Department of Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
NOTICE OF FINAL PERMIT

In the Matter of an
Application for Permit by:

Mr. Stanley J. Martin
General Manager, Big Bend Station
Tampa Electric Company
P. O. Box 111
Tampa, Florida 33601-0111
_______________________________/

FINAL Title V Permit No.: 0570039-002-AV
Big Bend Station

Enclosed is FINAL Permit Number 0570039-002-AV for the Big Bend Station located at Big Bend Road, North Ruskin, Hillsborough County, issued pursuant to Chapter 403, Florida Statutes (F.S.).

Any party to this order (permit) has the right to seek judicial review of the permit pursuant to Section 120.68, F.S., by the filing of a Notice of Appeal pursuant to Rule 9.110, Florida Rules of Appellate Procedure, with the Clerk of the permitting authority in the Legal Office; and by filing a copy of the Notice of Appeal accompanied by the applicable filing fees with the appropriate District Court of Appeal. The Notice of Appeal must be filed within 30 (thirty) days from the date this Notice is filed with the Clerk of the permitting authority.

Executed in Tallahassee, Florida.

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

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this NOTICE OF FINAL PERMIT (including the FINAL permit) was sent by certified mail (*) and copies were mailed by U.S. Mail before the close of business on 12-28-00 to the person(s) listed or as otherwise noted:

Stanley J. Martin, R.O.*
Gregory M. Nelson, D.R.
Shannon K. Todd, TEC
Thomas W. Reese, Esquire
USEPA, Region 4 (INTERNET E-mail Memorandum)
Gail Kamaras, Legal Environmental Assistance Foundation
Thomas W. Davis, ECT
Bill Thomas, SWD
Jerry Campbell, EPCHC

Clerk Stamp

FILING AND ACKNOWLEDGMENT FILED, on this date, pursuant to Section 120.52(7), Florida Statutes, with the designated agency Clerk, receipt of which is hereby acknowledged.

(Clerk) 12-28-00
(Date)

SENDER: *COMPLETE THIS SECTION*

- Complete items 1, 2, and 3. Also complete item 4 if Restricted Delivery is desired.
- Print your name and address on the reverse so that we can return the card to you.
- Attach this card to the back of the mailpiece, or on the front if space permits.

1. Article Addressed to:

Mr. Stanley Martin
General Manager
Big Bend Station
Tampa Electric Company
P.O. Box 111
Tampa, Florida 33601-0111

COMPLETE THIS SECTION ON DELIVERY

A. Received by *(Please Print Clearly)*

B. Date of Delivery 1/2/01

C. Signature

X

☐ Agent
☐ Addressee

D. Is delivery address different from item 1? ☐ Yes
If YES, enter delivery address below: ☐ No

3. Service Type
☒ Certified Mail ☐ Express Mail
☐ Registered ☐ Return Receipt for Merchandise
☐ Insured Mail ☐ C.O.D.

4. Restricted Delivery? *(Extra Fee)* ☐ Yes

2. Article Number *(Copy from service label)*
7000 0600 0021 2825 2340

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

FINAL PERMIT DETERMINATION

I. Comment(s).

Objections were received from USEPA. TECO submitted written comments on the objections. The objections were resolved. Approval of the resolutions was conveyed in a letter from Winston Smith dated December 19, 2000, and the PROPOSED Title V permit was changed. The comments were not considered significant enough to reissue a DRAFT Title V permit and require another public notice. TECO's comments and the department's changes are shown below.

A. EPA Objection Issues

EPA Objection Issue 1

Federally Enforceable Requirements: Section II, conditions 7, 8, 12 and 13 are identified as "not Federally enforceable." Conditions 7 and 8 are Federally enforceable because they are contained in the Federally approved portion of the Florida SIP. Conditions 12 and 13 address the requirement to provide compliance notifications and notification of potential permit modifications to the Environmental Protection Commission of Hillsborough County (EPCHC) and EPA, and provide the appropriate mailing addresses. Pursuant to 40 C.F.R. §70.6(c)(5)(iv), compliance certifications shall be submitted to the Administrator as well as to the permitting authority. Therefore, these conditions are also Federally enforceable since they are part of the required elements of a title V permit.

Section III, conditions A.15, A.20, A.31 are also identified as "not Federally enforceable." Condition A.15 specifies that compliance testing for particulate matter and visible emissions may be conducted either with or without fly ash reinjection. A source is required to conduct compliance testing at conditions that are representative of the day to day operation to better assess the compliance status of the facility. Therefore, this requirement is Federally enforceable and must be identified as such in the permit. Condition A.20 appears to be based on the requirements of 40 C.F.R. 60.46a(g), a Federal requirement. Condition A.31 requires the submission of quarterly reports to the Department and EPCHC detailing the 30-day NO_x rolling average, all time periods of boiler operation as well as a statement of CEM and/or boiler malfunction, start-up or shutdown. As noted above, this requirement appears to fall within the scope of the requirements of 40 C.F.R §70.6(c), thus making it Federally enforceable.

TEC Response: Tampa Electric Company (TEC) is not opposed to making these conditions Federally enforceable.

Proposed Change: These conditions will no longer be identified as "not Federally enforceable".

EPA Objection Issue 2

Appropriate Averaging Times: The emission limits for particulate matter in conditions A.7 and B.5, and for carbon monoxide in condition B.10 do not contain averaging times. Because the stringency of emission limits is a function of both magnitude and averaging time, appropriate averaging times must be added to the permit in order for the limits to be practicably enforceable. An approach that may be used to address this deficiency is to include a general condition in the permit stating that the averaging times for all specified emission standards are tied to or based on the run time of the test method(s) used for determining compliance.

Per special condition 2 of permit AO29-219924, the averaging time for the particulate matter emission limit in condition A.7 of the proposed title V permit for TEC - Big Bend should be two hours. Since the facility already uses this averaging time to evaluate compliance with the particulate matter limit for this unit, the Department should include the same averaging time in the title V permit.

TEC Response: Tampa Electric Company suggest striking the sentence "Per special condition 2 of permit AO29-219924, the averaging times for all specified emission standards are tied to or based on the run time of the test method(s) used for determining compliance: and addressing this concern by adding a footnote in each section. Suggested language for this footnote is as follows: "When not otherwise defined, averaging times for all specified emission standards shall be equal to the cumulative run time elapsed for all runs during the associated compliance test."

Proposed Change: The following will be added after each condition:
{Permitting note: The averaging time for the emissions standard in this condition shall be equal to the cumulative run time required by the specified test method.}

The requirement for a two-hour averaging time for particulate matter from Boiler Unit #1 has never been in a federally-enforceable permit. Its inclusion in AO29-219924 was based on Rule 17-2.600(5)(a)2., F.A.C. This rule no longer exists in our State Implementation Plan.

EPA Objection Issue 3
Federal Enforceability: Condition B.53 states the following:
"Compliance with standards in 40 C.F.R. 60, other than opacity standards, shall be determined ***only*** *by performance tests established by 40 C.F.R. 60.8, unless specified in the applicable standard."*
The language for this condition was taken from 40 C.F.R. 60.11(a), however, the words "in accordance with" were replaced with "only by." Since adding the word "only" precludes the use of credible evidence for determining compliance, this condition is not federally enforceable. Therefore, this condition must be changed so that it is consistent with 40 C.F.R. 60.11(a).

TEC Response: Tampa Electric Company suggests striking the word "only" from the above language.

Proposed Change: This condition will be changed to be consistent with 40 C.F.R. 60.11(a).

EPA Objection Issue 4

Reporting Requirements: Condition C.10 specifies that reporting requirements for PM, sulfur dioxide, VOC, etc., apply if the turbines emit pollutants at the specified level. However, the permit and the statement of basis are silent as to how the facility will evaluate its emissions from the turbines. The permit must specify how the facility will evaluate whether these reporting requirements apply.

TEC Response: Tampa Electric will evaluate emissions from the turbines through the use of AP-42 emission factors or another equivalent method such as fuel analysis.

PROPOSED CHANGE: The following language will be added: "Tampa Electric will evaluate emissions from the turbines through the use of AP-42 emission factors or another equivalent method such as fuel analysis."

EPA Objection Issue 5

Periodic Monitoring: As outlined below, the proposed title V permit for TEC - Big Bend does not contain adequate periodic monitoring requirements to assure compliance with all emissions and operational limits contained in the permit. All Title V permits must contain monitoring that is sufficient to assure compliance with the applicable permit requirements. In particular, 40 C.F.R. Part 70.6 (a)(3)(B) requires that permits include periodic monitoring that is sufficient to yield reliable data from the relevant time period that are representative of the source's compliance with the applicable emission limits. In addition to demonstrating compliance, a system of periodic monitoring will also provide the source with an indication of their emission unit's performance, so that periods of excess emissions and violations of the emission limits can be minimized or avoided. Therefore, periodic monitoring requirements sufficient to assure compliance with all permit limits must be incorporated in the permit or a technical demonstration must be included in the statement of basis explaining the rationale for the approach used by the Department to address periodic monitoring requirements for these units.

a. Subsection D: Condition D.1 specifies the maximum loading rate for the fly ash silos no. 1 and 2. For other units included in this permit, there is a permitting note clarifying that these conditions are not included as limits, but as a basis for determining the percent capacity of the units during source testing (see A.1. and B.1). Periodic monitoring requirements sufficient to assure compliance with the capacity limitations in condition D.1 must be included in the permit or clarifying language needs to be added to this condition.

TEC Response: TEC suggests the following permitting note: {Permitting note: The material loading limitations have been placed in each permit to identify the capacity of each emissions unit for the purposes of confirming that emissions testing is conducted within 90 to 100 percent of the emissions unit's rated capacity (or to limit future operation to 110 percent of the test load), to establish appropriate emission limits and to aid in determining future rule applicability. A note below the permitted capacity condition clarifies this. Regular record keeping is not required for material loading. Instead the owner or operator is expected to determine material loading whenever emission testing is required, to demonstrate at what percentage of the rated capacity that the emissions unit was tested. Rule 62-297.310(5), F.A.C., included in the permit, requires measurement of process variables for emission tests. Material loading determinations may be based on best engineering evaluation of the operating requirements necessary to achieve 90 to 100 percent of the rated loading, unless such operating conditions are otherwise specified by permit condition.}

Proposed Change: The following permit note will be added:
{Permitting note: The material loading limitations have been placed in each permit to identify the capacity of each emissions unit for the purposes of confirming that emissions testing is conducted within 90 to 100 percent of the emissions unit's rated capacity (or to limit future operation to 110 percent of the test load), to establish appropriate emission limits and to aid in determining future rule applicability. Regular recordkeeping is not required for material loading. Instead the owner or operator is expected to determine material loading whenever the emission testing is required, to demonstrate at what percentage of the rated capacity that the emissions unit was tested. Rule 62-297.310(5), F.A.C., included in the permit, requires measurement of process variables for emission tests. Material loading demonstrations may be based on best engineering evaluation of the operating requirements necessary to achieve 90 to 100 percent of the rated loading, unless such operating conditions are otherwise specified by permit condition.}

b. Subsections E and F: The permit does not contain periodic monitoring for the particulate matter and visible emissions limits contained in subsections E and F of the proposed permit, which address the requirements for the Flyash Silo no. 3 and the Limestone Handling and Storage. The permit must include the appropriate test methods that the facility will use to determine compliance with the emission limits and the frequency for testing. Also, conditions E.3 and F.4 require that the systems be operated under negative pressure and that they vent to the control system but there are no requirements to monitor the system pressure or the frequency for assessing whether the system is operating under the specified conditions. Appropriate periodic monitoring requirements must be included in the permit or the statement of basis must explain why no testing is needed for these units.

TEC Response: TEC will perform an annual VE to satisfy the periodic monitoring requirements of these conditions.

Proposed change: The following conditions will be added to permit subsections E and F: "Tampa Electric will perform an annual VE test to satisfy the periodic monitoring requirements of these conditions. In addition, the system pressure will be monitored quarterly to assess that the system is operating under negative pressure."

c. Subsection G: Condition G.2 limits the hours of operation for the coal bunkers, therefore, the permit must include a requirement to record hours of operation. Condition G.5 states that the facility shall determine compliance with the visible emissions limit using Method 9, however, the condition does not establish the frequency for testing. The appropriate testing frequency must be included in the permit.

TEC Response: TEC agrees to monitor the hours of operation of coal bunker loading. In addition, TEC requests a VE testing frequency of once per year.

Proposed change: Tampa Electric will monitor the hours of operation of coal bunker loading. In addition, Tampa Electric will perform an annual VE test to satisfy the periodic monitoring requirements of this condition.

d. {Note: Item d was omitted from the original letter.}

e. Subsection H: Condition H.2 of the proposed permit specifies that the facility will conduct visible emissions testing for the solid fuel yard within 90 days of completing the reconfiguration of the fuel yard. Periodic monitoring requirements sufficient to assess compliance with the VE limit for the solid fuel yard must be included in the permit.

TEC Response: This condition is actually outdated and is a product of the reconfiguration of the fuel yard to accommodate transloading operations for supplying fuel to Polk Power Station. TEC does, however, request an annual VE test to demonstrate compliance with the opacity standard established for the solid fuel yard.

Proposed change: Tampa Electric will perform an annual VE test to demonstrate compliance with the opacity standard established for the solid fuel yard.

f. Subsection J: Condition J.4 does not establish the frequency of testing for visible emission for the Abrasive Blast Booth and Abrasive Blast Media Storage. The appropriate testing frequency must be included in the permit. Also, since these units have baghouses, periodic monitoring requirements should be added to assess the proper operation of the control equipment.

TEC Response: TEC requests the use of an annual VE test to demonstrate compliance with the opacity standard established for the Abrasive Blast Booth and the Abrasive Blast Media Storage.

Proposed change: During each month that the Abrasive Blast Booth is used, a VE test must be performed. A monthly VE test is not required during any month that the Abrasive Blast Booth is not used. During each month that abrasive blast media is transferred to or from Abrasive Blast Media Storage, a VE test must be performed. A monthly VE test is not required during any month that no abrasive blast media is transferred to or from Abrasive Blast Media Storage. However, at a minimum, an annual VE test must be performed.

EPA Objection Issue 6

Practical Enforceability: Conditions M.2 and M.6 leave to the facility's discretion how to evaluate what constitutes proper operation of the baghouse without providing any criteria to make such determination. As written, these conditions are not enforceable as a practical matter. The conditions must contain sufficient detail to ensure that the facility clearly understands what its obligations are and how compliance with these requirements will be evaluated. Also, since this unit has a baghouse, the Department should consider adding periodic monitoring requirements to assess the proper operation of the unit.

TEC Response: TEC will perform an annual VE to satisfy the periodic monitoring requirements of these conditions.

Proposed change: The following condition shall be added to the permit: "Tampa Electric shall keep records of facility staff training, and shall maintain, on site, an Operations and Maintenance Plan for the baghouse that details how it shall be properly operated and maintained at all times. Tampa Electric shall also take weekly pressure readings from the baghouse pressure-sensing device."

EPA Objection Issue 7

Applicable Requirements: The Department must ensure that the conditions from the Consent Decree that are effective during the life of the permit for TEC - Big Bend is appropriately addressed in the permit. Although the Consent Decree can be included as an attachment to the permit, we found at least one instance where a permit condition conflicts with the stipulations of the Consent Decree. Paragraph 30 of the order requires the company to operate the existing scrubbers for units 1 and 2 at all times, effective September 1, 2000, however, condition A.9 of the permit allows for the intermittent operation of the scrubber to control SO_2 emissions. Please note that the terms of the

Consent Decree take precedence over any existing construction permit terms. The permit must be revised to incorporate the appropriate scrubber operating conditions.

Further, the facility will benefit from having all the relevant requirements included in one document. For example, the permit should include the requirements of Paragraph 42 of the order, which stipulate that the company must apply for a title V permit or an amendment to an existing title V permit to incorporate the changes to the facility resulting from the consent decree. This requirement will be triggered by the requirement in paragraph 32 to install a CEM for PM on or before March 1, 2002. We strongly recommend the Department to consider including the stipulations of the Consent Decree in the proposed title V permit for TEC- Big Bend.

TEC Response: TEC understands that the provisions of the Consent Decree take precedence over those found in the Title V permit and TEC intends to comply with all provisions of each document. In addition, TEC requests that Specific Conditions 29, 30, and 30.1 be added to the body of the Title V permit.

Proposed changes:

1. The Consent Final Judgement and the Consent Decree are specifically attached to the permit (see the "placard" page where attachments to the permit are listed under "Referenced attachments made a part of this permit:". For consistency purposes, clarifying language will be added to clearly indicate the attachments are part of this permit. To clarify that several terms and conditions of the Title V permit are superceded by the agreements, clarifying language will be added to facility-wide condition 11. The condition will be changed

> From: 11. The permittee shall comply with the Consent Final Judgement (DEP vs. TEC) dated December 6, 1999, and the Consent Decree (U.S. vs. TEC) dated February 29, 2000.
> [Rules 62-4.070(3)&(5) and 62-213.440, F.A.C.]
>
> To: 11. The Consent Final Judgement (DEP vs. TEC) dated December 6, 1999; and the Consent Decree (U.S. vs. TEC) dated February 29, 2000, including the October 2, 2000 amendment; are part of this permit. The permittee shall comply with the Consent Final Judgement and the Consent Decree. Wherever the Consent Decree conflicts with this permit the Consent Decree takes precedence. After the Consent Decree expires the Title V permit shall be modified accordingly.
> [Rules 62-4.070(3)&(5) and 62-213.440, F.A.C.]

2. The permit renewal application date is not changed.

3. A permitting note will be added to Specific Condition A.9.: {Permitting Note: The Consent Final Judgement (DEP vs. TEC) dated December 6, 1999; and the Consent Decree (U.S. vs. TEC) dated February 29, 2000, including the October 2, 2000

amendment; which are part of this permit, supercede this specific condition. Wherever the Consent Decree conflicts with this permit condition, the Consent Decree takes precedence.}

EPA Objection Issue 8

<u>Acid Rain Requirements:</u> The following items form Section IV, Phase II Acid Rain Part, must be corrected in order to make the requirements consistent with the Acid Rain regulations applicable to this facility:

a. Phase II of the Acid Rain Program began on January 1, 2000, which is the date by which initial Phase II permits for existing phase II units are to be effective (see: 40 CFR 72.73(b)(2), "State Issuance of Phase II Permits"). However, the effective date proposed for the title V permit containing the Phase II Acid Rain Part for the Big Bend Station is January 1, 2001. The permit needs to clarify that the effective period for the Phase II Acid Rain Part is five years beginning January 1, 2000.

TEC Response: TEC agrees that Phase II of the Acid Rain Program began on January 1, 2000. In addition, it is TEC's position that regardless of the effective date of the Acid Rain Part of the Title V permit, that TEC is in compliance with and operating under the terms of the Acid Rain Program regulations and the Acid Rain Permit application and associated compliance plans.

b. Section IV, Phase II Acid Rain Part, indicates that the Acid Rain, Phase II SO_2 allowance allocations for the Big Bend units BB01, BB02, BB03, BB04 are for the years 2001 through 2005. The SO_2 requirements under the Acid Rain Program are effective beginning January 1, 2000, therefore, the permit needs to be revised to include the allowance allocations for these units for the year 2000.

TEC Response: TEC agrees that SO_2 allowance allocations for Big Bend Units 1 through 4 should be included in the Acid Rain Part of the Permit.

c. Section IV, Phase II Acid Rain Part, contains the Phase II NO_x limitations for the years 2001 through 2004 for the Big Bend units BB01, BB02, BB03, BB04. The Phase II NO_x Averaging Plan that was submitted by the source (signed December 20, 1999) indicates that the plan is to be effective for the years 2000 through 2004. The permit needs to be revised to include NO_x limits for the year 2000. In addition, since the proposed expiration date of the Title V permit is December 31, 2005, the permit will need to be revised to include Phase II NO_x emission limits for the year 2005. The permits will also need to contain a Phase II NO_x Compliance Plan submitted by the source indicating how the source plans to comply with the Phase II NO_x emission limits for the year 2005.

TEC Response: EPA objection 8.a. indicates that Acid Rain permits must be effective for a period of five years. However, this objection suggests that if the Phase II Acid Rain NOx limits are carried out until 2005, the Acid Rain permit will be effective for a period of six years.

d. The NO_x limit for units BB01, BB02, BB03, BB04 in the Phase II Acid Rain Part indicates that, in addition to the specified alternative contemporaneous emission limit, the units shall not have an annual heat input greater than a specified value (mmBtu). This language must be changed to indicate that these units shall not have a heat input "less than" a specified value (mmBtu) in order to be consistent with 40 CFR 76.11(a)(4). The requirements of 40 CFR 76.11(a)(4) require that each unit in an averaging plan whose alternative contemporaneous annual emission limitation is more stringent than that unit's applicable emission limitation under § 76.4, 76.6, or 76.7, shall have a minimum allowable annual heat input value (mmBtu).

TEC Response: The Phase II NOx Averaging Plan submitted by TEC was done so in accordance with 40 CFR 76.9 and 40 CFR 76.11. The values used in the calculation are the minimum allowable annual heat inputs. It is worth noting that F.J. Gannon Station Units 3, 4, 5 and 6 are also included in this plan. Of those units, Units 3 and 6 have maximum allowable heat input limits.

Proposed changes: The expiration date of the Title V permit will be changed from December 31, 2005 to December 31, 2004 so that the Title V permit will be in sync with the NOx averaging plan submitted by Tampa Electric. The SO_2 allowance table will be changed to show the allowances for years 2000 to 2004 instead of years 2001 to 2005. The NOx language will be changed to the following:
"Pursuant to 40 CFR 76.11, the Florida Department of Environmental Protection approves the NOx emissions averaging plan submitted on 12/22/99 for this unit. Under the plan, this unit's NOx emissions shall not exceed the annual average alternative contemporaneous emission limitation of <u>0.74</u> lb/mmBtu. In addition, this unit shall not have an annual heat input <u>less</u> than <u>23,000,000</u> mmBtu."
(Information that is underlined will vary depending on the particular unit.)

II General Comments

1. <u>General Comment</u> - Please note that our opportunity for review and comment on this permit does not prevent EPA from taking enforcement action for issues that have not been raised in these comments. After final issuance, this permit shall be reopened if EPA or the permitting authority determines that it must be revised or revoked to assure compliance with applicable requirements.

2. <u>Section III, Subsection A, Condition A.1.b and G.6:</u> The Department should consider deleting everything except the first sentence of these conditions since such information is also contained in condition N.4.

3. Section III, A.18, A.26, B.12(3), B.13, B.15, B.20, B.25(1), B.26, B.29, B.33, B.34, B.35, B.38, D.5, D.11, G.5, L.6, L.8, M.5: These conditions refer to "specific condition XX," which is the terminology used in the Department's construction permits. In order to have consistency throughout the permit, the Department should replace "specific condition" with just "condition" and include the appropriate condition numbers, where applicable.

4. Section III. Condition B.9: Please add 40 C.F.R. 60.46a(c) to the regulatory citations for this condition.

5. Section III. Condition B.39: Since this condition specifies the submission of reports to the Department, the appropriate address where the reports should be sent should be included in Section II of the permit.

6. Section III. Condition B.42: Please correct the reference for the "representative actual emissions" to read **40 CFR 52.21(b)(33)**.

7. Section III. Condition C.4: The Department needs to clarify whether the notification is via phone or letter.

8. Section III. Condition H.2: The regulatory citation for this condition has the phrase "permitting note" in it. Please verify whether a permitting note should have been included in this condition.

9. Section III. Condition I.5: This condition refers to the limits contained in condition I.4. Please verify whether this condition should reference conditions I.2 and I.6 instead. Also, please verify whether the condition referred to in condition I.6(c) is the correct one.

10. Section III. Condition L.4: Please correct the note to identify 40 C.F.R. 60.672(a)(1) and (2) as basis for the limits in this condition. Also, the Department should consider streamlining condition L.8 into condition L.4.

11. Periodic Monitoring: As you are aware, on April 14, 2000, the U.S. Court of Appeals for the D.C. Circuit issued an opinion addressing industry's challenge to the validity of portions of EPA's periodic monitoring guidance. See. Appalachian Power Co. v. EPA, No. 98-1512 (D.C. Cir., April 14, 2000). The Court found that "State permitting authorities [ ] may not, on the basis of EPA's guidance or 40 C.F.R. 70.6(a)(3)(i)(B), require in permits that the regulated source conducts more frequent monitoring of its emissions than that provided in the applicable State or Federal standard, unless that standard requires no periodic testing, specifies no frequency, or requires only a one-time test." While the permit contains testing from "time to time," as discussed in the court opinion, EPA does not consider these conditions sufficient to ensure compliance. In light of the court case, EPA is withholding formal objection regarding the adequacy of the periodic monitoring

included in the permit for the following pollutants: Particulate Matter (PM), Visible Emissions (VE) and Sulfur Dioxide (SO_2). EPA's concerns are outlined below:

The permit does not contain adequate periodic monitoring for PM (conditions A.12, D.6, L.5 and M.3) and VE (conditions A.12, C.6, D.6, L.5 and M.4) Although the permit requires annual testing for these pollutants, this infrequent testing is not sufficient to provide a reasonable assurance of compliance with emission limits. All Title V permits must contain monitoring that is sufficient to assure compliance with the applicable permit requirements. In particular, 40 C.F.R. Part 70.6 (a)(3)(B) requires that permits include periodic monitoring that is sufficient to yield reliable data from the relevant time period that are representative of the source's compliance with the applicable emission limits. In addition to assuring compliance, a system of periodic monitoring will also provide the source with an indication of their emission unit's performance, so that periods of excess emissions and violations of the emission limits can be minimized or avoided. Therefore, the permit should include a periodic monitoring scheme that will provide data which is representative of the source's actual performance.

Since some of the emission units are equipped with control devices, the best approach to address the periodic monitoring requirements for these units is to utilize parametric monitoring of the control equipment. In order to do this, a correlation needs to be developed between the control equipment parameter(s) to be monitored and the pollutant emission levels. The source needs to provide an adequate demonstration (historical data, performance test, etc.) to support the approach used. In addition, an acceptable performance range for each parameter that is to be monitored should be established. The range, or the procedure used to establish the parametric ranges that are representative of proper operation of the control equipment, and the frequency for re-evaluating the range should be specified in the permit. Also, the permit should include a condition requiring a performance test to be conducted if an emission unit operates outside of the acceptable range for a specified percentage of the normal operating time. The Department should set the appropriate percentage of the operating time that would serve as trigger for this testing requirement.

As an alternative to the approaches described above, a technical demonstration can be included in the statement of basis explaining why the State has chosen not to require any additional testing to assure compliance with the PM and VE emission limitations for these units. The demonstration needs to identify the rationale for basing the compliance certification on data from a short-term test performed once a year.

12. Placard Page - Acid Rain: The "Referenced Attachments Made Part of This Permit " should include the Phase II Acid Rain Part application referred to in Section IV of the permit. EPA Region 4 requested a copy of the Phase II Acid Rain Part application for this source in order to assist us in our review of the

proposed permit for the Big Bend Station. However, it is unclear whether the application that we received (signed on December 19, 1995) is the same application referenced in Section IV of the proposed permit. The application referenced in Section IV was received by DEP on June 14, 1996. Please clarify if the application that we received by fax is indeed the application that was received by your office on June 14, 1996 and is to be considered part of the title V permit for the Big Bend Station.

TEC Response: TEC understands that the general comments are for informational purposes and are not issues that will result in an objection if left unresolved.

Proposed Changes: All necessary clarifications and corrections will be made.

STATEMENT OF BASIS

Tampa Electric Company
Big Bend Station
Facility ID No.: 0570039
Hillsborough County

Initial Title V Air Operation Permit
FINAL Permit No.: 0570039-002-AV

This Title V air operation permit is issued under the provisions of Chapter 403, Florida Statutes (F.S.), and Florida Administrative Code (F.A.C.) Chapters 62-4, 62-210, 62-213, and 62-214. The above named permittee is hereby authorized to perform the work or operate the facility shown on the application and approved drawing(s), plans, and other documents, attached hereto or on file with the permitting authority, in accordance with the terms and conditions of this permit.

This facility consists of the following regulated emissions units:

Unit No. 1 is a fossil fuel fired steam boiler generating unit rated at 4037 MMBtu/hour with an electrical generating capacity of 445 MW. It is a "wet" bottom utility boiler manufactured by Riley Stoker Corporation. This unit may be fired on coal or a coal/petroleum coke blend consisting of a maximum of 20.0 percent petroleum coke by weight. Unit No. 1 began commercial operation in 1970.

Unit No. 2 is a fossil fuel fired steam boiler generating unit rated at 3996 MMBtu/hour with an electrical generating capacity of 445 MW. It is a "wet" bottom utility boiler manufactured by Riley Stoker Corporation. This unit may be fired on coal or a coal/petroleum coke blend consisting of a maximum of 20.0 percent petroleum coke by weight. Unit No. 2 began commercial operation in 1973.

Unit No. 1 and Unit No. 2 share two common stacks (Stacks CS001 and CS0W1). Particulate emissions generated during the operation of the units are controlled by dry electrostatic precipitators (ESPs) manufactured by Western Precipitator Division, Joy Manufacturing Corporation. ESP control efficiency is 99.7%. Whenever either unit is fired with petcoke in any amount up to the allowable ratio (20% petcoke/80% coal, by wt.), its flue gases must be directed from its ESP to the FGD system and then to stack CS0W1. Otherwise, if petcoke is not fired, the flue gases may bypass the FGD system and stack CS0W1, and the flue gases are routed from the ESP directly to stack CS001.

Unit No. 3 is a fossil fuel fired steam boiler generating unit rated at 4115 MMBtu/hour with an electrical generating capacity of 445 MW. It is a "wet" bottom utility boiler manufactured by Riley Stoker Corporation. This unit may be fired on coal or a coal/petroleum coke blend consisting of a maximum of 20.0 percent petroleum coke by weight. Operation of this unit may include diverting all of the flue gas into the existing Big Bend Unit No. 4 flue gas desulfurization (FGD) system for sulfur dioxide emission reduction. Sulfur dioxide emissions that are generated and not diverted through the Unit No. 4 FGD system are uncontrolled. Particulate matter emissions generated during the operation of the unit are controlled by a dry electrostatic precipitator (ESP) manufactured by Research-Cottrell, Inc. The ESP control efficiency is 99.7%. Unit No. 3 began commercial operation in 1976.

Units No. 1, No. 2, and No. 3 are regulated under the federal Acid Rain Program, Phase I and Phase II, adopted and incorporated by reference in Rule 62-204.800, F.A.C.; and regulated under 62-296.405, F.A.C.

Unit No. 4 is a 4330 MMBTU/hour, dry-bottom tangentially fired utility boiler, SCC 1-01-002-12. Particulate matter emissions generated during the operation of the unit are controlled by a dry electrostatic precipitator (ESP) manufactured by Belco. The control efficiency of the ESP is 99.7%. Sulfur dioxide emissions are controlled by flue gas desulfurization equipment manufactured by Research-Cottrell.

As an option, Unit No. 3 exhaust gas, following particulate matter removal by the unit's ESP, will be routed to the inlet of the Unit No. 4 flue gas desulfurization (FGD) system scrubber. In this integrated mode, Unit No. 3 will meet the same sulfur dioxide emissions limitations as Unit No. 4. The FGD scrubber will continue to treat the exhaust gas from Unit No. 4. The FGD scrubber outlet stream, consisting of the combined Unit No. 3 and Unit No. 4 treated exhaust, will then be split and discharged through stacks CS002 and CS003. Stack CS003 does *not* include a recirculation duct to return exhaust gas to the inlet of the FGD scrubber. Continuous opacity monitoring systems (COMS) will be located at the outlet of Unit No. 3 and Unit No. 4 ESPs. Continuous SO_2, CO_2, and NOx emissions monitoring systems (CEMS) will be located in stacks CS002 and CS003. These monitoring systems will be used to determine compliance with all current applicable requirements.

{Applicable regulations: 40 CFR 60 Subpart Da, and the federal Acid Rain Program, Phase II, adopted and incorporated by reference in Rule 62-204.800, F.A.C.; PA79-12, PSD-FL-040 and an ASP for Coal Sampling.}

Combustion Turbine No. 1 is a self-contained combustion turbine generating unit. The unit is a predesigned integrated simple-cycle, single-shaft, three-bearing machine with the load connected at the exhaust end of the unit. The turbine is fired on No. 2 distillate fuel oil and operated for intermittent peaking and emergency services only.

Combustion Turbine No. 2 is a self-contained Westinghouse combustion turbine generating unit. The unit is a predesigned integrated simple-cycle, single-shaft, three-bearing machine with the load connected at the exhaust end of the unit. The turbine is fired on No. 2 distillate fuel oil and operated for intermittent peaking and emergency services only.

Combustion Turbine No. 3 is a self-contained Westinghouse combustion turbine generating unit. The unit is a predesigned integrated simple-cycle, single-shaft, multi-bearing machine with the load connected at the exhaust end of the unit. The turbine is fired on No. 2 distillate fuel oil and operated for intermittent peaking and emergency services only. This unit is rated at 78 MW.

Fly Ash Silo No. 1 handles fly ash from Steam Generator Units No. 1 and No. 2. Fly ash is pneumatically conveyed from the individual electrostatic precipitators to Silo No. 1. Also, the fly ash may be pneumatically conveyed from tanker trucks to Silo No. 1. The sum total loading rate to the silo for all the processes combined is 44.5 tons per hour. Fly ash from Silo No. 1 is discharged in either a wet or dry state. The dry fly ash is gravity fed by tubing into totally enclosed tanker trucks. The wet fly ash is processed through a pugmill and then unloaded into a dump truck. Particulate matter emissions generated by silo loading and silo unloading to a tanker truck are controlled by a 20,081 DSCFM Flex Kleen Model No. 84 UDTR-640 baghouse in addition to reasonable precautions.

Fly Ash Silo No. 2 handles fly ash from Steam Generator Units Nos. 1, 2, and/or 3. Fly ash is pneumatically conveyed in a series of pipes from the individual unit precipitators (Units 1, 2, and/or 3, only two units at any time) to the silo for temporary storage. From the silo, the fly ash is gravity fed by tubing into closed tanker trucks and transported to an off-site consumer. Particulate emissions generated during silo loading operation and from the tanker truck loadout chutes are controlled by a 20,081 DSCFM Flex Kleen, Model No. 84 UDTR-640 baghouse in addition to reasonable precautions.

Fly Ash Silo No. 3 handles fly ash from Steam Generator Unit No. 4. Particulate emissions are controlled by a 1,200 DSCFM Flex Kleen Model 84-WRTC-80-II-G baghouse.

Particulate emissions from the truck and railcar unloading of limestone are controlled by a Mikro-Pulsaire Model 400S12TR baghouse. Particulate emissions generated by the transfer of limestone from Handling Conveyor LB to Conveyor LC are controlled by a Sternvent Model DKED18003 baghouse. Particulate emissions generated by the transfer of limestone from Handling Conveyor LD to Conveyor LE are controlled by a Sternvent Model DKED 18003 baghouse. Particulate emissions generated by the transfer of limestone from Handling Conveyor LE to the South Storage Silo are controlled by a Flex Kleen Model 58-BVBC-36-IIG baghouse. Particulate emissions generated by the transfer of limestone from Handling Conveyor LE to the North Storage Silo are controlled by a Flex Kleen Model 58-BVBC-36-IIG baghouse.

Steam Generator Units Nos. 1-3 Coal Bunkers with an exhaust fan/cyclone collector (Roto-Clone controlling dust emission from each unit's respective bunker. Two moving transfer stations via their respective conveyor belts route coal through enclosed chutes to the various bunkers. Coal Bunkers 1-3 are each equipped with a 9400 ACFM American Air Filter (AAF) Company Type D Roto-Clone to abate dust emissions during ventilation. A number of vent pipes convey fresh air from each bunker to a Roto-Clone during particulate removal. Particulate matter removed by the Roto-Clones is returned to the coal bunkers via a hopper and return line. Unit No. 1 Coal Bunker is situated west of Unit No. 2 Coal Bunker. Unit No. 3 Coal Bunker is situated east of Unit No. 2 Coal Bunker.

