.0 |
| PM [d] | 111.1 | 112.2 | 103.7 | 83.4 | 35.8 | 89.3 | 108.0 |
| Pb AOR | 5.9 | 6.1 | 5.7 | 4.6 | 0.1 | 4.5 | 5.9 |
| VOC AP-42 (1998) | 17.9 | 18.5 | 17.3 | 13.9 | 8.5 | 15.2 | 17.9 |

(a) Actual emissions based on 0.10 lb/MMBtu emission rate per EPA/TEC Consent Decree.
(b) Actual emissions reduced by 95% per EPA/TEC Consent Decree.
(c) Actual emissions reduced by 35% to reflect retroactive BACT.
(d) Actual emissions based on 0.010 lb/MMBtu emission rate per EPA/TEC Consent Decree.

Sources: ECT, 2001.
TEC, 2001.

## Table 5. Bayside Station



### Bayside Units 1 - 4/F.J. Gannon Units 3 - 6 Emissions Netting Analysis

| | F. J. Gannon Units 3, 4, 5 & 6 (tpy) | | | | | Units 3 & 4 | Units 5 & 6 | Units 3 - 6 | | Net | PSD | PSD |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 1996 | 1997 | 1998 | 1999 | 2000 | 2 Yr [a] Avg | 2 Yr [b][c] Avg | 2 Yr [a][b][c] Avg | CT 1A-4B (tpy) | Change (tpy) | Threshold (tpy) | Review (Y/N) |
| Coal Usage (tons) | 2,252,402 | 2,348,406 | 2,345,753 | 2,074,717 | 1,746,108 | 888,241 | 1,439,585 | 2,327,825 | N/A | N/A | N/A | N/A |
| Wt % Ash | 7.08 | 7.70 | 7.54 | 7.17 | 7.09 | 7.01 | 8.23 | 15.24 | N/A | N/A | N/A | N/A |
| Heat Content ($10^6$ Btu/ton) | 23.79 | 22.29 | 21.81 | 22.25 | 20.00 | 20.25 | 24.07 | 44.32 | N/A | N/A | N/A | N/A |
| Wt % S | 1.15 | 1.13 | 1.04 | 1.05 | .1.01 | 0.90 | 1.20 | 2.10 | N/A | N/A | N/A | N/A |
| Oil Usage ($10^3$ gal) | 1,244.0 | 2,457.5 | 2,396.0 | 1,553.0 | 37,058.2 | 10,553.9 | 1,117.4 | 11,671.3 | N/A | N/A | N/A | N/A |
| Heat Content ($10^6$ Btu/$10^3$ gal) | 138.556 | 137.989 | 138.551 | 138.000 | 138.000 | 138.000 | 138.273 | 276.273 | N/A | N/A | N/A | N/A |
| Wt % S | 0.30 | 0.15 | 0.28 | 0.41 | 0.42 | 0.41 | 0.28 | 0.69 | N/A | N/A | N/A | N/A |
| Total Heat Input ($10^6$ Btu/yr) | 54,357,901 | 53,475,548 | 52,585,549 | 47,078,210 | 40,146,544 | 19,436,830 | 34,837,734 | 54,274,565 | N/A | N/A | N/A | N/A |
| $NO_x$ [d] | 2,717.9 | 2,673.8 | 2,629.3 | 2,353.9 | 2,007.3 | 971.8 | 1,741.9 | 2,713.7 | 1,113.0 | -1,600.8 | 40.0 | N |
| CO AOR | 679.0 | 709.0 | 590.0 | 522.6 | 440.4 | 224.1 | 385.2 | 609.3 | 1,382.8 | 773.5 | 100.0 | Y |
| $SO_2$ [e] | 2,476.9 | 2,686.9 | 2,720.8 | 2,177.9 | 1,763.1 | 752.7 | 1,820.9 | 2,573.6 | 486.5 | -2,087.1 | 40.0 | N |
| $H_2SO_4$ [f] AP-42 (1998) | 145.5 | 149.7 | 141.6 | 123.7 | 109.4 | 47.9 | 96.2 | 144.1 | 89.4 | -54.7 | 7.0 | N |
| $PM_{10}$ [g] | 271.8 | 267.4 | 262.9 | 235.4 | 200.7 | 97.2 | 174.2 | 271.4 | 978.1 | 706.7 | 15.0 | Y |
| PM [g] | 271.8 | 267.4 | 262.9 | 235.4 | 200.7 | 97.2 | 174.2 | 271.4 | 978.1 | 706.7 | 25.0 | Y |
| Pb AOR | 15.0 | 15.6 | 15.6 | 13.8 | 0.4 | 2.9 | 9.3 | 12.2 | 1.4 | -10.9 | 0.6 | N |
| VOC AP-42 (1998) | 72.7 | 81.4 | 79.7 | 71.1 | 71.4 | 49.9 | 28.2 | 78.1 | 134.9 | 56.8 | 40.0 | Y |

(a) 1999, 2000 average for Units 3 and 4.
(b) 1998, 1999 average for Unit 5.
(c) 1997, 1998 average for Unit 6.
(d) Actual emissions based on 0.10 lb/MMBtu emission rate per EPA/TEC Consent Decree.
(e) Actual emissions reduced by 95% per EPA/TEC Consent Decree.
(f) Actual emissions reduced by 35% to reflect retroactive BACT.
(g) Actual emissions based on 0.010 lb/MMBtu emission rate per EPA/TEC Consent Decree.

Sources: ECT, 2001.
TEC, 2001.

# VOC BACT ANALYSIS

# BAYSIDE UNITS 3 AND 4

# 4.0A BEST AVAILABLE CONTROL TECHNOLOGY ANALYSIS FOR VOLTILE ORGANIC COMPOUNDS

## 4.1A METHODOLOGY

The VOC BACT analysis was performed using the methodology previously described in Section 4.1 of the June 2001 Air Construction 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), NESHAP (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 base load at International Standards Organization (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 3 and 4 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 VOC emission limitations.

FDEP emission standards for stationary sources are contained in Chapters 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 62-296.417, F.A.C., specify emission standards for 17 categories of sources; none of these categories are applicable to CTs. Rule 62-204.800(7), F.A.C. incorporates the federal NSPS by reference, including Subpart GG.

Emission standards applicable to sources located in ozone nonattainment and maintenance areas are contained in Section 62-296.500, F.A.C. As mentioned in Section 3.0 of this report, all of Hillsborough County is classified as an Air Quality Maintenance Area for ozone.

The Bayside Power Station will be located at the existing F.J. Gannon Station south of downtown Tampa in Hillsborough County and therefore is situated within the Hillsborough County ozone Air Quality Maintenance Area. Sections 62-296.501 through 62-296.516, F.A.C., specify VOC emission standards for 16 categories of sources; none of these categories are applicable to CTs. In addition, these VOC emission standards are not applicable to modified VOC-emitting sources, such as Bayside Units 3 and 4, which will be subject to 40 CFR 52.21 (i.e., PSD NSR). Accordingly, there are no ozone Air Quality Maintenance Area VOC emission limits that are applicable to Bayside Units 3 and 4.

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 3 and 4 CTs. However, Subpart GG does not contain any VOC emission limitations. There are no applicable NESHAP requirements.

In summary, there are no federal or state VOC emission limitations applicable to Bayside Units 3 and 4.

## 4.3A BACT ANALYSIS FOR VOC

VOC emissions result from the incomplete combustion of carbon and organic compounds. Factors affecting VOC 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 VOCs 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 VOC 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 VOC emission rates. Emissions of $NO_x$ and VOC are inversely related; i.e., decreasing $NO_x$ emissions will result in an increase in VOC emissions. Accordingly, combustion turbine vendors have had to consider the competing factors involved in $NO_x$ and VOC 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 VOCs from gas turbines and duct burners: (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, VOC emissions are inherently low. During normal operations, VOC exhaust concentrations from the Bayside Unit 3 and 4 GE 7FA CTs are projected to be only 1.3 parts per million by volume, dry (ppmvd), corrected to 15-percent oxygen ($O_2$).

**Oxidation Catalysts**

Noble metal (commonly platinum or palladium) oxidation catalysts are used to promote oxidation of VOCs 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 VOC oxidation varies with inlet temperature. Control efficiency will increase with increasing temperature for VOCs up to a temperature of approximately

1,100°F; further temperature increases will have little effect on control efficiency. Temperatures on the order of 900°F are needed to oxidize VOCs. 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. VOC removal efficiency will vary with the species of hydrocarbon. In general, unsaturated hydrocarbons such as ethylene are more reactive with oxidation catalysts than saturated species such as ethane. A typical VOC control efficiency range using an oxidation catalyst control system is 30- to 50-percent. However, CTs with low uncontrolled VOC emission rates, such as the GE 7FA units, would be expected to have VOC control efficiencies on the low end of this range.

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 VOCs. 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.

**Technical Feasibility**

Both CT combustor design and oxidation catalyst control systems are considered to be technically feasible for Bayside Units 3 and 4. Information regarding energy, environmental, and economic impacts and proposed BACT limits for VOC 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 VOC 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 sulfur. Increased $H_2SO_4$ mist emissions will also occur, on a smaller scale, from CTs fired with natural gas.

Because VOC emission rates from CTs are inherently low, further reductions through the use of oxidation catalysts will result in minimal air quality improvements; i.e., negligible reductions in ambient VOC/ozone levels. The location of Bayside Units 3 and 4 (Hillsborough County, Florida) is classified attainment for all criteria pollutants.

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 3 and 4 CTs is projected to have a pressure drop across the catalyst bed of approximately 1.2 inch of water ($H_2O$). This pressure drop will result in a 0.24 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 3,574,080 kilowatt-hours (kwh) (12,195 MMBtu) per year at base load (170-MW) operation and 100 percent capacity factor per CT. This energy penalty is equivalent to the use of 46.5 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 four CTs. The lost power generation energy penalty, based on a power cost of $0.030/kwh, is $428,890 per year for all four CTs.

### 4.3.3A ECONOMIC IMPACTS

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

The base case Bayside Units 3 and 4 (i.e., for all four CT/HRSG units) annual VOC emission rate is 49.1 tpy. The controlled annual VOC emission rate, based on a 50 percent control efficiency, is 24.5 tpy. Base case and controlled VOC emission rates are summarized in Table 4-5A.

The cost effectiveness of oxidation catalyst for VOC emissions was determined to be $60,378 per ton of VOC removed. Based on the high control costs, use of oxidation catalyst technology to control VOC emissions is not considered to be economically feasible. Results of the oxidation catalyst economic analysis are summarized in Table 4-5A.

### 4.3.4A PROPOSED BACT EMISSION LIMITATIONS

The use of oxidation catalyst to control VOCs from CTs is typically required only for facilities located in ozone nonattainment areas. BACT VOC limits obtained from the RBLC database for natural gas-fired CTs are provided in Table 4-6A. A summary of recent FDEP VOC BACT determinations for natural gas-fired combustion turbines is provided in Table 4-7A.

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 and low sulfur distillate fuel oil. Because VOC 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., negligible reductions in ambient VOC/ozone levels.

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

Table 4-2A. 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, 2001.
TEC, 2001.