Also regulated are the solid fuel yard, consisting of various solid fuel handling and transfer equipment, surface coating of miscellaneous metal parts and marine vessels, and abrasive blasting.

Also included in this permit are miscellaneous unregulated/insignificant emissions units and/or activities. Based on the initial Title V permit application received June 14, 1996, this facility is a major source of hazardous air pollutants (HAPs).

Tampa Electric Company
Big Bend Station
Facility ID No.: 0570039
Hillsborough County

Initial Title V Air Operation Permit
FINAL Permit No.: 0570039-002-AV

Permitting Authority:
State of Florida
Department of Environmental Protection
Division of Air Resources Management
Bureau of Air Regulation
Title V Section

Mail Station #5505
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Telephone: 850/488-0114
Fax: 850/922-6979

Compliance Authority:
Environmental Protection Commission
of Hillsborough County
1410 North 21 Street
Tampa, Florida 33605
Telephone: 813/272-5530
Fax: 813/272-5605

December 22, 2000

Initial Title V Air Operation Permit
FINAL Permit No.: 0570039-002-AV

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Department of Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

Permittee:
Tampa Electric Company
P.O. Box 111
Tampa, Florida 33601-0111

FINAL Permit No.: 0570039-002-AV
Facility ID No.: 0570039
SIC Nos.: 49, 4911
Project: Initial Title V Air Operation Permit

This permit is for the operation of the Tampa Electric Company (TEC) Big Bend Station. This facility is located at Big Bend Road, North Ruskin, Hillsborough County; UTM Coordinates: Zone 17, 361.9 km East and 3075.0 km North; Latitude: 27° 47' 36" North and Longitude: 82° 24' 11" West.

STATEMENT OF BASIS: This Title V air operation permit is issued under the provisions of Chapter 403, Florida Statutes (F.S.), and Florida Administrative Code (F.A.C.) Chapters 62-4, 62-210, 62-213 and 62-214. The above named permittee is hereby authorized to perform the work or operate the facility shown on the application and approved drawing(s), plans, and other documents, attached hereto or on file with the permitting authority, in accordance with the terms and conditions of this permit.

Referenced attachments made a part of this permit:
Appendix U-1, List of Unregulated Emissions Units and/or Activities
Appendix I-1, List of Insignificant Emissions Units and/or Activities
APPENDIX TV-3, TITLE V CONDITIONS (version dated 04/30/99)
APPENDIX SS-1, STACK SAMPLING FACILITIES (version dated 10/07/96)
TABLE 297.310-1, CALIBRATION SCHEDULE (version dated 10/07/96)
FIGURE 1 - SUMMARY REPORT-GASEOUS AND OPACITY EXCESS EMISSIONS AND MONITORING SYSTEM PERFORMANCE REPORT (version dated 7/96)
DOCUMENT III.I.6 - PROCEDURES FOR STARTUP AND SHUTDOWN UNITS 1 - 4
DOCUMENT III.I.7 - OPERATION AND MAINTENANCE PLAN (version dated 7/18/97)
40 CFR 60 Subpart A – General Provisions
40 CFR 63 Subpart A - General Provisions modified for Subpart II
40 CFR 63 Subpart II – § 63.782 Definitions
40 CFR 63 Subpart II - Figure 1. Flow diagram of compliance procedures
40 CFR 63 Subpart II - TABLE 2 VOLATILE ORGANIC HAP (VOHAP) LIMITS FOR MARINE COATINGS
40 CFR 63 Subpart II - TABLE 3 SUMMARY OF RECORDKEEPING & REPORTING REQUIREMENTS
40 CFR 63 Subpart II - APPENDIX A VOC DATA SHEET
40 CFR 63 Subpart II - APPENDIX B
DEP Form No. 62-210.900(1)(a), version 07/01/95, received 12/26/95 (signed 12/19/95).
Consent Final Judgement (DEP vs. TEC) dated December 6, 1999
Phase II NOx Compliance Plan received December 22, 1999
Phase II NOx Averaging Plan received December 22, 1999
Consent Decree (U.S. vs. TEC) dated February 29, 2000; amended October 4, 2000.

Effective Date: January 1, 2001
Renewal Application Due Date: July 5, 2004
Expiration Date: December 31, 2004

for Howard L. Rhodes, Director
Division of Air Resources Management

HLR.CLP

Section I. Facility Information.

Subsection A. Facility Description.

TEC Big Bend is a nominal 2,028 MW electric generation facility. This facility consists of four steam boilers (Units Nos. 1 through 4); four steam turbines; three simple-cycle combustion turbines (CT Nos. 1, 2, and 3); solid fuels, fly ash, limestone, gypsum, slag, and bottom ash storage and handling facilities, and fuel oil storage tanks. Units No. 1, 2, 3, and 4 have nominal maximum heat inputs of 4037, 3996, 4115 and 4330 million BTU per hour, respectively. Units No. 1 through 4 are fired with coal and with petcoke in a mixture with coal up to 20.0% petcoke/80.0% coal (by weight). The combustion turbines are fired with No. 2 distillate fuel oil. In addition, there is a ship surface coating operation.

Also included in this permit are miscellaneous unregulated emissions units and insignificant emissions units and/or activities.

Based on the initial Title V permit application received June 14, 1996, this facility is a major source of hazardous air pollutants (HAPs).

<u>Overview of the facility's operation:</u>

Solid fuel is unloaded from ship/barge into the solid fuel yard or directly to the tripper room via belt conveyors. Solid fuel from the piles is loaded onto belt conveyors using a rail mounted or mobile reclaimer. The solid fuel is then belt conveyed to the blending tower, which consists of six storage bins, where the solid is blended for use at the plant, or transloaded into trucks for shipment off site. From the solid fuel yard conveyors, the solid fuel is screw conveyed into the bins. Particulate matter (PM) emissions from the conveyors in the solid fuel yard are controlled by 3 rotoclones, one for every 2 bins. PM emissions from the screw conveyor are controlled by the fourth rotoclone. Each has 2 hoppers, which feed the transloader, or are conveyed, via 2 parallel belts (T1, T2) to 2 crushers (each belt has a crusher), or diverted directly to the tripper room. PM emissions from the 2 crushers and transfer tower are controlled by 2 rotoclones.

From the solid fuel yard, the solid fuel is conveyed to the tripper room where 2 trippers bunker the solid fuels into 4 solid fuel bunkers. Each unit has its own respective bunker. Solid fuel samples are taken every 15 minutes during bunking, and composited for analysis. From the bunkers, the solid fuel is gravity fed into 14 crushers, and then gravity fed into the boilers. There are 3 tall crushers, each for Unit Nos. 1 – 3, and 5 bowl crushers for Unit No. 4. From the crushers, the solid fuel is pneumatically fed into classifiers, two for each crusher for a total of 28 classifiers, and then into the respective boilers.

PM emissions from Boiler Nos. 1-3 are controlled by individual Electrostatic Precipitators (ESPs). Unit No. 4 PM emissions are controlled by an ESP, and the SO2 emissions are controlled by an FGD scrubber system. When Unit No. 3 burns petroleum coke, the exhaust gas, following particulate matter removal by the unit's ESP, will be routed to the inlet of the Unit No. 4 flue gas desulfurization (FGD) system scrubber. In this integrated mode, Unit No. 3 will meet the same sulfur dioxide emissions limitations as Unit No. 4. The FGD scrubber will continue to treat the exhaust gas from Unit No. 4. The FGD scrubber outlet stream, consisting of the combined Unit No. 3 and Unit No. 4 treated exhaust, will then be split and discharged through stacks CS002 and CS003.

Fly ash from Units No. 1 and No. 2 is vented into Fly Ash Silo #1 which is controlled by a baghouse. Fly ash from Unit No. 3 is vented into Silo #2, while fly ash from Unit No. 4 is vented into Silo #3. The fly ash from each silo is then loaded into trucks and transported off site, while the bottom ash is conveyed across Big Bend Road south of the Big Bend facility to a settling pond.

The byproduct gypsum is conveyed to the east side of the plant for diverting and transporting off site. Limestone is unloaded to an underground hopper conveyor belt system to the limestone storage building on the east side of the by-product gypsum area. Particulate matter emissions from the limestone trucks unloading is controlled by a baghouse. From the storage building, limestone is belt conveyed into 2 storage silos and then gravity fed into the mill room. Two rotary mills grind the limestone and mix it with water to form a slurry that is stored in 2 storage tanks for use in the FGD. The slurry is then pumped to the 4 reaction tanks that are located directly south of and adjacent to the absorption towers of the FGD scrubber. Most of the by-product gypsum is wallboard grade, however, gypsum that is produced during start-up, shutdown or upset conditions is de-watered and belt-conveyed across the street to the southeast of the plant for drying and transportation off site.

There are 3-combusion turbines manufactured by Westinghouse. They are all fired on No. 2 fuel oil. Unit No. 1 is near the plant and Unit Nos. 2 and 3 are on the north side of the property. There is a large No. 2 fuel oil storage tank near Unit Nos. 2 and 3 and a small day tank near Unit No. 1.

Subsection B. Summary of Emissions Unit ID Nos. and Brief Descriptions.

E.U. ID No.	**Brief Description**
-001	Unit No. 1 Steam Generator
-002	Unit No. 2 Steam Generator
-003	Unit No. 3 Steam Generator
-004	Unit No. 4 Steam Generator
-005	Combustion Turbine No. 2
-006	Combustion Turbine No. 3
-007	Combustion Turbine No. 1
-008	Fly Ash Silo No. 1 Baghouse
-018	Flyash Silo No. 1 Truck Loadout
-009	Fly Ash Silo No. 2 Baghouse
-019	Flyash Silo No. 2 Truck Loadout
-026	Fly Ash Handling and Storage Fugitive Emissions (all except silos)
-014	Fly Ash Silo No. 3 Baghouse
-027	Fly Ash Silo No. 3 Truck Loadout
-028	Fly Ash Handling System Fugitive Emissions
-011	Truck Unloading of Limestone
-012	Limestone Silo A with one baghouse and one backup baghouse
-013	Limestone Silo B with one baghouse and one backup baghouse
-023	Limestone Handling Conveyor LB to Conveyor LC with baghouse
	Limestone Handling Conveyor LD to Conveyor LE with baghouse

E.U. ID No. **Subsection B. Summary of Emissions Unit ID Nos. and Brief Descriptions. (continued)**

E.U. ID No.	Brief Description
-024	Limestone Handling Conveyor LE to South Storage Silo with baghouse Limestone Handling Conveyor LE to North Storage Silo with baghouse
-025	Limestone Storage and Handling Fugitive Emissions
-010	Solid Fuel Yard, Fugitive Emissions
-029	Cylcone collectors for fuel blending bins (FH-032 and FH-035)
-030	Cylcone collectors for fuel crushers (FH-048 and FH-049)
-031	Cyclone collectors for bunkers (FH-059 through FH-062)
-015	Unit No. 1 Coal Bunker
-016	Unit No. 2 Coal Bunker
-017	Unit No. 3 Coal Bunker
-032	Surface coating of miscellaneous metal parts
-033	Abrasive Blast Booth with baghouse
-034	Abrasive Blast Media Storage with baghouse
-035	Surface coating of ships
-020	**Drops from limestone handling conveyors LE, LF, and LG and silo C belt feeder with baghouse**
-021	**Silo C with one baghouse**
-022	**Lime silo with one baghouse for the waste water treatment plant for the chloride bleed stream**
-036	Unregulated Emissions Units and/or Activities

Please reference the Permit No., Facility ID No., and appropriate Emissions Unit(s) ID No(s). on all correspondence, test report submittals, applications, etc.

Subsection C. Relevant Documents.

The documents listed below are not a part of this permit; however, they are specifically related to this permitting action.

These documents are provided to the permittee for information purposes only:
Appendix A-1, Abbreviations, Acronyms, Citations, and Identification Numbers
Appendix H-1, Permit History / ID Number Changes

These documents are on file with the permitting authority:
Phase I Acid Rain Permit dated July 15,1994
Initial Title V Permit Application received June 14, 1996
Additional Information Request dated February 13, 1997
Letter dated June 27, 1997, changing the Designated Representative
Additional Information Response received July 21, 1997

These documents are on file with the permitting authority (continued):

Additional Information Response received July 21, 1997
Proposed Compliance Plan dated December 30, 1998, requesting additional SO_2 limits
Memo from Power Plant Siting dated February 23, 1999, to confirm COC correction.
FDEP letter dated December 23, 1999 Allowing Discontinuance of TSP/SO_2 Ambient Monitoring
Additional Information received January 17, 2000
Plant diagrams as provided in the Title V Permit application and additional information
TEC comments dated June 23, 2000 and July 5, 2000 on the 2nd Revised DRAFT permit
USEPA Region 4 objections and comments letter dated September 5, 2000.
FDEP letter dated December 1, 2000 resolving USEPA Region 4 objections and comments.
FDEP letter dated December 14, 2000 clarifying December 1, 2000 resolution letter.

Section II. Facility-wide Conditions.

The following conditions apply facility-wide:

1. APPENDIX TV-3, TITLE V CONDITIONS, is a part of this permit.
{Permitting note: APPENDIX TV-3, TITLE V CONDITIONS, is distributed to the permittee only. Other persons requesting copies of these conditions shall be provided a copy when requested or otherwise appropriate.}

2. Not federally enforceable. General Pollutant Emission Limiting Standards. Objectionable Odor Prohibited. No person shall cause, suffer, allow, or permit the discharge of air pollutants which cause or contribute to an objectionable odor.
[Rule 62-296.320(2), F.A.C.]

3. General Particulate Emission Limiting Standards. General Visible Emissions Standard.
Except for emissions units that are subject to a particulate matter or opacity limit set forth or established by rule and reflected by conditions in this permit, no person shall cause, let, permit, suffer or allow to be discharged into the atmosphere the emissions of air pollutants from any activity, the density of which is equal to or greater than that designated as Number 1 on the Ringelmann Chart (20 percent opacity). EPA Method 9 is the method of compliance pursuant to Chapter 62-297, F.A.C.
[Rules 62-296.320(4)(b)1. & 4., F.A.C.]
{Permitting Note: Although the Permittee is not required to perform a visible emissions compliance test to demonstrate compliance with the facility-wide limitations annually or before renewal, if the Department believes that the general visible emissions standard is being violated, the Department may require that the owner or operator perform a visible emissions compliance test per Chapter 62-297.310(7)(b), Special Compliance Tests. In addition, Department personnel who are certified to perform visible emissions tests may determine compliance with the general visible emissions standard.}

4. Prevention of Accidental Releases (Section 112(r) of CAA).
a. The permittee shall submit its Risk Management Plan (RMP) to the Chemical Emergency Preparedness and Prevention Office (CEPPO) RMP Reporting Center when, and if, such requirement becomes applicable; and

b. The permittee shall submit to the permitting authority Title V certification forms or a compliance schedule in accordance with Rule 62-213.440(2), F.A.C.
[40 CFR 68]

5. Unregulated Emissions Units and/or Activities. Appendix U-1, List of Unregulated Emissions Units and/or Activities, is a part of this permit.
[Rule 62-213.440(1), F.A.C.]

6. Insignificant Emissions Units and/or Activities. Appendix I-1, List of Insignificant Emissions Units and/or Activities, is a part of this permit.
[Rules 62-213.440(1), 62-213.430(6) and 62-4.040(1)(b), F.A.C.]

7. General Pollutant Emission Limiting Standards. Volatile Organic Compounds (VOC) Emissions or Organic Solvents (OS) Emissions. The permittee shall allow no person to store, pump, handle, process, load, unload or use in any process or installation, volatile organic compounds or organic solvents without applying known and existing vapor emission control devices or systems deemed necessary and ordered by the Department.
[Rule 62-296.320(1)(a), F.A.C.]

8. The Permittee shall take reasonable precautions to prevent emissions of unconfined particulate matter at this facility.
[Rule 62-296.320(4)(c)2., F.A.C.]
{Note: This condition implements the requirements of Rules 62-296.320(4)(c)1., 3., & 4. F.A.C. (condition 58. of APPENDIX TV-3, TITLE V CONDITIONS.)}

9. When appropriate, any recording, monitoring, or reporting requirements that are time-specific shall be in accordance with the effective date of the permit, which defines day one.
[Rule 62-213.440, F.A.C.]

10. Statement of Compliance. The annual statement of compliance pursuant to Rule 62-213.440(3), F.A.C., shall be submitted within 60 (sixty) days after the end of the calendar year. {See condition 51, APPENDIX TV-3, TITLE V CONDITIONS}
[Rule 62-214.420(11), F.A.C.]

11. The Consent Final Judgement (DEP vs. TEC) dated December 6, 1999; and the Consent Decree (U.S. vs. TEC) dated February 29, 2000, including the October 4, 2000 amendment; are attached hereto and made a part of this permit. The permittee shall comply with the Consent Final Judgement and the Consent Decree. Wherever the Consent Decree conflicts with this permit the terms and conditions of the Consent Decree control. Upon expiration of the Consent Decree the Title V permit shall be modified to incorporate any terms and conditions that are deemed necessary by the permitting authority for the continued operation of the facility.
[Rules 62-4.070(3)&(5) and 62-213.440, F.A.C.]

12. Unless otherwise stated in a specific condition, averaging times for specified emission standards are based on the run time of the test method(s) used for determining compliance.
[Rule 62-4.070(3), F.A.C.]

the sulfur dioxide control device is 50 percent of maximum estimated hourly potential emissions oil fuel, alone or in combination with non-fossil fuel, the span value of the fuel fired.
[Rule 62-204.800(7)(b)2., F.A.C.; 40 CFR 60.47a(i); 40 CFR 60.13; 40 CFR 60 Appendix A, Methods 3B, 6, and 7; 40 CFR 60 Appendix B, Performance Specification 2.]

B.25. TEC may use the following as alternatives to the reference methods and procedures specified in conditions B.23. and B.24.:

(1) For Method 6, Method 6A or 6B (whenever Methods 6 and 3 or 3B data are used) or 6C may be used. Each Method 6B sample obtained over 24 hours represents 24 1-hour averages. If Method 6A or 6B is used under specific condition B.24., the conditions under 40 CFR 60.46(d)(1) apply; these conditions do not apply under specific condition B.23.

(2) For Method 7, Method 7A, 7C, 7D, or 7E may be used. If Method 7C, 7D, or 7E is used, the sampling time for each run shall be 1 hour.

(3) For Method 3, Method 3A or 3B may be used if the sampling time is 1 hour.

(4) For Method 3B, Method 3A may be used.

[Rule 62-204.800(7)(b)2., F.A.C.; 40 CFR 60.47a(j); 40 CFR 60.46(d)(1), 40 CFR 60 Appendix A, Methods 3, 3A, 3B, 6, 6A, 6B, 6C, 7, 7A, 7C, 7D, and 7E]

Compliance determination procedures and methods.

B.26. In conducting the performance tests required in *40 CFR 60.8*, the owner or operator shall use as reference methods and procedures the methods in appendix A of 40 CFR 60 or the methods and procedures as specified in conditions B.27. through B.30., except as provided in *40 CFR 60.8(b)*. *40 CFR 60.8(f)* does not apply to specific conditions B.28 and B.29. for SO_2 and NO_x. Acceptable alternative methods are given in specific condition B.30.
[Rule 62-204.800(7)(b)2., F.A.C.; 40 CFR 60.48a(a); 40 CFR 60.8]

B.27. TEC shall determine compliance with the particulate matter standards in specific condition B.5. as follows:

(1) The dry basis F factor (O_2) procedures in Method 19 shall be used to compute the emission rate of particulate matter.

(2) For the particular matter concentration, Method 5B shall be used after **wet** FGD systems.

(i) The sampling time and sample volume for each run shall be at least 120 minutes and 1.70 dscm (60 dscf). The probe and filter holder heating system in the sampling train may be set to provide an average gas temperature of no greater than 160±14 °C (320±25 °F).

(ii) For each particulate run, the emission rate correction factor, integrated or grab sampling and analysis procedures of Method 3B shall be used to determine the O_2 concentration. The O_2 sample shall be obtained simultaneously with, and at the same traverse points as, the particulate run. If the particulate run has more than 12 traverse points, the O_2 traverse points may be reduced to 12 provided that Method 1 is used to locate the 12 O_2 traverse points. If the grab sampling procedure is used, the O_2 concentration for the run shall be the arithmetic mean of all the individual O_2 concentrations at each traverse point.

(3) Method 9 and the procedures in *40 CFR 60.11* shall be used to determine opacity.

[Rule 62-204.800(7)(b)2., F.A.C.; 40 CFR 60.48a(b); 40 CFR 60.11, 40 CFR 60 Appendix A, Methods 1, 3B, 5B, 9, and 19]

B.28. TEC shall determine compliance with the SO_2 standards in specific condition B.7. as follows:

(1) The percent of potential SO_2 emissions (%Ps) to the atmosphere shall be computed using the following equation:

$\%P_s = [(100 - \%R_f)(100 - \%R_g)]/100$

where:

$\%P_s$	=	percent of potential SO_2 emissions, percent.
$\%R_f$	=	percent reduction from fuel pretreatment, percent.
$\%R_g$	=	percent reduction by SO_2 control system, percent.

(2) The procedures in Method 19 may be used to determine percent reduction ($\%R_f$) of sulfur by such processes as fuel pretreatment (physical coal cleaning, hydrodesulfurization of fuel oil, etc.), coal pulverizers, and bottom and flyash interactions. This determination is optional.

(3) The procedures in Method 19 shall be used to determine the percent SO_2 reduction ($\%R_g$ of any SO_2 control system. Alternatively, a combination of an "as fired" fuel monitor and emission rates measured after the control system, following the procedures in Method 19, may be used if the percent reduction is calculated using the average emission rate from the SO_2 control device and the average SO_2 input rate from the "as fired" fuel analysis for 30 successive boiler operating days.

(4) The appropriate procedures in Method 19 shall be used to determine the emission rate.

(5) The continuous monitoring systems specified in conditions B.17. and B.19. shall be used to determine the concentrations of SO_2 and CO_2 or O_2.

[Rule 62-204.800(7)(b)2., F.A.C.; 40 CFR 60.48a (c); 40 CFR 60 43a; 40 CFR 60.47a(b) and (d); 40 CFR 60 Appendix A, Method 19]

B.29. TEC shall determine compliance with the NO_x standards in specific condition B.9. as follows:

(1) The appropriate procedures in Method 19 shall be used to determine the emission rate of NO_x.

(2) The continuos monitoring systems specified in specific conditions B.18. and B.19. shall be used to determine the concentrations of NO_x and CO_2 or O_2.

[Rule 62-204.800(7)(b)2., F.A.C.; 40 CFR 60.48a(d); 40 CFR 60.44a; 40 CFR 60.47a(c); 40 CFR 60.47a(d)]

B.30. TEC may use the following as alternatives to the reference methods and procedures specified in condition B.27:

(1) For Method 5 or 5B, Method 17 may be used at Unit No. 4 if the stack temperature at the sampling location does not exceed an average temperature of 160 °C (320 °F). The procedures of sections 2.1 and 2.3 of Method 5B may be used in Method 17 only if it is used after wet FGD systems. Method 17 shall not be used after wet FGD systems if the effluent is saturated or laden with water droplets.

(2) The F_c factor (CO_2) procedures in Method 19 may be used to compute the emission rate of particulate matter under the stipulations of *40 CFR 60.46(d)(1)*. The CO_2 shall be determined in the same manner as the O_2 concentration.

[Rule 62-204.800(7)(b)2., F.A.C.; 40 CFR 60.48a(e); 40 CFR 60.46(d)(1); 40 CFR 60 Appendix A, Methods 5, 5B, 17, and 19]

Reporting requirements.

B.31. For sulfur dioxide, nitrogen oxides, and particulate matter emissions, the performance test data from the initial performance test and from the performance evaluation of the continuous monitors (including the transmissometer) shall be submitted to the Department and the EPCHC.
[Rule 62-204.800(7)(b)2., F.A.C.; 40 CFR 60.49a(a)]

B.32. For sulfur dioxide and nitrogen oxides the following information shall be reported to the Department and the EPCHC for each 24-hour period.

(1) Calendar date.

(2) The average sulfur dioxide and nitrogen oxide emission rates (lb/million Btu heat input) for each 30 successive boiler operating days, ending with the last 30-day period in the quarter; reasons for non-compliance with the emission standards; and, description of corrective actions taken.

(3) Percent reduction of the potential combustion concentration of sulfur dioxide for each 30 successive boiler operating days, ending with the last 30-day period in the quarter; reasons for non-compliance with the standard; and, description of corrective actions taken.

(4) Identification of the boiler operating days for which pollutant or dilutent data have not been obtained by an approved method for at least 18 hours of operation of the facility; justification or not obtaining sufficient data; and description of corrective actions taken.

(5) Identification of the times when emissions data have been excluded from the calculation of average emission rates because of startup, shutdown, malfunction (NO_x only), emergency conditions (SO_2 only), or other reasons, and justification for excluding data for reasons other than startup, shutdown, malfunction, or emergency conditions.

(6) Identification of "F" factor used for calculations, method of determination, and type of fuel combusted.

(7) Identification of times when hourly averages have been obtained based on manual sampling methods.

(8) Identification of the times when the pollutant concentration exceeded full span of the continuous monitoring system.

(9) Description of any modifications to the continuous monitoring system which could affect the ability of the continuous monitoring system to comply with 40 CFR 60 Appendix B, Performance Specifications 2 or 3.

[Rule 62-204.800(7)(b)2., F.A.C.; 40 CFR 60.49a(b); 40 CFR 60 Appendix B]

B.33. If the minimum quantity of emission data, as required by the emission monitoring specific conditions B.16. through B.25., is not obtained for any 30 successive boiler operating days, the following information obtained under the requirements of specific condition B.15. shall be reported to the Administrator for that 30-day period:

(1) The number of hourly averages available for outlet emission rates (n_o) and inlet emission rates (n_i) as applicable.

(2) The standard deviation of hourly averages for outlet emission rates (s_o) and inlet emission rates (s_i) as applicable.

(3) The lower confidence limit for the mean outlet emission rate (E_o*) and the upper confidence limit for the mean inlet emission rate (E_i*) as applicable.

(4) The applicable potential combustion concentration.

(5) The ratio of the upper confidence limit for the mean outlet emission rate (E_o*) and the allowable emission rate (E_{std}) as applicable.

[Rule 62-204.800(7)(b)2., F.A.C.; 40 CFR 60.49a(c); 40 CFR 60 Appendix A, Method 19]

B.34. If any sulfur dioxide standards under specific condition B.7. is exceeded during emergency conditions because of control system malfunction, the owner or operator of the affected facility shall submit a signed statement:

(1) Indicating if emergency conditions existed and requirements under specific condition B.14. were met during each period, and

(2) Listing the following information:

(i) Time periods the emergency condition existed;

(ii) Electrical output and demand on the owner or operator's electric utility system and the affected facility;

(iii) Amount of power purchased from interconnected neighboring utility companies during the emergency period;

(iv) Percent reduction in emissions achieved;

(v) Atmospheric emission rate (ng/J or lb/MMBtu) of the pollutant discharged; and

(vi) Actions taken to correct control system malfunction.

[Rule 62-204.800(7)(b)2., F.A.C.; 40 CFR 60.49a(d); 40 CFR 60.43a; 40 CFR 60.46a(d)]

B.35. If fuel pretreatment credit is claimed toward the sulfur dioxide emission standards in specific condition B.7. TEC shall submit a signed statement:

(1) Indicating what percentage cleaning credit was taken for the calendar quarter, and whether the credit was determined in accordance with the provisions of specific condition B.28. and Method 19 (Appendix A of 40 CFR 60); and

(2) Listing the quantity, heat content, and date each pretreated fuel shipment was received during the previous quarter; the name and location of the fuel pretreatment facility; and the total quantity and total heat content of all fuels received at the affected facility during the previous quarter.

[Rule 62-204.800(7)(b)2., F.A.C.; 40 CFR 60.49a(e), 40 CFR 60.48a(c)]

B.36. For any periods for which opacity, sulfur dioxide or nitrogen oxides emissions data are not available, the owner or operator of the affected facility shall submit a signed statement indicating if any changes were made in operation of the emission control system during the period of data unavailability. Operations of the control system and affected facility during periods of data unavailability are to be compared with operation of the control system and affected facility before and following the period of data unavailability.

[Rule 62-204.800(7)(b)2., F.A.C.; 40 CFR 60.49a(f)]

B.37. The owner or operator of the affected facility shall submit a signed statement indicating whether:

(1) The required continuous monitoring system calibration, span, and drift checks or other periodic audits have or have not been performed as specified.

(2) The data used to show compliance was or was not obtained in accordance with approved methods and procedures of this part and is representative of plant performance.

(3) The minimum data requirements have or have not been met; or, the minimum data requirements have not been met for errors that were unavoidable.

(4) Compliance with the standards has or has not been achieved during the reporting period.

[Rule 62-204.800(7)(b)2., F.A.C.; 40 CFR 60.49a(g)]

B.38. For the purposes of the reports required under *40 CFR 60.7*, periods of excess emissions are defined as all 6-minute periods during which the average opacity exceeds the applicable opacity standards under specific condition B.6. Opacity levels in excess of the applicable opacity standard and the date of such excesses are to be submitted to the Administrator each calendar quarter.
[Rule 62-204.800(7)(b)2., F.A.C.; 40 CFR 60.49a(h)]

B.39. The owner or operator of an affected facility shall submit the written reports required under this section and subpart A to the Department and the EPCHC for every calendar quarter. All quarterly reports shall be postmarked by the 30th day following the end of each calendar quarter.
[Rule 62-204.800(7)(b)2., F.A.C.; 40 CFR 60.49a(i)]

B.40. Gravimetric instrument data verifying that the 20.0% maximum petroleum coke content by weight has not been exceeded shall be maintained for **five** years and submitted to the Department and the EPCHC with each annual operating report. Also to be maintained and available for inspection shall be a daily record of operation showing the date, fuel used, mode of operation (integrated/non-integrated), and the duration of all startups, shutdowns and malfunctions. TEC shall maintain copies of fuel analyses containing information on sulfur content, ash content, and heating values.
[PSD-FL-040; Rules 62-4.070(3), 62-213.440(1)(b)2.b., F.A.C., and Power Plant Siting Certification PA 79-12]

B.41. TEC shall submit to the Department a standardized plan or procedure that will allow the permittee to monitor emission control equipment efficiency and enable the permittee to return malfunctioning equipment to proper operation as expeditiously as possible.
[Power Plant Siting Certification PA 79-12]

B.42. Pursuant to Rule 62-212.200(2)(d), F.A.C., the actual emissions of the No. 4 Unit shall equal the representative actual emissions as defined in 40 CFR 52.21(b)(33). TEC shall maintain and submit to the Department and the EPCHC on an annual basis for a period of 5 years from the date the unit begins firing petroleum coke, data demonstrating that the operational change did not result in an emissions increase.
[PSD-FL-040; PA 79-12, Conditions of Certification]

B.43. Stack height. The height of the boiler exhaust stack for Unit No. 4 (CS003) shall not be less than 490 ft. above grade.
[Power Plant Siting Certification PA 79-12]

The following requirements of 40 CFR 60, Subpart A - General Provisions Requirements, apply to Unit No. 4:

B.44. Definitions. For the purposes of Rule 62-204.800(7), F.A.C., the definitions contained in the various provisions of 40 CFR 60, shall apply except that the term "Administrator" when used in 40 CFR 60, shall mean the Secretary or the Secretary's designee.
[40 CFR 60.2; Rule 62-204.800(7)(a), F.A.C.]

40 CFR 60.7 Notification and record keeping.

B.45. The owner or operator subject to the provisions of 40 CFR 60 shall furnish the Administrator written notification as follows:

A notification of any physical or operational change to an existing facility which may increase the emission rate of any air pollutant to which a standard applies, unless that change is specifically exempted under an applicable subpart or in 40 CFR 60.14(e). This notice shall be postmarked 60 days or as soon as practicable before the change is commenced and shall include information describing the precise nature of the change, present and proposed emission control systems, productive capacity of the facility before and after the change, and the expected completion date of the change. The Administrator may request additional relevant information subsequent to this notice.
[40 CFR 60.7(a)(4)]

B.46. The owner or operator subject to the provisions of 40 CFR 60 shall maintain records of the occurrence and duration of any startup, shutdown, or malfunction in the operation of an affected facility; any malfunction of the air pollution control equipment; or, any periods during which a continuous monitoring system or monitoring device is inoperative.
[40 CFR 60.7(b)]

B.47. Each owner or operator required to install a continuous monitoring system (CMS) or monitoring device shall submit an excess emissions and monitoring systems performance report (excess emissions are defined in applicable subparts) and/or a summary report form [see 40 CFR 60.7(d)] to the Administrator semiannually, except when: more frequent reporting is specifically required by an applicable subpart; or, the CMS data are to be used directly for compliance determination, in which case quarterly reports shall be submitted; or, the Administrator, on a case-by-case basis, determines that more frequent reporting is necessary to accurately assess the compliance status of the source. All reports shall be postmarked by the 30th day following the end of each calendar half (or quarter, as appropriate). Written reports of excess emissions shall include the following information:
(1) The magnitude of excess emissions computed in accordance with 40 CFR 60.13(h), any conversion factor(s) used, and the date and time of commencement and completion of each time period of excess emissions. The process operating time during the reporting period.
(2) Specific identification of each period of excess emissions that occurs during startups, shutdowns, and malfunctions of the affected facility. The nature and cause of any malfunction (if known), the corrective action taken or preventative measures adopted.
(3) The date and time identifying each period during which the continuous monitoring system was inoperative except for zero and span checks and the nature of the system repairs or adjustments.
(4) When no excess emissions have occurred or the continuous monitoring system(s) have not been inoperative, repaired, or adjusted, such information shall be stated in the report.
[40 CFR 60.7(c)(1), (2), (3), and (4)]

B.48. The summary report form shall contain the information and be in the format shown in Figure 1 (attached) unless otherwise specified by the Administrator. One summary report form shall be submitted for each pollutant monitored at each affected facility.

(1) If the total duration of excess emissions for the reporting period is less than 1 percent of the total operating time for the reporting period and CMS downtime for the reporting period is less than 5 percent of the total operating time for the reporting period, only the summary report form shall be submitted and the excess emission report described in 40 CFR 60.7(c) need not be submitted unless requested by the Administrator.

(2) If the total duration of excess emissions for the reporting period is 1 percent or greater of the total operating time for the reporting period or the total CMS downtime for the reporting period is 5 percent or greater of the total operating time for the reporting period, the summary report form and the excess emission report described in 40 CFR 60.7(c) shall both be submitted.
{See attached Figure 1: Summary Report-Gaseous and Opacity Excess Emission and Monitoring System Performance} (electronic file name: figure1.doc)
[40 CFR 60.7(d)(1) and (2)]

B.49. (1) Notwithstanding the frequency of reporting requirements specified in 40 CFR 60.7(c), an owner or operator who is required by an applicable subpart to submit excess emissions and monitoring systems performance reports (and summary reports) on a quarterly (or more frequent) basis may reduce the frequency of reporting for that standard to semiannual if the following conditions are met:

(i) For 1 full year (e.g., 4 quarterly or 12 monthly reporting periods) the affected facility's excess emissions and monitoring systems reports submitted to comply with a standard under this part continually demonstrate that the facility is in compliance with the applicable standard;

(ii) The owner or operator continues to comply with all recordkeeping and monitoring requirements specified in 40 CFR 60, Subpart A, and the applicable standard; and

(iii) The Administrator does not object to a reduced frequency of reporting for the affected facility, as provided in 40 CFR 60.7(e)(2).

(2) The frequency of reporting of excess emissions and monitoring systems performance (and summary) reports may be reduced only after the owner or operator notifies the Administrator in writing of his or her intention to make such a change and the Administrator does not object to the intended change. In deciding whether to approve a reduced frequency of reporting, the Administrator may review information concerning the source's entire previous performance history during the required recordkeeping period prior to the intended change, including performance test results, monitoring data, and evaluations of an owner or operator's conformance with operation and maintenance requirements. Such information may be used by the Administrator to make a judgment about the source's potential for noncompliance in the future. If the Administrator disapproves the owner or operator's request to reduce the frequency of reporting, the Administrator will notify the owner or operator in writing within 45 days after receiving notice of the owner or operator's intention. The notification from the Administrator to the owner or operator will specify the grounds on which the disapproval is based. In the absence of a notice of disapproval within 45 days, approval is automatically granted.