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

| Item | Dollars | OAQPS Factor |
|---|---|---|
| Direct Costs | | |
| Purchased equipment | 2,680,000 | A |
| Sales tax | 160,800 | 0.06 x A |
| Freight | 134,000 | 0.05 x A |
| Instrumentation | 268,000 | 0.10 x A |
| **Subtotal Purchased Equipment Cost** | **3,242,800** | **B** |
| Installation | | |
| Foundations and supports | 259,424 | 0.08 x B |
| Handling and erection | 453,992 | 0.14 x B |
| Electrical | 129,712 | 0.04 x B |
| Piping | 64,856 | 0.02 x B |
| Insulation for ductwork | 32,428 | 0.01 x B |
| Painting | 32,428 | 0.01 x B |
| **Subtotal Installation Cost** | **972,840** | |
| **Subtotal Direct Costs** | **4,215,640** | |
| Indirect Costs | | |
| Engineering | 324,280 | 0.10 x B |
| Construction and field expenses | 162,140 | 0.05 x B |
| Contractor fees | 324,280 | 0.10 x B |
| Startup | 64,856 | 0.02 x B |
| Performance test | 32,428 | 0.01 x B |
| Contingency | 97,284 | 0.03 x B |
| **Subtotal Indirect Costs** | **1,005,268** | |
| **TOTAL CAPITAL INVESTMENT** | **5,220,908** (TCI) | |

Source: Engelhard, 2001.
ECT, 2001.

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

| Item | Dollars | | Basis |
|---|---|---|---|
| <u>Direct Costs</u> | | | |
| Catalyst costs | | | |
| Replacement (materials and labor) | 2,668,224 | | |
| Credit for used catalyst | (360,000) | | 15% credit |
| Subtotal Catalyst Costs | 2,308,224 | | |
| **Annualized Catalyst Costs** | **562,954** | | 5 yr @ 7.0% |
| Energy Penalties | | | |
| Turbine backpressure | 428,890 | | 0.24% penalty |
| **Subtotal Direct Costs** | **991,844** | (TDC) | |
| <u>Indirect Costs</u> | | | |
| Administrative charges | 104,418 | | 0.02 x TCI |
| Property taxes | 52,209 | | 0.01 x TCI |
| Insurance | 52,209 | | 0.01 x TCI |
| Capital recovery | 280,271 | | 15 yr @ 7.0% |
| **Subtotal Indirect Costs** | **489,107** | | |
| **TOTAL ANNUAL COST** | **1,480,951** | | |

Sources: Engelhard, 2001.
ECT, 2001.
TEC, 2001.

Table 4-5A. 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 | 5.6 | 24.5 | 24.5 | 5,220,908 | 1,480,951 | 60,378 | 48,781 | N | Y |
| Baseline | 11.2 | 49.1 | N/A | N/A | N/A | N/A | N/A | N/A | N/A |

Basis: Four GE PG7241 (FA) CTs, 100-percent load, natural gas-firing for 8,760 hr/yr.

Sources: ECT, 2001.
GE, 2001.
TEC, 2001.