(3) As soon as monitoring data indicate that the affected facility is not in compliance with any emission limitation or operating parameter specified in the applicable standard, the frequency of reporting shall revert to the frequency specified in the applicable standard, and the owner or operator shall submit an excess emissions and monitoring systems performance report (and summary report, if required) at the next appropriate reporting period following the noncomplying event. After demonstrating compliance with the applicable standard for another full year, the owner or operator may again request approval from the Administrator to reduce the frequency of reporting for that standard as provided for in 40 CFR 60.7(e)(1) and (e)(2).
[40 CFR 60.7(e)(1)]

B.50. Any owner or operator subject to the provisions of 40 CFR 60 shall maintain a file of all measurements, including continuous monitoring system, monitoring device, and performance testing measurements; all continuous monitoring system performance evaluations; all continuous monitoring system or monitoring device calibration checks; adjustments and maintenance performed on these

systems or devices; and, all other information required by 40 CFR 60 recorded in a permanent form suitable for inspection. The file shall be retained for at least **5 (five)** years following the date of such measurements, maintenance, reports, and records.
[40 CFR 60.7(f); Rule 62-213.440(1)(b)2.b., F.A.C.]

40 CFR 60.8 Performance tests.

B.51. Performance tests shall be conducted under such conditions as the Administrator shall specify to the plant operator based on representative performance of the affected facility. The owner or operator shall make available to the Administrator such records as may be necessary to determine the conditions of the performance tests. Operations during periods of startup, shutdown, and malfunction shall not constitute representative conditions for the purpose of a performance test nor shall emissions in excess of the level of the applicable emission limit during periods of startup, shutdown, and malfunction be considered a violation of the applicable emission limit unless otherwise specified in the applicable standard.
[40 CFR 60.8(c)]

B.52. The owner or operator of an affected facility shall provide the Administrator at least 30 days prior notice of any performance test, except as specified under other subparts, to afford the Administrator the opportunity to have an observer present.
[40 CFR 60.8(d)]

40 CFR 60.11 Compliance with standards and maintenance requirements.

B.53. Compliance with standards in 40 CFR 60, other than opacity standards, shall be determined in accordance with performance tests established by 40 CFR 60.8, unless otherwise specified in the applicable standard.
[40 CFR 60.11(a)]

B.54. Compliance with opacity standards in 40 CFR 60 shall be determined by conducting observations in accordance with Reference Method 9 in Appendix A of 40 CFR 60, any alternative method that is approved by the Administrator, or as provided in 40 CFR 60.11(e)(5).
[40 CFR 60.11(b)]

B.55. The opacity standards set forth in 40 CFR 60 shall apply at all times except during periods of startup, shutdown, malfunction, and as otherwise provided in the applicable standard.
[40 CFR 60.11(c)]

B.56. At all times, including periods of startup, shutdown, and malfunction, owners and operators shall, to the extent practicable, maintain and operate any affected facility including associated air pollution control equipment in a manner consistent with good air pollution control practice for minimizing emissions. Determination of whether acceptable operating and maintenance procedures are being used will be based on information available to the Administrator which may include, but is not limited to, monitoring results, opacity observations, review of operating and maintenance procedures, and inspection of the source.
[40 CFR 60.11(d)]

B.57. The owner or operator of an affected facility subject to an opacity standard may submit, for compliance purposes, continuous opacity monitoring system (COMS) data results produced during any performance test required under 40 CFR 60.8 in lieu of EPA Method 9 observation data. If an owner or operator elects to submit COMS data for compliance with the opacity standard, he or she shall notify the Administrator of that decision, in writing, at least 30 days before any performance test required under 40 CFR 60.8 is conducted. Once the owner or operator of an affected facility has notified the Administrator to that effect, the COMS data results will be used to determine opacity compliance during subsequent tests required under 40 CFR 60.8 until the owner or operator notifies the Administrator, in writing, to the contrary. For the purpose of determining compliance with the opacity standard during a performance test required under 40 CFR 60.8 using COMS data, the minimum total time of COMS data collection shall be averages of all 6-minute continuous periods within the duration of the mass emission performance test. Results of the COMS opacity determinations shall be submitted along with the results of the performance test required under 60.8. The owner or operator of an affected facility using a COMS for compliance purposes is responsible for demonstrating that the COMS meets the requirements specified in 40 CFR 60.13(c), that the COMS has been properly maintained and operated, and that the resulting data have not been altered in any way. If COMS data results are submitted for compliance with the opacity standard for a period of time during which EPA Method 9 data indicates noncompliance, the EPA Method 9 data will be used to determine opacity compliance.
[40 CFR 60.11(e)(5)]

40 CFR 60.12 Circumvention.

B.58. No owner or operator subject to the provisions of 40 CFR 60 shall build, erect, install, or use any article, machine, equipment or process, the use of which conceals an emission which would otherwise constitute a violation of an applicable standard. Such concealment includes, but is not limited to, the use of gaseous diluents to achieve compliance with an opacity standard or with a standard which is based on the concentration of a pollutant in the gases discharged to the atmosphere.
[40 CFR 60.12]

40 CFR 60.13 Monitoring requirements.

B.59. For the purposes of 40 CFR 60.13, all continuous monitoring systems (CMS) required under applicable subparts shall be subject to the provisions of 40 CFR 60.13 upon promulgation of performance specifications for continuous monitoring systems under Appendix B of 40 CFR 60 and, if the continuous monitoring system is used to demonstrate compliance with emission limits on a continuous basis, Appendix F of 40 CFR 60, unless otherwise specified in an applicable subpart or by the Administrator. Appendix F is applicable December 4, 1987.
[40 CFR 60.13(a)]

B.60. If the owner or operator of an affected facility elects to submit continuous opacity monitoring system (COMS) data for compliance with the opacity standard as provided under 40 CFR 60.11(e)(5), he shall conduct a performance evaluation of the COMS as specified in Performance Specification 1, Appendix B, of 40 CFR 60 before the performance test required under 40 CFR 60.8 is conducted. Otherwise, the owner or operator of an affected facility shall conduct a performance evaluation of the COMS or continuous emission monitoring system (CEMS) during any performance test required under

40 CFR 60.8 or within 30 days thereafter in accordance with the applicable performance specification in Appendix B of 40 CFR 60. The owner or operator of an affected facility shall conduct COMS or CEMS performance evaluations at such other times as may be required by the Administrator under section 114 of the Act.

(1) The owner or operator of an affected facility using a COMS to determine opacity compliance during any performance test required under 60.8 and as described in 40 CFR 60.11(e)(5) shall furnish the Administrator two or, upon request, more copies of a written report of the results of the COMS performance evaluation described in 40 CFR 60.13(c) at least 10 days before the performance test required under 60.8 is conducted.
[40 CFR 60.13(c)(1)]

B.61. (1) Owners and operators of all continuous emission monitoring systems (CEMS) installed in accordance with the provisions of this part shall check the zero (or low-level value between 0 and 20 percent of span value) and span (50 to 100 percent of span value) calibration drifts at least once daily in accordance with a written procedure. The zero and span shall, as a minimum, be adjusted whenever the 24-hour zero drift or 24-hour span drift exceeds two times the limits of the applicable performance specifications in Appendix B. The system must allow the amount of excess zero and span drift measured at the 24-hour interval checks to be recorded and quantified, whenever specified. For continuous monitoring systems measuring opacity of emissions, the optical surfaces exposed to the effluent gases shall be cleaned prior to performing the zero and span drift adjustments except that for systems using automatic zero adjustments. The optical surfaces shall be cleaned when the cumulative automatic zero compensation exceeds 4 percent opacity.

(2) Unless otherwise approved by the Administrator, the following procedures shall be followed for continuous monitoring systems measuring opacity of emissions. Minimum procedures shall include a method for producing a simulated zero opacity condition and an upscale (span) opacity condition using a certified neutral density filter or other related technique to produce a known obscuration of the light beam. Such procedures shall provide a system check of the analyzer internal optical surfaces and all electronic circuitry including the lamp and photo detector assembly.
[40 CFR 60.13(d)(1) and (2)]

B.62. Except for system breakdowns, repairs, calibration checks, and zero and span adjustments required under 40 CFR 60.13(d), all continuous monitoring systems (CMS) shall be in continuous operation and shall meet minimum frequency of operation requirements as follows:

(1) All continuous monitoring systems referenced by 40 CFR 60.13(c) for measuring opacity of emissions shall complete a minimum of one cycle of sampling and analyzing for each successive 10-second period and one cycle of data recording for each successive 6-minute period.

(2) All continuous monitoring systems referenced by 40 CFR 60.13(c) for measuring emissions, except opacity, shall complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period.
[40 CFR 60.13(e)(1) and (2)]

B.63. All continuous monitoring systems (CMS) or monitoring devices shall be installed such that representative measurements of emissions or process parameters from the affected facility are obtained. Additional procedures for location of continuous monitoring systems contained in the applicable Performance Specifications of Appendix B of 40 CFR 60 shall be used.
[40 CFR 60.13(f)]

B.64. When the effluents from a single affected facility or two or more affected facilities subject to the same emission standards are combined before being released to the atmosphere, the owner or operator may install applicable continuous monitoring systems (CMS) on each effluent or on the combined effluent. When the affected facilities are not subject to the same emission standards, separate continuous monitoring systems shall be installed on each effluent. When the effluent from one affected facility is released to the atmosphere through more than one point, the owner or operator shall install an applicable continuous monitoring system on each separate effluent unless the installation of fewer systems is approved by the Administrator. When more than one continuous monitoring system is used to measure the emissions from one affected facility (e.g., multiple breechings, multiple outlets), the owner or operator shall report the results as required from each continuous monitoring system.
[40 CFR 60.13(g)]

B.65. Owners or operators of all continuous monitoring systems for measurement of opacity shall reduce all data to 6-minute averages and for continuous monitoring systems other than opacity to 1-hour averages for time periods as defined in 40 CFR 60.2. Six-minute opacity averages shall be calculated from 36 or more data points equally spaced over each 6-minute period. For continuous monitoring systems other than opacity, 1-hour averages shall be computed from four or more data points equally spaced over each 1-hour period. Data recorded during periods of continuous monitoring system breakdowns, repairs, calibration checks, and zero and span adjustments shall not be included in the data averages computed under this paragraph. An arithmetic or integrated average of all data may be used. The data may be recorded in reduced or non reduced form (e.g., ppm pollutant and percent O_2 or ng/J of pollutant). All excess emissions shall be converted into units of the standard using the applicable conversion procedures specified in subparts. After conversion into units of the standard, the data may be rounded to the same number of significant digits as used in the applicable subparts to specify the emission limit (e.g., rounded to the nearest 1 percent opacity).
[40 CFR 60.13(h)]

Subsection C. Combustion Turbines
This section addresses the following Regulated Emissions Units:

E.U. ID No.	Brief Description
-007	Combustion Turbine No. 1
-005	Combustion Turbine No. 2
-006	Combustion Turbine No. 3

Descriptions
Combustion Turbine No. 1 is a self-contained combustion turbine generating unit. The unit is a predesigned integrated simple-cycle, single-shaft, three-bearing machine with the load connected at the exhaust end of the unit. The turbine is fired on No. 2 distillate fuel oil and operated for intermittent peaking and emergency services only. The generator nameplate capacity is 18 MW. Unit No. 1 began commercial operation in 1969.

Combustion Turbine No. 2 is a self-contained Westinghouse combustion turbine generating unit. The unit is a predesigned integrated simple-cycle, single-shaft, three-bearing machine with the load connected at the exhaust end of the unit. The turbine is fired on No. 2 distillate fuel oil and operated for intermittent peaking and emergency services only. The generator nameplate capacity is 78 MW. Unit No. 2 began commercial operation in 1974.

Combustion Turbine No. 3 is a self-contained Westinghouse combustion turbine generating unit. The unit is a predesigned integrated simple-cycle, single-shaft, multi-bearing machine with the load connected at the exhaust end of the unit. The turbine is fired on No. 2 distillate fuel oil and operated for intermittent peaking and emergency services only. The generator nameplate capacity is 78 MW. Unit No. 3 began commercial operation in 1974.

{Permitting note: These are pre-NSPS combustion turbines.}

The following conditions apply to the Emissions Units listed above:

Essential Potential to Emit (PTE) Parameters

C.1. Methods of Operation - Fuels. The combustion turbines shall be fired on No. 2 distillate fuel oil and operated for intermittent peaking and emergency services only.
[Rule 62-4.160(2), F.A.C., Construction application request]

C.2. Hours of Operation. Operation of each gas turbine shall not exceed 3650 hours of operation during any consecutive 12 months. [Design; Rule 62-210.200, F.A.C. (Definitions - PTE), Permit No. 057-0039-006-AC]

C.3. Inlet Fogger Operation: Combined operation of the inlet air foggers for both gas turbines CT-2 and CT-3 shall not exceed 1365 total hours during any consecutive 12 months. [Design; Rule 62-212.400, F.A.C. (BACT); Rule 62-210.200, F.A.C. (Definitions - PTE), Permit No. 057-0039-006-AC]

C.4. Plant Operation - Problems: If temporarily unable to comply with any of the conditions of this permit due to breakdown of equipment or destruction by fire, wind or other cause, the owner or operator shall notify the Compliance Authority by phone, FAX, or letter as soon as possible, but at least within one working day, excluding weekends and holidays. The notification shall include pertinent information as to the cause of the problem, the steps being taken to correct the problem and prevent future recurrence, and the owner's intent toward reconstruction of destroyed facilities. Such notification does not release the permittee from any liability for failure to comply with the conditions of this permit and the regulations. [Rule 62-4.130, F.A.C., Permit No. 057-0039-006-AC]

Emission Limitations and Standards

C.5. Visible emissions from each combustion turbine shall not be equal to or greater than 20 percent opacity.

[Rule 62-296.320(4)(b)1., F.A.C.]

C.6. During each federal fiscal year (October 1 - September 30) the Tampa Electric Company shall have formal compliance tests conducted on each combustion turbine for opacity. Any combustion turbine that does not operate for more than 400 hours per year shall conduct a visible emissions compliance test once per each five-year period, coinciding with the term of its air operation permit.
[Rule 62-296.712, Rule 62-297.310(7)(a)4.a., , and Rule 62-297.310(7)(a)8., F.A.C.]

C.7. The test methods for visible emissions shall be EPA Method 9, incorporated and adopted by reference in Chapter 62-297, F.A.C. Test procedures shall meet all applicable requirements of Chapter 62-297, F.A.C.

Recordkeeping and Reporting Requirements

C.8. If TEC chooses to conduct a visible emissions compliance test only once per five-year period, per Rule 62-297.310(7)(a)8., daily recordkeeping of the hours of operation is required to show that the 400-hour annual limit is not exceeded each year during the five-year period.
[Rule 62-297.310(7)(a)8., and Rule 62-4.070(3), F.A.C.]

C.9. Documentation of the type, quantity, and analysis of the fuel oil used/received is required. Records shall be kept for five years.
[Rules 62-4.070(3) and 62-213.440(1), F.A.C.]

C.10. The average daily and total annual hours of operation for each combustion turbine shall be submitted in an annual operation report. In addition, for each combustion turbine, annual emissions reporting requirements, apply to emissions of each pollutant that a turbine emits in the following quantities:

(1) for PM_{10}, sulfur oxides, VOC, and nitrogen oxides - 25 tons per year or more,
(2) for carbon monoxide - 250 tons per year or more,
(3) for lead or lead compounds, measured as elemental lead - 5 tons per year or more.
[62-210.370(3), F.A.C., 40 CFR 51.322(b)]

Tampa Electric will evaluate emissions from the turbines through the use of AP-42 emission factors or another equivalent method such as fuel analysis. [USEPA objection resolution.]

Compliance Demonstrations

C.11. Records: All measurements, records, and other data required by this permit shall be documented in a permanent, legible format and retained for at least five (5) years following the date on which such measurements, records, or data are recorded. Records shall be made available to DEP representatives upon request. [Rules 62-4.160(14) and 62-213.440(1)(b)2., F.A.C.]

C.12. Monthly Operations Summary: By the fifth calendar day of each month, the permittee shall record the following information in a written log for the previous month of operation and for the previous 12 months of operation: the number of operational hours for each gas turbine; the number of hours of inlet air fogging for each gas turbine; and the total combined number of hours of inlet air fogging for both gas turbines. The Monthly Operations Summary shall be maintained on site in a legible format available for inspection at the Department's request. [Rule 62-4.160(15), F.A.C.]

Subsection D. Flyash Handling and Storage
This section addresses the following Regulated Emissions Units:

E.U. ID No.	Brief Description
-008	Fly Ash Silo No. 1 Baghouse
-018	Fly Ash Silo No. 1 Truck Loadout
-009	Fly Ash Silo No. 2 Baghouse
-019	Fly Ash Silo No. 2 Truck Loadout
-026	Fly Ash Handling and Storage Fugitive Emissions (all except silos)

Descriptions

Fly Ash Silo No. 1 handles fly ash from Steam Generator Units No. 1 and No. 2. Fly ash is pneumatically conveyed from the individual electrostatic precipitators to Silo No. 1. Also, the fly ash may be pneumatically conveyed from tanker trucks to Silo No. 1 and Silo No. 2, and between Silo No. 1 and Silo No. 2. The sum total loading rate to the silo for all the processes combined is 44.5 tons per hour. Fly ash from Silo No. 1 is discharged in either a wet or dry state. The dry fly ash is gravity fed by tubing into totally enclosed tanker trucks. The wet fly ash is processed through a pugmill and then unloaded into a dump truck. Particulate matter emissions generated by silo loading and silo unloading to a tanker truck are controlled by a 20,081 DSCFM Flex Kleen Model No. 84 UDTR-640 baghouse in addition to reasonable precautions. All fly ash handled is generated on-site.

Fly Ash Silo No. 2 handles fly ash from Steam Generator Units Nos. 1, 2, and/or 3. Fly ash is pneumatically conveyed in a series of pipes from the individual unit precipitators (Units 1, 2, and/or 3, only two units at any time) to the silo for temporary storage. From the silo, the fly ash is gravity fed by tubing into closed tanker trucks and transported to an off-site consumer. Particulate emissions generated during silo loading operation and from the tanker truck loadout chutes are controlled by a 20,081 DSCFM Flex Kleen, Model No. 84 UDTR-640 baghouse in addition to reasonable precautions.

The following conditions apply to the Emissions Units listed above:

Essential Potential to Emit (PTE) Parameters

D.1. Capacity. The maximum permitted loading rate for all Fly Ash Silo No. 1 processes combined is 44.5 tons per hour. For Fly Ash Silo No. 2, the maximum permitted loading rate is the simultaneous maximum transfer of flyash from boiler Units 1, 2, and 3. Separate testing of emissions from each unit shall be conducted with each emissions unit operation at 90 to 100 percent of the maximum permitted heat input rate. If it is impractical to test at permitted capacity, an emissions unit may be tested at less than the minimum permitted capacity; in this case, subsequent emissions unit operation is limited to 110 percent of the test load until a new test is conducted. Once the unit is so limited, operation at higher capacities is allowed for no more than 15 consecutive days for the purpose of additional compliance testing to regain the authority to operate at the permitted capacity.
[AC29-194516; AO29-161082; Rule 62-4.160(2), and Rule 62-297.310(2), F.A.C.]
{Permitting note: The material loading limitations have been placed in each permit to identify the capacity of each emissions unit for the purposes of confirming that emissions testing is conducted within 90 to 100 percent of the emissions unit's rated capacity (or to limit future operation to 110

percent of the test load), to establish appropriate emission limits and to aid in determining future rule applicability. Regular recordkeeping is not required for material loading. Instead the owner or operator is expected to determine material loading whenever the emission testing is required, to demonstrate at what percentage of the rated capacity that the emissions unit was tested. Rule 62-297.310(5), F.A.C., included in the permit, requires measurement of process variables for emission tests. Material loading demonstrations may be based on best engineering evaluation of the operating requirements necessary to achieve 90 to 100 percent of the rated loading, unless such operating conditions are otherwise specified by permit condition.}

D.2. Hours of Operation. Fly Ash Silos No. 1 and No. 2 are each allowed to operate continuously, i.e., 8760 hours/year.
[Rule 62-210.200, F.A.C., Definitions (PTE)]

Emission Limitations and Standards

D.3. Visible emissions from each silo baghouse shall not be equal to or greater than 20 percent opacity. Visible emissions from each silo truck loadout shall not be equal to or greater than 20 percent opacity.
[Rule 62-296.320(4)(b)1., F.A.C.]

D.4. Visible emissions from the flyash handling system and flyash silos are limited to 5% opacity.
[Power Plant Siting Certification PA 79-12]

D.5. Total maximum allowable emissions of particulate matter from the each silo baghouse shall not exceed 0.03 grains/DSCF, 5.16 lbs./hr. and 22.62 tons/yr. based on a design flow rate of 20,081 DSCFM. The requirement of formal particulate matter compliance testing as provided in specific condition D.6. shall be waived if the baghouse meets the alternative standard of 5% opacity. If the Department or the Environmental Protection Commission of Hillsborough County has reason to believe that the particulate weight emission standard is not being met, the agency shall require that compliance be demonstrated by EPA Method 17 specified in Rule 62-297, F.A.C.
[Rule 62-4.160(2) and Rule 62-297.620(4), F.A.C.; AO29-160255; AO29-161082]

Test Methods and Procedures

D.6. During each federal fiscal year (October 1 - September 30), unless otherwise specified by rule, order, or permit, the Tampa Electric Company shall have formal compliance tests conducted on each silo baghouse for opacity and particulate matter and formal compliance test conducted on each silo truck loadout for opacity.
[Rule 62-297.310(7)(a)4., F.A.C.]

D.7. The test method for particulate emissions shall be EPA Method 17, with an acetone wash and an average stack temperature below 275 degrees Fahrenheit, or EPA Method 5 with an acetone wash. These test methods are incorporated and adopted by reference in Chapter 62-297, F.A.C. Test procedures shall meet all applicable requirements of Chapter 62-297, F.A.C.
[Rules 62-296.320(4)(a)3.a.(ii) and 62-296.320(4)(a)3.c., F.A.C.]

D.8. The test methods for visible emissions shall be EPA Method 9, incorporated and adopted by reference in Chapter 62-297, F.A.C. Test procedures shall meet all applicable requirements of Chapter 62-297, F.A.C.
[Rule 62-296.320(4)(b)4., F.A.C.]

D.9. All reasonable precautions shall be taken to prevent and control generation of unconfined emissions of particulate matter in accordance with the provisions in Rule 62-296.320(4), F.A.C. These provisions are applicable to any source, including, but not limited to, vehicular movement, transportation of materials, construction, alterations, demolition or wrecking, or industrial related activities such as loading, unloading, storing and handling. The following reasonable precaution shall be taken to control unconfined particulate matter emissions associated with the fly ash silo/truck operations. Reasonable precautions shall include, but not limited to:
A) Fly ash transported by dump truck shall be adequately wetted and processed through the pugmill.
B) Dump trucks used to transport fly ash shall utilize tarps at all times except when loading/unloading.
C) Fly ash transported in a dry state shall be accomplished utilizing an enclosed tanker truck.
D) Fly ash spilled and/or leaked on plant grounds shall be adequately wetted and disposed of daily.
E) Fly ash collected from spills and/or leaks must be adequately wetted at all times.
F) Ensure the proper seating of the unloader chute onto the tanker inlet prior to loading.
G) Keep the dust extractor operational during loading.
H) Close the tanker's inlet as soon as practical after the loading process.
I) Extend the tubing from the silo into the closed tanker type trucks during loadout.
J) Periodic watering of plant roads.
[Rule 62-296.320(4)(c)2., F.A.C., AO29-160255, and precautions specified in initial Title V application.]

D.10. Compliance testing for the silo and tanker truck loading operations shall be conducted under the following conditions:
a. All conveyance hoppers will be operational during the test.
b. All fly ash will be directed to the silo, no reinjection of fly ash to the boiler systems will occur during the test.
c. The boilers shall operate at the maximum capability of this unit under normal operating conditions during the test.
d. Two tanker trucks shall be loaded during the test. The loading valve shall be completely open during filling.
e. The visible emission test shall be at least 30 minutes in duration and the period of time during which truck loading occurred indicated on the test report.
[Rule 62-4.070(3), F.A.C.].

D.11. Compliance with the emission limitations of Specific Conditions Nos. 3 and 4 shall be determined using EPA Methods 1, 2, 4, 5 and 9 contained in 40 CFR 60, Appendix A and adopted by reference in Rule 62-297.401, F.A.C. The Method 9 observation period for the silo and tanker truck loading operations shall be at least thirty (30) minutes in duration. The minimum requirements for stack sampling facilities, source sampling and reporting, shall be in accordance with Rule 62-297, F.A.C. and 40 CFR 60, Appendix A.
[Rule 62-297, F.A.C.]

D.12. All compliance tests shall be conducted while loading the silo at approximately the maximum feed rate (24 hour average). Failure to submit the feed rate or operating at conditions during testing which do not reflect normal operating conditions may invalidate the data.
[Rule 62-4.070(3), F.A.C.].

Subsection E. Flyash Silo No. 3
This section addresses the following Regulated Emissions Units:

E.U. ID No.	Brief Description
-014	Fly Ash Silo No. 3 Baghouse
-027	Fly Ash Silo No. 3 Truck Loadout
-028	Fly Ash Handling System Fugitive Emissions

Description

Fly Ash Silo No. 3 handles fly ash from Steam Generator Unit No. 4. Also, fly ash may be pneumatically conveyed from tanker trucks to Silo No. 3. Particulate matter emissions are controlled by a 1,200 DSCFM Flex Kleen Model 84-WRTC-80-II-G baghouse.

The following conditions apply to the Emissions Unit listed above:

Essential Potential to Emit (PTE) Parameters

E.1. Particulate matter emissions from the flyash handling system and flyash silo shall not exceed 0.2 lb/hr.
[Power Plant Siting Certification PA 79-12; PSD-FL-040]

E.2. Visible emissions from the flyash handling system and the flyash silo are limited to 5% opacity.
[Power Plant Siting Certification PA 79-12]

E.3. The flyash handling system (including transfer and silo storage) will be maintained at negative pressures and vented to a control system.
[PSD-FL-040]

E.4. Tampa Electric will perform an annual VE test to satisfy the periodic monitoring requirements of these conditions. In addition, the system pressure will be monitored quarterly to assess that the system is operating under negative pressure.
[USEPA objection resolution.]

Subsection F. Limestone Handling and Storage
This section addresses the following Regulated Emissions Units:

E.U. ID No.	Brief Description
-011	Truck/Railcar Limestone Unloading Receiving Hopper with baghouse
-012	Limestone Silo A with 2 baghouses
-013	Limestone Silo B with 2 baghouses
-023	Limestone Handling Conveyor LB to Conveyor LC with baghouse, Limestone Handling Conveyor LD to Conveyor LE with baghouse
-024	Limestone Handling Conveyor LE to South Storage Silo with baghouse, Limestone Handling Conveyor LE to North Storage Silo with baghouse
-025	Limestone Storage and Handling Fugitive Emissions

Descriptions

Particulate matter emissions from the truck and railcar unloading of limestone are controlled by a Mikro-Pulsaire Model 400S12TR baghouse. Particulate matter emissions generated by the transfer of limestone from Handling Conveyor LB to Conveyor LC are controlled by a Sternvent Model DKED18003 baghouse. Particulate matter emissions generated by the transfer of limestone from Handling Conveyor LD to Conveyor LE are controlled by a Sternvent Model DKED 18003 baghouse. Particulate matter emissions generated by the transfer of limestone from Handling Conveyor LE to the South Storage Silo are controlled by a Flex Kleen Model 58-BVBC-36-IIG baghouse. Particulate matter emissions generated by the transfer of limestone from Handling Conveyor LE to the North Storage Silo are controlled by a Flex Kleen Model 58-BVBC-36-IIG baghouse.

The following conditions apply to the Emissions Units listed above:

Essential Potential to Emit (PTE) Parameters

F.1. Total combined particulate matter emissions from the limestone handling hoppers/conveyors shall not exceed 0.65 lb/hr. Visible emissions are limited to 5% opacity. Compliance testing for particulate matter emissions is not required provided the opacity limit is maintained.
[PSD-FL-040; Power Plant Siting Certification PA 79-12]

F.2. Total combined particulate matter emissions from the limestone silos shall not exceed 0.05 lb/hr. Visible emissions are limited to 5% opacity. Compliance testing for particulate matter emissions is not required provided the opacity limit is maintained.
[PSD-FL-040; Power Plant Siting Certification PA 79-12]

F.3. All conveyors and conveyor transfer points shall be enclosed to preclude particulate matter emissions.
[PSD-FL-040]

F.4. The limestone handling receiving hopper, conveyor transfer points and silos shall be maintained at negative pressures with the exhaust vented to a control system(s).
[PSD-FL-040]

F.5. Tampa Electric will perform an annual VE test to satisfy the periodic monitoring requirements of these conditions. In addition, the system pressure will be monitored quarterly to assess that the system is operating under negative pressure.
[USEPA objection resolution.]

Subsection G. Coal Bunkers with Roto-Clones
This section addresses the following Regulated Emissions Units:

E.U. ID No.	Brief Description
-015	Unit No. 1 Coal Bunker with Roto-Clone
-016	Unit No. 2 Coal Bunker with Roto-Clone
-017	Unit No. 3 Coal Bunker with Roto-Clone

Descriptions

These emission units are Steam Generator Units Nos. 1-3 Coal Bunkers with an exhaust fan/cyclone collector (Roto-Clone controlling dust emission from each unit's respective bunker. Two moving transfer stations via their respective conveyor belts route coal through enclosed chutes to the various bunkers. Coal Bunkers 1-3 are each equipped with a 9400 ACFM American Air Filter (AAF) Company Type D Roto-Clone to abate dust emissions during ventilation. A number of vent pipes convey fresh air from each bunker to a Roto-Clone during particulate matter removal. Particulate matter removed by the Roto-Clones is returned to the coal bunkers via a hopper and return line. Unit No. 1 Coal Bunker is situated west of Unit No. 2 Coal Bunker. Unit No. 3 Coal Bunker is situated east of Unit No. 2 Coal Bunker.

The following conditions apply to the Emissions Units listed above:

Essential Potential to Emit (PTE) Parameters

G.1. Capacity.. The annual coal throughput shall not exceed 4,000 TPH per bunker.
[Rule 62-4.160(2), F.A.C.]

G.2. Hours of Operation. To show compliance with the annual allowable emission rate, the hours of bunker loading operation shall not exceed 4167 hours per year.
[Rule 62-210.200, F.A.C., Definitions (PTE)]

Emission Limitations and Standards

G.3. Visible emissions from each unit shall not be equal to or greater than 20% opacity. The test method for visible emissions shall be EPA Method 9, incorporated and adopted by reference in Chapter 62-297, F.A.C.
[Rule 62-296.320(4)(b)1. and 4., F.A.C.]

G.4. Since a source of less than 1 TPY is exempt from particulate matter RACT provisions, the maximum allowable particulate emissions shall not exceed 0.99 tons per year from each cyclone exhaust. Also maximum allowable particulate matter emissions shall not exceed 0.48 lbs/hr from each cyclone exhaust.
[AO29-163788 to escape RACT]

G.5. The maximum allowable emission rate for particulate matter for this source is set by specific condition no. G.4. Because of the expense and complexity of conducting a stack test on minor sources of particulate matter, the Department hereby waives the requirement for a stack test. The alternative standard establishes a visible emission limitation not to exceed an opacity of 5%. Compliance with this alternate emission limitation shall be determined using DEP Method 9 contained in 62-297.401, F.A.C.
[AO29-163788]

G.6. Should the Department have reason to believe the particulate matter emission standard is not being met, the Department may require that compliance with the particulate emission standards be demonstrated by testing using EPA Methods 1, 2, 4 and 5 in accordance with 62-297.401, F.A.C.
[Rule 62-297.310(7)(b), F.A.C.]

G.7. Tampa Electric will monitor the hours of operation of coal bunker loading. In addition, Tampa Electric will perform an annual VE test to satisfy the periodic monitoring requirements of this condition.
[USEPA objection resolution.]

Subsection H. Solid Fuel Yard
This section addresses the following Regulated Emissions Units:

E.U. ID No.	Brief Description
-010	Solid Fuel Yard, Fugitive Emissions
-029	Cyclone collectors for fuel blending bins (FH-032 through FH-035)
-030	Cyclone collectors for fuel crushers (FH-048 and FH-049)
-031	Cyclone collectors for bunkers (FH-059 through FH-062)

Descriptions

Solid fuel is unloaded from ship/barge into the Solid fuel yard or directly to the tripper room via belt conveyors. Solid fuel from the piles is loaded onto belt conveyors using a rail mounted or mobile reclaimer. The solid fuel is then belt conveyed to the blending tower, which consists of six storage bins, where the solid is blended for use at the plant, or transloaded into trucks for shipment off site. From the solid fuel yard conveyors, the solid fuel is screw conveyed into the bins. Particulate matter (PM) emissions from the conveyors in the solid fuel yard are controlled by 3 rotoclones, one for every 2 bins. PM emissions from the screw conveyor are controlled by the fourth rotoclone. Each has 2 hoppers, which feed the transloader, or are conveyed, via 2 parallel belts (T1, T2) to 2 crushers (each belt has a crusher), or diverted directly to the tripper room. PM emissions from the 2 crushers and transfer tower are controlled by 2 rotoclones.

From the solid fuel yard, the solid fuel is conveyed to the tripper room where 2 trippers bunker the solid fuels into 4 solid fuel bunkers. Each unit has its own respective bunker. Solid fuel samples are taken every 15 minutes during bunking, and composited for analysis. From the bunkers, the solid fuel is gravity fed into 14 crushers, and then gravity fed into the boilers. There are 3 tall crushers, each for Unit Nos. 1 – 3, and 5 bowl crushers for Unit No. 4. From the crushers, the solid fuel is pneumatically fed into classifiers, two for each crusher for a total of 28 classifiers, and then into the respective boilers.

The following conditions apply to the Emissions Units listed above:

H.1. TEC shall maintain a daily log of the amounts and types of fuels used and copies of fuel analyses containing information on sulfur content, ash content and heating values.
[Power Plant Siting Certification PA 79-12]

H.2. Particulate matter emissions from the solid fuel handling facilities:
(a) Pursuant to Chapter 1-3.62 Rules of the Environmental Protection Commission of Hillsborough County, visible emission shall not exceed 20% opacity for any unconfined emission unit in the fuel yard. Unconfined emissions as defined by Rule 62-296.200, F.A.C., shall include the static fuel piles, etc. Pursuant to Rule 62.296.711(2), F.A.C., visible emissions shall not exceed 5 percent opacity for the remaining emission units in the fuel yard. Visible emissions compliance tests shall be demonstrated using EPA Reference Method 9, 40 CFR Part 60, Appendix A, Visual Determination of Fugitive Emissions form Material Sources (July 1, 1993 version). All testing shall be done within 90 days of completing reconfiguration of the fuel yard, and prior notification of testing shall be submitted in writing at least 15 days beforehand to the EPC of Hillsborough County. Particulate emissions shall

be controlled by use of control devices. Tampa Electric will perform an annual VE test to demonstrate compliance with the opacity standard established for the solid fuel yard.

(b) The permittee must submit to the Department within ten (10) working days after it becomes available, copies of technical data pertaining to the selected particulate emissions control for the coal handling facility. These data should include, but not be limited to, guaranteed efficiency and emission rates, and major design parameters such as air/cloth ratio and flow rate. The Department may, upon review of these data, disapprove the use of such device if the Department determines the selected control device to be inadequate to meet the emission limits specified in condition (a) above. Such disapproval shall be issued within 30 days of receipt of the technical data.