Table 4-6A. RBLC VOC Summary for Natural Gas Fired CTGs

| RBLC ID | Facility Name | City | Permit Dates Issuance | Permit Dates Update | Process Description | Thruput Rate | Emission Limit | Control System Description | Basis |
|---|---|---|---|---|---|---|---|---|---|
| AL-0128 | ALABAMA POWER COMPANY - THEODORE COGEN | THEODORE | 3/16/99 | 6/23/99 | TURBINE, WITH DUCT BURNER | 170.0 MW | 0.016 LB/MMBTU | EFFICIENT COMBUSTION | BACT-PSD |
| CA-0768 | NORTHERN CALIFORNIA POWER AGENCY | LODI | 10/2/97 | 3/16/98 | GE FRAME 5 GAS TURBINE | 325.0 MMBTU/HR | 8 LB/HR | NATURAL GAS AS PRIMARY FUEL | LAER |
| CA-0810 | SACRAMENTO COGENERATION AUTHORITY P&G | SACRAMENTO | 8/19/94 | 8/31/99 | TURBINE, GAS, COMBINED CYCLE LM6000 | 421.4 MMBTU/H | 1.1 LB/H | OXIDATION CATALYST | BACT |
| CA-0810 | SACRAMENTO COGENERATION AUTHORITY P&G | SACRAMENTO | 8/19/94 | 8/31/99 | TURBINE, GAS, COMBINED CYCLE LM6000 | 421.4 MMBTU/H | 1.1 LB/H | OXIDATION CATALYST | BACT |
| CA-0810 | SACRAMENTO COGENERATION AUTHORITY P&G | SACRAMENTO | 8/19/94 | 8/31/99 | TURBINE, SIMPLE CYCLE LM6000 GAS | 421.4 MMBTU/H | 1.1 LB/H | OXIDATION CATALYST | BACT |
| CA-0813 | SEPCO | RIO LINDA | 10/5/94 | 8/31/99 | TURBINE, GAS COMBINED CYCLE GE MODEL 7 | 920.0 MMBTU/H | 3.7 LB/H | OXIDATION CATALYST | BACT |
| CA-0853 | KERN FRONT LIMITED | BAKERSFIELD | 11/4/86 | 8/5/99 | TURBINE, GAS, GENERAL ELECTRIC LM-2500 | 25.0 MW | 3.12 LB/H | OXIDATION CATALYST, VOC IS SHOWN AS CH4. | BACT-OTHER |
| CA-0855 | CROCKETT COGENERATION - C&H SUGAR | CROCKETT | 10/5/93 | 4/19/99 | TURBINE, GAS, GENERAL ELECTRIC MODEL PG7221(FA) | 240.0 MW | 352.6 LB/D | ENGELHARD OXIDATION CATALYST | BACT-OTHER |
| CA-0858 | BEAR MOUNTAIN LIMITED | BAKERSFIELD | 8/19/94 | 9/28/99 | TURBINE, GE, COGENERATION, 48 MW | 48.0 MW | 0.6 PPMVD @ 15% O2 | OXIDATION CATALYST | BACT-OTHER |
| CO-0017 | THERMO INDUSTRIES, LTD. | FT. LUPTON | 2/19/92 | 3/24/95 | TURBINE, GAS FIRED, 5 EACH | 246.0 MMBTU/H | 16.7 LB/H | | OTHER |
| CO-0018 | BRUSH COGENERATION PARTNERSHIP | BRUSH | | 7/20/94 | TURBINE | 350.0 MMBTU/H | 26.7 T/YR | | OTHER |
| CO-0019 | COLORADO POWER PARTNERSHIP | BRUSH | | 7/20/94 | TURBINES, 2 NAT GAS & 2 DUCT BURNERS | 385.0 MMBTU/H EACH TURBIN | 35.2 T/YR | | OTHER |
| CO-0024 | PUBLIC SERVICE OF COLO.-FORT ST VRAIN | PLATTEVILLE | 5/1/96 | 5/19/98 | COMBINED CYCLE TURBINES (2), NATURAL | 471.0 MW | 1.4 PPMVD, SMPL CY | GOOD COMBUSTION CONTROL PRACTICES. | BACT-PSD |
| CO-0039 | FULTON COGENERATION ASSOC., L.P. | BRUSH | 8/23/99 | 12/11/00 | ELECTRIC GENERATION, TURBINES, NATURAL GAS | 142.0 MW | 3 PPMVD @ 15% O2 | COMBUSTION CONTROLS | BACT-PSD |
| CT-0073 | PRATT & WHITNEY, UTC. | MIDDLETOWN | 7/7/89 | 4/30/90 | ENGINE, GAS TURBINE | 238.0 MMBTU/H | 0.014 LB/MMBTU | | BACT-PSD |
| CT-0139 | PDC EL PASO MILFORD LLC | MILFORD | 4/16/99 | 6/17/99 | TURBINE, COMBUSTION, ABB GT-24, #1 | 2.0 MMCF/H | 3 LB/H NAT GAS | COMBUSTION CONTROLS | BACT |
| CT-0140 | PDC EL PASO MILFORD LLC | MILFORD | 4/16/99 | 6/17/99 | TURBINE, COMBUSTION, ABB GT-24E,#2 | 2.0 MMCF/H | 3 LB/H NAT GAS | COMBUSTION CONTROLS | BACT |
| FL-0042 | ORLANDO UTILITIES COMMISSION | TITUSVILLE | 9/1/88 | 5/14/93 | TURBINE, 2 EA | 35.0 MW | 7 PPM @ 15% O2 | COMBUSTION CONTROL | BACT-PSD |
| FL-0052 | FLORIDA POWER AND LIGHT | NORTH PALM BEACH | 6/5/91 | 3/24/95 | TURBINE, CG, 4 EACH | 400.0 MW | 9 PPM @ 15% O2 | COMBUSTION CONTROL | BACT-PSD |
| FL-0052 | FLORIDA POWER AND LIGHT | NORTH PALM BEACH | 33394 | 3/24/95 | TURBINE, GAS, 4 EACH | 400.0 MW | 1.6 PPM @ 15% O2 | COMBUSTION CONTROL | BACT-PSD |
| FL-0053 | FLORIDA POWER AND LIGHT | LAVOGROME REPOWER | 3/14/91 | 3/24/95 | TURBINE, GAS, 4 EACH | 240.0 MW | 1 PPM @ 15% O2 | COMBUSTION CONTROL | BACT-PSD |
| FL-0056 | ORLANDO UTILITIES COMMISSION | TITUSVILLE | 11/5/91 | 5/14/93 | TURBINE, GAS, 4 EACH | 35.0 MW | 7 PPM @ 15% O2 | COMBUSTION CONTROL | BACT-PSD |
| FL-0068 | ORANGE COGENERATION LP | BARTOW | 12/30/93 | 1/13/95 | TURBINE, NATURAL GAS, 2 | 368.3 MMBTU/H | 10 PPMVD | GOOD COMBUSTION | BACT-PSD |
| FL-0080 | AUBURNDALE POWER PARTNERS, LP | AUBURNDALE | 12/14/92 | 1/13/95 | TURBINE,GAS | 1,214.0 MMBTU/H | 6 LB/H | GOOD COMBUSTION PRACTICES | BACT-PSD |
| FL-0082 | FLORIDA POWER CORPORATION POLK COUNTY SITE | BARTOW | 2/25/94 | 1/13/95 | TURBINE, NATURAL GAS (2) | 1,510.0 MMBTU/H | 7 PPMVW | GOOD COMBUSTION PRACTICES | BACT-PSD |
| GA-0052 | SAVANNAH ELECTRIC AND POWER CO. | | 2/12/92 | 3/24/95 | TURBINES, 8 | 1,032.0 MMBTU/H, NAT GAS | 0.003 LB/MMBTU | FUEL SPEC: LOW SULFUR FUEL OIL | BACT-PSD |
| GA-0063 | MID-GEORGIA COGEN. | KATHLEEN | 4/3/96 | 8/19/96 | COMBUSTION TURBINE (2), NATURAL GAS | 116.0 MW | 6 PPMVD | COMPLETE COMBUSTION | BACT-PSD |
| GA-0069 | TENUSKA GEORGIA PARTNERS, L P | FRANKLIN | 12/18/98 | 6/23/99 | TURBINE, COMBUSTION, SIMPLE CYCLE, 6 | 160.0 MW EA | 0.03 LB/MMBTU | VOC EMISSION IS BECAUSE OF NATURAL GAS | BACT-PSD |
| GA-0069 | TENUSKA GEORGIA PARTNERS, L.P | FRANKLIN | 12/18/98 | 6/23/99 | TURBINE, COMBUSTION, SIMPLE CYCLE, 6 | 160.0 MW EA | 0.0055 LB/MMBTU | VOC EMISSION IS BECAUSE OF NO.2 FUEL OIL. | BACT-PSD |
| LA-0086 | INTERNATIONAL PAPER | MANSFIELD | 2/24/94 | 4/17/95 | TURBINE/HRSG, GAS COGEN | 338.0 MM BTU/HR TURBINE | 3.6 LB/HR COMBINED | COMBUSTION CONTROLS, FUEL SELECTION | BACT |
| LA-0118 | OCCIDENTAL CHEMICAL CORPORATION | HAHNVILLE | 3/19/99 | 3/19/01 | GAS TURBINES (3 UNITS) | 170.0 MW | 3 LB/H | DLN COMBINATION WITH OTHER TECHNOLOGIES | BACT-PSD |
| MA-0023 | DIGHTON POWER ASSOCIATE, LP | DIGHTON | 10/6/97 | 4/19/99 | TURBINE, COMBUSTION, ABB GT11N2 | 1,327.0 MMBTU/H | 5.1 LB/H | DRY LOW NOX COMBUSTION TECHNOLOGY WITH | BACT-PSD |
| ME-0018 | WESTBROOK POWER LLC | WESTBROOK | 12/4/98 | 4/19/99 | TURBINE, COMBINED CYCLE, TWO | 528.0 MW TOTAL | 0.4 PPM @ 15% O2 | | BACT-PSD |
| ME-0019 | CHAMPION INTERNATL CORP. & CHAMP. CLEAN ENERGY | BUCKSPORT | 9/14/98 | 4/19/99 | TURBINE, COMBINED CYCLE, NATURAL GAS | 175.0 MW | 3 LB/H GAS | | BACT-OTHER |
| ME-0020 | CASCO RAY ENERGY CO | VEAZIE | 7/13/98 | 4/19/99 | TURBINE, COMBINED CYCLE, NATURAL GAS, TWO | 170.0 MW EACH | 1 PPM | LOW NOX BURNER | BACT-PSD |
| MI-0245 | SOUTHERN ENERGY, INC | ZEELAND | 3/16/00 | 8/22/00 | COMBINED CYCLE TURBINE | 9,000.0 GIGAJOULES | 0.008 LB/MMBTU | PER CT. GOOD COMBUSTION PRACTICE | BACT-PSD |
| NC-0055 | DUKE POWER CO. LINCOLN COMBUSTION TURBINE | LOWESVILLE | 12/20/91 | 3/24/95 | TURBINE, COMBUSTION | 1,313.0 MM BTU/HR | 2 LB/HR | COMBUSTION CONTROL | BACT-PSD |
| NJ-0013 | LAKEWOOD COGENERATION, L.P. | LAKEWOOD TOWNSHIP | 4/1/91 | 5/29/95 | TURBINES (NATURAL GAS) (2) | 1,190.0 MMBTU/HR (EACH) | 0.0046 LB/MMBTU | TURBINE DESIGN | OTHER |
| NJ-0017 | NEWARK BAY COGENERATION PARTNERSHIP, L.P. | NEWARK | 6/9/93 | 5/29/95 | TURBINES, COMBUSTION, NATURAL GAS-FIRED (2) | 617.0 MMBTU/HR (EACH) | 4 PPMDV | TURBINE DESIGN | BACT-PSD |
| NM-0021 | WILLIAMS FIELD SERVICES CO. - EL CEDRO | BLANCO | 10/29/93 | 3/2/94 | TURBINE, GAS-FIRED | 11,257.0 HP | 25 PPM @ 15% O2 | COMBUSTION CONTROL | BACT-PSD |
| NM-0028 | SOUTHWESTERN PUBLIC SERVICE CO/CUNNINGHAM | HOBBS | 11/4/96 | 12/30/96 | COMBUSTION TURBINE, NATURAL GAS | 100.0 MW | 0 SEE P2 | GOOD COMBUSTION PRACTICES | BACT-PSD |
| NM-0029 | SOUTHWESTERN PUBLIC SERVICE COMPANY | HOBBS | 2/15/97 | 3/31/97 | COMBUSTION TURBINE, NATURAL GAS | 100.0 MW | 0 | | BACT-PSD |
| NY-0036 | ONEIDA COGENERATION FACILITY | ONEIDA | 2/26/90 | 5/18/90 | TURBINE, GE FRAME 6 | 417.0 MMBTU/H | 0.013 LB/MMBTU | COMBUSTION CONTROL | OTHER |
| NY-0038 | EMPIRE ENERGY - NIAGARA COGENERATION CO. | LOCKPORT | 5/2/89 | 5/18/90 | TURBINE, GR FRAME 6, 3 EA | 416.0 MMBTU/H | 0.012 LB/MMBTU | COMBUSTION CONTROL | BACT-PSD |
| NY-0039 | FULTON COGENERATION ASSOCIATES | FULTON | 1/29/90 | 5/18/90 | TURBINE, GE LM5000, GAS FIRED | 500.0 MMBTU/H | 5 LB/H | COMBUSTION CONTROL | BACT-PSD |
| NY-0040 | JMC SELKIRK, INC | SELKIRK | 11/21/89 | 5/18/90 | TURBINE, GE FRAME 7, GAS FIRED | 80.0 MW | 7 PPM | COMBUSTION CONTROL | BACT-PSD |
| NY-0046 | SARANAC ENERGY COMPANY | PLATTSBURGH | 7/31/92 | 9/13/94 | TURBINES, COMBUSTION (2) (NATURAL GAS) | 1,123.0 MMBTU/HR (EACH) | 0.0045 LB/MMBTU | OXIDATION CATALYST | BACT-OTHER |
| OH-0218 | CNG TRANSMISSION | WASHINGTON CRT HSE | 8/12/92 | 4/5/95 | TURBINE (NATURAL GAS) (3) | 5,500.0 HP (EACH) | 0.1 G/HP-HR | FUEL SPEC: USE OF NATURAL GAS | OTHER |
| PA-0083 | NORTHERN CONSOLIDATED POWER | NORTH EAST | 5/3/91 | 7/20/94 | TURBINES, GAS, 2 | 34.6 KW EACH | 105 PPM @ 15% O2 | OXIDATION CATALYST | OTHER |
| PA-0099 | FLEETWOOD COGENERATION ASSOCIATES | FLEETWOOD | 4/22/94 | 11/22/94 | NG TURBINE (GE LM6000) WITH WASTE HEAT BOILER | 360.0 MMBTU/HR | 4.4 LB/HR | GOOD COMBUSTION PRACTICES | BACT-OTHER |
| PA-0148 | BLUE MOUNTAIN POWER, LP | RICHLAND | 7/31/96 | 1/12/99 | COMBUSTION TURBINE WITH HEAT RECOVERY BOILER | 153.0 MW | 4 PPM @ 15% O2 | OXIDATION CATALYST WHEN FIRING NO. 2 OIL | LAER |
| PA-0149 | BUCKNELL UNIVERSITY | LEWISBURG | 11/26/97 | 11/30/97 | NG FIRED TURBINE, SOLAR TAURUS T-7300S | 5.0 MW | 25 PPMV@15%O2 | GOOD COMBUSTION | BACT-OTHER |
| PR-0004 | ECOELECTRICA, L.P. | PENUELAS | 10/1/96 | 5/6/98 | TURBINES, COMBINED-CYCLE COGENERATION | 461.0 MW | 5 PPMDV | COMBUSTION CONTROLS. | BACT-PSD |
| RI-0008 | PAWTUCKET POWER | PAWTUCKET | 1/30/89 | 3/31/91 | TURBINE/DUCT BURNER | 533.0 MMBTU/H | 19 PPM @ 15% O2, GAS | | BACT-PSD |
| RI-0010 | NARRAGANSETT ELECTRIC/NEW ENGLAND POWER CO. | PROVIDENCE | 4/13/92 | 5/31/92 | TURBINE, GAS AND DUCT BURNER | 1,360.0 MMBTU/H EACH | 5 PPM @ 15% O2 | | BACT-PSD |
| RI-0012 | ALGONQUIN GAS TRANSMISSION CO. | BURRILLVILLE | 33450 | 5/31/92 | TURBINE, GAS, 2 | 49.0 MMBTU/H | 0.016 LB/MMBTU | GOOD COMBUSTION PRACTICES | BACT-OTHER |
| RI-0018 | TIVERTON POWER ASSOCIATES | TIVERTON | 2/13/98 | 2/8/99 | COMBUSTION TURBINE, NATURAL GAS | 265.0 MW | 2 PPM @ 15% O2 | GOOD COMBUSTION | BACT-PSD |
| SC-0031 | BMW MANUFACTURING CORPORATION | GREER | 1/7/94 | 8/12/96 | TURBINE, NAT.GAS FIRED (3 -1 SPARE) AND 2 BOILERS | 54.5 MM BTU/HR TURBINES | 77.86 LBS/DAY | | LAER |
| TN-0077 | TN VALLEY AUTHORITY LAGOON CREEK COMBUS TURB | BROWNSVILLE | 4/26/00 | 8/16/00 | COMBUSTION TURBINE | 194,400.0 MMBTU/H | 1.4 PPM @ 15% O2 | ANNUAL PRODUCTION LIMITS | BACT-PSD |
| TX-0231 | WEST CAMPUS COGENERATION COMPANY | COLLEGE STATION | 5/2/94 | 10/31/94 | GAS TURBINES | 75.3 MW (TOTAL POWER) | 38 TPY | INTERNAL COMBUSTION CONTROLS | BACT |
| VA-0163 | VIRGINIA POWER | | 9/7/89 | 4/30/90 | TURBINE, GAS | 1,308.0 MMBTU/H | 2 LB/H/UNIT NAT GAS FI | | BACT-PSD |
| VA-0177 | DOSWELL LIMITED PARTNERSHIP | | 5/4/90 | 3/24/95 | TURBINE, COMBUSTION | 1,261.0 MMBTU/H | 4.4 LB/H | COMBUSTOR DESIGN & OPERATION, GAS | OTHER |
| VA-0180 | COMMONWEALTH GAS PIPELINE CORPORATION | GOOCHLAND | 9/30/90 | 3/24/95 | TURBINES, GAS FIRED, SINGLE CYCLE, 5 | 14.5 MMBTU/H EACH | 0 | EQUIPMENT DESIGN & OPERATION | BACT-PSD |
| VA-0184 | BERMUDA HUNDRED ENERGY LIMITED PARTNERSHIP | CHESTERFIELD | 3/3/92 | 5/7/97 | TURBINE, COMBUSTION | 1,175.0 MMBTU/H NAT. GAS | 2.3 LB/H/UNIT | FURNACE DESIGN | BACT-PSD |
| VA-0238 | COMMONWEALTH CHESAPEAKE CORPORATION | NEW CHURCH | 5/21/96 | 7/21/97 | 3 COMBUSTION TURBINES (OIL-FIRED) | 6,000.0 HRS/YR | 38.9 TPY | GOOD COMBUSTION OPERATING PRACTICES | BACT/NSPS |

Source: RBLC 2001.