(c) The fuel pile operations are subject to Rule 62-296.310(3), F.A.C., Unconfined Emissions of Particulate Matter. Reasonable precautions to minimize unconfined particulate matter shall be in accordance with Rule 62-296.310(3)(c), F.A.C.,; and, may include, but shall not be limited to, the coating of roads and construction sites used by contractors and regrassing or watering areas of disturbed fuel.

(d) From each fuel transloading source/emissions point (i.e., off-loading and loading of fuel {for export from Big Bend Station}), the maximum hourly transloading transfer of fuel shall not exceed 4,000 tons, 24-hour rolling average.

(e) From each fuel transloading source/emissions point, (i.e., off-loading and loading of fuel {for export from Big Bend Station}), the maximum annual transloading transfer of fuel shall not exceed 1,428,030 tons.

(f) The number of railcars and trucks and the quantity of fuel loaded by each fuel transloading source/emissions point (i.e., off-loading and loading of fuel {for export from Big Bend Station*}) shall be recorded, maintained, and kept on fuel for a minimum of five years. The annual quantity of fuel loaded by each fuel transloading source/emissions point shall be submitted in the Annual Operation Report.

[Power Plant Siting Certification PA 79-12]
*Permitting Note.

H.3. All conveyors and conveyor transfer points shall be enclosed to preclude particulate matter emissions excepting the coal handling stacker reclaimer, the tail end conveyor feeding the tripper and the barge unloading belt which are exempted for feasibility considerations.
[PSD-FL-040]

H.4. Coal storage piles shall be shaped, compacted and oriented to minimize wind erosion.
[PSD-FL-040]

H.5. Water sprays for storage piles, handling equipment, etc., including the handling equipment exempted from the conveyor enclosure requirement, shall be applied during dry periods and as necessary to all facilities to maintain opacity below 20 percent.
[Rules 62-4.160(2) and 62-296.320(4)(c), F.A.C.]

Subsection I. Surface Coating of Miscellaneous Metal Parts

This section addresses the following Regulated Emissions Units:

-032 Surface coating of miscellaneous metal parts

Description
These conditions apply to the surface coating of miscellaneous metal parts as defined in Rule 62-296.513, F.A.C. These parts include such things as pumps, compressors, conveyor components, fans, blowers, transformers.

The following conditions apply to the Emissions Unit listed above:

I.1. Hours of Operation. Miscellaneous metal parts surface coating operations are allowed to operate for a total 3500 hours/year.
[Rule 62-210.200, F.A.C., Definitions (PTE)]

I.2. Capacity. The total maximum coating usage shall not exceed 2 gallons per hour, on a 24-hr basis, and 7000 gallons per year.
[Rule 62-210.200, F.A.C., Definitions (PTE)]

I.3. Recordkeeping. TEC shall maintain daily records of operations for the most recent 5 year period. The records shall be made available to the local, state, or federal air pollution agency upon request. The records shall include, but not be limited to, the following:
a. The rule number applicable to the operation for which the records are being maintained.
b. The application method and substrate type (metal, etc.).
c. The amount and type of adhesive, coatings (including catalyst and reducer for multicomponent coatings), solvent, and/or graphic arts material used at each point of application, including exempt compounds.
d. The VOC content as applied in each adhesive, coating, solvent, and/or graphic arts material.
e. The date for each application of each adhesive, coating, solvent, and/or graphic arts material.
f. The amount of surface preparation, clean-up, wash-up of solvent (including exempt compounds) used and the VOC content of each.
[Rule 62-296.500(2)(b)1., F.A.C.]

I.4. The VOC content shall be calculated using a percent solids basis (less water and exempt solvents) for adhesives, coating, and inks, using EPA Reference Method 24.
[Rule 62-296.500(2)(b)2., F.A.C.]

I.5. Reporting. Annually, in accordance with a schedule and reporting format provided by the Department or EPCHC, TEC shall provide EPCHC with proof of compliance with the limitations in this section.
[Rule 62-296.500(2)(c), F.A.C.]

The following conditions apply to the Emissions Unit listed above if the Emissions Unit emits more than 15 pounds of VOC in any one day and 3 pounds VOC in any one hour:

I.6. Emissions Limits for surface coating of miscellaneous metal parts.
(a) No owner or operator of a coating line for miscellaneous metal parts and products shall cause, allow, or permit the discharge into the atmosphere of any volatile organic compounds in excess of:
(1) 4.3 pounds per gallon of coating (0.52 kilograms per liter), excluding water, delivered to a coating applicator that applies clear coatings;
(2) 3.5 pounds per gallon of coating (0.42 kilograms per liter), excluding water, delivered to a coating applicator in coating application system that is air dried or forced warm air dried at temperatures up to 194 degrees Fahrenheit (90 degrees Celsius);
(3) 3.5 pounds per gallon of coating (0.42 kilograms per liter), excluding water, delivered to a coating applicator that applies extreme performance coatings; or,
(4) 3.0 pounds per gallon of coating (0.36 kilograms per liter), excluding water, delivered to a coating applicator for all other coatings and coating application systems.
(b) If more than one emission limitation in condition I.5.(a) above applies to a specific coating, then the least stringent emission limitation shall be applied.
(c) All volatile organic compound emissions from solvent washings shall be considered in the emission limitations in condition I.6.(a) above unless the solvent is directed into containers that prevent evaporation into the atmosphere.
[Rule 62-296.513(2), F.A.C.]

I.7. Control Technology. The emission limits in condition I.6.(a) above shall be achieved by:
The application of low solvent coating technology.
[Rule 62-296.513(3), F.A.C.]

I.8. Test Methods and Procedures to Determine Low Solvent Technology. The test method for volatile organic compounds shall be EPA Method 24 or EPA 450/3-84-019, incorporated and adopted by reference in Chapter 62-297, F.A.C. Test procedures shall meet all applicable requirements of Chapter 62-297, F.A.C.]
[Rules 62-296.513(4)(a) and (c), F.A.C.]

Subsection J. Abrasive Blasting

This section addresses the following Regulated Emissions Units:
-033 Abrasive Blast Booth with baghouse
-034 Abrasive Blast Media Storage with baghouse

Description
The abrasive blast booth is used to prepare miscellaneous metal parts for surface coating. Particulate matter emissions from the abrasive blast booth are controlled by a Torit Model No. DFT 4-16 pulse jet baghouse with an inlet flow rate of 7,500 acfm. Particulate emissions from the abrasive blast media storage are controlled by a pulse jet baghouse with an inlet air flow rate of 800 dscfm.

The following conditions apply to the Emissions Units listed above:

J.1. Capacity. The maximum annual usage of abrasive blast media in the abrasive blast booth shall not exceed 300 tons per year.
[Rules 62-4.160(2), 62-210.200(PTE)]

J.2. Hours of Operation. These emissions units are each allowed to operate continuously, i.e., 8760 hours/year.
[Rule 62-210.200, F.A.C., Definitions (PTE)]

J.3. Emission Limitations. The particulate matter emissions from each baghouse shall not exceed 0.03 gr/dscf, or any visible emissions greater than 5% opacity. However, TEC may exceed these emission limits if a pollution control device for particulate matter is utilized that has an actual particulate matter collection efficiency of at least 98 percent. The opacity standard for the emissions units shall be the average opacity level achieved during the initial compliance test which established compliance with the standard, plus 5% opacity.
[Rules 62-296.712(2), F.A.C.]

J.4. Test Methods and Procedures.
(a) The test method for visible emissions shall be EPA Method 9, incorporated and adopted by reference by reference in Chapter 62-297, F.A.C.
(b) The test method for particulate matter emissions shall be EPA Method 5, incorporated and adopted by reference in Chapter 62-297, F.A.C. The minimum sample volume shall be 30 dry standard cubic feet.
(c) A visible emissions test indicating no visible emissions (5 percent opacity) may be submitted in lieu of a particular stack test for materials handling emissions subject to this rule, where the emissions unit is equipped with a baghouse.
(d) Test procedures shall meet all applicable requirements of Chapter 62-297, F.A.C.
[Rule 62-296.712(3), F.A.C.]

J.5. Particulate matter emissions from the abrasive blasting operations shall not exceed 15 tons for any 12 consecutive month period.
[Rule 62-212.300, F.A.C.]

13. a. The permittee shall submit all compliance related notifications and reports required of this permit to the Environmental Protection Commission of Hillsborough County:

Environmental Protection Commission
of Hillsborough County
1410 North 21 Street
Tampa, Florida 33605
Telephone: 813/272-5530
Fax: 813/272-5605

b. The permittee shall provide timely notification to the Environmental Protection Commission of Hillsborough County prior to implementing any changes that may result in a modification to this permit. The changes may include, but are not limited to, the following, and may also require prior authorization before implementation:

1. Alteration or replacement of any equipment* or parameter listed in the Facility or Subsection descriptions.
2. Installation or addition of any equipment* which is a source of air pollution.
3. Any changes in the method of operation, raw materials, products of fuels.

*Not applicable to normal maintenance and repairs, and vehicles used for transporting material.
[Rules 62-4.070(3) and 62-210.300, F.A.C.]

14. Any reports, data, notifications, certifications, and requests required to be sent to the United States Environmental Protection Agency, Region 4, should be sent to:

United States Environmental Protection Agency
Region 4
Air, Pesticides & Toxics Management Division
Air and EPCRA Enforcement Branch, Air Enforcement Section
61 Forsyth Street
Atlanta, Georgia 30303
Telêphone: 404/562-9155, Fax: 404/562-9163

Section III. Regulated Emissions Units Conditions.

Subsection A. Steam Generators Units Nos. 1, 2, & 3
This section addresses the following Regulated Emissions Units:

E.U. ID No.	Brief Description
-001	Unit No. 1 Steam Generator
-002	Unit No. 2 Steam Generator
-003	Unit No. 3 Steam Generator

Descriptions. Unit No. 1 is a fossil fuel fired steam boiler generating unit rated at 4037 MMBtu/hour with an electrical generating capacity of 445 MW. It is a "wet" bottom utility boiler manufactured by Riley Stoker Corporation. This unit may be fired on coal or a coal/petroleum coke blend consisting of a maximum of 20.0 percent petroleum coke by weight. Unit No. 1 began commercial operation in 1970.

Unit No. 2 is a fossil fuel fired steam boiler generating unit rated at 3996 MMBtu/hour with an electrical generating capacity of 445 MW. It is a "wet" bottom utility boiler manufactured by Riley Stoker Corporation. This unit may be fired on coal or a coal/petroleum coke blend consisting of a maximum of 20.0 percent petroleum coke by weight. Unit No. 2 began commercial operation in 1973.

Unit No. 1 and Unit No. 2 share two common stacks (Stacks CS001 and CS0W1). Particulate emissions generated during the operation of the units are controlled by dry electrostatic precipitators (ESPs) manufactured by Western Precipitator Division, Joy Manufacturing Corporation. ESP control efficiency is 99.7%. Whenever either unit is fired with petcoke in any amount up to the allowable ratio (20% petcoke/80% coal, by wt.), its flue gases must be directed from its ESP to the FGD system and then to stack CS0W1. Otherwise, if petcoke is not fired, the flue gases may bypass the FGD system and stack CS0W1, and the flue gases are routed from the ESP directly to stack CS001.

Unit No. 3 is a fossil fuel fired steam boiler generating unit rated at 4115 MMBtu/hour with an electrical generating capacity of 445 MW. It is a "wet" bottom utility boiler manufactured by Riley Stoker Corporation. This unit may be fired on coal or a coal/petroleum coke blend consisting of a maximum of 20.0 percent petroleum coke by weight. Operation of this unit may include diverting all of the flue gas into the existing Big Bend Unit No. 4 flue gas desulfurization (FGD) system for sulfur dioxide emission reduction. Sulfur dioxide emissions that are generated and not diverted through the Unit No. 4 FGD system are uncontrolled. Particulate matter emissions generated during the operation of the unit are controlled by a dry electrostatic precipitator (ESP) manufactured by Research-Cottrell, Inc. The ESP control efficiency is 99.7%. Unit No. 3 began commercial operation in 1976.

{Permitting note: Units No. 1, No. 2, and No. 3 are regulated under the federal Acid Rain Program for Phase II SO_2 and NO_x, adopted and incorporated by reference in Rule 62-204.800, F.A.C.; and regulated under 62-296.405, F.A.C. These units were also formerly regulated under the federal Acid Rain Program as Phase I SO_2 substitution units.}

The following specific conditions apply to the emissions units listed above:

ESSENTIAL POTENTIAL TO EMIT (PTE) PARAMETERS

A.1. Capacity. The maximum permitted heat input rate for each unit is as follows:

Unit No.	MMBTU/hr
1	4037
2	3996
3	4115

[Rules 62-4.160(2), 62-210.200(PTE) and 62-296.405, F.A.C.]

{Permitting note: The heat input limitations have been placed in this permit to identify the capacity of each unit for the purposes of confirming that emissions testing is conducted within 90 to 100 percent of the unit's rated capacity (or to limit future operation to 110 percent of the test load), to establish appropriate emission limits and to aid in determining future rule applicability. Regular recordkeeping, other than annual, is not required for heat input. Instead the owner or operator is expected to determine heat input whenever emission testing is required, to demonstrate at what percentage of the rate capacity that the unit was tested. Rule 62-297.310(5), F.A.C., requires measurement of the process variables for emission tests. Such heat input determination may be based on measurements of fuel consumption by various methods to calculate average hourly heat input during the test. Annual heat input must be calculated in order to determine annual emissions of pollutants whose limits are based upon heat input.}

A.2. Methods of Operation - Fuels.

a. Normal operation: The only fuels allowed to be burned in Units Nos. 1, 2, and 3 is coal or a coal/petroleum coke blend containing a maximum of 20.0% petroleum coke by weight. The sulfur content of the petroleum coke burned in Unit 3 shall not exceed 6.0 % by weight (dry basis). The vanadium content of the mineral ash from the petroleum coke fired in Unit 3 shall not exceed 35.0% by weight (ignited basis).

b. Other operation: In addition to the fuels allowed to be burned during normal operation, each unit may also burn new No. 2 fuel during startup, shutdown, flame stabilization, and during the start of a mill on an already operating unit. Evaporation of up to 150,000 gallons per year, total at the facility, is allowed of non-hazardous, but potentially HAP-emitting, mineral acid solution boiler chemical cleaning waste which was generated on site.

[Rules 62-4.070(3), 62-4.160(2), 62-210.200, and 62-213.440(1), F.A.C.]

{Permitting note: "Flame stabilization" is defined as the use of new No. 2 fuel oil to stabilize a flame during times of unexpected poor coal quality or equipment failure such as coal piping pluggage. Flame stabilization due to poor coal quality occurs when coal is wet or does not provide the necessary heat to maintain a stable flame. In this situation, new No. 2 fuel oil is combusted to provide the additional required heat input to maintain a stable flame. Flame stabilization due to equipment failure occurs when coal piping is plugged, or equipment is otherwise damaged, that results in an inconsistent amount of coal reaching the burners. Under certain conditions, this may result in the burners intermittently seeing large amounts of fuel at one time, causing a potentially explosive flame "puff". In this situation, new No. 2 fuel oil must be used for stabilization to prevent flame "puffing" and ensure safe operation. Combustion of No. 2 fuel oil is also necessary during periods of load change to initialize and stabilize the flame until coal flow to the burners reaches steady state. As defined in 62-210.700(3), F.A.C., Load change occurs when the operational capacity of a unit is in the 10 to 100 percent capacity range, other than startup or shutdown, which exceeds 10 percent of the unit's rated capacity and which occurs at a rate of 0.5 percent per minute or more.}

A.3. FGD Operation Required for Petcoke:

a. Whenever emissions Unit No. 1 or No. 2 is fired with petcoke in any amount up to the allowable percentage, its flue gases shall be directed to FGD system for Units No. 1 and No. 2. [Permit Nos. 0570039-003-AC and 0570039-004-AC]

{Note: The owner or operator may operate each emissions unit without directing its emissions to the FGD system whenever petcoke is not being fired in the emissions unit.}

{Note: The excess emissions provisions of specific condition A.11. of this permit are also applicable to the FGD system operation.}

b. The permittee is allowed to divert and integrate all of Unit No. 3 flue gas for purposes of treating that flue gas in the existing Unit No. 4 flue gas desulfurization (FGD) system. At all times while firing any permitted blend of coal and petroleum coke, Unit No. 3 shall operate only in the integrated mode except during startups, shutdowns, and/or malfunctions during all of which best operational practices shall be employed including the cessation of petroleum coke bunkering.
[Rule 62-4.070(3), F.A.C., 40 CFR 60.40a, and Permit No. PSD-FL-040]

A.4. Limit on Petcoke Bunkering: The owner or operator at any given time shall not bunker more than the amount of petcoke that may be fired in each emissions Unit No. 1 or No. 2 in one day. [0570039-003-AC and 0570039-004-AC]

[Note: This condition is intended to limit possible excess emissions in the event of an unexpected breakdown of the FGD system that requires its shutdown while either emissions unit is firing petcoke.]

A.5. Hours of Operation. Unit No. 1, Unit No. 2, and Unit No. 3 are each allowed to operate continuously, i.e., 8760 hours/year.
[Rule 62-210.200, F.A.C., Definitions (PTE)]

EMISSION LIMITATIONS AND STANDARDS

A.6. Except as provided in Specific Condition No. A.11., visible emissions from each unit shall not exceed 20% opacity except for one six-minute period per hour during which opacity shall not exceed 27%.
[Rule 62-296.405(1)(a), F.A.C.]

A.7. Except as provided in Specific Condition No. A.11., the particulate matter emission rate for each unit shall not exceed 0.1 pounds per million BTU heat input. {Permitting note: The averaging time for the emissions standard in this condition shall be equal to the cumulative run time required by the specified test method.}
[Rule 62-296.405(1)(b), F.A.C.]

A.8. Based on the maximum permitted heat input rates listed in Specific Condition A.1., the maximum permitted particulate matter annual emission rate for each unit is as follows:

Unit No.	tons/yr

1	1768
2	1750
3	1802

In the event that a maximum permitted heat input rate for a unit is reduced, the maximum annual permitted particulate matter emission rate for that unit shall also be reduced accordingly.
[Rule 62-296.700(4)(b)1., F.A.C.]

A.9. Sulfur Dioxide Emission Limits. {Permitting Note: The Consent Final Judgement (DEP vs. TEC) dated December 6, 1999; and the Consent Decree (U.S. vs. TEC) dated February 29, 2000, including the October 4, 2000 amendment; which are part of this permit, supercede this specific condition. Wherever the Consent Decree conflicts with this permit condition, the Consent Decree takes precedence.}

a. Units No. 1, No. 2, and No. 3, each shall not emit more than 6.5 pounds of sulfur dioxide per million BTU heat input on a two-hour average; nor shall Units No. 1, No. 2, and No. 3, in total, emit more than 31.5 tons per hour of sulfur dioxide on a three-hour average and 25 tons per hour of sulfur dioxide on a 24-hour block average (midnight to midnight).
[Rules 62-296.405(1)(c)2.b. and 3., F.A.C.; and Rule 62-204.240(1), F.A.C.]

b. Integrated Operation - While in the integrated mode Units No. 3 and 4 shall meet the pounds per million Btu and percent reduction sulfur dioxide limitations that are applicable to Unit No. 4. (Specific Conditions B.7. and B.8.). Unit 3 will be operated in this integrated mode except during unit or FGD startups, shutdowns, maintenance and/or malfunctions, during all of which best operational practices shall be employed, including the cessation of bunkering fuels that would emit higher than 6.5 lb SO_2 per MMBtu.

c. Units No. 1 and No. 2, in total, shall not emit more than 16.5 tons per hour of sulfur dioxide on a 24-hour block average.

d. Unit No. 3 shall not emit more than 8.5 tons per hour of sulfur dioxide on a twenty-four hour block average.

e. While scrubbing sulfur dioxide emissions, the following table lists the sulfur dioxide emissions limits (lbs/hr) for six different operating scenarios:

	Operating Mode, Emission Limits (lbs/hour)			**Averaging**
Operating Scenario	**Unit 1**	**Unit 2**	**Unit 3**	**Period (Calendar day basis)**
1	Scrubbed, 3310	Scrubbed*, 3277	Unscrubbed*, 14814	24 hours
2	Scrubbed, 3310	Unscrubbed, 9590	Unscrubbed, 9876	24 hours
3	Scrubbed, 3310	Scrubbed, 3277	Scrubbed, 3374	24 hours
4	Scrubbed, 3310	Unscrubbed, 11588	Scrubbed, 3374	24 hours
5	Unscrubbed, 11707	Scrubbed, 3277	Scrubbed, 3374	24 hours
6	Unscrubbed, 9689	Scrubbed, 3277	Unscrubbed, 9876	24 hours

*"Scrubbed" refers to operation while directing flue gas to the FGD system. "Unscrubbed" refers to operation while not directing flue gas to the FGD system.

[40 CFR 60.40a; Permit Nos. PSD-FL-040, 0570039-003-AC, and 0570039-004-AC; Applicant request.]

A.10. Unit No. 3 shall not emit more than 0.70 of a pound of nitrogen oxides (expressed as NO_2) per million BTU heat input based upon a 30-day rolling average. [Rule 62-296.405(1)(d)4. and Rule 62-296.405(1)(e)4., F.A.C.]

A.11. *Excess Emissions.*

(1) Excess emissions resulting from startup, shutdown or malfunction of any emissions unit shall be permitted providing (a) best operational practices to minimize emissions are adhered to and (b) the duration of excess emissions shall be minimized but in no case exceed two hours in any 24 hour period unless specifically authorized by the Department or the Environmental Protection Commission of Hillsborough County (EPCHC) for longer duration.

(2) Excess emissions from existing fossil fuel steam generators resulting from startup or shutdown shall be permitted provided that best operational practices to minimize emissions are adhered to and the duration of excess emissions shall be minimized.

(3) Excess emissions from existing fossil fuel steam generators resulting from boiler cleaning (soot blowing) and load change shall be permitted provided the duration of such excess emissions shall not exceed 3 hours in any 24-hour period and visible emissions shall not exceed Number 3 of the Ringelmann Chart (60 percent opacity), and providing (a) best operational practices to minimize emissions are adhered to and (b) the duration of excess emissions shall be minimized. A load change occurs when the operational capacity of a unit is in the 10 percent to 100 percent capacity range, other than startup or shutdown, which exceeds 10 percent of the unit's rated capacity and which occurs at a rate of 0.5 percent per minute or more. Visible emissions above 60 percent opacity shall be allowed for not more than 4, six (6)-minute periods, during the 3-hour period of excess emissions allowed by this specific condition A.11.(3), for boiler cleaning and load changes, at units which have installed and are operating continuous opacity monitors. Particulate matter emissions shall not exceed an average of 0.3 lbs. per million BTU heat input during the 3-hour period of excess emissions allowed by this specific condition A.10.(3).

(4) Excess emissions which are caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure which may reasonably be prevented during startup, shutdown, or malfunction shall be prohibited.

(5) In case of excess emissions resulting from malfunctions, TECO shall notify the EPCHC in accordance with Rule 62-4.130, F.A.C. A full written report on the malfunctions shall be submitted in a quarterly report, if requested by the permitting authority or the EPCHC.
[Rule 62-210.700, F.A.C.]

TEST METHODS AND PROCEDURES

{Permitting note: Table 2-1, Summary of Compliance Requirements, summarizes information for convenience purposes only. This table does not supersede any of the terms or conditions of this permit.}

A.12. During each federal fiscal year (October 1 - September 30), unless otherwise specified by rule, order, or permit, the TEC shall have formal compliance tests conducted on each Steam Generator Unit. Unit No. 1, Unit No. 2, and Unit No. 3 shall each be individually stack tested for particulate matter and visible emissions, under both sootblowing and non-sootblowing operation conditions. When testing in CS0W1 or when testing in CS001, Unit No. 1 shall not be in operation during the compliance testing of

Unit No. 2, and Unit No. 2 shall not be in operation during the compliance testing of Unit No. 1, but when testing in the ductwork between CS001 and the scrubber tower inlet, Unit No. 1 may operate during the compliance testing of Unit No. 2 and Unit No. 2 may operate during the compliance testing of Unit No. 1. Testing of Unit No. 3 emissions shall be prior to their mixing with the exhaust from the scrubber for Unit No. 4.
[Rules 62-297.310(7)(a)2. and 4., and 62-4.070(3), F.A.C.]

A.13. The test method for visible emissions shall be DEP Method 9, incorporated in Chapter 62-297, F.A.C. In lieu of Method 9 testing, a transmissometer utilizing a 6-minute block average for opacity measurement may be used, provided such transmissometer is installed, certified, calibrated, operated and maintained in accordance with the provisions of 40 CFR Part 75.
[Rule 62-296.405(1)(e)1., F.A.C., and request of applicant.]

A.14. The test methods for particulate emissions shall be EPA Methods 17, 5, 5B, or 5F, incorporated and adopted by reference in Chapter 62-297, F.A.C. The minimum sample volume shall be 30 dry standard cubic feet. EPA Method 5 may be used with filter temperature at no more than 320 degrees Fahrenheit. For EPA Method 17, stack temperature shall be less than 375 degrees Fahrenheit. The owner or operator may use EPA Method 5 to demonstrate compliance. EPA Method 3 or 3A with Orsat analysis shall be used when the oxygen base F-factor computed according to EPA Method 19 is used in lieu of heat input. Acetone wash shall be used with EPA Method 5 or 17.
[Rule 62-296.405(1)(e)2., F.A.C.]

A.15. Compliance testing for particulate matter emissions and visible emissions may be conducted either: (a) without fly ash re-injections occurring, or (b) while fly ash collected by the electrostatic precipitator is being re-injected into the boiler at a rate which is representative of the maximum anticipated fly ash re-injection rate. If the most recent particulate and visible emission compliance tests were conducted without fly ash re-injection occurring, and fly ash re-injection occurs for any reason other than a malfunction, then the results from new particulate and visible emissions compliance tests, conducted while fly ash collected by the precipitator is being re-injected into the boiler at a rate which is representative of the maximum anticipated fly ash re-injection rate, shall be submitted to the EPCHC within 60 days of the date that such fly ash re-injection occurred. The EPCHC may, for good cause shown, grant an extension of the 60-day time limit on a case-by-case basis.
[AO29-219924, AO29-179912, and AO29-179911]

A.16. <u>Petcoke Sulfur Content</u>: The owner or operator shall measure the sulfur content of representative samples of all petcoke received using appropriate ASTM methods to demonstrate compliance with the sulfur content limit of this permit. [Permit Nos. 0570039-003-AC & 0570039-004-AC]

A.17. <u>Monitor Petcoke Usage</u>: The owner or operator shall operate and maintain equipment to record and calculate the weight percentage of petcoke and coal bunkered and fired in each emissions unit, to verify compliance with the bunkering limit and the percentage limitation on petcoke usage of this permit. [Rule 62-4.070(3), F.A.C.]

A.18. The permittee shall demonstrate compliance with the sulfur dioxide limits in Specific Condition A.9. by means of continuous emissions monitoring systems (CEMS). In addition to any other requirements associated with the operation and maintenance of these CEMS (i.e., Acid Rain requirements), operation of the CEMS shall be in accordance with the requirements listed in Specific

Condition A.19. The annual calibration RATA associated with these CEMS may be used in lieu of the required annual EPA Reference Method 6, as long as all of the requirements of Rule 62-297.310, F.A.C., are met (i.e., prior test notification, proper test result submittal, etc.). [Applicant request.]

A.19. Continuous Monitor Performance Specifications. If continuous monitoring systems are required by rule or are elected by the permittee to be used for demonstrating compliance with the standards of the Department, they must be installed, maintained and calibrated, either:

(a) in accordance with the EPA performance specifications listed below. These Performance Specifications are contained in 40 CFR 60, Appendix B, and are adopted by reference in Rule 62-204.800, F.A.C.

(1) [Reserved]

(2) Performance Specification 2--Specifications and Test Procedures for SO_2 Continuous Emission Monitoring Systems in Stationary Sources.

(3) [Reserved], Or,

(b) in accordance with the applicable requirements of 40 CFR 75, Subparts B and C. Excess emissions pursuant to Rule 62-210.700, F.A.C., shall be determined using the 40 CFR part 75 CEMS.

[Rule 62-297.520, F.A.C.; 40 CFR 75; and, Applicant request.]

A.20. Compliance with nitrogen oxides emission limit for Unit No. 3 shall be demonstrated continuously based upon a 30-day rolling average. The 30-day rolling average shall be determined by calculating the arithmetic average of all hourly emission rates for NO_x for the 30 successive boiler operating days, except for data obtained during startup, shutdown, malfunction. The calculations shall be consistent with the equations in 40 CFR 60, Appendix A, Reference Method 19. For the purpose of calculating a 30-day rolling average, a boiler operating day is defined as a 24-hour period (between 12:01 a.m. and 12:00 midnight) during which fossil fuel is combusted in a steam operating unit for the entire 24-hours.
[Permit No. AO29-179911 (July 29, 1994 amendment); 40 CFR 60.46a(g)]

A.21. The continuous emission monitors shall meet the quality assurance requirements and performance specifications contained in 40 CFR 75.
[Rule 62-296.401(1)(e)4., F.A.C.]

A.22. Test procedures shall meet all applicable requirements of Chapter 62-297, F.A.C.
[Rule 62-296.401(1)(e)5., F.A.C.]

A.23. For Units. No. 1, No. 2, and No. 3, TEC shall operate, calibrate, and maintain a continuous monitoring system for continuously monitoring opacity. For Unit No. 3, TECO shall also operate calibrate, and maintain a continuous monitoring system for continuously monitoring nitrogen oxides (expressed as NO_2). In addition, TEC shall operate calibrate, and maintain a continuous monitoring system for continuously monitoring sulfur dioxide for Unit Nos. 1, 2, and 3 in a manner sufficient to demonstrate compliance with the emission limits of this permit. Performance specifications, location of monitor, data requirements, data reduction and reporting requirements shall conform with the requirements of 40 CFR Part 51, Appendix P, adopted and incorporated by reference in Rule 62-204.800(2), F.A.C., and 40 CFR Part 60, Appendix B, adopted by reference in Rule 62-204.800(7), F.A.C.
[Rule 62-296.401(1)(f), F.A.C.]

A.24. An oxygen or carbon dioxide continuous monitoring system shall be operated for Unit No. 3. Measurements of oxygen or carbon dioxide in the flue gas shall be utilized to convert nitrogen oxides and sulfur dioxide continuous emission monitoring data to units of pounds per million BTU heat input for proof of compliance.
[Rule 62-296.401(1)(f)1.d., F.A.C.]

REPORTING AND RECORD KEEPING REQUIREMENTS

A.25. Records of Operation: The owner or operator shall make and maintain a daily record of operation of each emissions unit showing the date, fuel(s) used, whether flue gas was directed to the FGD system, and the duration of all startups, shutdowns and malfunctions. Records of fuel bunkering and petcoke usage (weight percent of petcoke fired) shall also be made on at least a daily basis. Data that verifies compliance with the percentage limitation on petcoke usage shall be submitted with the annual operating report. [Rule 62-4.070(3), F.A.C.]

A.26. Records of Petcoke Sulfur Content: The owner or operator shall maintain records of petcoke sampling and analysis results performed as required by Specific Condition A.16. of this section. [Rule 62-4.070(3), F.A.C., and permit nos. 0570039-003-AC & 0570039-004-AC]

A.27. Quarterly Reporting Requirements: The owner or operator shall submit to the Department a written report of emissions in excess of emission limiting standards of this permit for each calendar quarter. The nature and cause of the excessive emissions shall be explained. This report does not relieve the owner or operator of the legal liability for violations. All recorded data shall be maintained on file for a period of five years. Copies of all submittals shall be submitted to the Air Management Division, Hillsborough County Environmental Protection Commission. [Rules 62-4.070(3) and 62-296.405(1)(g), F.A.C.]

A.28. For each unit, TEC shall submit to the EPCHC a written report of emissions in excess of the emission limiting standards as set forth in Rule 62-296.405(1), F.A.C., for each calendar quarter. The nature and cause of the excessive emissions shall be explained. This report does not relieve TEC of the legal liability for violations. All recorded data shall be maintained on file for a period of at least 5 years. The report shall be submitted within 30 days following each calendar quarter.
[Rule 62-296.405(1)(g) and Rule 62-213.440(1)(b)2.b., F.A.C.]

A.29. For Unit No. 3, gravimetric instrument data verifying that the 20.0% maximum petroleum coke content by weight has not been exceeded shall be maintained for two years and submitted to the Department and the EPCHC with each annual operating report. Also to be maintained and available for inspection shall be a record of operation showing the date, fuel used, mode of operation (integrated/non-integrated), and the duration of all startups, shutdowns and malfunctions.
[Rule 62-4.070(3), F.A.C.]

A.30. For Unit No. 3, TEC shall maintain and submit to the Department and the EPCHC on an annual basis for a period of 5 years from the date the unit begins firing petroleum coke, data demonstrating that the operational change did not result in an emissions increase.
[Rule 62-4.070(3), F.A.C.]

A.31. For Unit No. 3, TEC shall submit a quarterly report to the Department and the EPCHC within 30 days following each calendar quarter. This report shall contain the 30-day NO_X rolling average, all time periods of boiler operation as well as a statement of CEM and/or boiler malfunction, start-up or shutdown.
[Permit No. AO29-179911 (July 29, 1994 amendment)]

A.32. Continuous Emission Monitoring Network and Alarms:
To demonstrate compliance with emission limits that are protective of AAQS, data inputs will consist of hourly CEM data from the SO_2, flow, and CO_2 monitors for Units 1-3 at Big Bend Station. TEC will use CEM data from common stack CS001 to represent individual unit compliance with the emission limitations for each Unit 1 and Unit 2. When Unit 3 is operated in the integrated mode, TEC will use apportioned CEM data from both common stacks CS002 and CS003 to represent individual unit compliance with the emission limitations for Unit 3. In the event any monitor fails, TEC will comply with 40 CFR 75, Subpart D – Missing Data Substitution Procedures.
[Applicant request.]

A.33. Compliance Plan Verification:
1. *Frequency* – Reporting of compliance status shall be performed on a quarterly calendar basis. Reports will be due no later than 45 days following the last day of the reporting quarter.
2. *Content* – Quarterly reports will consist of:
   a. two-hour average SO_2 emissions rate for each Units 1, 2, and 3 in lb/MMBtu;
   b. three-hour average SO_2 emissions for Units 1-3 in ton per hour;
   c. 24-hour average SO_2 emissions for Units 1-3 in tons per hour; and
   d. 24-hour average SO_2 emissions for Units 1-2 and Unit 3 in tons per hour.

[Applicant request.]

Subsection B. Steam Generator Unit No. 4 (and No. 3 in integrated mode)
This section addresses the following Regulated Emissions Units:

E.U. ID No.	Brief Description
-004	Unit No. 4 Steam Generator
-003	Unit No. 3 Steam Generator, only when operated in integrated mode.

Unit No. 4 is a 4330 MMBTU/hour, dry-bottom tangentially fired utility boiler, SCC 1-01-002-12. The generator nameplate capacity is 486 MW. Unit No. 4 began commercial operation in 1985. Particulate matter emissions generated during the operation of the unit are controlled by a dry electrostatic precipitator (ESP) manufactured by Belco. The control efficiency of the ESP is 99.7%. Sulfur dioxide emissions are controlled by flue gas desulfurization equipment manufactured by Research-Cottrell.

As an option, Unit No. 3 exhaust gas, following particulate matter removal by the unit's ESP, will be routed to the inlet of the Unit No. 4 flue gas desulfurization (FGD) system scrubber. In this integrated mode, Unit No. 3 will meet the same sulfur dioxide emissions limitations as Unit No. 4. The FGD scrubber will continue to treat the exhaust gas from Unit No. 4. The FGD scrubber outlet stream, consisting of the combined Unit No. 3 and Unit No. 4 treated exhaust, will then be split and discharged through stacks CS002 and CS003. Stack CS003 does *not* include a recirculation duct to return exhaust gas to the inlet of the FGD scrubber. Continuous opacity monitoring systems (COMS) will be located at the outlet of Unit No. 3 and Unit No. 4 ESPs. Continuous SO_2, CO_2, and NOx emissions monitoring systems (CEMS) will be located in stacks CS002 and CS003. These monitoring systems will be used to determine compliance with all current applicable requirements.

{Applicable regulations for Unit No. 4: 40 CFR 60 Subpart Da, and the federal Acid Rain Program, Phase II SO_2 and NO_x, adopted and incorporated by reference in Rule 62-204.800, F.A.C.; PA79-12, PSD-FL-040 and an ASP for Coal Sampling.}

The following conditions apply to the emissions unit listed above:

Essential Potential to Emit (PTE) Parameters

B.1. Capacity. The maximum permitted heat input rate for Unit No. 4 is 4330 MMBTU/hr.
[Rules 62-4.160(2), and 62-4.070(3), F.A.C.]
{Permitting note: The heat input limitation has been placed in this permit to identify the capacity of the unit for the purposes of confirming that emissions testing is conducted within 90 to 100 percent of the unit's rated capacity (or to limit future operation to 110 percent of the test load), to establish appropriate emission limits and to aid in determining future rule applicability. Regular recordkeeping, other than annual, is not required for heat input. Instead the owner or operator is expected to determine heat input whenever emission testing is required, to demonstrate at what percentage of the rate capacity that the unit was tested. Rule 62-297.310(5), F.A.C., requires measurement of the process variables for emission tests. Such heat input determination may be based on measurements of fuel consumption by various methods to calculate average hourly heat input during the test. Annual heat input must be calculated in order to determine annual emissions of pollutants whose limits are based upon heat input.}

B.2. Methods of Operation - Fuels.

a. Normal operation: The only fuels fired in Unit No. 4 shall be coal or a coal/petroleum coke blend containing a maximum of 20.0% petroleum coke by weight. The sulfur content of the petroleum coke shall not exceed 6.0 % by weight (dry basis). Vanadium content of the mineral ash from the petroleum coke fired shall not exceed 35.0% by weight (ignited basis).

b. Other operation: In addition to the fuels allowed to be burned during normal operation, Unit No. 4 may also burn new No. 2 fuel during startup, shutdown, flame stabilization and during the start of an additional solid fuel crusher on an already operating unit. Evaporation of up to 150,000 gallons per year, total at the facility, is allowed of non-hazardous, but potentially HAP-emitting, mineral acid solution boiler chemical cleaning waste which was generated on site.

c. Coal shall not be burned in Unit No. 4 unless both the electrostatic precipitator and limestone scrubber are operating properly.

d. Coal burned in Unit No. 4 shall be washed before it is transported to the plant site. TEC shall maintain records of all coal washing and preparation activities for any coal which is to be fired in Big Bend Unit No. 4. These reports shall be submitted to the Department on a quarterly basis.

e. TEC shall maintain a daily log of the amounts and types of fuels used and copies of fuel analyses containing information on sulfur content, ash content and heating values.
[Rules 62-4.070(3), 62-4.160(2), 62-210.200, and 62-213.440(1), F.A.C.; PSD-FL-040; Power Plant Siting Certification PA 79-12]

{Permitting note: "Flame stabilization" is defined as the use of No. 2 fuel oil to stabilize a flame during times of unexpected poor coal quality or equipment failure such as coal piping pluggage. Flame stabilization due to poor coal quality occurs when coal is wet or does not provide the necessary heat to maintain a stable flame. In this situation, No. 2 fuel oil is combusted to provide the additional required heat input to maintain a stable flame. Flame stabilization due to equipment failure occurs when coal piping is plugged, or equipment is otherwise damaged, that results in an inconsistent amount of coal reaching the burners. Under certain conditions, this may result in the burners intermittently seeing large amounts of fuel at one time, causing a potentially explosive flame "puff". In this situation, No. 2 fuel oil must be used for stabilization to prevent flame "puffing" and ensure safe operation. Combustion of No. 2 fuel oil is also necessary during periods of load change to initialize and stabilize the flame until coal flow to the burners reaches steady state. As defined in 62-210.700(3), F.A.C., Load change occurs when the operational capacity of a unit is in the 10 to 100 percent capacity range, other than startup or shutdown, which exceeds 10 percent of the unit's rated capacity and which occurs at a rate of 0.5 percent per minute or more.}

B.3. Mode of Operation. Tampa Electric Company is allowed to divert and integrate all of the flue gas from Unit No. 3 for purposes of treating that flue gas in the existing Unit No. 4 flue gas desulfurization (FGD) system.
[Rule 62-4.070(3), F.A.C., 40 CFR 60.40a, and Permit No. PSD-FL-040]

B.4. Hours of Operation. Unit No. 4 is allowed to operate continuously, i.e., 8760 hours/year.
[Rule 62-210.200, F.A.C., Definitions (PTE)]

Emission Limitations and Standards

B.5.a. Particulate matter emissions from Unit No. 4 shall not exceed 0.03 lb/million Btu heat input. This standard applies at all times except during periods of startup, shutdown, or malfunction.
[Rule 62-204.800(7)(b)2., F.A.C.; 40 CFR 60.42a(a); 40 CFR 60.46a(a); 40 CFR 60.46a(c)]

b. Based on the maximum permitted heat input rate listed in Specific Condition B.1., particulate matter emissions from Unit No. 4 shall not exceed 129.9 lbs/hour, 3118 lbs/day, and 569.0 tons/year.
[PSD-FL-040 and Rule 62-296.700(4)(b)1., F.A.C.]
{Permitting note: The averaging time for the emissions standard in this condition shall be equal to the cumulative run time required by the specified test method.}

B.6. Visible emissions from Unit No. 4 shall not exceed 20 (twenty) percent opacity (6-minute average), except for one 6-minute period per hour of not more than 27 (twenty-seven) percent opacity.
[Rule 62-204.800(7)(b)2., F.A.C.; 40 CFR 60.42a(b); PSD-FL-040]

B.7. Sulfur dioxide emissions from Unit No. 4 when combusting solid fuel shall not exceed 0.82 lb/million Btu heat input and 10 percent of the potential combustion concentration (90 percent reduction). Based upon a heat input of 4330 million Btu/hour, SO_2 emissions shall not exceed 3551 lb/hr.
[Rule 62-204.800(7)(b)2., F.A.C.; 40 CFR 60.43a(a)(1); PSD-FL-040]

B.8. Compliance with sulfur dioxide emission limitations and percent reduction requirements is determined on a 30-day rolling average basis.
[Rule 62.204.800(7)(b)2., F.A.C.; 40 CFR 60.43a(g)]

B.9. Nitrogen dioxide emissions from Unit No. 4 when combusting bituminous or anthracite coal, or a coal/petroleum coke blend, shall not exceed 0.60 lb/million Btu heat input. Based upon a heat input of 4330 million Btu/hour, NO_x emissions shall not exceed 2598 lb/hr. These emission limits are based on a 30-day rolling average. These standards apply at all times except during periods of startup, shutdown, or malfunction.
[Rule 62-204.800(7)(b)2., F.A.C.; 40 CFR 60.44a(a); 40 CFR 60.4a(c), PSD-FL-040]

B.10. Carbon monoxide (CO) emissions from Unit No. 4 shall not exceed 0.029 lb/million Btu heat input, and shall not exceed 124 lb/hr.
[PSD-FL-040 (October 9, 1985 modification)]
{Permitting note: The averaging time for the emissions standard in this condition shall be equal to the cumulative run time required by the specified test method.}

Compliance provisions.

B.11. The sulfur dioxide emission standards in specific condition B.7. apply at all times except during periods of startup, shutdown, or when both emergency conditions exist and the following procedures in specific condition B.12. are implemented.
[Rule 62-296.800(7)(b)2., F.A.C.; 40 CFR 60.46a(c)]

B.12. During emergency conditions in the principal company, an affected facility with a malfunctioning flue gas desulfurization system may be operated if sulfur dioxide emissions are minimized by:

(1) Operating all operable flue gas desulfurization system modules, and bringing back into operation any malfunctioned module as soon as repairs are completed,

(2) Bypassing flue gases around only those flue gas desulfurization system modules that have been taken out of operation because they were incapable of any sulfur dioxide emission reduction or which would have suffered significant physical damage if they had remained in operation, and

(3) Operating a *spare* flue gas desulfurization system module. The Department or EPCHC may at their discretion require TEC within 60 days of notification to demonstrate spare module capability. To demonstrate this capability, the owner or operator must demonstrate compliance with the appropriate requirements of specific conditions B.5. and B.7. for any period of operation lasting from 24 hours to 30 days when:

(i) Any one flue gas desulfurization module is not operated,

(ii) The affected facility is operating at the maximum heat input rate,

(iii) The fuel fired during the 24-hour to 30-day period is representative of the type and average sulfur content of fuel used over a typical 30-day period, and

(iv) TEC has given the Department or EPCHC at least 30 days notice of the date and period of time over which the demonstration will be performed.

[Rule 62-204.800(7)(b)2., F.A.C.; 40 CFR 60.46a(d)]

B.13. Compliance with the sulfur dioxide emission limitations and percentage reduction requirements in specific condition B.7., and the nitrogen oxides emission limitations in specific condition B.10., is based on the *average emission rate* for 30 successive boiler operating days. A separate performance test is completed at the end of each boiler operating day after the initial performance test, and a new 30 day *average emission rate* for both sulfur dioxide and nitrogen oxides and a new percent reduction for sulfur dioxide are calculated to show compliance with the standards.
[Rule 62-204.800(7)(b)2., F.A.C.; 40 CFR 60.46a(e)]

B.14. Compliance is determined by calculating the arithmetic average of all hourly *emission rates* for SO_2 and NO_x for the 30 successive boiler operating days, except for data obtained during startup, shutdown, malfunction (NO_x only), or emergency conditions (SO_2 only). Compliance with the percentage reduction requirement for SO_2 is determined based on the average inlet and average outlet SO_2 emission rates for the 30 successive boiler operating days.
[Rule 62-204.800(7)(b)2., F.A.C.; 40 CFR 60.46a(g)]

B.15. If TEC has not obtained the minimum quantity of emission data as required in the following emission monitoring specific conditions B.16. through B.25, compliance of Unit No. 4 with the sulfur dioxide and nitrogen oxides standards for the day on which the 30-day period ends may be determined by the Administrator by following the applicable procedures in section 7 of Method 19, *Determination of Compliance When Minimum Data Requirement Is Not Met.*
[Rule 62-204.800(7)(b)2., F.A.C.; 40 CFR 60.46a(h); 40 CFR 60, Appendix A, Method 19]

Emission Monitoring.

B.16. TEC shall calibrate, maintain, and operate a continuous monitoring system, and record the output of the system, for measuring the opacity of emissions discharged to the atmosphere. If opacity interference due to water droplets exists in the stack (for example, from the use of an FGD system), the opacity is monitored upstream of the interference (at the inlet to the FGD system). If opacity interference

is experienced at all locations (both at the inlet and outlet of the sulfur dioxide control system), alternate parameters indicative of the particulate matter control system's performance are monitored (subject to the approval of the Department and the EPCHC.)
[Rule 62-204.800(7)(b)2., F.A.C.; 40 CFR 60.47a(a)]

B.17. TEC shall calibrate, maintain, and operate a continuous monitoring system, and record the output of the system, for measuring sulfur dioxide emissions as follows:
(1) Sulfur dioxide emissions are monitored at both the inlet and outlet of the sulfur dioxide control device.
(2) An "as fired" fuel monitoring system (upstream of coal pulverizers) meeting the requirements of Method 19, Determination of Sulfur Dioxide Removal Efficiency and Particulate Matter, Sulfur Dioxide, and Nitrogen Oxides Emission Rates, may be used to determine potential sulfur dioxide emissions in place of a continuous sulfur dioxide emission monitor at the inlet to the sulfur dioxide control device as required in the preceding specific condition B.17.(1).
[Rule 62-204.800(7)(b)2., F.A.C.; 40 CFR 60.47a(b); 40 CFR 60, App. A, Method 19]

B.18. TEC shall calibrate, maintain, and operate a continuous monitoring system, and record the output of the system, for measuring nitrogen oxides emissions discharged to the atmosphere.
[Rule 62-204.800(7)(b)2., F.A.C.; 40 CFR 60.47a(c)]

B.19. TEC shall calibrate, maintain, and operate a continuous monitoring system, and record the output of the system, for measuring the oxygen and/or carbon dioxide content of the flue gases at each location where sulfur dioxide or nitrogen oxides emissions are monitored. The sulfur dioxide, nitrogen dioxide, oxygen and/or carbon dioxide, and opacity monitoring devices shall meet the applicable requirements of Section 62-214, F.A.C., 40 CFR 60.47a., and 40 CFR 75.). The opacity monitor shall be placed in the duct work between the electrostatic precipitator and the FGD scrubber. When Units 3 and 4 are operating in the integrated mode (Unit 3 flue gases routed through the Unit 4 FGD system), the continuous monitoring system will measure sulfur dioxide emissions at the inlet and outlet of the Unit 4 FGD system and from the Unit 3 stack (CS002), while emissions of nitrogen oxides, oxygen and/or carbon dioxide, and opacity shall be measured in the Unit 4 duct prior to the FGD system. When Units 3 and 4 are not operating in the integrated mode, the continuous monitoring system will measure only Unit 4's inlet duct and stack for SO_2 emissions. The emissions of nitrogen oxides, oxygen and/or carbon dioxide, and opacity shall be measured in the Unit 4 duct prior to the FGD system.
[Rule 62-204.800(7)(b)2., F.A.C.; 40 CFR 60.47a(d); Power Plant Siting Certification PA 79-12D]

B.20. The continuous monitoring systems required in specific conditions B.17., B.18., and B.19., shall be operated and record data during all periods of operation of Unit No. 4 including periods of startup, shutdown, malfunction or emergency conditions, except for continuous monitoring system breakdowns, repairs, calibration checks, and zero and span adjustments.
[Rule 62-204.800(7)(b)2., F.A.C.; 40 CFR 60.47a(e)]

B.21. TEC shall obtain emission data for at least 18 hours in at least 22 out of 30 successive boiler operating days. If this minimum data requirement cannot be met with a continuous monitoring system, TEC shall supplement emission data with other monitoring systems approved by the Department or the EPCHC, or the reference methods and procedures as described in Specific Condition B.23.
[Rule 62-204.800(7)(b)2., F.A.C.; 40 CFR 60.47a (f)]

B.22. The 1-hour averages required under 40 CFR 60.13(h), *Monitoring Requirements*, are expressed in lbs/million Btu heat input and used to calculate the average emission rates required in specific conditions B.13. and B.14. The 1-hour averages are calculated using the data points required under 40 CFR 60.13(b), *Monitoring Requirements*. At least two data points must be used to calculate the 1-hour averages.
[Rule 62-204.800(7)(b)2., F.A.C.; 40 CFR 60.47a(g)]

B.23. When it becomes necessary to supplement continuous monitoring system data to meet the minimum data requirements in specific condition B.21., TEC shall use the following reference methods and procedures. Acceptable alternative methods and procedures are given in specific condition B.25.
(1) Method 6 shall be used to determine the SO_2 concentration at the same location as the SO_2 monitor. Samples shall be taken at 60-minute intervals. The sampling time and sample volume for each sample shall be at least 20 minutes and 0.020 dscm (0.71 dscf). Each sample represents a 1-hour average.
(2) Method 7 shall be used to determine the NO_X concentration at the same location as the NO_X monitor. Samples shall be taken at 30-minute intervals. The arithmetic average of two consecutive samples represents a 1-hour average.
(3) The emission rate correction factor, integrated bag sampling and analysis procedure of Method 3B shall be used to determine the O_2 or CO_2 concentration at the same location as the O_2 or CO_2 monitor. Samples shall be taken for at least 30 minutes in each hour. Each sample represents a 1-hour average.
(4) The procedures in Method 19 shall be used to compute each 1-hour average concentration in lb/million Btu heat input.
[Rule 62-204.800(7)(b)2., F.A.C.; 40 CFR 60.47a(h); 40 CFR 60, Appendix A, Methods 3B, 6, 7, and 19]

B.24. TEC shall use the following methods and procedures to conduct the monitoring system performance evaluations required under *40 CFR 60.13(c), Monitoring Requirements,* and the calibration checks required under *40 CFR 60.13(d), Monitoring Requirements*. Acceptable alternative methods and procedures are given in specific condition B.25.
(1) Methods 6, 7, and 3B, as applicable, shall be used to determine O_2, SO_2, and NO_X concentrations
(2) SO_2 or NO_X (NO), as applicable, shall be used for preparing the calibration gas mixtures (in N_2, as applicable) under 40 CFR 60 Appendix B, Performance Specification 2.
(3) The span value for a continuous monitoring system for measuring opacity is between 60 and 80 percent and for a continuous monitoring system measuring nitrogen oxides is determined as follows

Fossil fuel	Span value for nitrogen oxides (ppm)
Solid..............................	1,000

(4) Reserved
(5) For affected facilities burning fossil fuel alone or in combination with non-fossil fuel, the span value of the sulfur dioxide continuous monitoring system at the inlet to the sulfur dioxide control device is 125 percent of the maximum estimated hourly potential emissions of the fuel fired, and the outlet of

J.6. No used or waste oils shall be burned in the diesel compressors. The observation point for the blasting operation tests shall be at the point of maximum opacity leaving the enclosure.
[Rule 62-070(3), F.A.C.]

J.7. TEC shall maintain monthly records on the type and amount of abrasive blasting material used . A rolling 12-month total shall be kept as well.
[Rule 62-070(3), F.A.C.]

J.8. During each month that the Abrasive Blast Booth is used, a VE test must be performed. A monthly VE test is not required during any month that the Abrasive Blast Booth is not used. During each month that abrasive blast media is transferred to or from Abrasive Blast Media Storage, a VE test must be performed. A monthly VE test is not required during any month that no abrasive blast media is transferred to or from Abrasive Blast Media Storage. However, at a minimum, an annual VE test must be performed.

[USEPA objection resolution.]

Subsection K. Surface Coating of Ships

This section addresses the following Regulated Emissions Units:

-035 Surface coating of ships

Description
Surface coating maintenance of ships.

The following conditions apply to the Emissions Units listed above:

K.1. The emissions unit must comply with the attached 40 CFR 63 Subpart A – General Provisions modified for Subpart II.
[40 CFR 63 Subpart A, Rule 62-204.800, F.A.C.]

K.2. This emissions unit must also comply with the following:

40 CFR 63 Subpart II – National Emission Standards for Shipbuilding and Ship Repair (Surface Coating)

{Source: 40 CFR 63 Subpart II (7/1/96 version), and Fed. Register revision dated 12/17/96}

63.781 Applicability
63.782 Definitions
63.783 Standards.
63.784 Compliance dates.
63.785 Compliance procedures.
63.786 Test methods and procedures.
63.787 Notification requirements.
63.788 Recordkeeping and reporting requirements.}

§ 63.781 Applicability.

(a) The provisions of this subpart apply to shipbuilding and ship repair operations at any facility that is a major source.

(b) The provisions of this subpart do not apply to coatings used in volumes of less than 200 liters (52.8 gallons) per year, provided the total volume of coating exempt under this paragraph does not exceed 1,000 liters per year (264 gallons per year) at any facility. Coatings exempt under this paragraph shall be clearly labeled as ''low-usage exempt,'' and the volume of each such coating applied shall be maintained in the facility's records.

(c) The provisions of this subpart do not apply to coatings applied with hand-held, nonrefillable, aerosol containers or to unsaturated polyester resin (i.e., fiberglass lay-up) coatings. Coatings applied to suitably prepared fiberglass surfaces for protective or decorative purposes are subject to this subpart.

(d) The provisions in subpart A of this part [See specific condition K.1., General Provisions] pertaining to startups, shutdowns, and malfunctions and continuous monitoring do not apply to this source category unless an add-on control system is used to comply with this subpart in accordance with § 63.783(c).

The following specific conditions from 40 CFR Part 63, Subpart II - Shipbuilding and Ship Repair (Surface Coating) apply:

40 CFR 63.783 Standards

(a) No owner or operator of any existing or new affected source shall cause or allow the application of any coating to a ship with an as-applied VOHAP content exceeding the applicable limit given in Table 2 of this subpart (see attachment), as determined by the procedures described in 40 CFR 63.785(c)(1)-(4). For the compliance procedures described in 40 CFR 63.785(c)(1)-(3), VOC shall be used as a surrogate for VOHAP, and the EPA Reference Method 24 shall be used as the definitive measure for determining compliance. For the compliance procedure described in 40 CFR 63.785(c)(4), an alternative test method capable of measuring independent VOHAP shall be used to determine compliance. The method must be submitted to and approved by the Administrator.
[40 CFR 63.783(a)]

(b) Each owner or operator of a new or existing affected source shall ensure that:

(1) All handling and transfer of VOHAP-containing materials to and from containers, tanks, vats, drums, and piping systems is conducted in a manner that minimizes spills.

(2) All containers, tanks, vats, drums, and piping systems are free of cracks, holes, and other defects and remain closed unless materials are being added to or removed from them.
[40 CFR 63.783(b)]

(c) Approval of alternative means of limiting emissions.

(1) The owner or operator of an affected source may apply to the Permitting authority for permission to use an alternative means (such as an add-on control system) of limiting emissions from coating operations. The application must include:

(i) An engineering material balance evaluation that provides a comparison of the emissions that would be achieved using the alternative means to those that would result from using coatings that comply with the limits in Table 2 of this section, or the results from an emission test that accurately measures the capture efficiency and control device efficiency achieved by the control system and the composition of the associated coatings so that the emissions comparison can be made;

(ii) A proposed monitoring protocol that includes operating parameter values to be monitored for compliance and an explanation of how the operating parameter values will be established through a performance test; and

(iii) Details of appropriate recordkeeping and reporting procedures.

(2) The Permitting authority shall approve the alternative means of limiting emissions if, in the Permitting authority's judgment, postcontrol emissions of VOHAP per volume applied solids will be no greater than those from the use of coatings that comply with the limits in Table 2 of this section.

(3) The Permitting authority may condition approval on operation, maintenance, and monitoring requirements to ensure that emissions from the source are no greater than those that would otherwise result from this subpart. [Rule 62-296.820, F.A.C.; 40 CFR 63.783(c)]

40 CFR 63.784 Compliance Dates
(a) Each owner or operator of an existing affected source shall comply by 12/16/97.
[40 CFR 63.784(a)]

(b) Each owner or operator of an existing unaffected area source that increases its emissions of (or its potential to emit) HAP such that the source becomes a major source that is subject to this subpart shall comply within 1 year after the date of becoming a major source.
[40 CFR 63.784(b)]

(c) Each owner or operator of a new or reconstructed source shall comply with this subpart according to the schedule in 40 CFR 63.6(b) of subpart A.
[40 CFR 63.784(c)]

40 CFR 63.785 Compliance Procedures
(a) For each batch of coating that is received by an affected source, the owner or operator shall (see Figure 1 for a flow diagram of the compliance procedures):

(1) Determine the coating category and the applicable VOHAP limit as specified in 40 CFR 63.783(a).

(2) Certify the as-supplied VOC content of the batch of coating. The owner or operator may use a certification supplied by the manufacturer for the batch, although the owner or operator retains liability should subsequent testing reveal a violation. If the owner or operator performs the certification testing, only one of the containers in which the batch of coating was received is required to be tested.
[40 CFR 63.785(a)]

(b) (1) In lieu of testing each batch of coating, as applied, the owner or operator may determine compliance with the VOHAP limits using any combination of the procedures described in paragraphs (c)(1), (c)(2), (c)(3), and (c)(4) of this section. The procedure used for each coating shall be determined and documented prior to application.

(2) The results of any compliance demonstration conducted by the affected source or any regulatory agency using Method 24 shall take precedence over the results using the procedures in paragraphs (c)(1), (c)(2), or (c)(3) of this section.

(3) The results of any compliance demonstration conducted by the affected source or any regulatory agency using an approved test method to determine VOHAP content shall take precedence over the results using the procedures in paragraph (c)(4) of this section.
[40 CFR 63.785(b)]

(c) (1) Coatings to which thinning solvent will not be added. For coatings to which thinning solvent (or any other material) will not be added under any circumstance or to which only water is added, the owner or operator of an affected source shall comply as follows:

(i) Certify the as-applied VOC content of each batch of coating.

(ii) Notify the persons responsible for applying the coating that no thinning solvent may be added to the coating by affixing a label to each container of coating in the batch or through another means described in the implementation plan required in 40 CFR 63.787(b).

(iii) If the certified as-applied VOC content of each batch of coating used during a calendar month is less than or equal to the applicable VOHAP limit in 40 CFR 63.783(a) (either in terms of g/L of coating or g/L of solids), then compliance is demonstrated for that calendar month, unless a violation is revealed using Method 24.

(2) Coatings to which thinning solvent will be added--coating-by-coating compliance. For a coating to which thinning solvent is routinely or sometimes added, the owner or operator shall comply as follows:

(i) Prior to the first application of each batch, designate a single thinner for the coating and calculate the maximum allowable thinning ratio (or ratios, if the affected source complies with the cold-weather limits in addition to the other limits specified in Table 2) for each batch as follows:

$$R = \frac{(V_s)(VOHAP\ limit) - m_{VOC}}{D_{th}} \qquad \text{Eqn. 1}$$

where:

R = Maximum allowable thinning ratio for a given batch (L thinner/L coating as supplied);

V_s = Volume fraction of solids in the batch as supplied (L solids/L coating as supplied);

VOHAP limit = Maximum allowable as-applied VOHAP content of the coating (g VOHAP/L solids);

m_{VOC} = VOC content of the batch as supplied [g VOC (including cure volatiles and exempt compounds on the HAP list)/L coating (including water and exempt compounds) as supplied];

D_{th} = Density of the thinner (g/L).

If V_s is not supplied directly by the coating manufacturer, the owner or operator shall determine V_s as follows:

$$V_s = 1 - \frac{m_{volatiles}}{D_{avg}} \qquad \text{Eqn. 2}$$

where:

$m_{volatiles}$ = Total volatiles in the batch, including VOC, water, and exempt compounds, (g/L coating); and

D_{avg} = Average density of volatiles in the batch (g/L).

The procedures specified in 40 CFR 63.786(d) may be used to determine the values of variables defined in this paragraph. In addition, the owner or operator may choose to construct nomographs, based on Equation 1, similar or identical to the one provided in appendix B as a means of easily estimating the maximum allowable thinning ratio.

(ii) Prior to the first application of each batch, notify painters and other persons, as necessary, of the designated thinner and maximum allowable thinning ratio(s) for each batch of the coating by affixing a label to each container of coating or through another means described in the implementation plan required in 40 CFR 63.787(b).

(iii) By the 15th day of each calendar month, determine the volume of each batch of the coating used, as supplied, during the previous month.

(iv) By the 15th day of each calendar month, determine the total allowable volume of thinner for the coating used during the previous month as follows:

$$V_{th} = \sum_{i=1}^{n}(R \times V_b)_i + \sum_{i=1}^{n}(R_{cold} \times V_{b\text{-}cold})_i \qquad \text{Eqn. 3}$$

where:

V_{th} = Total allowable volume of thinner for the previous month (L thinner);

V_b = Volume of each batch, as supplied and before being thinned, used during non-cold-weather days of the previous month (L coating as supplied);

R_{cold} = Maximum allowable thinning ratio for each batch used during cold-weather days (L thinner/L coating as supplied);

$V_{b\text{-}cold}$ = Volume of each batch, as supplied and before being thinned, used during cold-weather days of the previous month (L coating as supplied);

i = Each batch of coating; and

n = Total number of batches of the coating.

(v) By the 15th day of each calendar month, determine the volume of thinner actually used with the coating during the previous month.

(vi) If the volume of thinner actually used with the coating [paragraph (c)(3)(v) of this section] is less than or equal to the total allowable volume of thinner for the coating [paragraph (c)(3)(iv) of this section], then compliance is demonstrated for the coating for the previous month, unless a violation is revealed using Method 24.

(3) Coatings to which the same thinning solvent will be added--group compliance. For coatings to which the same thinning solvent (or other material) is routinely or sometimes added, the owner or operator shall comply as follows:

(i) Designate a single thinner to be added to each coating during the month and "group" coatings according to their designated thinner.

(ii) Prior to the first application of each batch, calculate the maximum allowable thinning ratio (or ratios, if the affected source complies with the cold-weather limits in addition to the other limits specified in Table 2) for each batch of coating in the group using the equations in paragraph (c)(2) of this section.

(iii) Prior to the first application of each "batch," notify painters and other persons, as necessary, of the designated thinner and maximum allowable thinning ratio(s) for each batch in the group by affixing a label to each container of coating or through another means described in the implementation plan required in 40 CFR 63.787(b).

(iv) By the 15th day of each calendar month, determine the volume of each batch of the group used, as supplied, during the previous month.

(v) By the 15th day of each calendar month, determine the total allowable volume of thinner for the group for the previous month using Equation 3.

(vi) By the 15th day of each calendar month, determine the volume of thinner actually used with the group during the previous month.

(vii) If the volume of thinner actually used with the group [paragraph (c)(3)(vi) of this section] is less than or equal to the total allowable volume of thinner for the group [paragraph (c)(3)(v) of this section], then compliance is demonstrated for the group for the previous month, unless a violation is revealed using Method 24.

(4) Demonstration of compliance through an alternative (i.e., other than Method 24) test method. The owner or operator shall comply as follows:

(i) Certify the as-supplied VOHAP content (g VOHAP/L solids) of each batch of coating.

(ii) If no thinning solvent will be added to the coating, the owner or operator of an affected source shall follow the procedure described in 40 CFR 63.785(c)(1), except that VOHAP content shall be used in lieu of VOC content.

(iii) If thinning solvent will be added to the coating, the owner or operator of an affected source shall follow the procedure described in 40 CFR 63.785(c)(2) or (3), except that in Equation 1: the term "m_{VOC}" shall be replaced by the term "m_{VOHAP}," defined as the VOHAP content of the coating as supplied (g VOHAP/L coating) and the term "D_{th}" shall be replaced by the term "$D_{th(VOHAP)}$" defined as the average density of the VOHAP thinner(s) (g/L).
[40 CFR 63.785(c)]

(d) A violation revealed through any approved test method shall result in a 1-day violation for enforcement purposes. A violation revealed through the recordkeeping procedures described in paragraphs (c)(1) through (c)(4) of this section shall result in a 30-day violation for enforcement purposes, unless the owner or operator provides sufficient data to demonstrate the specific days during which noncompliant coatings were applied.
[40 CFR 63.785(d)]

40 CFR 63.786 Test Methods and Procedures

(a) For the compliance procedures described in 40 CFR 63.785(c)(1)-(3), Method 24 of 40 CFR part 60, appendix A, is the definitive method for determining the VOC content of coatings, as supplied or as applied. When a coating or thinner contains exempt compounds that are volatile HAP or VOHAP, the owner or operator shall ensure, when determining the VOC content of a coating, that the mass of these exempt compounds is included.
[40 CFR 63.786(a)]

(b) For the compliance procedure described in 40 CFR 63.785(c)(4), the Permitting authority must approve the test method for determining the VOHAP content of coatings and thinners. As part of the approval, the test method must meet the specified accuracy limits indicated below for sensitivity, duplicates, repeatability, and reproducibility coefficient of variation each determined at the 95 percent confidence limit. Each percentage value below is the corresponding coefficient of variation multiplied by 2.8 as in the ASTM Method E180-93: Standard Practice for Determining the Precision of ASTM Methods for Analysis and Testing of Industrial Chemicals (incorporation by reference--see 40 CFR 63.14).

Sensitivity: The overall sensitivity must be sufficient to identify and calculate at least one mass percent of the compounds of interest based on the original sample. The sensitivity is defined as ten times the noise level as specified in ASTM Method D3257-93: Standard Test Methods for Aromatics in Mineral Spirits by Gas Chromatography (incorporation by reference--see 40 CFR 63.14). In determining the sensitivity, the level of sample dilution must be factored in.

Repeatability: First, at the 0.1-5 percent analyte range the results would be suspect if duplicates vary by more than 6 percent relative and/or day to day variation of mean duplicates by the same analyst exceeds 10 percent relative. Second, at greater than 5 percent analyte range the results would be suspect if duplicates vary by more than 5 percent relative and/or day to day variation of duplicates by the same analyst exceeds 5 percent relative.

Reproducibility: First, at the 0.1-5 percent analyte range the results would be suspect if lab to lab variation exceeds 60 percent relative. Second, at greater than 5 percent range the results would be suspect if lab to lab variation exceeds 20 percent relative.

Any test method should include information on the apparatus, reagents and materials, analytical procedure, procedure for identification and confirmation of the volatile species in the mixture being analyzed, precision and bias, and other details to be reported. The reporting should also include information on quality assurance (QA) auditing.

Multiple and different analytical techniques must be used for positive identification if the components in a mixture under analysis are not known. In such cases a single column gas chromatograph (GC) may not be adequate. A combination of equipment may be need such as a GC/mass spectrometer or GC/infrared system. (If a GC method is used, the operator must use practices in ASTM Method E260-91: Standard Practice for Gas Chromatography [incorporation by reference--see 40 CFR 63.14].) . [40 CFR 63.786(b)]

(c) A coating manufacturer or the owner or operator of an affected source may use batch formulation data as a test method in lieu of Method 24 to certify the as-supplied VOC content of a coating if the manufacturer or the owner or operator has determined that batch formulation data have a consistent and quantitatively known relationship to Method 24 results. This determination shall consider the role of cure volatiles, which may cause emissions to exceed an amount based solely upon coating formulation data. Notwithstanding such determination, in the event of conflicting results, Method 24 shall take precedence.
[40 CFR 63.786(c)]

(d) Each owner or operator of an affected source shall use or ensure that the manufacturer uses the form and procedures mentioned in appendix A of this subpart to determine values for the thinner and coating parameters used in Equations 1 and 2. The owner or operator shall ensure that the coating/thinner manufacturer (or supplier) provides information on the VOC and VOHAP contents of the coatings/thinners and the procedure(s) used to determine these values.
[40 CFR 63.786(d)]

40 CFR 63.787 Notification Requirements

(a) Each owner or operator of an affected source shall comply with all applicable notification requirements in 40 CFR 63.9(a)-(d) and (i)-(j) of subpart A (General Provisions), with the exception that the deadline specified in 40 CFR 63.9(b)(2) and (3) shall be extended from 120 days to 180 days. Any owner or operator that receives approval pursuant to 40 CFR 63.783(c) of this subpart to use an add-on control system to control coating emissions shall comply with the applicable requirements of 40 CFR 63.9(e)-(h) of subpart A.
[40 CFR 63.787(a)]

(b) Implementation plan. The provisions of 40 CFR 63.9(a) (Notification requirements/Applicability and general information) of subpart A apply to the requirements of this paragraph.

(1) Each owner or operator of an affected source shall:

(i) Prepare a written implementation plan that addresses each of the subject areas specified in paragraph (b)(3) of this section; and

(ii) Not later than December 16, 1996, submit the implementation plan to the Administrator along with the notification required by 40 CFR 63.9(b)(2) or (5) of subpart A, as applicable.

(2) [Reserved]

(3) *Implementation plan contents.* Each implementation plan shall address the following subject areas:

(i) *Coating compliance procedures.* The implementation plan shall include the compliance procedure(s) under 40 CFR 63.785(c) that the source intends to use.

(ii) *Recordkeeping procedures.* The implementation plan shall include the procedures for maintaining the records required under 40 CFR 63.788, including the procedures for gathering the necessary data and making the necessary calculations.

(iii) *Transfer, handling, and storage procedures.* The implementation plan shall include the procedures for ensuring compliance with 40 CFR 63.783(b).

(4) *Major sources that intend to become area sources by the compliance date.* Existing major sources that intend to become area sources by the December 16, 1997 compliance date may choose to submit, in lieu of the implementation plan required under paragraph (b)(1) of this section, a statement that, by the compliance date, the major source intends to obtain and comply with federally enforceable limits on their potential to emit which make the facility an area source.
[40 CFR 63.787(b)]

40 CFR 63.788 Recordkeeping and reporting requirements.

(a) Each owner or operator of an affected source shall comply with the applicable recordkeeping and reporting requirements in 40 CFR 63.10(a), (b), (d), and (f) of subpart A (General Provisions). Any owner that receives approval pursuant to 40 CFR 63.783(c) of this subpart to use an add-on control system to control coating emissions shall also comply with the applicable requirements of 40 CFR 63.10(c) and (e). A summary of recordkeeping and reporting requirements is provided in Table 3. [40 CFR 63.788(a)]

(b) Recordkeeping requirements.