| | |
|---|---|
| MAXIMUM | 105.0 PPM @ 15% O2 |
| MINIMUM | 0.4 PPM @ 15% O2 |
| MEDIAN | 5.0 PPM @ 15% O2 |

Table 4-7A. Florida BACT VOC Summary—Natural Gas-Fired CTGs

| Permit Date | Source Name | Turbine Size (MW) | VOC Emission Limit (ppmvd @ 15% $O_2$) | Control Technology |
|---|---|---|---|---|
| 03/07/95 | Orange Cogeneration, L.P. | 39 | 10.0 | Good combustion |
| 07/10/98 | City of Lakeland McIntosh Unit 5 | 250 | 4.0 | Good combustion |
| 09/29/98 | Florida Power Corporation Hines Energy Complex | 165 | 7.0 | Good combustion |
| 11/25/98 | Florida Power & Light Fort Myers Repowering | 170 | 1.4 | Good combustion |
| 12/04/98 | Santa Rosa Energy, LLC | 167 | 1.4 | Good combustion |
| 10/8/99 | Tampa Electric Company – Polk Power Station | 165 | 1.4 | Good combustion |
| 7/23/99 | Seminole Electric Cooperative, Inc., Payne Creek | 158 | 5.0 | Good combustion |
| 9/20/99 | Lake Worth Generating | 170 | 1.4 | Good combustion |
| 10/18/99 | Vandolah Power Project | 170 | 1.4 | Good combustion |
| 12/28/99 | Osceola Power Project | 170 | 3.7 | Good combustion |
| 1/13/00 | Shady Hills Generating Station | 170 | 1.4 | Good combustion |
| 2/00 | Kissimmee Utility – Cane Island Unit 3 | 167 | 1.4 | Good combustion |
| 2/22/00 | Reliant Energy Osceola | 170 | 1.5 | Good combustion |
| 2/24/00 | Gainesville Regional Utilities | 83 | 1.4 | Good combustion |
| 7/31/00 | Gulf Power – Smith Unit 3 | 170 | 4.0 | Good combustion |
| 2/6/01 (Draft) | Calpine Blue Heron | 170 | 1.2 | Good combustion |
| 3/30/01 | Tampa Electric Company – Bayside Units 1 & 2 | 170 | 1.3 | Good combustion |
| 7/5/01 | Calpine Osprey | 170 | 2.3 | Good combustion |
| 8/15/01 | Ft. Pierce Re-Powering | 180 | 2.2 | Good combustion |

Source: FDEP, 2001.

within the past 5 years. Maximum natural gas-firing VOC exhaust concentrations from the CT/HRSG units will be less than or equal to 1.3 ppmvd at 15 percent oxygen. This VOC exhaust concentration is consistent with recent FDEP VOC BACT determinations for CT/HRSG units; e.g., City of Tallahassee Purdom Unit 8 and Lakeland Utilities McIntosh Unit 5. VOC BACT emission limits proposed for Bayside Units 3 and 4 are provided in Table 4-8A.

Table 4-8A. Proposed VOC BACT Emission Limits

| Emission Source | Proposed VOC BACT Emission Limits | |
|---|---|---|
| | ppmvd at 15 percent oxygen | lb/hr |
| GE PG7241 (FA) CT/HRSGs (Per CT/HRSG Unit) | | |
| VOC (Natural Gas) | 1.3 | 3.0 |

Sources: ECT, 2001.
TEC, 2001.

## Adams, Patty

**From:** Koerner, Jeff
**Sent:** Monday, August 20, 2001 9:44 AM
**To:** Tom Davis (E-mail)
**Cc:** Shannon Todd (E-mail)
**Subject:** TEC Bayside - SAM Emission Factor, Coal-Fired Boilers

Tom,

1. The application indicates the 1998 AP-42 emission factor as the reference for sulfuric acid mist emissions from the coal-fired units. What is the emission factor? Please note any assumptions.

2. Cleve had sent a letter in July regarding the PSD increment for PM. I did not see the response for this item in your last submittal. Please let me know the status of this item.

Thanks!

Jeff Koerner
New Source Review Section
850/921-9536

## Adams, Patty

**From:** Koerner, Jeff
**Sent:** Monday, August 20, 2001 11:05 AM
**To:** Tom Davis (E-mail)
**Cc:** Shannon Todd (E-mail)
**Subject:** TEC Bayside - Emission Factors, VOC Emissions and Oil Firing

Tom,

1. Please submit the emission factors used to estimate past actual coal-firing emissions.

2. Your most recent submittal indicates a net increase in VOC emissions of 21.5 TPY, which is below the 40 TPY PSD significant emission rate for VOC. However, based on TEC's annual operating reports, I estimate a 64.3 TPY increase. This makes the project subject to PSD for this pollutant, similar to the Bayside Units 1 and 2 project. Therefore, the Department will be making a BACT determination for VOC emissions. Please submit a proposal for BACT controls.

3. There were discussions near the end of the last project indicating that TEC may not fire oil at all for this project. The current application for Bayside Units 3 and 4 indicates that these units will fire only natural gas. Please indicate whether or not Bayside Units 1 and 2 will fire distillate oil as a backup fuel.

Thanks!

Jeff Koerner
New Source Review Section
850/921-9536

TECO

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OCT 14 2002

BUREAU OF AIR REGULATION

October 11, 2002

Mr. Al Linero, P.E.
Acting Bureau Chief
Florida Department of Environmental Protection
111 South Magnolia Drive, Suite 4
Tallahassee, FL 32301

**Via FedEx**
**Airbill No. 7901 0888 6579**

**Re: Tampa Electric Company**
**Bayside Power Station**
**Project No. 0570040-015-AC**
**Air Permit No. PSD-FL-301A**
**Permitting Exemption**

Dear Mr. Linero:

Tampa Electric Company (TEC) would like to courtesy notify the Florida Department of Environmental Protection (FDEP) that a temporary package boiler will be utilized on-site at Bayside Power Station. Bayside Unit 1 and 2 are under construction and the package boiler will be used to heat water for the cleaning of steam pipes and associated equipment in preparation for the startup of Bayside Unit 1 and 2. The package boiler will have a maximum of 600 horsepower. This is will have a maximum heat input capacity of 1.5 MMBtu per hour with a fuel usage of 70 gallons per hour of 0.5 percent sulfu, No.2 fuel oil. TEC believes that this package boiler is exempt from permitting under FDEP categorical exemption in the regulations 62-210.300(3)(a)1. F.A.C.

> " *One or more fossil fuel steam generators and hot water generating units located within a single facility; collectively having a total rated heat input equaling 100 million BTU per hour or less; and collectively burning annually no more than 145,000 gallons of fuel oil containing no more than 1.0 percent sulfur, or no more than 290,000 gallons of fuel oil containing no more than 0.5 percent sulfur, or an equivalent prorated amount of fuel oil if multiple fuels are used, provided none of the generators or hot water generating units is subject to the Federal Acid Rain Program or any standard or requirement under 42 U.S.C. section 7411 or 7412.*"

The package boiler will be brought on-site for Bayside Unit 1 in October and will remain on-site for a duration of approximately five (5) weeks. TEC requests FDEP confirmation of this exemption from permitting. TEC appreciates your cooperation in this matter and if you have any questions, please call me at (813) 641-5034.

Sincerely,

Dru Latchman for

Laura R. Crouch
Manager Air Programs
Environmental Affairs

Advised Ms. Latchman by phone that we disagree. She will submit exemption claim on different rule basis. aag 10/16

EA/bmr/DNL133

cc: Mr. Scott Sheplak (FDEP)
Mr. Sterlin Woodard (EPCHC)
Mr. Jerry Kissel (FDEP)

TAMPA ELECTRIC

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AUG 13 2001

BUREAU OF AIR REGULATION

August 10, 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. 7901 2705 9498**

**Re:** **Request for Additional Information**
**Project No. 0570040-015-AC**
**Bayside Units 3 and 4 Re-powering Project**

Dear Mr. Koerner:

Tampa Electric Company (TEC) has received your letter of incompleteness dated July 17, 2001 addressing the proposed repowering of F.J. Gannon Station Units 3 and 4 to Bayside Power Station Units 3 and 4. This correspondence is intended to provide a response to each specific issue raised by the Department. For your convenience, TEC has restated each point and provided a response below each specific issue.

FDEP Issue 1
In March of 2001, the Department issued a final permit for Bayside Units 1 and 2, which will re-power the steam turbines for existing Gannon Units 5 and 6. The application to re-power the steam turbines for existing Gannon Units 3 and 4 was submitted only three months later. The Department believes that this application is the second phase of the Gannon re-powering project. Please revise PSD netting analysis to include the following:

- Specify the PSD contemporaneous period as defined in Rule 62-212.400(2)(e)3, F.A.C.
- Include all emissions increases that have occurred or will occur during the contemporaneous period from all projects.
- Include all of the emissions decreases that have occurred or will occur during the contemporaneous period from all projects.
- Update the net emissions changes and PSD applicability accordingly.

**TEC Response**
**The requested analysis is enclosed as attachment 1. Please note that Tampa Electric does not agree with the Department's position that the repowering of Gannon 3 and 4 is not a separate project from the repowering of Gannon 5 and 6.**

TAMPA ELECTRIC COMPANY
P. O. BOX 111 TAMPA, FL 33601-0111 (813) 228-4111
AN EQUAL OPPORTUNITY COMPANY
HTTP://WWW.TAMPAELECTRIC.COM
CUSTOMER SERVICE:
HILLSBOROUGH COUNTY (813) 223-0800
OUTSIDE HILLSBOROUGH COUNTY 1 (888) 223-0800

FDEP Issue 2

Has TEC considered re-powering the existing steam turbines for Gannon Units 1 and 2? Has TEC contracted for any work involving the re-powering of these remaining steam turbines? Please submit a revised construction schedule for all units to be re-powered showing the planned startup date for each Bayside Unit and the shutdown date for each Gannon Unit.

**TEC Response**

**At this time, TEC has no intention of repowering the existing steam turbines serving Gannon Units 1 and 2, nor has it contracted for any work involving the repowering of these two units. However, if TEC elects to repower these two steam turbines in the future, TEC will submit a permit application to the Department requesting permission to do so as outlined in Paragraph 27 of the EPA Consent Decree.**

**The proposed schedule for the repowering of the Gannon units 3-6 is provided below. This schedule is subject to change during the construction of the units. TEC will notify the Department of any significant deviation from this schedule.**

| Event | Estimated Date |
|---|---|
| Shutdown of Gannon 5 | 2/08/03 |
| Startup of BPS 1 | 5/1/03* |
| Shutdown of Gannon 6 | 10/01/03 |
| Startup of BPS 2 | 5/01/04* |
| Shutdown of Gannon 3 | 1/29/04 |
| Startup of BPS 3 | 5/1/04* |
| Shutdown of Gannon 4 | 1/29/04 |
| Startup of BPS 4 | 5/1/04* |

***This is the expected date of commercial operation.**

FDEP Issue 3

Is TEC requesting any emissions standards, operational constraints, monitoring provisions, etc. that are different from those contained in the final permit issued for Bayside Units 1 and 2?

**TEC Response**

**TEC is not requesting any emissions standards, operational constraints, monitoring provisions, etc. that are different from those contained in the final permit issued for Bayside Units 1 and 2.**

FDEP Issue 4

Page 1-2 of the application states, "Following installation and commercial operation of Bayside Unit 3, existing coal fired operation at F.J. Gannon Station Unit 3 will permanently cease. Following installation and commercial operation of Bayside Unit 4, existing coal fired operation at F.J. Gannon Station Unit 4 will permanently cease." The Department notes that, for an emissions decrease to be enforceable, each existing unit must be completely shutdown and rendered incapable of operation prior to startup of the corresponding new unit. Please comment.

**TEC Response**

**Page 1-2 of the application should read, "Prior to the commencement of commercial operation of Bayside Unit 3, existing coal fired operation at F.J. Gannon Station Unit 3 will permanently cease.**

**Prior to the commencement of commercial operation of Bayside Unit 4, existing coal fired operation at F.J. Gannon Station Unit 4 will permanently cease."**

FDEP Issue 5

Each new "Bayside Unit" will consist of two combined cycle units described as:

Each unit consists of a General Electric Model PG7241(FA) gas turbine-electrical generator set, an automated gas turbine control system, an inlet air filtration system, an evaporative inlet air cooling system, an unfired heat recovery steam generator (HRSG), a single exhaust stack that is 150 feet tall and 19.0 feet in diameter and associated support equipment. The project also includes electric fuel heaters and cooling towers. Natural gas is the exclusive fuel.