(1) Each owner or operator of a major source shipbuilding or ship repair facility having surface coating operations with less than 1000 liters (264 gallons) annual marine coating usage shall record the total volume of coating applied at the source to ships. Such records shall be compiled monthly and maintained for a minimum of 5 years.

(2) Each owner or operator of an affected source shall compile records on a monthly basis and maintain those records for a minimum of 5 years. At a minimum, these records shall include:

(i) All documentation supporting initial notification;

(ii) A copy of the affected source's approved implementation plan;

(iii) The volume of each low-usage-exempt coating applied;

(iv) Identification of the coatings used, their appropriate coating categories, and the applicable VOHAP limit;

(v) Certification of the as-supplied VOC content of each batch of coating;

(vi) A determination of whether containers meet the standards as described in 40 CFR 63.783(b)(2); and

(vii) The results of any Method 24 or approved VOHAP measurement test conducted on individual containers of coating, as applied.

(3) The records required by paragraph (b)(2) of this section shall include additional information, as determined by the compliance procedure(s) described in 40 CFR 63.785(c) that each affected source followed:

(i) Coatings to which thinning solvent will not be added. The records maintained by facilities demonstrating compliance using the procedure described in 40 CFR 63.785(c)(1) shall contain the following information:

(A) Certification of the as-applied VOC content of each batch of coating; and

(B) The volume of each coating applied.

(ii) Coatings to which thinning solvent will be added--coating-by-coating compliance. The records maintained by facilities demonstrating compliance using the procedure described in 40 CFR 63.785(c)(2) shall contain the following information:

(A) The density and mass fraction of water and exempt compounds of each thinner and the volume fraction of solids (nonvolatiles) in each batch, including any calculations;

(B) The maximum allowable thinning ratio (or ratios, if the affected source complies with the cold-weather limits in addition to the other limits specified in Table 2 of this subpart) for each batch of coating, including calculations;

(C) If an affected source chooses to comply with the cold-weather limits, the dates and times during which the ambient temperature at the affected source was below 4.5°C (40°F) at the time the coating was applied and the volume used of each batch of the coating, as supplied, during these dates;

(D) The volume used of each batch of the coating, as supplied;

(E) The total allowable volume of thinner for each coating, including calculations; and

(F) The actual volume of thinner used for each coating.

(iii) Coatings to which the same thinning solvent will be added--group compliance. The records maintained by facilities demonstrating compliance using the procedure described in 40 CFR 63.785(c)(3) shall contain the following information:

(A) The density and mass fraction of water and exempt compounds of each thinner and the volume fraction of solids in each batch, including any calculations;

(B) The maximum allowable thinning ratio (or ratios, if the affected source complies with the cold-weather limits in addition to the other limits specified in Table 2) for each batch of coating, including calculations;

(C) If an affected source chooses to comply with the cold-weather limits, the dates and times during which the ambient temperature at the affected source was below 4.5°C (40°F) at the time the coating was applied and the volume used of each batch in the group, as supplied, during these dates;

(D) Identification of each group of coatings and their designated thinners;

(E) The volume used of each batch of coating in the group, as supplied;

(F) The total allowable volume of thinner for the group, including calculations; and

(G) The actual volume of thinner used for the group.

(iv) Demonstration of compliance through an alternative (i.e., non-Method 24) test method. The records maintained by facilities demonstrating compliance using the procedure described in 40 CFR 63.785(c)(4) shall contain the following information:

(A) Identification of the Permitting authority-approved VOHAP test method or certification procedure;

(B) For coatings to which the affected source does not add thinning solvents, the source shall record the certification of the as-supplied and as-applied VOHAP content of each batch and the volume of each coating applied;

(C) For coatings to which the affected source adds thinning solvent on a coating-by-coating basis, the source shall record all of the information required to be recorded by paragraph (b)(3)(ii) of this section; and

(D) For coatings to which the affected source adds thinning solvent on a group basis, the source shall record all of the information required to be recorded by paragraph (b)(3)(iii) of this section.

(4) If the owner or operator of an affected source detects a violation of the standards specified in 40 CFR 63.783, the owner or operator shall, for the remainder of the reporting period during which the violation(s) occurred, include the following information in his or her records:

(i) A summary of the number and duration of deviations during the reporting period, classified by reason, including known causes for which a Federally-approved or promulgated exemption from an emission limitation or standard may apply.

(ii) Identification of the data availability achieved during the reporting period, including a summary of the number and total duration of incidents that the monitoring protocol failed to perform in accordance with the design of the protocol or produced data that did not meet minimum data accuracy and precision requirements, classified by reason.

(iii) Identification of the compliance status as of the last day of the reporting period and whether compliance was continuous or intermittent during the reporting period.

(iv) If, pursuant to paragraph (b)(4)(iii) of this section, the owner or operator identifies any deviation as resulting from a known cause for which no Federally-approved or promulgated exemption from an emission limitation or standard applies, the monitoring report shall also include all records that the source is required to maintain that pertain to the periods during which such deviation occurred and:

(A) The magnitude of each deviation;

(B) The reason for each deviation;

(C) A description of the corrective action taken for each deviation, including action taken to minimize each deviation and action taken to prevent recurrence; and

(D) All quality assurance activities performed on any element of the monitoring protocol.

[40 CFR 63.788(b)]

(c) Reporting requirements. Before the 60th day following completion of each 6-month period after the compliance date specified in 40 CFR 63.784, each owner or operator of an affected source shall submit a report to the Permitting authority for each of the previous 6 months. The report shall include all of the information that must be retained pursuant to paragraphs (b)(2)-(3) of this section, except for that information specified in paragraphs (b)(2)(i)-(ii), (b)(2)(v), (b)(3)(i)(A), (b)(3)(ii)(A), and (b)(3)(iii)(A). If a violation at an affected source is detected, the source shall also report the information specified in paragraph (b)(4) of this section for the reporting period during which the violation(s) occurred. To the extent possible, the report shall be organized according to the compliance procedure(s) followed each month by the affected source.

[40 CFR 63.788(c)]

Subsection L. Limestone Handling System for FGD System for Units 1 & 2

This section addresses the following Regulated Emissions Units:
-020 Drops from limestone conveyors LE, LF and LG and Silo C belt feeder with baghouse
-021 Silo C with one baghouse

Description

New components of the limestone handling system to provide limestone for the new FGD system. The components are Silo C and its related rotary unloader, belt feeder and wet ball mill, and reversible belt conveyors LF and LG. Conveyors LF and LG replace an existing bifurcated chute which feeds from conveyor LE to silos A and B. Particulate emissions from drops from limestone handling conveyors LE, LF and LG and the silo C belt feeder are controlled by a baghouse: American Air Filter Fabripulse - Model B, size 12-72-1155. Particulate emissions from displaced air in silo C will be controlled by a baghouse: American Air Filter Fabripak, size 6-16-132. The new wet ball mill is a wet process with no expected particulate emissions.

[Note: These emissions units are subject to 40 CFR 60, Subpart OOO, Standards of Performance for Nonmetallic Mineral Processing Plants (40 CFR 60.670 - 60.676) and 40 CFR 60 Subpart A; Rule 1-3.61, Rules of the Environmental Protection Commission (EPC) of Hillsborough County; Rule 62-296.700, F.A.C.; and are subject to the requirements of the state rules as indicated in this permit. The visible emission limit of specific condition 16 is more stringent than the limitations of 40 CFR 60.672(a)(2) and 60.672(f), and compliance with this limit will assure compliance with those requirements.]

The following conditions apply to the Emissions Units listed above:

OPERATIONAL REQUIREMENTS

L.1. Hours of Operation: These emissions units may operate continuously, i.e., 8,760 hours/year. [Rule 62-210.200, F.A.C., Definitions-potential to emit (PTE)]

L.2. Enclosure of Equipment: All conveyors and conveyor transfer points shall be enclosed and exhaust from this equipment shall be directed to a baghouse to minimize particulate matter emissions. [62-4.070(3),F.A.C.]

L.3. Operating Procedures: Enclosures and baghouses for these emissions units shall be properly operated and maintained at all times in a condition to minimize particulate emissions. The owner and operator shall ensure that all facility staff responsible for these emissions units are trained in their operation and maintenance in accordance with the guidelines and procedures as established by the equipment manufacturers. [Rule 62-4.070(3), F.A.C.]

EMISSION LIMITATIONS AND PERFORMANCE STANDARDS

L.4. Particulate and Visible Emissions: No owner or operator shall cause or allow visible emissions from the baghouses controlling these emissions units in excess of 0.03 gr/dscf and 5% opacity. [40 CFR 60.672(a)(1) and (2); Rules 62-4.070(3) and Rule 62-296.711(2)(b), F.A.C., Rule 1-3.61, Rules of the EPC, and request of applicant (VE limit)]

[Note: The visible emission limit of this condition is more stringent than the limitations of 40 CFR 60.672(a)(2) and 60.672(f), and compliance with this limit will assure compliance with those requirements.]

COMPLIANCE MONITORING AND TESTING REQUIREMENTS

L.5. Visible Emissions Tests: Compliance with the visible emission limits of this permit shall be demonstrated by an annual compliance test using EPA Method 9. The duration of initial tests shall be three hours and the duration of subsequent annual tests shall be thirty minutes. [Rules 62-4.070(3) and 62-297.310(4)(a)2., F.A.C., and 40 CFR 60.11(b)]

[Note: The three hour duration of initial tests complies with the requirements of the NSPS and the thirty minute duration of subsequent tests complies with state rules.]

L.6. Visible Emissions Tests in Lieu of Stack Tests, Emissions Unit 020: After passing the initial test required by specific condition 21 of this section, the owner or operator is permitted to comply with the visible emission limit of specific condition 16 and the testing requirement of specific condition 17 of this section in lieu of regularly demonstrating compliance with the limitations of 40 CFR 60.672(a)(1) and (2) and the particulate matter limitation of specific condition 16 of this section. If the Department has reason to believe that the particulate weight emission limit of 40 CFR 60.672(a)(1) or the particulate matter limitation of specific condition 16 of this section is not being met, it shall require compliance be demonstrated by the test method specified by 40 CFR 60.675. [Rules 62-4.070(3) and 62-297.620(4), F.A.C.]

REPORTING AND RECORD KEEPING REQUIREMENTS

L.7. Records of Maintenance: The owner or operator shall make and maintain records of maintenance on the enclosures and baghouses sufficient to demonstrate compliance with the operating procedures requirements of specific condition 15 of this section. [Rule 62-4.070(3), F.A.C.]

NSPS SUBPART OOO REQUIREMENTS

[Note: The numbering of the original rules in the following conditions has been preserved for ease of reference to the rules. The definitions of terms of this part shall have the meanings as defined in 40 CFR 60.671 Definitions. The term "Administrator" when used in 40 CFR 60 shall mean the Secretary or the Secretary's designee.]

L.8. Pursuant to 40 CFR 60.672 Standard for Particulate Matter:

[Note: The requirements of 40 CFR 60.672(a)(1) and (2) apply to emissions unit 020, and the requirements of 40 CFR 60.672(f) apply to emissions unit 021.]

(a) No owner or operator shall cause to be discharged into the atmosphere from any transfer point on belt conveyors or from any other affected facility any stack emissions which:

(1) Contain particulate matter in excess of 0.05 g/dscm; and

(2) Exhibit greater than 7 percent opacity.

[Note: The emission limit of specific condition 16 of this section is more stringent than the limitation of 40 CFR 60.672(a)(2).]

(f) No owner or operator shall cause to be discharged into the atmosphere from any baghouse that controls emissions from only an individual, enclosed storage bin, stack emissions which exhibit greater than 7 percent opacity.

[Note: The emission limit of specific condition 16 of this section is more stringent than the limitation of 40 CFR 60.672(f). See the note for that condition.]

L.9.Pursuant to 40 CFR 60.675 Test Methods and Procedures:

(a) In conducting the performance tests required in 40 CFR 60.8, the owner or operator shall use as reference methods and procedures the test methods in appendix A of 40 CFR 60 or other methods and procedures as specified in this section, except as provided in 40 CFR 60.8(b).

(b) The owner or operator shall determine compliance with the particulate matter standards in 40 CFR 60.672(a) as follows:

(1) Method 5 or Method 17 shall be used to determine the particulate matter concentration. The sample volume shall be at least 1.70 dscm (60 dscf). For Method 5, if the gas stream being sampled is at ambient temperature, the sampling probe and filter may be operated without heaters. If the gas stream is above ambient temperature, the sampling probe and filter may be operated at a temperature high enough, but no higher than 121 °C (250 °F), to prevent water condensation on the filter.

(2) Method 9 and the procedures in 40 CFR 60.11 shall be used to determine opacity.

[Note: The owner or operator is required to demonstrate compliance with the particulate matter emission limitation of 40 CFR 60.672(a)(1) by performing and passing an initial particulate matter test in accordance with the requirements of this section, unless such requirement is waived by the US Environmental Protection Agency. No subsequent regular annual particulate matter testing is required. The owner or operator is permitted to comply with the visible emission limit of specific condition 16 of this section in lieu of regularly demonstrating compliance with the limitations of 40 CFR 60.672(a)(1) and (2). See also specific condition 18 of this section.]

(c) (2) In determining compliance with the opacity of stack emissions from any baghouse that controls emissions only from an individual enclosed storage bin under 40 CFR 60.672(f) of this subpart, using Method 9, the duration of the Method 9 observations shall be 1 hour (ten 6-minute averages).

[Note: The initial Method 9 test duration for emissions unit 021 is one hour pursuant to 40 CFR 60.675(c)(2), while the initial Method 9 test duration for emissions unit 020 is 3 hours pursuant to 40 CFR 60.11(b). Subsequent annual Method 9 tests shall be conducted for 30 minutes for emissions units 020 and 021.]

(g) If, after 30 days notice for an initially scheduled performance test, there is a delay (due to operational problems, etc.) in conducting any rescheduled performance test required in this section, the owner or operator of an affected facility shall submit a notice to the Administrator at least 7 days prior to any rescheduled performance test.

L.10. Pursuant to 40 CFR 60.676 Reporting and Recordkeeping:

(f) The owner or operator of any affected facility shall submit written reports of the results of all performance tests conducted to demonstrate compliance with the standards set forth in 40 CFR 60.672 of this subpart.

(h) The subpart A requirement under 40 CFR 60.7(a)(2) for notification of the anticipated date of initial startup of an affected facility shall be waived for owners or operators of affected facilities regulated under this subpart.

(i) A notification of the actual date of initial startup of each affected facility shall be submitted to the Administrator.

(1) For a combination of affected facilities in a production line that begin actual initial startup on the same day, a single notification of startup may be submitted by the owner or operator to the Administrator. The notification shall be postmarked within 15 days after such date and shall

include a description of each affected facility, equipment manufacturer, and serial number of the equipment, if available.

L.11. The attached 40 CFR 60 Subpart A NSPS General Provisions also apply to these emissions units.

Subsection M. Lime Silo for Wastewater Treatment Plant for the Chloride Bleed Stream

This section addresses the following Regulated Emissions Units:

-022 Lime silo with one baghouse for the waste water treatment plant for the chloride bleed stream

Description

A lime silo with one baghouse (Griffin Environmental 36-LS Filter Vent) to serve a new waste water treatment plant for the chloride bleed stream. This plant will serve the new and existing FGD systems. Particulate emissions from displaced air from periodically filling the lime silo will be controlled with the related baghouse.

[Note: This emissions unit is subject to the requirements of the state rules as indicated in this permit. This emissions unit is subject to Rule 1-3.61, Rules of the Environmental Protection Commission (EPC) of Hillsborough County, but it exempt from the requirements of Rule 62-296.711, F.A.C., pursuant to Rule 62-296.700(2)(c), F.A.C., because it has an allowable emission rate of less than one ton per year.]

The following conditions apply to the Emissions Unit listed above:

OPERATIONAL REQUIREMENTS

M.1. Hours of Operation: This emissions units may operate continuously, i.e., 8,760 hours/year. [Rule 62-210.200, F.A.C., Definitions-potential to emit (PTE)]

M.2. Operating Procedures: The baghouse for this emissions unit shall be properly operated and maintained at all times in a condition to minimize particulate emissions. The owner and operator shall ensure that all facility staff responsible for these emissions units are trained in their operation and maintenance in accordance with the guidelines and procedures as established by the equipment manufacturers. [Rule 62-4.070(3), F.A.C.]

EMISSION LIMITATIONS AND PERFORMANCE STANDARDS

M.3. Particulate and Visible Emissions: No owner or operator shall cause or allow visible emissions from the baghouse controlling this emissions unit in excess of 0.03 gr/dscf and 5% opacity. [Rules 62-4.070(3) and 62-296.700(2)(c), F.A.C.]

[Note: The particulate matter limitation will ensure that allowable emissions are less than one ton per year for this emissions unit.]

COMPLIANCE MONITORING AND TESTING REQUIREMENTS

M.4. Visible Emissions Tests: Compliance with the visible emission limit of this permit shall be demonstrated by an annual compliance test using EPA Method 9. The duration of annual tests shall be thirty minutes. [Rules 62-4.070(3) and 62-297.310(4)(a)2., F.A.C.]

M.5. Visible Emissions Tests in Lieu of Stack Tests: The owner or operator is permitted to comply with the visible emission limit of specific condition 25 and the testing requirement of specific condition 26 of this section in lieu of regularly demonstrating compliance with the particulate matter limitation of specific condition 25 of this section. If the Department has reason to believe that the particulate matter limitation of specific condition 25 of this section is not being met, it shall require compliance be demonstrated by conducting a particulate matter test in accordance with EPA Method 5 specified at 40 CFR 60 Appendix A. [Rules 62-4.070(3) and 62-297.620(4), F.A.C.]

REPORTING AND RECORD KEEPING REQUIREMENTS

M.6. Records of Maintenance: The owner or operator shall make and maintain records of maintenance on the baghouse sufficient to demonstrate compliance with the operating procedures requirements of specific condition M.2. of this section. [Rule 62-4.070(3), F.A.C.]

M.7. Tampa Electric shall keep records of facility staff training, and shall maintain, on site, an Operations and Maintenance Plan for the baghouse that details how it shall be properly operated and maintained at all times. Tampa Electric shall also take weekly pressure readings from the baghouse pressure-sensing device.
[USEPA objection resolution.]

Subsection N. Common Conditions

**This section addresses the all of the Regulated Emissions Units:
{Permitting note: For emissions units subject to NESHAP or NSPS requirements, when more stringent, the requirements of the NESHAPS or NSPS supercede these common conditions.}**

N.1. Compliance Test Notification. TECO shall notify the EPCHC, at least 15 days prior to the date on which each formal compliance test is to begin, of the date, time, and place of each such test, and the test contact person who will be responsible for coordinating and having such test conducted for TECO.
[Rule 62-297.310(7)(a)9., F.A.C.]

N.2. Special Compliance Tests. When, after inspection, the Department or the Environmental Protection Commission of Hillsborough County has good reason (such as complaints, increased visible emissions or questionable maintenance of control equipment) to believe that any applicable emission standard contained in a Department rule or in a permit issued pursuant to those rules is being violated, it shall require the Tampa Electric Company to conduct compliance tests which identify the nature and quantity of pollutant emissions from the emission unit and to provide a report on the results of said test to the requesting agency.
[Rule 62-297.310(7)(b), F.A.C.]

GENERAL TEST REQUIREMENTS

N.3. Required Number of Test Runs. For mass emission limitations, a compliance test shall consist of three complete and separate determinations of the total air pollutant emission rate through the test section of the stack or duct and three complete and separate determinations of any applicable process variables corresponding to the three distinct time periods during which the stack emission rate was measured provided, however, that three complete and separate determinations shall not be required if the process variables are not subject to variation during a compliance test, or if three determinations are not necessary in order to calculate the unit's emission rate. The three required test runs shall be completed within one consecutive five day period. In the event that a sample is lost or one of the three runs must be discontinued because of circumstances beyond the control of the owner or operator, and a valid third run cannot be obtained within the five day period allowed for the test, the Secretary or his or her designee may accept the results of the two complete runs as proof of compliance, provided that the arithmetic mean of the results of the two complete runs is at least 20 percent below the allowable emission limiting standards.
[Rule 297.310(1), F.A.C.]

N.4. Operating Rate During Testing for Emission Units other than Combustion Turbines. Unless otherwise stated an emission unit's specific condition in this permit, testing of emissions shall be conducted with the emissions unit operation at 90 to 100 percent of the maximum operation rate allowed by specific condition in this permit. If it is impracticable to test at permitted capacity, an emissions unit may be tested at less than the minimum permitted capacity; in this case, subsequent emissions unit operation is limited to 110 percent of the test load until a new test is conducted. Once the unit is so limited, operation at higher capacities is allowed for no more than 15 consecutive days for the purpose of additional compliance testing to regain the authority to operate at the permitted capacity.
[Rule 62-297.310(2), F.A.C.]

N.5. Calculation of Emission Rate. The indicated emission rate or concentration shall be the arithmetic average of the emission rate or concentration determined by each of the three separate test runs unless otherwise specified in a particular test method or applicable rule.
[Rule 62-297.310(3), F.A.C.]

N.6. Applicable Test Procedures.

(a) Required Sampling Time.

1. Unless otherwise specified in the specific conditions of this permit, the required sampling time for each test run shall be no less than one hour and no greater than four hours, and the sampling time at each sampling point shall be of equal intervals of at least two minutes.

2. Opacity Compliance Tests. When either EPA Method 9 or DEP Method 9 is specified as the applicable opacity test method, the required minimum period of observation for a compliance test shall be sixty (60) minutes for emissions units which emit or have the potential to emit 100 tons per year or more of particulate matter, and thirty (30) minutes for emissions units which have potential emissions less than 100 tons per year of particulate matter and are not subject to a multiple-valued opacity standard. The opacity test observation period shall include the period during which the highest opacity emissions can reasonably be expected to occur. Exceptions to these requirements are as follows:

a. For batch, cyclical processes, or other operations which are normally completed within less than the minimum observation period and do not recur within that time, the period of observation shall be equal to the duration of the batch cycle or operation completion time.

b. The observation period for special opacity tests that are conducted to provide data to establish a surrogate standard pursuant to Rule 62-297.310(5)(k), F.A.C., Waiver of Compliance Test Requirements, shall be established as necessary to properly establish the relationship between a proposed surrogate standard and an existing mass emission limiting standard.

c. The minimum observation period for opacity tests conducted by employees or agents of the Department to verify the day-to-day continuing compliance of a unit or activity with an applicable opacity standard shall be twelve minutes.

(b) Minimum Sample Volume. Unless otherwise specified in the applicable rule, the minimum sample volume per run shall be 25 dry standard cubic feet.

(c) Required Flow Rate Range. For EPA Method 5 particulate sampling, acid mist/sulfur dioxide, and fluoride sampling which uses Greenburg Smith type impingers, the sampling nozzle and sampling time shall be selected such that the average sampling rate will be between 0.5 and 1.0 actual cubic feet per minute, and the required minimum sampling volume will be obtained.

(d) Calibration of Sampling Equipment. Calibration of the sampling train equipment shall be conducted in accordance with the schedule shown in Table 297.310-1 (see attachment).

(e) Allowed Modification to EPA Method 5. When EPA Method 5 is required, the following modification is allowed: the heated filter may be separated from the impingers by a flexible tube.
[Rule 297.310(4), F.A.C.]

N.7. Determination of Process Variables.

(a) Required Equipment. The owner or operator of an emissions unit for which compliance tests are required shall install, operate, and maintain equipment or instruments necessary to determine process variables, such as process weight input or heat input, when such data are needed in conjunction with emissions data to determine the compliance of the emissions unit with applicable emission limiting standards.

(b) Accuracy of Equipment. Equipment or instruments used to directly or indirectly determine process variables, including devices such as belt scales, weight hoppers, flow meters, and tank scales,

shall be calibrated and adjusted to indicate the true value of the parameter being measured with sufficient accuracy to allow the applicable process variable to be determined within 10% of its true value.
[Rule 62-297.310(5), F.A.C.]

N.8. Frequency of Compliance Tests. The following provisions apply to those emissions units that are subject to an emissions limiting standard for which compliance testing is required, unless otherwise provided in a specific emission unit condition of this permit.

(a) General Compliance Testing.

1. The owner or operator of a new or modified emissions unit that is subject to an emission limiting standard shall conduct a compliance test that demonstrates compliance with the applicable emission limiting standard prior to obtaining an operation permit for such emissions unit.

2. For excess emission limitations for particulate matter specified in Rule 62-210.700, F.A.C., a compliance test shall be conducted annually while the emissions unit is operating under soot blowing conditions in each federal fiscal year during which soot blowing is part of normal emissions unit operation, except that such test shall not be required in any federal fiscal year in which a fossil fuel steam generator does not burn liquid and/or solid fuel for more than 400 hours other than during startup.

3. The owner or operator of an emissions unit that is subject to any emission limiting standard shall conduct a compliance test that demonstrates compliance with the applicable emission limiting standard prior to obtaining a renewed operation permit. Emissions units that are required to conduct an annual compliance test may submit the most recent annual compliance test to satisfy the requirements of this provision. In renewing an air operation permit pursuant to Rule 62-210.300(2)(a)3.b., c., or d., F.A.C., the Department shall not require submission of emission compliance test results for any emissions unit that, during the year prior to renewal:

a Did not operate; or

b. In the case of a fuel burning emissions unit, burned liquid and/or solid fuel for a total of no more than 400 hours.

4. During each federal fiscal year (October 1 - September 30), unless otherwise specified by rule, order, or permit, the owner or operator of each emissions unit shall have a formal compliance test conducted for:

a. Visible emissions, if there is an applicable standard;

b. Each of the following pollutants, if there is an applicable standard, and if the emissions unit emits or has the potential to emit: 5 tons per year or more of lead or lead compounds measured as elemental lead; 30 tons per year or more of acrylonitrile; or 100 tons per year or more of any other regulated air pollutant; and

c. Each NESHAP pollutant, if there is an applicable emission standard.

5. An annual compliance test for particulate matter emissions shall not be required for any fuel burning emissions unit that, in a federal fiscal year, does not burn liquid and/or solid fuel, other than during startup, for a total of more than 400 hours.

6. For fossil fuel steam generators on a semi-annual particulate matter emission compliance testing schedule, a compliance test shall not be required for any six-month period in which liquid and/or solid fuel is not burned for more than 200 hours other than during startup.

7. For emissions units electing to conduct particulate matter emission compliance testing quarterly pursuant to Rule 62-296.405(2)(a), F.A.C., a compliance test shall not be required for any quarter in which liquid and/or solid fuel is not burned for more than 100 hours other than during startup.

8. Any combustion turbine that does not operate for more than 400 hours per year shall conduct a visible emissions compliance test once per each five-year period, coinciding with the term of its air operation permit.

9. The owner or operator shall notify the Department and the Environmental Protection Commission of Hillsborough County, at least 15 days prior to the date on which each formal compliance test is to begin, of the date, time, and place of each such test, and the test contact person who will be responsible for coordinating and having such test conducted for the owner or operator.

10. An annual compliance test conducted for visible emissions shall not be required for units exempted from permitting at Rule 62-210.300(3)(a), F.A.C., or units permitted under the General Permit provisions at Rule 62-210.300(4), F.A.C.

(b) Special Compliance Tests. When the Department or Environmental Protection Commission of Hillsborough County, after investigation, has good reason (such as complaints, increased visible emissions or questionable maintenance of control equipment) to believe that any applicable emission standard contained in a Department rule or in a permit issued pursuant to those rules is being violated, it shall require the owner or operator of the emissions unit to conduct compliance tests which identify the nature and quantity of pollutant emissions from the emissions unit and to provide a report on the results of said tests to the Department and the Environmental Protection Commission of Hillsborough County.

(c) Waiver of Compliance Test Requirements. If the owner or operator of an emissions unit that is subject to a compliance test requirement demonstrates to the Department, pursuant to the procedure established in Rule 62-297.620, F.A.C., that the compliance of the emissions unit with an applicable weight emission limiting standard can be adequately determined by means other than the designated test procedure, such as specifying a surrogate standard of no visible emissions for particulate matter sources equipped with a bag house or specifying a fuel analysis for sulfur dioxide emissions, the Department shall waive the compliance test requirements for such emissions units and order that the alternate means of determining compliance be used, provided, however, the provisions of Rule 62-297.310(7)(b), F.A.C., shall apply.
[Rule 62-297.310(7), F.A.C.]

N.9. <u>Test Reports</u>.

(a) The owner or operator of an emissions unit for which a compliance test is required shall file a report with the Department and the EPCHC on the results of each such test.

(b) The required test report shall be filed with the EPCHC as soon as practical but no later than 45 days after the last sampling run of each test is completed.

(c) The test report shall provide sufficient detail on the emissions unit tested and the test procedures used to allow the EPCHC and the Department to determine if the test was properly conducted and the test results properly computed. As a minimum, the test report, other than for an EPA or DEP Method 9 test, shall provide the following information:

1. The type, location, and designation of the emissions unit tested.
2. The facility at which the emissions unit is located.
3. The owner or operator of the emissions unit.
4. The normal type and amount of fuels used and materials processed, and the types and amounts of fuels used and material processed during each test run.
5. The means, raw data and computations used to determine the amount of fuels used and materials processed, if necessary to determine compliance with an applicable emission limiting standard.
6. The type of air pollution control devices installed on the emissions unit, their general condition, their normal operating parameters (pressure drops, total operating current and GPM scrubber water), and their operating parameters during each test run.
7. A sketch of the duct within 8 stack diameters upstream and 2 stack diameters downstream of the sampling ports, including the distance to any upstream and downstream bends or other flow disturbances.
8. The date, starting time and duration of each sampling run.

9. The test procedures used, including any alternative procedures authorized pursuant to Rule 62-297.620, F.A.C. Where optional procedures are authorized in this chapter, indicate which option was used.

10. The number of points sampled and configuration and location of the sampling plane.

11. For each sampling point for each run, the dry gas meter reading, velocity head, pressure drop across the stack, temperatures, average meter temperatures and sample time per point.

12. The type, manufacturer and configuration of the sampling equipment used.

13. Data related to the required calibration of the test equipment.

14. Data on the identification, processing and weights of all filters used.

15. Data on the types and amounts of any chemical solutions used.

16. Data on the amount of pollutant collected from each sampling probe, the filters, and the impingers, are reported separately for the compliance test.

17. The names of individuals who furnished the process variable data, conducted the test, analyzed the samples and prepared the report.

18. All measured and calculated data required to be determined by each applicable test procedure for each run.

19. The detailed calculations for one run that relate the collected data to the calculated emission rate.

20. The applicable emission standard, and the resulting maximum allowable emission rate for the emissions unit, plus the test result in the same form and unit of measure.

21. A certification that, to the knowledge of the owner or his authorized agent, all data submitted are true and correct. When a compliance test is conducted for the EPCHC or the Department, the person who conducts the test shall provide the certification with respect to the test procedures used. The owner or his authorized agent shall certify that all data required and provided to the person conducting the test are true and correct to his knowledge.

[Rule 62-297.310(8), F.A.C.]

Section IV. This section is the Phase II Acid Rain Part.
Operated by: Tampa Electric Company
ORIS code: 0645

The emissions units listed below are regulated under Acid Rain:

E.U. ID No.	**Brief Description**
-001	Unit No. 1 Steam Generator [EPA ID #: BB01]
-002	Unit No. 2 Steam Generator [EPA ID #: BB02]
-003	Unit No. 3 Steam Generator [EPA ID #: BB03]
-004	Unit No. 4 Steam Generator [EPA ID #: BB04]

1. The Phase II permit application, the Phase II NOx compliance plan, and the Phase II NOx averaging plan submitted for this facility, as approved by the Department, is a part of this permit. The owners and operators of these acid rain units must comply with the standard requirements and special provisions set forth in the application listed below:

DEP Form No. 62-210.900(1)(a), version 07/01/95, received 12/26/95 (signed 12/19/95).
DEP Form No. 62-210.900(1)(a)4., F.A.C., received 12/22/99 (signed 12/20/99).
DEP Form No. 62-210.900(1)(a)5., F.A.C., received 12/22/99 (signed 12/20/99).

[Chapter 62-213, F.A.C. and Rule 62-214.320, F.A.C.]

2. Sulfur dioxide (SO_2) allowance allocations and nitrogen oxide (NO_x) requirements for each Acid Rain unit are as follows:

<table>
<tr><th rowspan="2">E.U. ID No.</th><th rowspan="2">EPA ID</th><th rowspan="2"></th><th colspan="5">Year</th></tr>
<tr><th>2000</th><th>2001</th><th>2002</th><th>2003</th><th>2004</th></tr>
<tr><td rowspan="2">-001</td><td rowspan="2">BB01</td><td>SO_2 allowances, under Table 2 of 40 CFR 73</td><td>12132*</td><td>12132*</td><td>12132*</td><td>12132*</td><td>12132*</td></tr>
<tr><td>NO_x limit**</td><td colspan="5">Note: The applicable emission limitation, under 40 CFR 76.6(a)(2), is 0.84 lb/mmBtu.

2.a. Pursuant to 40 CFR 76.11, the Florida Department of Environmental Protection approves the NO_x emissions averaging plan submitted on 12/22/99 for this unit. Under the plan, this unit's NO_x emissions shall not exceed the annual average alternative contemporaneous emission limitation of 0.74 lb/MMBtu. In addition, this unit shall not have an annual heat input less than 23,000,000 MMBtu.</td></tr>
</table>

<table>
<tr><th rowspan="2">E.U. ID No.</th><th rowspan="2">EPA ID</th><th rowspan="2"></th><th colspan="5">Year</th></tr>
<tr><th>2000</th><th>2001</th><th>2002</th><th>2003</th><th>2004</th></tr>
<tr><td rowspan="2">-002</td><td rowspan="2">BB02</td><td>SO_2 allowances, under Table 2 of 40 CFR 73</td><td>12196*</td><td>12196*</td><td>12196*</td><td>12196*</td><td>12196*</td></tr>
<tr><td>NO_x limit**</td><td colspan="5">Note: The applicable emission limitation, under 40 CFR 76.6(a)(2), is 0.84 lb/mmBtu.

2.b. Pursuant to 40 CFR 76.11, the Florida Department of Environmental Protection approves the NO_x emissions averaging plan submitted on 12/22/99 for this unit. Under the plan, this unit's NO_x emissions shall not exceed the annual average alternative contemporaneous emission limitation of 0.74 lb/MMBtu. In addition, this unit shall not have an annual heat input less than 24,000,000 MMBtu.</td></tr>
<tr><td rowspan="2">-003</td><td rowspan="2">BB03</td><td>SO_2 allowances, under Table 2 of 40 CFR 73</td><td>11444*</td><td>11444*</td><td>11444*</td><td>11444*</td><td>11444*</td></tr>
<tr><td>NO_x limit**</td><td colspan="5">Note: The applicable emission limitation, under 40 CFR 76.6(a)(2), is 0.84 lb/mmBtu.

2.c. Pursuant to 40 CFR 76.11, the Florida Department of Environmental Protection approves the NO_x emissions averaging plan submitted on 12/22/99 for this unit. Under the plan, this unit's NO_x emissions shall not exceed the annual average alternative contemporaneous emission limitation of 0.53 lb/MMBtu. In addition, this unit shall not have an annual heat input less than 10,000,000 MMBtu.</td></tr>
</table>

E.U. ID No.	EPA ID		Year				
			2000	2001	2002	2003	2004
-004	BB04	SO_2 allowances, under Table 2 of 40 CFR 73	8780*	8780*	8780*	8780*	8780*
		NO_x limit**	Note: The applicable emission limitation, under 40 CFR 76.6(a)(2), is **0.45** lb/mmBtu. **2.d.** Pursuant to 40 CFR 76.11, the Florida Department of Environmental Protection approves the NO_x emissions averaging plan submitted on 12/22/99 for this unit. Under the plan, this unit's NO_x emissions shall not exceed the annual average alternative contemporaneous emission limitation of **0.44** lb/MMBtu. In addition, this unit shall not have an annual heat input less than **20,000,000** MMBtu.				