**Controls:** Emissions of CO, PM/$PM_{10}$, SAM, $SO_2$, and VOC are minimized by the efficient combustion of natural gas at high temperatures. NOx emissions are reduced by a Selective Catalytic Reduction (SCR) system combined with dry low-NOx (DLN) combustion technology when firing natural gas.

**Heat Input:** At a compressor inlet air temperature of 59° F and firing 1842 mmBTU (HHV) per hour of natural gas, each unit produces approximately 169 MW. Exhaust gases exit the stack with a volumetric flow rate of approximately 1,020,000 acfm at 215° F.

**Generating Capacity:** Bayside Units 3A and 3B will supply steam to a single steam electrical generator (formerly serving Gannon Unit 3) with a nameplate rating of 180 MW. Bayside Units 4A and 4B will supply steam to a single steam electrical generator (formerly serving Gannon Unit 4) with a nameplate rating of 188 MW of electrical power. Bayside Unit 3 is designed to produce a nominal 512 MW and Bayside Unit 4 is designed to produce a nominal 520 MW of electrical power. Is this an accurate description?

**TEC Response**

**Based on the continued development and design of the Bayside Units 3 and 4 repowering project, some of the above description should be changed. Below is the suggested revised text, changed from the original using the strikethrough and underline convention.**

**Each new "Bayside Unit" will consist of two combined cycle units described as:**

**Each unit consists of a General Electric Model PG7241(FA) gas turbine-electrical generator set, an automated gas turbine control system, an inlet air filtration system, an evaporative inlet air cooling system, an unfired heat recovery steam generator (HRSG), a single exhaust stack that is 150 feet tall and 19.0 feet in diameter and associated support equipment. The project also includes electric fuel heaters and cooling towers. Natural gas is the exclusive fuel.**

**Controls: Emissions of CO, PM/$PM_{10}$, SAM, $SO_2$, and VOC are minimized by the efficient combustion of natural gas at high temperatures. NOx emissions are reduced by a Selective Catalytic Reduction (SCR) system combined with dry low-NOx (DLN) combustion technology when firing natural gas.**

**<u>Heat Input</u>: At a compressor inlet air temperature of 59° F and firing 1659.5 mmBTU (LHV) per hour of natural gas, each unit produces approximately 169 MW. Exhaust gases exit the stack with a volumetric flow rate of approximately 1,030,163 acfm at 220° F.**

**<u>Generating Capacity</u>: Bayside Units 3A and 3B will supply steam to a single steam electrical generator (formerly serving Gannon Unit 3) with a nameplate rating of 163 MW. Bayside Units 4A and 4B will supply steam to a single steam electrical generator (formerly serving Gannon Unit 4) with a nameplate rating of 170 MW of electrical power. Bayside Unit 3 is designed to produce a nominal 497 MW and Bayside Unit 4 is designed to produce a nominal 488 MW of electrical power.**

<u>FDEP Issue 6</u>
The Bayside 1 and 2 re-powering project combined with the Bayside 3 and 4 re-powering project will result in total formaldehyde emissions greater that 10 tons per year and total hazardous air pollutant emissions (HAP) greater that 25 tons per year. Please submit a case-by-case MACT analysis for the Department's review. The Department will make a case-by-case MACT determination for these phased projects.

**<u>TEC Response</u>**
**General Electric has recently completed HAP emissions testing that suggests that actual HAP emissions are lower than those developed by EPA as part of the AP-42 emission factor inventory. In the Bayside Units 1 and 2 and the Bayside Units 3 and 4 permit applications, TEC used modified AP-42 emission factors to estimate the HAP emissions from the combustion turbines associated with each project. Based on the additional research completed by General Electric, it appears that HAP emissions will be lower than those originally submitted by TEC. Consequently, TEC requests that a formal MACT determination for Bayside Units 1 through 4 be deferred until the units commence commercial operation and TEC has an opportunity to perform HAP emissions testing. Specifically, Condition 2 of the Bayside Power Station Units 1 and 2 Air Construction Permit states:**

*"<u>MACT Determination</u>: The MACT applicability determination for this project is deferred until a combined cycle gas turbine is tested for HAP emissions in accordance with Condition No. 22 of this section. However, the permittee shall plan accordingly for the possibility of future applicable controls. If additional controls are later required, the Department shall allow the permittee a reasonable time to install equipment and conform to new or additional conditions. [Rules 62-4.080 and 62-204.800(10)(d), F.A.C.; Section 112(g), CAAA]"*

**TEC requests that this language be incorporated into the Bayside Units 3 and 4 Air Construction Permit.**

<u>FDEP Issue 7</u>
Please provide a new vendor's quote for this project based on 11 proposed systems firing natural gas. Revise the cost analysis if necessary.

**<u>TEC Response</u>**
**The requested information is provided as attachment 2. Based on the quotation obtained from Engelhard, it will cost $3,194 to remove one ton of carbon monoxide from each Bayside Unit. TEC believes that this cost exceeds that which has recently been considered to be economically feasible by the Department. It is also worth noting that this analysis is extremely conservative. Due to**

**combustion modifications completed on Gannon 5 and 6 to control $NO_x$ emissions, actual CO emissions are likely much higher than those used as the baseline in this evaluation. As such, the actual increase in CO emissions due to this project is likely much lower than the 883.2 tons per year used in the netting calculations. This, in turn, drives up the cost to control one ton of CO.**

FDEP Issue 8
The Department reserves the right to ask for additional information regarding the air quality analysis within the 30-day period after receiving the application with sufficient fee (on or before July 26, 2001).

**TEC Response**
**TEC does not have any issues with the above statement.**

FDEP Issue 9
The Department will forward any comments or questions if received from EPA Region 4, the National Park Service, the Hillsborough County Environmental Protection Commission, or the Department's Southwest District Office.

**TEC Response**
**TEC appreciates the opportunity to comment on any questions raised by the above mentioned agencies.**

TEC understands that with the submission of this additional information, the Department will continue processing the application.

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

Sincerely,

Karen Sheffield

Karen Sheffield
General Manager- Gannon Station
Tampa Electric Company

EP\gm\SKT270

Attachments

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

# Attachment 1

## Bayside Units 1, 2, 3 and 4 PSD Netting Analysis

The procedures for determining applicability of the PSD NSR permitting program to modifications planned at existing major Florida facilities are specified in Rule 62-212.400(2)(d)4., F.A.C. Because the existing F.J. Gannon Station is a major facility (i.e., has potential emissions of 100 tpy or more of an air pollutant subject to regulation under Chapter 403, Florida Statutes) that would be subject to PSD preconstruction review if it were itself a proposed new facility (i.e., has potential emissions of 100 tpy or more of a pollutant regulated under the Clean Air Act and is located in an attainment area), modifications to the existing F.J. Gannon Station which result in a *significant net emissions increase* of any pollutant regulated under the Clean Air Act are subject to PSD NSR.

The term "significant net emission increase" is defined by Rule 62-212.400(2)(e), F.A.C. For each regulated pollutant, the net emission increase for a modification project is equal to the sum of the increases in emissions associated with the proposed project plus all facility-wide creditable, contemporaneous emission increases minus all facility-wide creditable, contemporaneous emission decreases. If this net emissions increase is equal to or greater than the applicable Table 212.400-2, F.A.C. Regulated Pollutants—Significant Emission Rates, then the net emission increase is considered to be "significant" and the modification will be subject to PSD NSR for that particular regulated pollutant.

In accordance with Rule 62-212.400(2)(e)3., F.A.C., the "contemporaneous" period for a modification project begins five years prior to the date of submittal of a complete permit application and ends when the new or modified emission units are estimated to begin operation.

In accordance with Rule 62-212.400(2)(e)4., F.A.C., contemporaneous emission increases and decreases are "creditable" if:

(1) the emission increase or decrease will affect PSD increment consumption; i.e., will consume or expand the available increment;

(2) The emission increase or decrease was not previously considered in the issuance of a PSD NSR permit (to avoid "double counting"); and

(3) The FDEP has not relied on the emission increase or decrease in attainment or reasonable further progress demonstrations.

Contemporaneous emission increases and decreases are based on *actual* emission rates. The term "actual emissions" is defined by Rule 62-210.200(12), F.A.C. For new emission units, including new electric utility steam generating units, actual emissions are equal to potential emissions. For changes to existing emission units, actual emissions are generally the actual average emission rates, in tpy, for the two year period preceding the change and which are representative of normal operations. The Department may allow the use of a different time period if it is determined that the other time period is more representative of the normal operation of an emissions unit.

For emission decreases, the old level of actual or allowable emissions (whichever is lower) must be greater than the new level of actual emissions. The actual emission decrease must also take place on or before the date that emissions from the modification project first occur and must be federally enforceable on and after the date the Department issues a construction permit for the modification project.

For Bayside Units 1, 2, 3 and 4, the contemporaneous period is projected to begin in September 1995 and end in June 2005. Creditable emission decreases that will occur within this contemporaneous period consist of the actual emissions associated with the cessation of coal-fired operations of F.J. Gannon Station Units 3, 4, 5 and 6. Creditable emission increases consist of those associated with Bayside Units 1, 2, 3 and 4. There are no other permanent creditable emission increases that have occurred or will occur at the F.J. Gannon Station during the September 1995 through June 2005 contemporaneous period.

Summaries of historical, actual emission rates for F.J. Gannon Station Units 1, 2, 3 and 4 for the 1996 – 2000 five year period are provided on Tables 1 through 4, respectively.

Table 5 provides an analysis of PSD NSR applicability for Bayside Units 1, 2, 3 and 4. Contemporaneous, creditable emission decreases were determined based on the average actual emissions for F.J. Gannon Station Units 3 and 4 for the 1999/2000 two-year period, F.J. Gannon Station Unit 5 for the 1998/1999 two-year period, and F.J. Gannon Station Unit 6 for the 1997/1998 two-year period. These actual emission rates reflect the retroactive application of $NO_x$, $SO_2$, and PM BACT in accordance with provisions of the EPA/TEC Consent Decree. The net emission rate changes due to the increase in potential emissions for Bayside Units 1, 2, 3 and 4, minus the two-year average actual emissions for F.J. Gannon Station Units 3, 4, 5 and 6 are all below the applicable Table 212.400-2, F.A.C. Regulated Pollutants—Significant Emission Rates with the exception of CO and $PM/PM_{10}$. For most regulated pollutants, there will be a substantial reduction in emissions; e.g., approximately 1,300 and 1,800 tpy for $SO_2$ and $NO_x$, respectively. Reductions in real actual emission rates (i.e., excluding adjustments for the retroactive application of $NO_x$, $SO_2$, and PM BACT) will be considerably higher. Accordingly, Bayside Units 1, 2, 3 and 4 are subject to PSD NSR for CO and $PM/PM_{10}$ only.

## Table 1. Bayside Station Units 1, 2, 3 and 4
## Netting Analysis - F.J. Gannnon Station Unit 3 Historical Emissions

| | 1996 | 1997 | 1998 | 1999 | 2000 | 96-00, 5 Yr Avg | 99,00 Avg |
|---|---|---|---|---|---|---|---|
| Coal Usage (tons) | 298,202 | 502,172 | 441,838 | 431,164 | 474,944 | 429,664 | 453,054 |
| Wt % Ash | 6.60 | 6.88 | 6.79 | 6.87 | 7.09 | 6.85 | 6.98 |
| Heat Content ($10^6$ Btu/ton) | 23.31 | 20.06 | 19.19 | 21.00 | 20.00 | 20.71 | 20.50 |
| Wt % S | 1.12 | 1.15 | 0.87 | 0.95 | 0.85 | 0.99 | 0.90 |
| Oil Usage ($10^3$ gal) | 311.0 | 639.9 | 599.0 | 397.0 | 10,156.9 | 2,420.7 | 5,277 |
| Heat Content ($10^6$ Btu/$10^3$ gal) | 138.556 | 137.989 | 138.551 | 138.000 | 138.000 | 138.219 | 138.000 |
| Wt % S | 0.30 | 0.15 | 0.28 | 0.41 | 0.42 | 0.31 | 0.42 |
| Total Heat Input ($10^6$ Btu/yr) | 6,994,776 | 10,161,863 | 8,561,862 | 9,109,230 | 10,900,532 | 9,145,653 | 10,004,881 |
| $NO_x$ [(a)] | 349.7 | 508.1 | 428.1 | 455.5 | 545.0 | 457.3 | 500.2 |
| CO AOR | 90.0 | 153.0 | 111.0 | 108.8 | 119.8 | 116.5 | 114.3 |
| $SO_2$ [(b)] | 320.3 | 488.6 | 372.9 | 372.9 | 367.5 | 384.4 | 370.2 |
| $H_2SO_4$ [(c)] AP-42 (1998) | 18.7 | 32.3 | 21.6 | 23.0 | 25.9 | 24.3 | 24.4 |
| $PM_{10}$ [(d)] | 35.0 | 50.8 | 42.8 | 45.5 | 54.5 | 45.7 | 50.0 |
| PM [(d)] | 35.0 | 50.8 | 42.8 | 45.5 | 54.5 | 45.7 | 50.0 |
| Pb AOR | 2.0 | 3.3 | 2.9 | 2.9 | 0.1 | 2.2 | 1.5 |
| VOC AP-42 (1998) | 16.4 | 27.7 | 24.4 | 23.8 | 27.1 | 23.9 | 25.4 |

(a) Actual emissions based on 0.10 lb/MMBtu emission rate per EPA/TEC Consent Decree.
(b) Actual emissions reduced by 95% per EPA/TEC Consent Decree.
(c) Actual emissions reduced by 35% to reflect retroactive BACT.
(d) Actual emissions based on 0.010 lb/MMBtu emission rate per EPA/TEC Consent Decree.

Sources: ECT, 2001.
TEC, 2001.

**Table 2. Bayside Station Units 1, 2, 3 and 4**
**Netting Analysis - F.J. Gannnon Station Unit 4 Historical Emissions**

| | 1996 | 1997 | 1998 | 1999 | 2000 | 96-00, 5 Yr Avg | 99,00 Avg |
|---|---|---|---|---|---|---|---|
| Coal Usage (tons) | 486,874 | 474,906 | 486,831 | 408,955 | 461,418 | 463,797 | 435,187 |
| Wt % Ash | 6.75 | 6.85 | 6.79 | 6.95 | 7.13 | 6.89 | 7.04 |
| Heat Content ($10^6$ Btu/ton) | 22.35 | 20.87 | 20.04 | 20.00 | 20.00 | 20.65 | 20.00 |
| Wt % S | 1.08 | 1.04 | 0.87 | 0.94 | 0.86 | 0.96 | 0.90 |
| Oil Usage ($10^3$ gal) | 311.0 | 576.9 | 599.0 | 397.0 | 10,156.9 | 2,408.1 | 5,277 |
| Heat Content ($10^6$ Btu/$10^3$ gal) | 138.556 | 137.989 | 138.551 | 138.000 | 138.000 | 138.219 | 138.000 |
| Wt % S | 0.30 | 0.15 | 0.28 | 0.41 | 0.41 | 0.31 | 0.41 |
| Total Heat Input ($10^6$ Btu/yr) | 10,924,725 | 9,990,887 | 9,839,084 | 8,233,886 | 10,630,012 | 9,923,719 | 9,431,949 |
| $NO_x$[a] | 546.2 | 499.5 | 492.0 | 411.7 | 531.5 | 496.2 | 471.6 |
| CO AOR | 147.0 | 143.0 | 123.0 | 103.2 | 116.4 | 126.5 | 109.8 |
| $SO_2$[b] | 492.8 | 519.2 | 477.7 | 373.5 | 391.6 | 450.9 | 382.5 |
| $H_2SO_4$[c] AP-42 (1998) | 29.4 | 27.6 | 23.7 | 21.6 | 25.4 | 25.5 | 23.5 |
| $PM_{10}$[d] | 54.6 | 50.0 | 49.2 | 41.2 | 53.2 | 49.6 | 47.2 |
| PM[d] | 54.6 | 50.0 | 49.2 | 41.2 | 53.2 | 49.6 | 47.2 |
| Pb AOR | 3.2 | 3.2 | 3.2 | 2.7 | 0.1 | 2.5 | 1.4 |
| VOC AP-42 (1998) | 26.8 | 26.2 | 26.8 | 22.5 | 26.4 | 25.7 | 24.5 |

(a) Actual emissions based on 0.10 lb/MMBtu emission rate per EPA/TEC Consent Decree.
(b) Actual emissions reduced by 95% per EPA/TEC Consent Decree.
(c) Actual emissions reduced by 35% to reflect retroactive BACT.
(d) Actual emissions based on 0.010 lb/MMBtu emission rate per EPA/TEC Consent Decree.

Sources: ECT, 2001.
TEC, 2001.

**Table 3. Bayside Station Units 1, 2, 3 and 4**
**Netting Analysis - F.J. Gannnon Station Unit 5 Historical Emissions**

| | 1996 | 1997 | 1998 | 1999 | 2000 | 96 - 00, 5 Yr Avg | 98, 99 Avg |
|---|---|---|---|---|---|---|---|
| Coal Usage (tons) | 574,584 | 450,802 | 556,487 | 541,559 | 418,667 | 508,420 | 549,023 |
| Wt % Ash | 7.47 | 8.26 | 8.15 | 7.58 | 6.95 | 7.68 | 7.87 |
| Heat Content ($10^6$ Btu/ton) | 24.65 | 23.96 | 24.00 | 24.00 | 24.00 | 24.12 | 24.00 |
| Wt % S | 1.19 | 1.16 | 1.21 | 1.17 | 1.22 | 1.19 | 1.19 |
| Oil Usage ($10^3$ gal) | 311.0 | 600.9 | 599.0 | 397.0 | 10,156.9 | 2,413.0 | 498.0 |
| Heat Content ($10^6$ Btu/$10^3$ gal) | 138.556 | 137.989 | 138.551 | 138.000 | 138.000 | 138.219 | 138.276 |
| Wt % S | 0.30 | 0.15 | 0.28 | 0.41 | 0.42 | 0.31 | 0.35 |
| Total Heat Input ($10^6$ Btu/yr) | 14,208,885 | 10,884,135 | 13,438,679 | 13,052,202 | 11,449,660 | 12,606,712 | 13,245,440 |
| $NO_x$[(a)] | 710.4 | 544.2 | 671.9 | 652.6 | 572.5 | 630.3 | 662.3 |
| CO AOR | 173.0 | 135.0 | 140.0 | 136.4 | 105.7 | 138.0 | 138.2 |
| $SO_2$[(b)] | 648.4 | 537.7 | 685.1 | 630.1 | 538.6 | 608.0 | 657.6 |
| $H_2SO_4$[(c)] AP-42 (1998) | 38.2 | 29.2 | 37.7 | 35.4 | 31.9 | 34.5 | 36.6 |
| $PM_{10}$[(d)] | 71.0 | 54.4 | 67.2 | 65.3 | 57.2 | 63.0 | 66.2 |
| PM[(d)] | 71.0 | 54.4 | 67.2 | 65.3 | 57.2 | 63.0 | 66.2 |
| Pb AOR | 3.8 | 3.0 | 3.7 | 3.6 | 0.1 | 2.8 | 3.4 |
| VOC AP-42 (1998) | 31.6 | 24.9 | 30.7 | 29.8 | 24.0 | 28.2 | 28.2 |

(a) Actual emissions based on 0.10 lb/MMBtu emission rate per EPA/TEC Consent Decree.
(b) Actual emissions reduced by 95% per EPA/TEC Consent Decree.
(c) Actual emissions reduced by 35% to reflect retroactive BACT.
(d) Actual emissions based on 0.010 lb/MMBtu emission rate per EPA/TEC Consent Decree.

Sources: ECT, 2001.
TEC, 2001.

**Table 4. Bayside Station Units 1, 2, 3 and 4**
**Netting Analysis - F.J. Gannnon Station Unit 6 Historical Emissions**

| | 1996 | 1997 | 1998 | 1999 | 2000 | 96 - 00, 5 Yr Avg | 97, 98 Avg |
|---|---|---|---|---|---|---|---|
| Coal Usage (tons) | 892,742 | 920,526 | 860,597 | 693,039 | 391,079 | 751,597 | 890,562 |
| Wt % Ash | 7.48 | 8.79 | 8.41 | 7.28 | 7.18 | 7.83 | 8.60 |
| Heat Content ($10^6$ Btu/ton) | 24.85 | 24.28 | 24.01 | 24.00 | 16.00 | 22.63 | 24.15 |
| Wt % S | 1.19 | 1.18 | 1.22 | 1.13 | 1.10 | 1.16 | 1.20 |
| Oil Usage ($10^3$ gal) | 311.0 | 639.9 | 599.0 | 362.0 | 6,587.5 | 1,699.9 | 619.4 |
| Heat Content ($10^6$ Btu/$10^3$ gal) | 138.556 | 137.989 | 138.551 | 138.000 | 138.000 | 138.219 | 138.270 |
| Wt % S | 0.30 | 0.15 | 0.28 | 0.41 | 0.42 | 0.31 | 0.22 |
| Total Heat Input ($10^6$ Btu/yr) | 22,229,515 | 22,438,664 | 20,745,925 | 16,682,892 | 7,166,339 | 17,852,667 | 21,592,294 |
| $NO_x$ [a] | 1,111.5 | 1,121.9 | 1,037.3 | 834.1 | 358.3 | 892.6 | 1,079.6 |
| CO AOR | 269.0 | 278.0 | 216.0 | 174.2 | 98.5 | 207.1 | 247.0 |
| $SO_2$ [b] | 1,015.4 | 1,141.5 | 1,185.2 | 801.5 | 465.5 | 921.8 | 1,163.3 |
| $H_2SO_4$ [c] AP-42 (1998) | 59.3 | 60.6 | 58.7 | 43.8 | 26.2 | 49.7 | 59.6 |
| $PM_{10}$ [d] | 111.1 | 112.2 | 103.7 | 83.4 | 35.8 | 89.3 | 108.0 |
| PM [d] | 111.1 | 112.2 | 103.7 | 83.4 | 35.8 | 89.3 | 108.0 |
| Pb AOR | 5.9 | 6.1 | 5.7 | 4.6 | 0.1 | 4.5 | 5.9 |
| VOC AP-42 (1998) | 49.1 | 50.7 | 47.4 | 38.2 | 22.2 | 41.5 | 49.0 |

(a) Actual emissions based on 0.10 lb/MMBtu emission rate per EPA/TEC Consent Decree.
(b) Actual emissions reduced by 95% per EPA/TEC Consent Decree.
(c) Actual emissions reduced by 35% to reflect retroactive BACT.
(d) Actual emissions based on 0.010 lb/MMBtu emission rate per EPA/TEC Consent Decree.

Sources: ECT, 2001.
TEC, 2001.