*The number of allowances held by an Acid Rain source in a unit account may differ from the number allocated by the USEPA under Table 2 of 40 CFR 73. "Allowance" means an authorization by the USEPA Administrator under the federal Acid Rain Program to emit up to one ton of sulfur dioxide during a specified calendar year.
** Based on the Phase II NO_x applications.

2.e. Additional Requirements
i. Under the plan (NO_x Phase II averaging plan), the actual Btu-weighted annual average NO_x emission rate for the units in the plan shall be less than or equal to the Btu-weighted annual average NO_x emission rate for the same units had they each been operated, during the same period of time, in accordance with the applicable emission limitations under 40 CFR 76.5, 76.6, or 76.7, except that for any early election units, the applicable emission limitations shall be under 40 CFR 76.7. If the designated representative demonstrates that the requirement of the prior sentence (as set forth in 40 CFR 76.11(d)(1)(ii)(A)) is met for a year under the plan, then this unit shall be deemed to be in compliance for that year with its alternative contemporaneous annual emission limitation and annual heat input limit.

ii. In addition to the described NO_x compliance plan, these units shall comply with all other applicable requirements of 40 CFR Part 76, including the duty to reapply for a NO_x compliance plan and requirements covering excess emissions.

3. Emission Allowances. Emissions from sources subject to the Federal Acid Rain Program (Title IV) shall not exceed any allowances that the source lawfully holds under the Federal Acid Rain Program. Allowances shall not be used to demonstrate compliance with a non-Title IV applicable requirement of the Act.

a. No permit revision shall be required for increases in emissions that are authorized by allowances acquired pursuant to the Federal Acid Rain Program, provided that such increases do not require a permit revision pursuant to Rule 62-213.400(3), F.A.C.

b. No limit shall be places on the number of allowances held by the source under the Federal Acid Rain Program.

c. Allowances shall be accounted for under the Federal Acid Rain Program.

[Rule 62-213.440(1)(c), F.A.C.]

4. Fast-Track Revisions of Acid Rain Parts. Those Acid Rain sources making a change described at Rule 62-214.370(4), F.A.C., may request such change as provided in Rule 62-213.413, F.A.C.
[Rules 62-213.413 and 62-214.370(4), F.A.C.]

5. No permit revision shall be required for increases in emissions that are authorized by allowances acquired pursuant to the Federal Acid Rain Program, provided that such increases do not require a permit revision pursuant to Rule 62-213.400, F.A.C.
[40 CFR 70.6(a)(4)(i); and, Rule 62-213.440(1)(c)1., F.A.C.]

6. Where an applicable requirement of the Act is more stringent than applicable regulations promulgated under Title IV of the Act, both provisions shall be incorporated into the permit and shall be enforceable by the Administrator.
[40 CFR 70.6(a)(1)(ii); and, Rule 62-210.200, F.A.C., Definitions – Applicable Requirements.]

7. Comments, notes, and justifications:
The designated representative was changed to Gregory M. Nelson, P.E., effective July 1, 1998.

Phase II Permit Application

For more information, see instructions and refer to 40 CFR 72.30 and 72.31 and Chapter 62-214, F.A.C.

This submission is: [X] New [ ] Revised

STEP 1
Identify the source by plant name, State, and ORIS code from NADB

Plant Name Big Bend State FL ORIS Code 645

STEP 2
Enter the boiler ID# from NADB for each affected unit, and indicate whether a repowering plan is being submitted for the unit by entering "yes" or "no" at column c. For new units, enter the requested information in columns d and e

a	b	c	d	e
	Compliance Plan			
Boiler ID#	Unit Will Hold Allowances in Accordance with 40 CFR 72.9(c)(1)	Repowering Plan	New Units Commence Operation Date	New Units Monitor Certification Deadline
BB01	Yes	No		
BB02	Yes	No		
BB03	Yes	No		
BB04	Yes	No		
	Yes			
	Yes			
	Yes			
	Yes			
	Yes			
	Yes			
	Yes			
	Yes			

STEP 3
Check the box if the response in column c of Step 2 is "Yes" for any unit

[ ] For each unit that will be repowered, the Repowering Extension Plan form is included and the Repowering Technology Petition form has been submitted or will be submitted by June 1, 1997.

STEP 4
Read the standard requirements and certification, enter the name of the designated representative, and sign and date

Standard Requirements

Permit Requirements.

(1) The designated representative of each Acid Rain source and each Acid Rain unit at the source shall:
(i) Submit a complete Acid Rain part application (including a compliance plan) under 40 CFR part 72, Rules 62-214.320 and 330, F.A.C. in accordance with the deadlines specified in Rule 62-214.320, F.A.C.; and
(ii) Submit in a timely manner any supplemental information that the permitting authority determines is necessary in order to review an Acid Rain part application and issue or deny an Acid Rain permit;
(2) The owners and operators of each Acid Rain source and each Acid Rain unit at the source shall:
(i) Operate the unit in compliance with a complete Acid Rain part application or a superseding Acid Rain part issued by the permitting authority; and
(ii) Have an Acid Rain Part.

Monitoring Requirements.

(1) The owners and operators and, to the extent applicable, designated representative of each Acid Rain source and each Acid Rain unit at the source shall comply with the monitoring requirements as provided in 40 CFR part 75, and Rule 62-214.420, F.A.C.
(2) The emissions measurements recorded and reported in accordance with 40 CFR part 75 shall be used to determine compliance by the unit with the Acid Rain emissions limitations and emissions reduction requirements for sulfur dioxide and nitrogen oxides under the Acid Rain Program.
(3) The requirements of 40 CFR part 75 shall not affect the responsibility of the owners and operators to monitor emissions of other pollutants or other emissions characteristics at the unit under other applicable requirements of the Act and other provisions of the operating permit for the source.

Sulfur Dioxide Requirements.

(1) The owners and operators of each source and each Acid Rain unit at the source shall:
(i) Hold allowances, as of the allowance transfer deadline, in the unit's compliance subaccount (after deductions under 40 CFR 73.34(c)) not less than the total annual emissions of sulfur dioxide for the previous calendar year from the unit; and
(ii) Comply with the applicable Acid Rain emissions limitations for sulfur dioxide.
(2) Each ton of sulfur dioxide emitted in excess of the Acid Rain emissions limitations for sulfur dioxide shall constitute a separate violation of the Act.
(3) An Acid Rain unit shall be subject to the requirements under paragraph (1) of the sulfur dioxide requirements as follows:
(i) Starting January 1, 2000, an Acid Rain unit under 40 CFR 72.6(a)(2); or
(ii) Starting on the later of January 1, 2000 or the deadline for monitor certification under 40 CFR part 75, an Acid Rain unit under 40 CFR 72.6(a)(3).
(4) Allowances shall be held in, deducted from, or transferred among Allowance Tracking System accounts in accordance with the Acid Rain Program.
(5) An allowance shall not be deducted in order to comply with the requirements under paragraph (1)(i) of the sulfur dioxide requirements prior to the calendar year for which the allowance was allocated.
(6) An allowance allocated by the Administrator under the Acid Rain Program is a limited authorization to emit sulfur dioxide in accordance with the Acid Rain Program. No provision of the Acid Rain Program, the Acid Rain permit application, the Acid Rain permit, or the written exemption under 40 CFR 72.7 and 72.8 and no provision of law shall be construed to limit the authority of the United States to terminate or limit such authorization.
(7) An allowance allocated by the Administrator under the Acid Rain Program does not constitute a property right.

Nitrogen Oxides Requirements. The owners and operators of the source and each Acid Rain unit at the source shall comply with the applicable Acid Rain emissions limitation for nitrogen oxides.

Excess Emissions Requirements.

(1) The designated representative of an Acid Rain unit that has excess emissions in any calendar year shall submit a proposed offset plan, as required under 40 CFR part 77.
(2) The owners and operators of an Acid Rain unit that has excess emissions in any calendar year shall:
(i) Pay without demand the penalty required, and pay upon demand the interest on that penalty, as required by 40 CFR part 77; and
(ii) Comply with the terms of an approved offset plan, as required by 40 CFR part 77.

Recordkeeping and Reporting Requirements.

(1) Unless otherwise provided, the owners and operators of the source and each Acid Rain unit at the source shall keep on site at the source each of the following documents for a period of 5 years from the date the document is created. This period may be extended for cause, at any time prior to the end of 5 years, in writing by the Administrator or permitting authority:
(i) The certificate of representation for the designated representative for the source and each Acid Rain unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation, in accordance with Rule 62-214.350, F.A.C.; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such documents are superseded because of the submission of a new certificate of representation changing the designated representative;
(ii) All emissions monitoring information, in accordance with 40 CFR part 75;
(iii) Copies of all reports, compliance certifications, and other submissions and all records made or required under the Acid Rain Program; and,

Plant Name (from Step 1)

Recordkeeping and Reporting Requirements (cont.)

(iv) Copies of all documents used to complete an Acid Rain part application and any other submission under the Acid Rain Program or to demonstrate compliance with the requirements of the Acid Rain Program.

(2) The designated representative of an Acid Rain source and each Acid Rain unit at the source shall submit the reports and compliance certifications required under the Acid Rain Program, including those under 40 CFR part 72 subpart I and 40 CFR part 75.

Liability.

(1) Any person who knowingly violates any requirement or prohibition of the Acid Rain Program, a complete Acid Rain part application, an Acid Rain part, or a written exemption under 40 CFR 72.7 or 72.8, including any requirement for the payment of any penalty owed to the United States, shall be subject to enforcement pursuant to section 113(c) of the Act.
(2) Any person who knowingly makes a false, material statement in any record, submission, or report under the Acid Rain Program shall be subject to criminal enforcement pursuant to section 113(c) of the Act and 18 U.S.C. 1001.
(3) No permit revision shall excuse any violation of the requirements of the Acid Rain Program that occurs prior to the date that the revision takes effect.
(4) Each Acid Rain source and each Acid Rain unit shall meet the requirements of the Acid Rain Program.
(5) Any provision of the Acid Rain Program that applies to an Acid Rain source (including a provision applicable to the designated representative of an Acid Rain source) shall also apply to the owners and operators of such source and of the Acid Rain units at the source.
(6) Any provision of the Acid Rain Program that applies to an Acid Rain unit (including a provision applicable to the designated representative of an Acid Rain unit) shall also apply to the owners and operators of such unit. Except as provided under 40 CFR 72.44 (Phase II repowering extension plans), and except with regard to the requirements applicable to units with a common stack under 40 CFR part 75 (including 40 CFR 75.16, 75.17, and 75.18), the owners and operators and the designated representative of one Acid Rain unit shall not be liable for any violation by any other Acid Rain unit of which they are not owners or operators or the designated representative and that is located at a source of which they are not owners or operators or the designated representative.
(7) Each violation of a provision of 40 CFR parts 72, 73, 75, 77, and 78 by an Acid Rain source or Acid Rain unit, or by an owner or operator or designated representative of such source or unit, shall be a separate violation of the Act.

Effect on Other Authorities. No provision of the Acid Rain Program, an Acid Rain part application, an Acid Rain part, or a written exemption under 40 CFR 72.7 or 72.8 shall be construed as:

(1) Except as expressly provided in title IV of the Act, exempting or excluding the owners and operators and, to the extent applicable, the designated representative of an Acid Rain source or Acid Rain unit from compliance with any other provision of the Act, including the provisions of title I of the Act relating to applicable National Ambient Air Quality Standards or State Implementation Plans;
(2) Limiting the number of allowances a unit can hold; *provided*, that the number of allowances held by the unit shall not affect the source's obligation to comply with any other provisions of the Act;
(3) Requiring a change of any kind in any State law regulating electric utility rates and charges, affecting any State law regarding such State regulation, or limiting such State regulation, including any prudence review requirements under such State law;
(4) Modifying the Federal Power Act or affecting the authority of the Federal Energy Regulatory Commission under the Federal Power Act; or,
(5) Interfering with or impairing any program for competitive bidding for power supply in a State in which such program is established.

Certification

I am authorized to make this submission on behalf of the owners and operators of the Acid Rain source or Acid Rain units for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.

Name Hugh W. Smith	
Signature Hugh W. Smith	Date 12/19/95

STEP 5 (optional)
Enter the source AIRS and FINDS identification numbers, if known

AIRS	0570039
FINDS	

IN THE CIRCUIT COURT OF THE THIRTEENTH JUDICIAL CIRCUIT
IN AND FOR HILLSBOROUGH COUNTY, FLORIDA

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL PROTECTION,

Plaintiff,

vs. CASE NO.:

TAMPA ELECTRIC COMPANY,

Defendant.
______________________________/

CONSENT FINAL JUDGMENT

I. INTRODUCTION AND PURPOSE

A. This Consent Final Judgment is entered into between Plaintiff, State of Florida, Department of Environmental Protection (the "DEP"), and Defendant, Tampa Electric Company ("TAMPA ELECTRIC COMPANY"), to reach a settlement of certain matters at issue between them. The Consent Final Judgment provides for the implementation of certain actions, the investigation and implementation of certain pollution prevention technology, and the contribution of funds to assist the DEP in its Bay Regional Air Chemistry Experiment program relating to nitrogen deposition in Tampa Bay.

B. "Consent Final Judgment" means this Consent Final Judgment, including any future modifications, and any reports, plans, specifications and schedules required by the Consent Final Judgment which, upon the approval of each by the DEP, shall be deemed incorporated into and become an enforceable part of this Consent Final Judgment as though each was originally set forth herein.

II. JURISDICTION

A. The DEP is the administrative agency of the State of Florida having the power and duty to protect Florida's air and water resources, and to administer and enforce the provisions of Chapter 403, Florida Statutes, and the rules promulgated thereunder, Florida Administrative Code ("F.A.C.") Title 62 including the rules which Florida has the responsibility to administer and enforce under the federally approved Florida State Implementation Plan (SIP) and the separate Environmental Protection Agency delegation of PSD authority.

B. This Court has jurisdiction over the subject matter herein and over the Parties hereto pursuant to Chapter 403, Florida Statutes.

C. This Court retains jurisdiction over both the subject matter of this Consent Final Judgment and the Parties during the performance of its terms to enforce compliance therewith, if necessary.

III. PARTIES BOUND

This Consent Final Judgment shall apply to and be binding upon the DEP and TAMPA ELECTRIC COMPANY, (hereinafter individually defined as a "Party" or together defined as "Parties") and their successors and assigns. Each person signing this Consent Final Judgment certifies that he or she is authorized to execute the Consent Final Judgment and to legally bind to it the party on whose behalf he or she signs the Consent Final Judgment.

IV. STATEMENT OF FACTS

A. TAMPA ELECTRIC COMPANY owns and is an operator of the Big Bend coal fired electric generation plant in Hillsborough County. Big Bend generates electricity from four steam generating boilers which are designated as Big Bend Unit 1, Big Bend Unit 2, Big Bend Unit 3, and Big Bend Unit 4. TAMPA ELECTRIC COMPANY also owns and is an operator of the Gannon coal fired electric generation plant in Hillsborough County. Gannon generates electricity from six steam generating boilers which are designated as Gannon Unit 1, Gannon Unit 2, Gannon Unit 3, Gannon Unit 4, Gannon Unit 5, and Gannon Unit 6.

B. The DEP has alleged that Tampa Electric Company undertook a number of activities at the Gannon and Big Bend Generating Stations without appropriate regulatory review and permits, in violation of Chapter 403, Florida Statutes, and applicable provisions of the federally approved SIP. These activities include, but are not limited to, the following:

1. TAMPA ELECTRIC COMPANY modified, and thereafter operated, its electric generating units at Big Bend and Gannon, which are coal fired electricity generating power plants in Hillsborough County, Florida, without first obtaining appropriate permits authorizing this construction and without installing the best control technology (BACT) to control emissions of nitrogen oxides, sulfur dioxide, and particulate matter, as required by Florida law.

2. As a result of TAMPA ELECTRIC COMPANY's operation of the power plants, these unlawful modifications and the absence of appropriate controls, sulfur dioxide, nitrogen oxides, and particulate matter have been, and still are being, released into the atmosphere aggravating air pollution locally and downwind from these plants.

3. At various times, TAMPA ELECTRIC COMPANY commenced construction of modifications at Big Bend. These modifications included, but are not

limited to: (1) replacement of steam drum internals in Big Bend Units 1 and 2 in 1994 and 1991, respectively; (2) replacement of the waterwall in Big Bend Unit 2 in 1994, and (3) replacement of the high temperature reheater in Big Bend Unit 2 in 1994.

4. Such modifications by TAMPA ELECTRIC COMPANY were done without obtaining a permit from the DEP and without applying BACT for nitrogen oxide, sulfur dioxide and particulate matter as required by Chapter 403, Florida Statutes.

5. At various times, TAMPA ELECTRIC COMPANY commenced construction of modifications to Gannon. These modifications included, but were not limited to: (1) replacement of the furnace floor in Gannon Unit 3 with a new design in 1996; and, (2) replacement of the cyclone in Gannon Unit 4 in 1994.

6. Such modifications by TAMPA ELECTRIC COMPANY were done without obtaining a permit from the DEP and without applying BACT for nitrogen oxide, sulfur dioxide and particulate matter as required by Chapter 403, Florida Statutes.

C. Tampa Electric Company has agreed to the entry of the Consent Final Judgment and has agreed to implement the requirements of the Consent Final Judgment without an admission of liability and in recognition of the benefits of resolving litigation and elimination of such related expenses as settlement of the claims set forth in the Complaint, which Tampa Electric Company believes to be disputed claims. Tampa Electric Company neither admits nor denies the facts set forth in the Complaint and in Section IV.B. of this Consent Final Judgment.

V. <u>REQUIREMENTS OF THE CONSENT FINAL JUDGMENT</u>

A. TAMPA ELECTRIC COMPANY shall shut down coal-fired Units 1, 2, and 6 at Gannon Station and repower Units 3, 4, & 5 for gas to be phased-in between

January 1, 2003 and December 31, 2004. The repowered Units shall meet BACT for nitrogen oxide applicable to combined cycle gas turbines with an emission rate of 3.5 ppm. This requirement shall be included as a permit condition issued through the normal process.

B. TAMPA ELECTRIC COMPANY shall evaluate using "zero-ammonia" nitrogen oxide control technology at its Gannon facility. If, by May, 2000, such technology is found by the DEP to be commercially viable, TAMPA ELECTRIC COMPANY shall install such technology on one of the units it intends to repower so long as the incremental capital cost differential above the cost of Selective Catalytic Reduction (SCR) does not exceed $8 million and TAMPA ELECTRIC COMPANY obtains acceptable performance guarantees and remedies from the manufacturer of the technology. The installation shall be performed as part of the repowering process and shall be completed no later than December 31, 2004. In the event that the DEP does not find that the technology is commercially viable, then by December 31, 2004, TAMPA ELECTRIC COMPANY shall spend up to $8 million to demonstrate alternative commercially viable nitrogen oxide reduction technologies for natural gas-fired or coal-fired generating facilities as determined by the DEP and TAMPA ELECTRIC COMPANY.

C. At Big Bend Station, the new scrubber serving Units 1&2 is currently going through performance testing and is scheduled for commercial operation on or about January 1, 2000. It has a guaranteed removal efficiency of 93% but is the first Unit with a large, high velocity tower serving approximately 800 mega watts TAMPA ELECTRIC COMPANY shall use reasonable commercial efforts to optimize the removal efficiency to achieve a 95% removal efficiency by May 1, 2002 if such rate is not achieved by commercial operation.

D. TAMPA ELECTRIC COMPANY shall maximize scrubber utilization on all four boilers at Big Bend. The DEP recognizes the need for shut down for operational reasons.

E. TAMPA ELECTRIC COMPANY shall add nitrogen oxide controls, repower or shut down Units 1 through 3 at Big Bend Station by May 2010 and at Unit 4 at Big Bend Station by May 2007. If SCRs or similar nitrogen oxide controls are installed, BACT for nitrogen oxide will be .10 lbs./mmBTU on Unit 4 and .15 lbs./mmBTU on Units 1, 2, and 3.

F. TAMPA ELECTRIC COMPANY shall undertake a performance optimization study and a BACT analysis of its electrostatic precipitators and make reasonable upgrades to the electrostatic precipitators at Big Bend Station by May 1, 2003, if the study indicates that reasonable upgrades are necessary to obtain performance optimization.

G. TAMPA ELECTRIC COMPANY shall report to DEP on the technical feasibility of installing a particulate matter continuous emissions monitor on one stack at Big Bend March 1, 2002. If the DEP determines by May 31, 2002 that installation to be technically feasible, TAMPA ELECTRIC COMPANY shall install a particulate matter continuous emissions monitor on one stack at Big Bend station no later than May 1, 2003. Such monitor shall be installed solely for demonstration and informational purposes.

H. TAMPA ELECTRIC COMPANY shall be entitled to retain all sulfur dioxide reduction credits as currently authorized by law and freely trade them as allowed by the acid rain program. These credits were an integral part of the economics of the repowering project. If a credit trading program is developed by state or federal law for nitrogen oxide, TAMPA ELECTRIC COMPANY shall bank such credits obtained from the reductions achieved through the implementation of this Consent Final Judgment, but such credits shall not be eligible for sale to third parties but shall be held for TAMPA ELECTRIC COMPANY's (or any affiliate's) own account.

I. TAMPA ELECTRIC COMPANY shall agree to cooperate with the DEP on its Bay Regional Air Chemistry Experiment BRACE program relating to nitrogen deposition in Tampa Bay, including allowing necessary stack testing access to the DEP, and contributing $2 million dollars to the Hillsborough Environmental Protection Commission (EPC) for use in the BRACE program, in lieu of civil penalties. The DEP will enter into an agreement with EPC to ensure that the funds are spent on the BRACE program. TAMPA ELECTRIC COMPANY shall make the first payment to EPC in the amount of $500,000 by July 1, 2000, and shall pay $500,000 each six months thereafter until the full $2 million dollars has been paid.

J. TAMPA ELECTRIC COMPANY shall collaborate with the DEP to develop and implement State tax policy aimed at emissions reductions and such other supplemental environmental programs which are agreed to by TAMPA ELECTRIC COMPANY and the DEP.

K. TAMPA ELECTRIC COMPANY shall be entitled to relief from the time requirements of this Consent Final Judgment in the event of a force majeure that includes, among other things, delays in regulatory approvals, construction, labor, material or equipment delays, natural gas and gas transportation availability delays, acts of God or other similar events that are beyond the control of the company and not resulting from its owns actions, for the length of time necessarily imposed by the delay.

L. TAMPA ELECTRIC COMPANY shall be released from civil liability for all past New Source Review (NSR) related acts and State Implementation Plan (SIP) violations associated with the Prevention of Significant Deterioration (PSD), New Source Performance Standards (NSPS) and NSR related matters set forth herein and in the Complaint.

M. TAMPA ELECTRIC COMPANY shall also be protected from triggering NSR requirements with respect to repairs, maintenance and physical or operation changes during the term of the Consent Final Judgment which term shall remain effective until the actions required hereunder have been implemented.

N. The DEP shall cooperate with TAMPA ELECTRIC COMPANY and the United States Environmental Protection Agency in an effort to clarify the NSR regulations for repairs, maintenance, physical and operation changes in the future.

O. TAMPA ELECTRIC COMPANY's obligation to implement the emissions reductions and other requirements set forth herein will be conditioned on the receipt of necessary federal, state and local environmental permits, and acceptable regulatory treatment, including cost recovery by the Florida Public Service Commission.

P. DEP will defend the terms of this Consent Final Judgment in any action to which it is a party.

VI. MISCELLANEOUS

A. This Consent Final Judgment embodies the entire agreement and understanding of the Parties and supersedes any and all prior agreements, drafts, arrangements, conversations, negotiations or understandings relating to matters provided for in the Consent Final Judgment.

B. This Consent Final Judgment may be executed in one or more counterparts, each of which will be deemed an original, but all of which together will constitute one and the same instrument.

C. Each provision of the Consent Final Judgment shall be interpreted in such a manner as to be effective and valid under applicable law, but if any provision of the Consent Final Judgment shall be prohibited or invalid under applicable law, such provision shall be ineffective to the extent of such prohibition or invalidity, without invalidating the remainder of such provision or the remaining provisions of the Consent Final Judgment.

D. This Consent Final Judgment is not, and shall not be construed to be, a permit issued pursuant to any federal, State or local law, rule or regulation.

E. If, for any reason, the Court should decline to enter this Consent Final Judgment in the form in which it is lodged, the Consent Final Judgment as lodged is voidable, at the sole discretion of either Party. The Parties agree that because the claims of the DEP contained herein were disputed as to validity and amount, none of the terms of the lodged but voided Consent Final Judgment may be used as evidence in any litigation for any purpose, except with the written consent of TAMPA ELECTRIC COMPANY.

F. Except as provided for herein, there shall be no modifications or amendments of this Consent Final Judgment without written agreement of the Parties to this Consent Final Judgment and approval by the Court.

VII. FINAL JUDGMENT/RETENTION OF JURISDICTION

This Consent Final Judgment constitutes a final judgment in this action. This Court will retain jurisdiction for the purpose of enabling the Parties to apply to the Court at any time for such further order, direction or relief as may be necessary or appropriate for the construction or modification of this Consent Final Judgment, or to effectuate or enforce compliance with its terms, or to resolve disputes.

DONE AND ORDERED IN CHAMBERS this ___ day of ____________________, 1999.

ORIGINAL SIGNED

DEC 16 1999

ROBERT H. BONANNO
CIRCUIT JUDGE

____
Circuit Judge

FLORIDA DEPARTMENT OF
ENVIRONMENTAL PROTECTION

By: David B. Struhs
Secretary of the Florida Department of
Environmental Protection

Date: December 6, 1999

TAMPA ELECTRIC COMPANY

By: J.B. Ramil
John B. Ramil
President

Date: December 6, 1999

Florida Department of Environmental Protection

Phase II NO_X Compliance Plan

For more information, see instructions and refer to 40 CFR 76.9

This submission is: ☐ New X Revised

STEP 1 Indicate plant name, state, and ORIS code from NADB, if applicable.	Plant Name Tampa Electric Company Big Bend Station	State FL	ORIS Code 645
STEP 2	Identify each affected Group 1 and Group 2 boiler using the boiler ID# from NADB, if applicable. Indicate boiler type: "CB" for cell burner, "CY" for cyclone, "DBW" for dry bottom wall-fired, "T" for tangentially fired, "V" for vertically fired, and "WB" for wet bottom. Indicate the compliance option selected for each unit.		

	ID# BB01	ID# BB02	ID# BB03	ID# BB04	ID#	ID#
	Type WB	Type WB	Type WB	Type T	Type	Type
(a) Standard annual average emission limitation of 0.50 lb/mmBtu (for Phase I dry bottom wall-fired boilers)	☐	☐	☐	☐	☐	☐
(b) Standard annual average emission limitation of 0.45 lb/mmBtu (for Phase I tangentially fired boilers)	☐	☐	☐	☐	☐	☐
(c) EPA-approved early election plan under 40 CFR 76.8 through 12/31/07 (also indicate above emission limit specified in plan)	☐	☐	☐	☐	☐	☐
(d) Standard annual average emission limitation of 0.46 lb/mmBtu (for Phase II dry bottom wall-fired boilers)	☐	☐	☐	☐	☐	☐
(e) Standard annual average emission limitation of 0.40 lb/mmBtu (for Phase II tangentially fired boilers)	☐	☐	☐	☐	☐	☐
(f) Standard annual average emission limitation of 0.68 lb/mmBtu (for cell burner boilers)	☐	☐	☐	☐	☐	☐
(g) Standard annual average emission limitation of 0.86 lb/mmBtu (for cyclone boilers)	☐	☐	☐	☐	☐	☐
(h) Standard annual average emission limitation of 0.80 lb/mmBtu (for vertically fired boilers)	☐	☐	☐	☐	☐	☐
(i) Standard annual average emission limitation of 0.84 lb/mmBtu (for wet bottom boilers)	☐	☐	☐	☐	☐	☐
(j) NO_x Averaging Plan (include NO_x Averaging form)	X	X	X	X	☐	☐
(k) Common stack pursuant to 40 CFR 75.17(a)(2)(i)(A) (check the standard emission limitation box above for most stringent limitation applicable to any unit utilizing stack)	☐	☐	☐	☐	☐	☐

Plant Name (from Step 1)	Tampa Electric Company Big Bend Station

STEP 2, cont'd.

	ID# BB01	ID# BB02	ID# BB03	ID# BB04	ID#	ID#
	Type WB	Type WB	Type WB	Type T	Type	Type
(l) Common stack pursuant to 40 CFR 75.17(a)(2)(i)(B) with NO_x Averaging (check the NO_x Averaging Plan box and include NO_x Averaging Form)	X	X	☐	☐	☐	☐
(m) EPA-approved common stack apportionment method pursuant to 40 CFR 75.17 (a)(2)(i)(C), (a)(2)(iii)(B), or (b)(2)	☐	☐	☐	☐	☐	☐
(n) AEL (include Phase II AEL Demonstration Period, Final AEL Petition, or AEL Renewal form as appropriate)	☐	☐	☐	☐	☐	☐
(o) Petition for AEL demonstration period or final AEL under review by U.S. EPA or demonstration period ongoing	☐	☐	☐	☐	☐	☐
(p) Repowering extension plan approved or under review	☐	☐	☐	☐	☐	☐

STEP 3
Read the standard requirements and certification, enter the name of the designated representative, sign and date.

Standard Requirements

General. This source is subject to the standard requirements in 40 CFR 72.9 (consistent with 40 CFR 76.8(e)(1)(i)). These requirements are listed in this source's Acid Rain Part of its Title V permit.

Special Provisions for Early Election Units

Nitrogen Oxides. A unit that is governed by an approved early election plan shall be subject to an emissions limitation for NO_x as provided under 40 CFR 76.8(a)(2) except as provided under 40 CFR 76.8(e)(3)(iii).

Liability. The owners and operators of a unit governed by an approved early election plan shall be liable for any violation of the plan or 40 CFR 76.8 at that unit. The owners and operators shall be liable, beginning January 1, 2000, for fulfilling the obligations specified in 40 CFR Part 77.

Termination. An approved early election plan shall be in effect only until the earlier of January 1, 2008 or January 1 of the calendar year for which a termination of the plan takes effect. If the designated representative of the unit under an approved early election plan fails to demonstrate compliance with the applicable emissions limitation under 40 CFR 76.5 for any year during the period beginning January 1 of the first year the early election takes effect and ending December 31, 2007, the permitting authority will terminate the plan. The termination will take effect beginning January 1 of the year after the year for which there is a failure to demonstrate compliance, and the designated representative may not submit a new early election plan. The designated representative of the unit under an approved early election plan may terminate the plan any year prior to 2008 but may not submit a new early election plan. In order to terminate the plan, the designated representative must submit a notice under 40 CFR 72.40(d) by January 1 of the year for which the termination is to take effect. If an early election plan is terminated any year prior to 2000, the unit shall meet, beginning January 1, 2000, the applicable emissions limitation for NO_x for Phase II units with Group 1 boilers under 40 CFR 76.7. If an early election plan is terminated on or after 2000, the unit shall meet, beginning on the effective date of the termination, the applicable emissions limitation for NO_x for Phase II units with Group 1 boilers under 40 CFR 76.7.

STEP 3, cont'd.

Certification

I am authorized to make this submission on behalf of the owners and operators of the affected source or affected units for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.

Name Gregory M. Nelson	
Signature Gregory M. Nelson	Date 12/20/99

Florida Department of Environmental Protection

Phase II NO_x Averaging Plan

For more information, see instructions for DEP Form No. 62-210.900(1)(a)4.and refer to 40 CFR 76.11

This submission is: X New ☐ Revised

STEP 1

Identify the units participating in this averaging plan by plant name, state, and boiler ID# from NADB. In column (a), fill in each unit's applicable emission limitation from 40 CFR 76.5, 76.6, or 76.7. In column (b), assign an alternative contemporaneous annual emissions limitation in lb/mmBtu to each unit. In column (c), assign an annual heat input limitation in mmBtu to each unit.
Continue to page 3 if necessary.

Plant Name	State	ID#	(a) Emission Limitation	(b) Alt. Contemp. Emission Limitation	(c) Annual Heat Input Limit
F.J. Gannon Station	FL	GN03	0.86	0.89	8,500,000
F.J. Gannon Station	FL	GN04	0.86	0.82	7,500,000
F.J. Gannon Station	FL	GN05	0.84	0.76	10,000,000
F.J. Gannon Station	FL	GN06	0.84	1.10	27,000,000
Big Bend Station	FL	BB01	0.84	0.74	23,000,000
Big Bend Station	FL	BB02	0.84	0.74	24,000,000
Big Bend Station	FL	BB03	0.84	0.53	10,000,000

STEP 2

Use the formula to enter the Btu-weighted annual emission rate averaged over the units if they are operated in accordance with the proposed averaging plan and the Btu-weighted annual average emission rate for the same units if they are operated in compliance with 40 CFR 76.5, 76.6, or 76.7. The former must be less than or equal to the latter.

Btu-weighted annual emission rate averaged over the units if they are operated in accordance with the proposed averaging plan		Btu-weighted annual average emission rate for same units operated in compliance with 40 CFR 76.5, 76.6 or 76.7
0.77	≤	0.78

$$\frac{\sum_{i=1}^{n} (R_{Li} \, x \, HI_i)}{\sum_{i=1}^{n} HI_i} \leq \frac{\sum_{i=1}^{n} [R_{Ii} \, x \, HI_i]}{\sum_{i=1}^{n} HI_i}$$

Where,

R_{Li} = Alternative contemporaneous annual emmision limitation for unit i, in 16/mmBtu, as specified in column (b) of Step 1;

R_{Ii} = Applicable emission limitation for unit i, in lb/mmBtu, as specified in column (a) of Step 1;

HI_i = Annual heat input for unit i, in mmBtu, as specified in column (c) of Step 1;

n = Number of units in the averaging plan

Big Bend Station
Plant Name (from Step 1)

STEP 3

Mark one of the two options and enter dates.

☐ This plan is effective for calendar year ________ through calendar year ________ unless notification to terminate the plan is given.

X Treat this plan as X identical plans, each effective for one calendar year for the following calendar years: 2000, 2001, 2002, 2003 and 2004 unless notification to terminate one or more of these plans is given.

STEP 4

Read the special provisions and certification, enter the name of the designated representative, and sign and date.

Special Provisions

Emission Limitations

Each affected unit in an approved averaging plan is in compliance with the Acid Rain emission limitation for NO_x under the plan only if the following requirements are met:

(i) For each unit, the unit's actual annual average emission rate for the calendar year, in lb/mmBtu, is less than or equal to its alternative contemporaneous annual emission limitation in the averaging plan, and

(a) For each unit with an alternative contemporaneous emission limitation less stringent than the applicable emission limitation in 40 CFR 76.5, 76.6, or 76.7, the actual annual heat input for the calendar year does not exceed the annual heat input limit in the averaging plan,

(b) For each unit with an alternative contemporaneous emission limitation more stringent than the applicable emission limitation in 40 CFR 76.5, 76.6, or 76.7, the actual annual heat input for the calendar year is not less than the annual heat input limit in the averaging plan, or

(ii) If one or more of the units does not meet the requirements of (i), the designated representative shall demonstrate, in accordance with 40 CFR 76.11(d)(1)(ii)(A) and (B), that the actual Btu-weighted annual average emission rate for the units in the plan is less than or equal to the Btu-weighted annual average rate for the same units had they each been operated, during the same period of time, in compliance with the applicable emission limitations in 40 CFR 76.5, 76.6, or 76.7.

(iii) If there is a successful group showing of compliance under 40 CFR 76.11(d)(1)(ii)(A) and (B) for a calendar year, then all units in the averaging plan shall be deemed to be in compliance for that year with their alternative contemporaneous emission limitations and annual heat input limits under (i).

Liability

The owners and operators of a unit governed by an approved averaging plan shall be liable for any violation of the plan or this section at that unit or any other unit in the plan, including liability for fulfilling the obligations specified in part 77 of this chapter and sections 113 and 411 of the Act.