**Table 5. Bayside Station**

**Bayside Units 1 - 4/F.J. Gannon Units 3 - 6 Emissions Netting Analysis**

| | F. J. Gannon Units 3, 4, 5 & 6 (tpy) | | | | | Units 3 & 4 2 Yr [a] Avg | Units 5 & 6 2 Yr [b][c] Avg | Units 3 - 6 2 Yr [a][b][c] Avg | CT 1A-4B (tpy) | Net Change (tpy) | PSD Threshold (tpy) | PSD Review (Y/N) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 1996 | 1997 | 1998 | 1999 | 2000 | | | | | | | |
| Coal Usage (tons) | 2,252,402 | 2,348,406 | 2,345,753 | 2,074,717 | 1,746,108 | 888,241 | 1,439,585 | 2,327,825 | N/A | N/A | N/A | N/A |
| Wt % Ash | 7.08 | 7.70 | 7.54 | 7.17 | 7.09 | 7.01 | 8.23 | 15.24 | N/A | N/A | N/A | N/A |
| Heat Content ($10^6$ Btu/ton) | 23.79 | 22.29 | 21.81 | 22.25 | 20.00 | 20.25 | 24.07 | 44.32 | N/A | N/A | N/A | N/A |
| Wt % S | 1.15 | 1.13 | 1.04 | 1.05 | 1.01 | 0.90 | 1.20 | 2.10 | N/A | N/A | N/A | N/A |
| Oil Usage ($10^3$ gal) | 1,244.0 | 2,457.5 | 2,396.0 | 1,553.0 | 37,058.2 | 10,553.9 | 1,117.4 | 11,671.3 | N/A | N/A | N/A | N/A |
| Heat Content ($10^6$ Btu/$10^3$ gal) | 138.556 | 137.989 | 138.551 | 138.000 | 138.000 | 138.000 | 138.273 | 276.273 | N/A | N/A | N/A | N/A |
| Wt % S | 0.30 | 0.15 | 0.28 | 0.41 | 0.42 | 0.41 | 0.28 | 0.69 | N/A | N/A | N/A | N/A |
| Total Heat Input ($10^6$ Btu/yr) | 54,357,901 | 53,475,548 | 52,585,549 | 47,078,210 | 40,146,544 | 19,436,830 | 34,837,734 | 54,274,565 | N/A | N/A | N/A | N/A |
| $NO_x$[d] | 2,717.9 | 2,673.8 | 2,629.3 | 2,353.9 | 2,007.3 | 971.8 | 1,741.9 | 2,713.7 | 1,422.9 | -1,290.8 | 40.0 | N |
| CO AOR | 679.0 | 709.0 | 590.0 | 522.6 | 440.4 | 224.1 | 385.2 | 609.3 | 1,492.5 | 883.2 | 100.0 | Y |
| $SO_2$[e] | 2,476.9 | 2,686.9 | 2,720.8 | 2,177.9 | 1,763.1 | 752.7 | 1,820.9 | 2,573.6 | 757.1 | -1,816.5 | 40.0 | N |
| $H_2SO_4$[f] AP-42 (1998) | 145.5 | 149.7 | 141.6 | 123.7 | 109.4 | 47.9 | 96.2 | 144.1 | 129.9 | -14.2 | 7.0 | N |
| $PM_{10}$[g] | 271.8 | 267.4 | 262.9 | 235.4 | 200.7 | 97.2 | 174.2 | 271.4 | 1,077.1 | 805.7 | 15.0 | Y |
| PM[g] | 271.8 | 267.4 | 262.9 | 235.4 | 200.7 | 97.2 | 174.2 | 271.4 | 1,077.1 | 805.7 | 25.0 | Y |
| Pb AOR | 15.0 | 15.6 | 15.6 | 13.8 | 0.4 | 2.9 | 9.3 | 12.2 | 1.6 | -10.6 | 0.6 | N |
| VOC AP-42 (1998) | 124.0 | 129.4 | 129.3 | 114.3 | 99.7 | 49.9 | 77.3 | 127.2 | 148.7 | 21.5 | 40.0 | N |

(a) 1999, 2000 average for Units 3 and 4.
(b) 1998, 1999 average for Unit 5.
(c) 1997, 1998 average for Unit 6.
(d) Actual emissions based on 0.10 lb/MMBtu emission rate per EPA/TEC Consent Decree.
(e) Actual emissions reduced by 95% per EPA/TEC Consent Decree.
(f) Actual emissions reduced by 35% to reflect retroactive BACT.
(g) Actual emissions based on 0.010 lb/MMBtu emission rate per EPA/TEC Consent Decree.

Sources: ECT, 2001.
TEC, 2001.

# Attachment 2

ENGELHARD


101 WOOD AVENUE
ISELIN, NJ 08830

ENGELHARD CORPORATION
2205 CHEQUERS COURT
BEL AIR, MD 21015
PHONE 410-569-0297
FAX 410-569-1841
E-Mail fred.booth@engelhard.com


| | | | |
|---|---|---|---|
| **DATE:** | **August 1, 2001** | **NO. PAGES** | **3** |
| **TO:** | **ECT** | **via e-mail** | |
| **ATTN:** | **Tom Davis** | | |
| | **ENGELHARD** | | |
| **ATTN:** | **Nancy Ellison** | | |
| **FROM:** | **Fred Booth** | **Ph 410-569-0297 // FAX 410-569-1841** | |

**RE:** **TECO - Gannon**
**CO Oxidation System Components**
**Engelhard Budgetary Proposal EPB00385**

We provide Engelhard Proposal EPB00385 for Engelhard **Camet®** metal substrate CO oxidation system per your e-mail request of July 31, 2001.

Our Proposal is based on:

- Given data for GE 7FA Gas Turbine operating in unfired combined cycle mode;
- CO Catalyst for 90% CO Reduction;
- Advise VOC reduction - inlet levels not provided. VOC Composition assumed Non-Methane / Non-Ethane – 50% Saturated.
- Assumed HRSG inside liner dimensions of 67 ft H x 26 ft W.
- Three (3) Year Performance Guarantee;

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

Sincerely yours,

**ENGELHARD CORPORATION**

Frederick A. Booth

Frederick A. Booth
Senior Sales Engineer

ENGELHARD

**ECT**
**TECO - Gannon**
**CO Oxidation System Components**
**Engelhard Budgetary Proposal EPB00385**
**August 1, 2001**

## ENGELHARD CORPORATION
## CAMET® CO OXIDATION SYSTEMS

Scope of Supply: The equipment supplied is installed by others in accordance with the Engelhard design and installation instructions.

- Engelhard **CAMET®** CO Oxidation Catalyst Modules;
- Internal support structures for catalyst modules (frame). Frame design allows adding one more layer.
- Technical Service during installation and Start-Up;

Excluded from Scope of Supply:
Any internally insulated reactor ductwork to house catalysts
Any transitions to and from reactor
Any monorails and hoists for handling modules
Electrical grounding equipment
Foundations
All other items not specifically listed in Scope of Supply
Structural support
Any interconnecting field piping or wiring
Utilities
All Monitors

**PRICES**: fob, plant gate, job site **See Below**

WARRANTY AND GUARANTEE:

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

DOCUMENT / MATERIAL DELIVERY SCHEDULE
Drawings / Documentation – 2-3 weeks after notice to proceed and Engelhard receipt of all engineering specifications and details
Material Delivery

| | |
|---|---|
| CO Modules | 20 - 24 weeks after approval and release for fabrication |

CO SYSTEM DESIGN BASIS:

| | |
|---|---|
| Gas Flow from: | GE 7FA Combustion Turbine - Combined Cycle – NO duct burner |
| Gas Flow: | Horizontal |
| Fuel: | Natural Gas |
| Gas Flow Rate (At catalyst face): | See Performance data |
| Temperature (At catalyst face): | See Performance data |
| CO Concentration (At catalyst face): | See Performance Data |
| CO Reduction: | 90% CO Reduction |
| CO Pressure Drop: | See Performance data |
| VOC Concentration (At catalyst face): | Not Provided |
| VOC Reduction: | Advise |
| VOC Composition | Assumed Non-Methane / Non-Ethane – 50% Saturated |

ENGELHARD

**ECT**
**TECO - Gannon**
**CO Oxidation System Components**
**Engelhard Budgetary Proposal EPB00385**
**August 1, 2001**

## Performance Data and Budget Pricing

| | | | |
|---|---|---|---|
| GIVEN / CALCULATED DATA | CASE | 1 | 2 |
| | AMBIENT | 18 | 93 |
| | FUEL | NG | NG |
| | TURBINE EXHAUST FLOW, lb/hr | 3,811,000 | 2,302,000 |
| | TURBINE EXHAUST GAS ANALYSIS, % VOL. - $N_2$ | 75.09 | 73.45 |
| | $O_2$ | 12.52 | 12.79 |
| | $CO_2$ | 3.88 | 3.53 |
| | $H_2O$ | 7.71 | 9.36 |
| | Ar | 0.80 | 0.87 |
| | GIVEN TURBINE CO, ppmvd @ 15% $O_2$ | 7.2 | 7.8 |
| | GIVEN TURBINE CO, lb/hr | 31.0 | 18.6 |
| | GIVEN TURBINE VOC, ppmvd @ 15% $O_2$ | N / A | N / A |
| | GIVEN TURBINE VOC, lb/hr | N / A | N / A |
| | CALC. GAS MOL. WT. | 28.46 | 28.26 |
| | ASSUMED GAS TEMP. @ CO CATALYST, °F (+/-25) | 650 | 600 |
| DESIGN REQUIREMENTS | CO OUT, ppmvd @ 15% $O_2$ | 0.72 | 0.78 |
| | VOC OUT, ppmvd @ 15% $O_2$ | Advise | Advise |
| | CO PRESSURE DROP - "WG MAX. | Advise | Advise |
| GUARANTEED PERFORMANCE DATA | | | |
| | CO CONVERSION, % - Min. | 90.0% | 90.0% |
| | CO OUT, lb/hr - Max. | 3.1 | 1.9 |
| | CO OUT, ppmvd @ 15% $O_2$ | 0 7 | 0.8 |
| | $SO_2$ -> $SO_3$ CONVERSION, % - Max. | 10% | 7% |
| | VOC** CONVERSION, % - Min. | 42% | 44% |
| | VOC** OUT, lb/hr | N / A | N / A |
| | VOC** OUT, ppmvd @ 15% $O_2$ | N / A | N / A |
| ** VOC - NON-METHANE / NON-ETHANE – 50% SATURATED | | | |
| | CO PRESSURE DROP, "WG - Max. | 1.2 | 0.6 |
| | **CO SYSTEM - $$** | **$670,000** | |
| | **REPLACEMENT CO CATALYST MODULES - $$** | **$600,000** | |

**Dimensions:**

| | |
|---|---|
| **Inside Liner Width** | **(A) 26 ft** |
| **Inside Liner Height** | **(B) 67 ft** |
| **Frame Depth** | **(C) 18 in** |

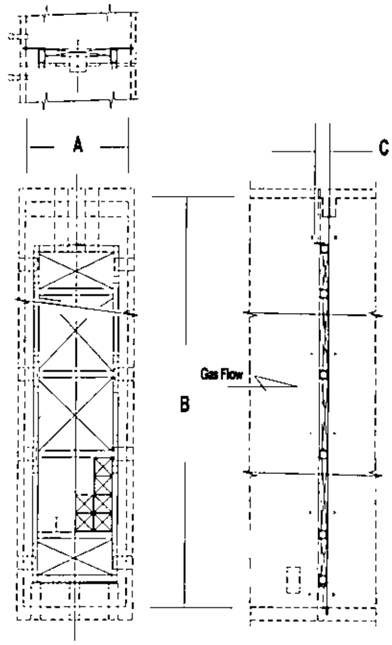

Table 4-4. Capital Costs for Oxidation Catalyst System, Eleven CT/HRSGs

| Item | Dollars | OAQPS Factor |
|---|---|---|
| Direct Costs | | |
| Purchased equipment | 7,370,000 | A |
| Sales tax | 442,200 | 0.06 x A |
| Instrumentation | 737,000 | 0.10 x A |
| Freight | 368,500 | 0.05 x A |
| **Subtotal Purchased Equipment** | **8,917,700** | **B** |
| Installation | | |
| Foundations and support | 713,416 | 0.08 x B |
| Handling and erection | 1,248,478 | 0.14 x B |
| Electrical | 356,708 | 0.04 x B |
| Piping | 178,354 | 0.02 x B |
| Insulation for ductwork | 89,177 | 0.01 x B |
| Painting | 89,177 | 0.01 x B |
| **Subtotal Installation Cost** | **2,675,310** | |
| **Total Direct Costs (TDC)** | **11,593,010** | |
| Indirect Costs | | |
| Engineering | 891,770 | 0.01 x B |
| Construction and field expense | 445,885 | 0.05 x B |
| Contractor fees | 891,770 | 0.10 x B |
| Startup | 178,354 | 0.02 x B |
| Performance test | 89,177 | 0.01 x B |
| Contingency | 267,531 | 0.03 x B |
| **Total Indirect Costs (TIC)** | **2,764,487** | |
| **TOTAL CAPITAL INVESTMENT (TCI)** | **14,357,497** | TDC + TIC |

Source: ECT, 2001.

Table 4-5. Annual Operating Costs for Oxidation Catalyst System, Eleven CT/HRSGs

| Item | Dollars | OAQPS Factor |
|---|---|---|
| Direct Costs | | |
| Catalyst costs | | |
| Replacement (materials and labor) | 7,337,616 | |
| Credit for used catalyst | (990,000) | 15% credit |
| **Annualized Catalyst Cost** | **1,548,124** | |
| Energy Penalties | | |
| Turbine backpressure | 1,081,159 | 0.2% penalty |
| **Total Direct Costs (TDC)** | **2,629,284** | |
| Indirect Costs | | |
| Administrative charges | 287,150 | 0.02 x TCI |
| Property taxes | 143,575 | 0.01 x TCI |
| Insurance | 143,575 | 0.01 x TCI |
| Capital recovery | 770,745 | 15 yrs @ 7.0% |
| **Total Indirect Costs (TIC)** | **1,345,045** | |
| **TOTAL ANNUAL COST (TAC)** | **3,974,329** | TDC + TIC |

Source: ECT, 2001.

Table 4-6. Summary of CO BACT Analysis (Revised August 2001)

| Control Option | Emission Impacts: Emission Rates (lb/hr) | Emission Rates (tpy) | Emission Reduction (tpy) | Economic Impacts: Installed Capital Cost ($) | Total Annualized Cost ($/yr) | Cost Effectiveness Over Baseline ($/ton) | Energy Impacts: Increase Over Baseline (MMBtu/yr) | Environmental Impacts: Toxic Impact (Y/N) | Adverse Envir. Impact (Y/N) |
|---|---|---|---|---|---|---|---|---|---|
| Oxidation catalyst | 31.6 | 138.3 | 1,244.4 | 14,357,497 | 3,974,329 | 3,194 | 122,969 | N | Y |
| Baseline | 315.7 | 1,382.7 | N/A | N/A | N/A | N/A | N/A | N/A | N/A |

Basis: Eleven GE PG7241 (FA) CTs, 100-percent load, natural gas-firing for 8,760 hr/yr.

Sources: ECT, 2001.
GE, 2001.
TEC, 2001.

# Department of Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

July 26, 2001

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

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

Re: Request for Additional Information
Project No. 0570040-015-AC
Bayside Units 3 and 4 Repowering Project

Dear Ms. Sheffield:

On June 26, 2001, the Department received the above referenced application. The modeling information in the application is incomplete. Rule 62-212.400(5)(d) requires a PSD Class I and Class II increment analysis for $PM_{10}$. This analysis was not provided. In order to continue processing your application, the Department will need this information

Any additional comments from EPA and the U.S. Fish and Wildlife Service will be forwarded to you after we receive them.

The Department will resume processing this 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. A new certification statement by the authorized representative or responsible official must accompany any material changes to the application. Rule 62-4.055(1), F.A.C. now requires applicants to respond to requests for information within 90 days.

We will be happy to meet and discuss the details with you and your staff. You may discuss the modeling requirements with Mr. Cleve Holladay at 850/921-8689.

Sincerely,

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

AAL/sa

cc: G. Worley, EPA
J. Bunyak, NPS
B. Thomas, DEP-SWD
T. Davis, Ph.D., ECT

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1. Article Addressed to:

Ms. Karen Sheffield, Gen. Mgr.
Tampa Electric Company
Bayside Power Station
Port Sutton Road
Tampa, FL 33619

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B. Date of Delivery 7-28-01

C. Signature

X Alphaeus Noel

☐ Agent
☐ Addressee

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0682
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07/26/2001

*Recipient's Name (Please Print Clearly) (to be completed by mailer)*
Ms. Karen Sheffield

*Street, Apt. No.; or PO Box No.*
Port Sutton Rd.

*City, State, ZIP+4*
Tampa, FL 33619

PS Form 3800, February 2000 See Reverse for Instructions

# Department of Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary


July 17, 2001

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

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

Re: **Request for Additional Information**
Project No. 0570040-015-AC
Bayside Units 3 and 4 Re-powering Project

Dear Ms. Sheffield:

On June 26, 2001, the Department received your application and sufficient fee for an air construction permit to re-power the steam turbines for existing Gannon Units 3 and 4 with four combined cycle gas turbines to become part of the new 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 the below items require new calculations, please submit the new calculations, assumptions, reference material and appropriate revised pages of the application form.

1. Revised PSD Netting Analysis: In March of 2001, the Department issued a final permit for Bayside Units 1 and 2, which will re-power the steam turbines for existing Gannon Units 5 and 6. The application to re-power the steam turbines for existing Gannon Units 3 and 4 was submitted was submitted only three months later. The Department believes that this application is the second phase of the Gannon re-powering project. Please revise PSD netting analysis to include the following:
   - Specify the PSD contemporaneous period as defined in Rule 62-212.400(2)(e)3, F.A.C.
   - Include all emissions increases that have occurred or will occur during the contemporaneous period from all projects.
   - Include all of the emissions decreases that have occurred or will occur during the contemporaneous period from all projects.
   - Update the net emissions changes and PSD applicability accordingly.
2. Other Re-powering: Has TEC considered re-powering the existing steam turbines for Gannon Units 1 and 2? Has TEC contracted for any work involving the re-powering of these remaining steam turbines? Please submit a revised construction schedule for all units to be re-powered showing the planned startup date for each Bayside Unit and the shutdown date for each Gannon Unit.
3. Comparison of Bayside 1-2 with 3-4: Is TEC requesting any emissions standards, operational constraints, monitoring provisions, etc. that are different from those contained in the final permit issued for Bayside Units 1 and 2?

4. Emissions Decreases: Page 1-2 of the application states, "Following installation and commercial operation of Bayside Unit 3, existing coal fired operation at F.J. Gannon Station Unit 3 will permanently cease. Following installation and commercial operation of Bayside Unit 4, existing coal fired operation at F.J. Gannon Station Unit 4 will permanently cease." The Department notes that, for an emissions decrease to be enforceable, each existing unit must be completely shutdown and rendered incapable of operation prior to startup of the corresponding new unit. Please comment.

5. Unit Description: Each new "Bayside Unit" will consist of two combined cycle units described as:

   Each unit consists of a General Electric Model PG7241(FA) gas turbine-electrical generator set, an automated gas turbine control system, an inlet air filtration system, an evaporative inlet air cooling system, an unfired heat recovery steam generator (HRSG), a single exhaust stack that is 150 feet tall and 19.0 feet in diameter and associated support equipment. The project also includes electric fuel heaters and cooling towers. Natural gas is the exclusive fuel.

   **Controls**: Emissions of CO, PM/$PM_{10}$, SAM, $SO_2$, and VOC are minimized by the efficient combustion of natural gas at high temperatures. NOx emissions are reduced by a Selective Catalytic Reduction (SCR) system combined with dry low-NOx (DLN) combustion technology when firing natural gas.

   **Heat Input**: At a compressor inlet air temperature of 59° F and firing 1842 mmBTU (HHV) per hour of natural gas, each unit produces approximately 169 MW. Exhaust gases exit the stack with a volumetric flow rate of approximately 1,020,000 acfm at 215° F.

   **Generating Capacity**: Bayside Units 3A and 3B will supply steam to a single steam electrical generator (formerly serving Gannon Unit 3) with a nameplate rating of 180 MW. Bayside Units 4A and 4B will supply steam to a single steam electrical generator (formerly serving Gannon Unit 4) with a nameplate rating of 188 MW of electrical power. Bayside Unit 3 is designed to produce a nominal 512 MW and Bayside Unit 4 is designed to produce a nominal 520 MW of electrical power.

   Is this an accurate description?

6. HAP Emissions: The Bayside 1 and 2 re-powering project combined with the Bayside 3 and 4 re-powering project will result in total formaldehyde emissions greater that 10 tons per year and total hazardous air pollutant emissions (HAP) greater that 25 tons per year. Please submit a case-by-case MACT analysis for the Department's review. The Department will make a case-by-case MACT determination for these phased projects.

7. Catalytic Oxidation System: Please provide a new vendor's quote for this project based on 11 proposed systems firing natural gas. Revise the cost analysis if necessary.

8. Air Quality Analysis: The Department reserves the right to ask for additional information regarding the air quality analysis within the 30-day period after receiving the application with sufficient fee (on or before July 26, 2001).

9. Other Reviews: The Department will forward any comments or questions if received from EPA Region 4, the National Park Service, the Hillsborough County Environmental Protection Commission, or the Department's Southwest District Office.

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 any material changes to the application, please include a new certification statement by the authorized representative or responsible official. You are reminded that Rule 62-4.055(1), F.A.C. now requires applicants to respond to requests for information within 90 days or provide a written request for an additional period of time to submit the information.

If you have any questions regarding this matter, please call me at 850/921-9536.

Sincerely,

Jeffery F. Koerner

Jeffery F. Koerner
New Source Review Section

AAL/jfk

cc: Mr. Patrick Shell, TEC
Mr. Shannon Todd, TEC
Mr. Tom Davis, ECT
Mr. Jerry Campbell, HCEPC
Mr. Gerald Kissel, SWD
Mr. Gregg Worley, EPA Region 4
Mr. John Bunyak, NPS

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| 1. Article Addressed to:<br><br>Ms. Karen Sheffield, Gen. Mgr.<br>Tampa Electric Company<br>Bayside Power Station<br>Port Sutton Road<br>Tampa, FL 33619 | 3. Service Type<br>☒ Certified Mail ☐ Express Mail<br>☐ Registered ☐ Return Receipt for Merchandise<br>☐ Insured Mail ☐ C.O.D.<br>4. Restricted Delivery? *(Extra Fee)* ☐ Yes |

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*Recipient's Name (Please Print Clearly) (to be completed by mailer)*
Ms. Karen Sheffield, Gen. Mgr.
*Street, Apt. No.; or PO Box No.*
Port sutton Rd.
*City, State, ZIP+4*
Tampa, FL 33619

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