Termination

The designated representative may submit a notification to terminate an approved averaging plan, in accordance with 40 CFR 72.40(d), no later than October 1 of the calendar year for which the plan is to be terminated.

Certification

I am authorized to make this submission on behalf of the owners and operators of the affected source or affected units for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.

Name Gregory M. Nelson, P.E.	
Signature Gregory M. Nelson	Date 12/20/99

Plant Name (from Step 1)
Big Bend Station F.J. Gannon Station

STEP 1

Continue the identification of units from Step 1, page 1, here.

Plant Name	State	ID#	(a) Emission Limitation	(b) Alt. Contemp. Emission Limitation	(c) Annual Heat Input Limit
Big Bend Station	FL	BB04	0.45	0.44	20,000,000

Review Draft . . . 10/20/00

UNITED STATES DISTRICT COURT
MIDDLE DISTRICT OF FLORIDA

UNITED STATES OF AMERICA,	
Plaintiff,	CIVIL ACTION NO. 99-2524 CIV-T-23F
v.	
TAMPA ELECTRIC COMPANY,	
Defendant.	

AMENDMENT TO CONSENT DECREE

WHEREAS, on October 4, 2000, this Court entered a Consent Decree resolving this matter;

WHEREAS Tampa Electric Company ("Tampa Electric") has for sometime been undertaking work related to carrying out its obligations under the Consent Decree, including but not limited to work involving scrubbers -- which are pollution control devices that reduce emission of certain pollutants into the air;

WHEREAS Tampa Electric reports that it has not issued its final acceptance to the scrubber contractor for the supply and installation of the scrubber that serves Big Bend Units 1 and 2 and has also retained a consultant to analyze options for improving performance of that scrubber, and Tampa Electric further reports that detailed inspection of the scrubber serving Big Bend Units 3 and 4 reveals that this scrubber will require more maintenance and upgrading than originally anticipated as part of bringing the scrubber up to performance levels required by the Consent Decree;

WHEREAS Tampa Electric reports that scrubber work necessary for Big Bend Units 3 and 4 would be most easily performed during the next scheduled outage for those units, which should be during April or May 2000;

WHEREAS Tampa Electric has proposed certain adjustments to the Consent Decree to address these issues concerning scrubbers and also has identified several small corrections to the Decree;

WHEREAS the United States believes that the adjustments and corrections effected by this amendment are appropriate;

NOW, THEREFORE, without any admission of fact or law, it is hereby ORDERED AND DECREED that the Consent Decree is amended as follows:

A. ADJUSTMENTS

1. Alter first sentence of Paragraph 29 to extend deadline for certain work on the scrubber serving Big Bend Units 1 and 2, by replacing "September 1, 2000," with "December 31, 2000,".

2. Add New Paragraph 30.1, as follows:

   30.1. One-time increase in number of days Tampa Electric may operate Big Bend Unit 3 without treatment by a scrubber. In addition to the number of calendar days that Tampa Electric may, under Paragraph 30.A(1) of this

Decree, operate Big Bend Unit 3 without treating emissions from that Unit with a scrubber, Tampa Electric also may operate Unit 3 for up to an additional 30 calendar days without treating emissions from that Unit with a scrubber if and only if:

A. Each day of such operation (and scrubber outage) under this provision takes place prior to May 31, 2001;

B. The purpose of the scrubber outage during such operation of Unit 3 is repair, improvement, and/or upgrade of the scrubber;

C. Tampa Electric complies with paragraph 30.B of this Decree while operating Unit 3 during such scrubber outage; and

D. Tampa Electric documents in detail each day of Unit 3 operation and scrubber outage that the company claims under this provision, and supplies such documentation as part of the periodic reporting requirements that apply to Tampa Electric under this Decree.

3. Alter Paragraph 53.I by adding "30.1" between "30" and "31" in the list of paragraphs identified in Paragraph 53.I

B. CORRECTIONS

1. At page 6, in first line of Paragraph 4 of the Decree, delete "2.2 lb/mmBTU" and replace with "2.2 lbs SO_2 /mmBTU".

Steven A. Herman
Assistant Administrator for Office of Enforcement
and Compliance Assurance
U.S. Environmental Protection Agency
Washington, D.C.

Bruce Buckheit
Director

Gregory Jaffe
Senior Enforcement Counsel

Air Enforcement Division
Office of Enforcement and Compliance Assurance
U.S. Environmental Protection Agency
Washington, D.C.

THROUGH ITS UNDERSIGNED REPRESENTATIVES, TAMPA ELECTRIC COMPANY AGREES AND CONSENTS TO ENTRY OF THE FOREGOING CONSENT DECREE

FOR TAMPA ELECTRIC COMPANY

______________________________ Date: __________

John B. Ramil
President
Tampa Electric Company

____

Sheila M. McDevitt
General Counsel
Tampa Electric Company

UNITED STATES DISTRICT COURT
MIDDLE DISTRICT OF FLORIDA

UNITED STATES OF AMERICA,	)	
	)	
Plaintiff,	)	
	)	CIVIL ACTION NO. 99-2524
v.	)	CIV-T-23F
	)	
	)	
TAMPA ELECTRIC COMPANY,	)	
	)	
Defendant.	)	
	)	

CONSENT DECREE

WHEREAS, Plaintiff, the United States of America ("Plaintiff" or "the United States"), on behalf of the United States Environmental Protection Agency ("EPA") filed a Complaint on November 3, 1999, alleging that Defendant, Tampa Electric Company ("Tampa Electric") commenced construction of major modifications of major emitting facilities in violation of the Prevention of Significant Deterioration ("PSD") requirements at Part C of the Clean Air Act ("Act"), 42 U.S.C. §§ 7470-7492;

WHEREAS, EPA issued a Notice of Violation with respect to such allegations to Tampa Electric on November 3, 1999 (the "NOV");

WHEREAS, the parties recognize, and the Court by entering this Consent Decree finds, that this Consent Decree has been negotiated in good faith and at arm's length; that the parties have voluntarily agreed to this Consent Decree; that implementation of this Consent Decree will avoid prolonged and complicated litigation between the parties; and that this Consent Decree is fair, reasonable, consistent with the goals of the Act, and in the public interest;

WHEREAS, the United States alleges that the Complaint states a claim upon which relief can be granted against Tampa Electric under Sections 113 and 167 of the Act, 42 U.S.C. §§ 7413 and 7477, and 28 U.S.C. § 1355;

WHEREAS, Tampa Electric has not answered or otherwise responded to the Complaint in light of the settlement memorialized in this Consent Decree;

WHEREAS, Tampa Electric has denied and continues to deny the violations alleged in the NOV and the Complaint; maintains that it has been and remains in compliance with the Clean Air Act and is not liable for civil penalties or injunctive relief; and states that it is agreeing to the obligations imposed by this Consent Decree solely to avoid the costs and uncertainties of litigation and to improve the environment in and around the Tampa Bay area of Florida;

WHEREAS, Tampa Electric is the first electric utility of those against which the United States brought enforcement actions in November, 1999, to come forward and invest time and effort sufficient to develop a settlement with the United States;

WHEREAS, Tampa Electric's decision to Re-Power some of its coal-fired electric generating Units with natural gas will significantly reduce emissions of both regulated and unregulated pollutants below levels that would have been achieved merely by installing appropriate pollution control technologies on Tampa Electric's existing coal-fired electric generating Units;

WHEREAS, prior to the filing of the Complaint or issuance of the Notice of Violation in this matter, Tampa Electric already had placed in service or installed both scrubbers and electrostatic precipitators that serve all existing coal-fired electric generating Units at the company's Big Bend electric generating plant;

WHEREAS, the United States recognizes that a BACT Analysis conducted under existing procedures most likely would not find it cost effective to replace Tampa Electric's existing control equipment at Big Bend for particulate matter, in light of the design and performance of that equipment;

WHEREAS, Tampa Electric and the United States have crafted this Consent Decree to take into account physical and operational constraints resulting from the unique, Riley Stoker wet bottom, turbo-fired boiler technology now in operation at Big Bend, which could limit the efficiency of nitrogen oxides emissions controls installed for those boilers;

WHEREAS, Tampa Electric regularly combusts coal with a sulphur content of five or six pounds per mmBTU heat input;

WHEREAS, Tampa Electric is a mid-sized electric utility and is smaller on a financial basis than some of the other electric utilities against which the United States brought similar enforcement actions in November 1999;

WHEREAS, Tampa Electric owns and operates fewer coal-fired electric generating plants than some of the other electric utilities against which the United States brought similar enforcement actions in November 1999;

WHEREAS, the two Tampa Electric plants addressed by this enforcement action constitute over ninety percent of the entire base load generating capacity of Tampa Electric;

WHEREAS, the United States and Tampa Electric have agreed that settlement of this action is in the best interest of the parties and in the public interest, and that entry of this Consent Decree without further litigation is the most appropriate means of resolving this matter; and

WHEREAS, the United States and Tampa Electric have consented to entry of this Consent Decree without trial of any issue;

NOW, THEREFORE, without any admission of fact or law, and without any admission of the violations alleged in the Complaint or NOV, it is hereby ORDERED AND DECREED as follows:

I. JURISDICTION AND VENUE

1. This Court has jurisdiction over the subject matter herein and over the parties consenting hereto pursuant to 28 U.S.C. § 1345 and pursuant to Sections 113 and 167 of the Act, 42 U.S.C. §§ 7413 and 7477. Venue is proper under Section 113(b) of the Act, 42 U.S.C. § 7413(b), and under 28 U.S.C. § 1391(b) and (c).

Solely for the purposes of this Consent Decree and the underlying Complaint, Tampa Electric waives all objections and defenses that it may have to the claims set forth in the Complaint, the jurisdiction of the Court or to venue in this District. Tampa Electric shall not challenge the terms of this Consent Decree or this Court's jurisdiction to enter and enforce this Consent Decree. Except as expressly provided for herein, this Consent Decree shall not create any rights in any party other than the United States and Tampa Electric. Tampa Electric consents to entry of this Consent Decree without further notice.

II. APPLICABILITY

2. The provisions of this Consent Decree shall apply to and be binding upon the United States and upon Tampa Electric, its successors and assigns, and Tampa Electric's officers, employees and agents solely in their capacities as such. If Tampa Electric proposes to sell or transfer any of its real property or operations subject to this Consent Decree, it shall advise the purchaser or transferee in writing of the existence of this Consent Decree, and shall send a copy of such written notification by certified mail, return receipt requested, to EPA sixty (60) days before such sale or transfer. Tampa Electric shall not be relieved of its responsibility to comply with all requirements of this Consent Decree unless the purchaser or transferee assumes responsibility for full performance of Tampa Electric's responsibilities under this Consent Decree, including liabilities for

nonperformance. Tampa Electric shall not purchase or otherwise acquire capacity and/or energy from a third party in lieu of obtaining it from Gannon or Big Bend unless the seller or provider agrees that the facilities providing such capacity and/or energy will meet the emission control requirements set forth in this Consent Decree or equivalent requirements approved in advance by the United States.

3. Tampa Electric shall provide a copy of this Consent Decree to all vendors, suppliers, consultants, contractors, agents, and any other company or other organization performing any of the work described in Sections IV or VII of this Consent Decree. Notwithstanding any retention of contractors, subcontractors or agents to perform any work required under this Consent Decree, Tampa Electric shall be responsible for ensuring that all work is performed in accordance with the requirements of this Consent Decree. In any action to enforce this Consent Decree, Tampa Electric shall not assert as a defense the failure of its employees, servants, agents, or contractors to take actions necessary to comply with this Consent Decree, unless Tampa Electric establishes that such failure resulted from a Force Majeure event as defined in this Consent Decree.

III. DEFINITIONS

4. "Alternative Coal" shall mean coal with a sulphur content of no more than 2.2 lb/mmBTU, on an as determined basis.

5. "BACT Analysis" shall mean the technical study, analysis, review, and selection of recommendations typically performed in connection with an application for a PSD permit. Except as otherwise provided in this Consent Decree, such study, analysis, review, and selection of recommendations shall be carried out in conformance with applicable federal and state regulations and guidance describing the process and analysis for determining Best Available Control Technology (BACT).

6. "Big Bend" shall mean the electric generating plant, presently coal-fired, owned and operated by Tampa Electric and located in Hillsborough County, Florida, which presently includes four steam generating boilers and associated and ancillary systems and equipment, known as Big Bend Units 1, 2, 3, and 4.

7. "Consent Decree" shall mean this Consent Decree and the Appendix thereto.

8. "Emission Rate" shall mean the average number of pounds of pollutant emitted per million BTU of heat input ("lb/mmBTU") or the average concentration of a pollutant in parts per million by volume ("ppm"), as dictated by the unit of measure specified for the rate in question, where:

1

2 in the case of a coal-fired, steam electric generating unit, such rates shall be calculated as a 30 day rolling average. A 30 day rolling average for an Emission Rate expressed as lb/mmBTU shall be determined by calculating the emission rate for a given operating day, and then arithmetically averaging the emission rates for

the previous 29 operating days with that date. A new 30 day rolling average shall be calculated for each new operating day;

A in the case of a gas-fired, electric generating unit, such rates shall be calculated as a 24-hour rolling average, excluding periods of start up, shutdown, and malfunction as provided by applicable Florida regulations at the time the Emission Rate is calculated. A rolling average for Emission Rates expressed as ppm shall be determined on a given day by summing hourly emission rates for the immediately preceding 24-hour period and dividing by 24;

A the reference methods for determining Emission Rates for SO_2 and NO_x shall be those specified in 40 C.F.R. Part 75, Appendix F. The reference methods for determining Emission Rates for PM shall be those specified in 40 C.F.R. Part 60, Appendix A, Method 5, Method 5B, or Method 17; and

A nothing in this Consent Decree is intended to nor shall alter applicable law concerning the use of data, for any purpose under the Clean Air Act, generated by methods other than the reference methods specified herein.

9. "EPA" shall mean the United States Environmental Protection Agency.

10. "Gannon" shall mean the electric generating plant, presently coal-fired, owned and operated by Tampa Electric, located in Hillsborough County, Florida, which presently includes six steam generating boilers and associated and ancillary systems and equipment, known as Gannon Units 1, 2, 3, 4, 5, and 6. Tampa Electric intends to rename Gannon "Bayside Power Station" upon completion of

the Re-Powering required under this Consent Decree.

11. "lb/mmBTU" shall mean pounds per million British Thermal Units of heat input.

12. "NOx" shall mean oxides of nitrogen.

13. "NOV" shall mean the Notice of Violation issued by EPA to Tampa Electric dated November 3, 1999.

14. "PM" shall mean total particulate matter, and the reference method for measuring PM shall be that specified in the definition of Emission Rate in this Consent Decree.

15. "ppm" shall mean parts per million by dry volume, corrected to 15% O_2.

16. "Project Dollars" shall mean Tampa Electric's expenditures and payments incurred or made in carrying out the dollar-limited projects identified in Paragraph 35 of Section IV of this Consent Decree (Early Reductions of NO_x from Big Bend Units 1 through 3) and in Section VII of this Consent Decree (NO_x Reduction Projects and Mitigation Projects), to the extent that such expenditures or payments both: (A) comply with the Project Dollar and other requirements set by this Consent Decree for such expenditures and payments in Section VII and in Paragraph 35 of Section IV of this Consent Decree, and (B) constitute either Tampa Electric's properly documented external costs for contractors, vendors, as well as equipment, or its internal costs consisting of employee time, travel, and other out-of-pocket expenses specifically attributable to these particular projects.

17. "PSD" shall mean Prevention of Significant Deterioration within the meaning of

Part C of the Clean Air Act, 42 U.S.C. §§ 7470, et seq.

18. "Re-Power" shall mean the removal or permanent disabling of devices, systems, equipment, and ancillary or supporting systems at a Gannon or Big Bend Unit such that the Unit cannot be fired with coal, and the installation of all devices, systems, equipment, and ancillary or supporting systems needed to fire such Unit with natural gas under the limits set in this Consent Decree (or with No. 2 fuel oil, as a back up fuel only, and under the limits specified by this Consent Decree) plus installation of the control technology and compliance with the Emission Rates called for under this Consent Decree.

19. "Reserve / Standby" shall mean those devices, systems, equipment, and ancillary or supporting systems that: (1) are not used as part of the Units that must be Re-Powered under Paragraph 26, (2) are not in operation subsequent to the Re-Powering required under Paragraph 26, (3) are maintained and held by Tampa Electric for system reliability purposes, and (4) may be restarted only by Re-Powering.

20. "SCR" shall mean Selective Catalytic Reduction.

21. "Shutdown" shall mean the permanent disabling of a coal-fired boiler such that it cannot burn any fuel nor produce any steam for electricity production, other than through Re-Powering.

22. "SO_2" shall mean sulphur dioxide.

23. "Title V Permit" shall mean the permit required under Subchapter V of the Clean

Air Act, 42 U.S.C. § 7661, et seq.

24. "Total Baseline Emissions" shall mean calendar year 1998 emissions of NO_x, SO_2, and PM comprised of the following amounts for each pollutant:

A. for Gannon: 30,763 tons of NO_x, 64,620 tons of SO_2, and 1,914 tons of PM; and

A.

B. for Big Bend: 36,077 tons of NO_x, 107,334 tons of SO_2, and 3,002 tons of PM.

25. "Unit" shall mean for the purpose of this Consent Decree a generator, the steam turbine that drives the generator, the boiler that produces the steam for the steam turbine, the equipment necessary to operate the generator, turbine and boiler, and all ancillary equipment, including pollution control equipment or systems necessary for the production of electricity. An electric generating plant may be comprised of one or more Units.

IV. EMISSIONS REDUCTIONS AND CONTROLS – GANNON AND BIG BEND

A. GANNON

26. Consent Decree-Required Re-Powering of Gannon. Tampa Electric shall Re-Power Units at Gannon with a coal-fired generating capacity of no less than 550 MW ("Megawatt"), as follows.

A. On or before May 1, 2003, Tampa Electric shall Re-Power Units with a coal-fired generating capacity of no less than 200 MW. On or before December 31, 2004, Tampa Electric shall Re-Power additional Units with a coal-fired generating capacity equal to or greater than the difference between 550 MW of coal-fired generating capacity and the MW value of coal-fired generating capacity that Tampa Electric Re-Powered in complying with the first sentence of this Subparagraph A.

A. All Re-Powering required by this Paragraph shall include installation and operation of SCR, other pollution control technology approved in advance and in writing by EPA, or any innovative technology demonstration project approved pursuant to Paragraph, 52.C to control Unit emissions. Each Re-Powered Unit shall, in conformance with the definition of Re-Power, use natural gas as its primary fuel and shall meet an Emission Rate for NO_x of no greater than 3.5 ppm.

A. A Unit Re-Powered under this or any other provision of this Consent Decree may be fired with No. 2 fuel oil if and only if: (1) the Unit cannot be fired with natural gas; (2) the Unit has not yet been fired with No. 2 fuel oil as a back up fuel for more than 875 full load equivalent hours in the calendar year in which Tampa Electric wishes to fire the Unit with such oil; (3) the oil to be used in firing the Unit has a sulphur content of less than 0.05 percent (by weight); (4) Tampa Electric uses all emission control equipment for that Unit when it is fired with such oil to the maximum extent possible; and (5) Tampa Electric complies with all applicable permit conditions, including emission rates for firing with No. 2 fuel oil, as set forth in applicable preconstruction and operating permits.

A. Tampa Electric shall timely apply for a preconstruction permit under Rule 62-212, F.A.C., prior to commencing such Re-Powering. In applying for such permit Tampa Electric shall seek, as part of the permit, provisions requiring installation of SCR or other EPA-approved control technology and a NO_x Emission Rate no greater than 3.5 ppm.

27. Schedule for Shutdown of Units. Tampa Electric shall Shutdown and cease any and all operation of all six (6) Gannon coal-fired boilers with a combined coal-fired capacity of not less than 1194 MW on or before December 31, 2004. Notwithstanding the requirements of this Paragraph, Tampa Electric may retain any Unit Shutdown pursuant to this Paragraph on Reserve / Standby, unless such Unit is to be, or has been, Re-Powered under Paragraph 26, above. If Tampa Electric later decides to restart any Shutdown Unit retained on Reserve / Standby, then prior to such re-start, Tampa Electric shall timely apply for a PSD permit for the Unit(s) to be Re-Powered, and Tampa Electric shall abide by the permit issued as a result of that application, including installation of BACT and its corresponding Emission Rate, as determined at the time of the restart. Tampa Electric shall operate the Re-Powered Unit to meet the NO_x Emission Rate established in the PSD Permit or an Emission Rate for NO_x of 3.5 ppm, whichever is more stringent. Tampa Electric shall provide a copy of any permit application(s), proposed permit(s), and permit(s) to the United States as specified in Paragraph 82 (Notice). For any Unit Shutdown and placed on Reserve / Standby under this Paragraph, and notwithstanding the definition of Re-Power in

this Consent Decree, Tampa Electric also may elect to fuel such a Unit with a gaseous fuel other than or in addition to natural gas, if and only if Tampa Electric: applies for and secures a PSD permit before using such fuel in any such Unit, complies with all requirements issued in such a permit, and complies with all other requirements of this Consent Decree applicable to Re-Powering.

28. Permanent Bar on Combustion of Coal. Commencing on January 1, 2005, Tampa Electric shall not combust coal in the operation of any Unit at Gannon.

B. BIG BEND

29. Initial Reduction and Control of SO_2 Emissions from Big Bend Units 1 and 2 . Commencing upon the later of the date of entry of this Consent Decree or September 1, 2000, and except as provided in this Paragraph, Tampa Electric shall operate the existing scrubber that treats emissions of SO_2 from Big Bend Units 1 and 2 at all times that either Unit 1 or 2 is in operation. Tampa Electric shall operate the scrubber so that at least 95% of all the SO_2 contained in the flue gas entering the scrubber is removed. Notwithstanding the requirement to operate the scrubber at all times Unit 1 or 2 is operating, the following operating conditions shall apply:

A.

B. Tampa Electric may operate Units 1 and/or 2 during outages of the scrubber serving Units 1 and 2, but only so long as Tampa Electric:

(1) in calendar year 2000, does not operate Unit 1 and/or 2, or any combination of the two of them, on more than sixty (60) calendar days, or any part thereof (providing that when both Units 1 and 2 operate on the same calendar day, such operation shall count as two days of the sixty (60) day limit), and in calendar years 2001 - 2009, does not operate Unit 1 and/or 2, or any combination of the two of them, on more than forty-five (45) calendar days, or any part thereof, in any calendar year (providing that when both Units 1 and 2 operate on the same calendar day, such operation shall count as two days of the forty-five (45) day limit) ; or

A.

B. must operate Unit 1 and/or 2 in any calendar year from 2000 through 2009 either to avoid interruption of electric service to its customers under interruptible service tariffs, or to respond to a system-wide or state-wide emergency as declared by the Governor of Florida under Section 366.055, F.S. (requiring availability of reserves), or under Section 377.703, F.S.

D. (energy policy contingency plan), or under Section 252.36, F.S. (Emergency management powers of the Governor), in which Tampa Electric must generate power from Unit 1 and/or 2 to meet such emergency.

1.

2. Whenever Tampa Electric operates Units 1 and/or 2 without all emissions from such Unit(s) being treated by the scrubber, Tampa Electric shall: (1) combust only Alternative Coal at the Unit(s) operating during the outage (except for coal already bunkered in the hopper(s) for Units 1 or 2 at the time the outage commences); (2) use all existing electric generating capacity at Big Bend and Gannon that is served by fully operational pollution control equipment before operating Big Bend Units1 and/or 2; and (3) continue to control SO_2 emissions from Big Bend Units 1 and/or 2 as required by Paragraph 31 (Optimizing Availability of Scrubbers Serving Big Bend Units 1, 2, and 3).

A. In calendar years 2010 through 2012, Tampa Electric may operate Units 1 and/or 2 during outages of the scrubber serving Units 1 and 2, but only so long as Tampa Electric complies with the requirements of Subparagraphs A and B, above, and uses only coal with a sulphur content of 1.2 lb/mmBTU, or less, in place of Alternative Coal.

A. If Tampa Electric Re-Powers Big Bend Unit 1 or 2, or replaces the scrubber or provides additional scrubbing capacity to comply with Paragraph 40, then upon such compliance the provisions of Subparagraphs 29.A, 29.B, and 29.C shall not apply to the affected Unit.

30. Initial Reduction and Control of SO_2 Emissions from Big Bend Unit 3.

Commencing upon entry of the Consent Decree, and except as provided in this Paragraph, Tampa Electric shall operate the existing scrubber that treats emissions of SO_2 from Big Bend Units 3 and 4 at all times that Unit 3 is in operation. When Big Bend Units 3 and 4 are both operating, Tampa Electric shall operate the scrubber so that at least 93% of all the SO_2 contained in the flue gas entering the scrubber is removed. When Big Bend Unit 3 alone is operating, until May 1, 2002, Tampa Electric shall operate the scrubber so that at least 93% of all SO_2 contained in the flue gas entering the scrubber is removed or the Emission Rate for SO_2 for Unit 3 does not exceed 0.35 lb/mmBTU. When Unit 3 alone is operating, from May 1, 2002 until January 1, 2010, Tampa Electric shall operate the scrubber so that at least 95% of the SO_2 contained in the flue gas entering the scrubber is removed or the Emission Rate for SO_2 does not exceed 0.30 lb/mmBTU. Notwithstanding the requirement to operate the scrubber at all times Unit 3 is operating, and providing Tampa Electric is otherwise in compliance with this Consent Decree, the following operating conditions shall apply:

A.

B. In any calendar year from 2000 through 2009, Tampa Electric may operate Unit 3 in the case of outages of the scrubber serving Unit 3, but only so long as Tampa Electric:

(1) does not operate Unit 3 during outages on more than thirty (30)

calendar days, or any part thereof, in any calendar year; or

A.

B. must operate Unit 3 either: to avoid interruption of electric service to its customers under interruptible service tariffs, or to respond to a system-wide or state-wide emergency as declared by the Governor of Florida under Section 366.055, F.S. (requiring availability of reserves), or under Section 377.703, F.S. (energy policy contingency plan), or under Section 252.36, F.S. (Emergency management powers of the Governor), in which Tampa Electric must generate power from Unit 3 to meet such emergency.

C.

1.

2. Whenever Tampa Electric operates Unit 3 without treating all emissions from that Unit with the scrubber, Tampa Electric shall: (1) combust only Alternative Coal at Unit 3 during the outage (except for coal already bunkered in the hopper(s) for Unit 3 at the time the outage commences); (2) use all existing electric generating capacity at Big Bend and Gannon that is served by fully operational pollution control equipment before operating Big Bend Unit 3; and (3) continue to control SO_2 emissions from Big Bend Unit 3 as required by Paragraph 31 (Optimizing Availability of Scrubbers Serving Big Bend Units, 1, 2, and 3).

A. If Tampa Electric Re-Powers Big Bend Unit 3, or replaces the scrubber or provides additional scrubbing capacity to comply with Paragraph 40, then upon compliance with Paragraph 40 the provisions of Subparagraphs 30.A and 30.B shall not apply to Unit 3.

A.

B. Nothing in this Consent Decree shall alter requirements of the New Source Performance Standards (NSPS), 40 C.F.R. Part 60 Subpart Da, that apply to operation of the scrubber serving Unit 4.

31. Optimizing Availability of Scrubbers Serving Big Bend Units 1, 2, and 3.

Tampa Electric shall maximize the availability of the scrubbers to treat the emissions of Big Bend Units 1, 2, and 3, as follows:

A. As soon as possible after entry of this Consent Decree, Tampa Electric shall submit to EPA for review and approval a plan addressing all operation and maintenance changes to be made that would maximize the availability of the existing scrubbers treating emissions of SO_2 from Big Bend Units 1 and 2, and from Unit 3. In order to improve operations and maintenance practices as soon as possible, Tampa Electric may submit the plan in two phases.

(1) Each phase of the plan proposed by Tampa Electric shall include a schedule pursuant to which Tampa Electric will implement measures relating to operation and maintenance of the scrubbers called for by that phase of the plan, within sixty days of its approval by EPA. Tampa Electric shall implement each phase of the plan as approved by EPA.

Such plan may be modified from time to time with prior written approval of EPA.

(2) The proposed plan shall include operation and maintenance activities that will minimize instances during which SO_2 emissions are not scrubbed, including but not limited to improvements in the flexibility of scheduling maintenance on the scrubbers, increases in the stock of spare parts kept on hand to repair the scrubbers, a commitment to use of overtime labor to perform work necessary to minimize periods when the scrubbers are not functioning, and use of all existing capacity at Big Bend and Gannon Units that are served by available, operational pollution control equipment to minimize pollutant emissions while meeting power needs.

(3) If Tampa Electric elects to submit the plan to EPA in two phases, the first phase to be submitted shall address, at a minimum, use of overtime hours to accomplish repairs and maintenance of the scrubber and increasing the stock of scrubber spare parts that Tampa Electric shall keep at Big Bend to speed future maintenance and repairs. If Tampa Electric elects to submit the plan in two phases, EPA shall complete review of the first phase within fifteen business days of receipt. For the second phase of the plan or submission of the plan in its entirety, EPA shall complete review of such plan or phase thereof within 60 days of receipt. Within sixty days after EPA's approval of the plan or any phase of the plan,

Tampa Electric shall complete implementation of that plan or phase and continue operation under it subject only to the terms of this Consent Decree.

32. <u>PM Emission Minimization and Monitoring at Big Bend</u>.

A. Within twelve months after entry of this Consent Decree, Tampa Electric shall complete an optimization study which shall recommend the best operational practices to minimize emissions from each Electrostatic Precipitator (ESP) and shall deliver the completed study to EPA for review and approval. Tampa Electric shall implement these recommendations within sixty days after EPA has approved them and shall operate each ESP in conformance with the study and its recommendations until otherwise specified under this Consent Decree.

B. Within twelve months after entry of this Consent Decree, Tampa Electric shall complete a BACT Analysis for upgrading each existing ESP now located at Big Bend and shall deliver the Analysis to EPA for review and approval. Notwithstanding the definition of BACT Analysis in this Consent Decree, Tampa Electric need not consider in this BACT Analysis the replacement of any existing ESP with a new ESP, scrubber, or baghouse, or the installation of a supplemental pollution control device of similar cost to a replacement ESP, scrubber, or baghouse. Tampa Electric shall simultaneously deliver to EPA all documents that support the BACT

Analysis or that were considered in preparing the Analysis. Tampa Electric shall retain a qualified contractor to assist in the performance and completion of the BACT Analysis. On or before May 1, 2004, after EPA approval of the recommendation(s) made by the BACT Analysis, Tampa Electric shall complete installation of all equipment called for in the recommendation(s) of the Analysis and thereafter shall operate each ESP in conformance with the recommendation(s), including compliance with the Emission Rate(s) specified by the recommendation(s).

C. Within six months after Tampa Electric completes installation of the equipment called for by the BACT Analysis, as approved by EPA, Tampa Electric shall revise the previous optimization study and shall recommend the best operational practices to minimize emissions from each ESP, taking into account the recommendations from the BACT Analysis required by this Paragraph, and shall deliver the completed study to EPA for review and approval. Commencing no later than 180 days after EPA approves the study and its recommendation(s), Tampa Electric shall operate each ESP in conformance with the study's recommendation.

D. Tampa Electric shall include the recommended operational practices for each ESP and the recommendations from the BACT Analysis in Tampa Electric's Title V Permit application and all other relevant applications for operating or construction permits.

E. Installation and Operation of a PM Monitor. On or before March 1, 2002, Defendant shall install, calibrate, and commence continuous operation of a continuous particulate matter emissions monitor (PM CEM) in the duct at Big Bend that services Unit 4. Data from the PM CEM shall be used by Tampa Electric, at a minimum, to monitor progress in reducing PM emissions.

F. "Continuous operation"of the PM CEM shall mean operation at all times that Unit 4 operates, except for periods of malfunction of the PM CEM or routine maintenance performed on the PM CEM. If after Tampa Electric operates this PM CEM for at least two years, and if the parties then agree that it is infeasible to sustain continuous operation of the PM CEM, Tampa Electric shall submit an alternative PM monitoring plan for review and approval by EPA. The plan shall include an explanation of the basis for stopping operation of the PM CEM and a proposal for an alternative monitoring protocol. Until EPA approves such plan, Tampa Electric shall continue to operate the PM CEM.

G. Installation and Operation of Second PM Monitor. If Tampa Electric advises EPA, pursuant to Paragraph 36, that it has elected to continue to combust coal at Big Bend Units 1, 2, or 3, and Tampa Electric has not ceased operating the first PM CEM as described in Subparagraph F, above, then Tampa Electric shall install, calibrate, and commence continuous operation of a PM CEM on a second duct at Big Bend on or before May 1, 2007. The requirement to operate a PM CEM under any provision of this Paragraph shall terminate if and when the Unit monitored by the PM CEM is Re-Powered.

H. Testing and Reporting Requirement. Prior to installation of the PM CEM on each duct, Tampa Electric shall conduct a stack test on each stack at Big Bend on at least an annual basis and report its results to EPA as part of the quarterly report under Section V. The stack test requirement in this Subparagraph may be satisfied by Tampa Electric's annual stack tests conducted as required by its permit from the State of Florida. Following installation of each PM CEM, Defendant shall include in its quarterly reports to EPA pursuant to Section V all data recorded by the PM CEM, in electronic format, if available.

I. Nothing in this Consent Decree is intended to nor shall alter applicable law concerning the use of data, for any purpose under the Clean Air Act, generated by the PM CEMs.

33. Election for Big Bend Unit 4: Shutdown, Re-Power, or Continued Combustion of Coal. Tampa Electric shall advise EPA in writing, on or before May 1, 2005, whether Big Bend Unit 4 will be Shutdown, will be Re-Powered, or will continue to be fired by coal.

34. Reduction of NO_x at Big Bend Unit 4 after 2005 Election. Based on Tampa Electric's election in Paragraph 33, Tampa Electric shall take one of the following actions:

7.

8. If Tampa Electric elects to continue firing Unit 4 with coal, on or before June 1, 2007, Tampa Electric shall install and commence operation of SCR, or other technology if approved in writing by EPA in advance, sufficient to limit the coal-fired Emission Rate of NO_x from Unit 4 to no more than 0.10 lb/mmBTU. Thereafter, Tampa Electric shall continue operation of SCR or other EPA approved control technology, and Tampa Electric shall continue to meet an Emission Rate for NO_x from Unit 4 no greater than 0.10 lb/mmBTU; or

A. If Tampa Electric elects to Re-Power Unit 4, Tampa Electric shall not combust coal at Unit 4 on or after June 1, 2007. Tampa Electric shall timely apply for a preconstruction permit under Rule 62-212, F.A.C., prior to commencing construction of the Re-Powering of Unit 4. In applying for such permit, Tampa Electric shall seek, as part of the permit, provisions requiring installation of SCR or other EPA approved control technology and a NO_x Emission Rate no greater than 3.5 ppm. Tampa Electric shall operate the Re-Powered Unit 4 to meet an Emission Rate for NO_x of no greater than 3.5 ppm or the rate established in the preconstruction permit, whichever is more stringent; or

A. If Tampa Electric elects to Shutdown Big Bend Unit 4, Tampa Electric shall complete Shutdown of Big Bend Unit 4 on or before June 1, 2007. Notwithstanding the requirements of this Subparagraph, Tampa Electric may retain this Unit, after it is Shutdown pursuant to this Subparagraph, on Reserve / Standby. If Tampa Electric later decides to restart Unit 4 then, prior to such restart, Tampa Electric shall timely apply for a PSD permit, and Tampa Electric shall abide by the permit issued as a result of that application, including installation of BACT and its corresponding Emission Rate, as determined at the time of the restart. Tampa Electric shall operate the Re-Powered Unit 4 to meet an Emission Rate for NO_x of no greater than 3.5 ppm or the Emission Rate established in the PSD permit, whichever is more stringent. Tampa Electric shall provide a copy of any permit application(s), proposed permit(s), and permit(s) to the United States as specified in Paragraph 82 (Notice). Upon Shutdown of a Unit under this Subparagraph, Tampa Electric may never again use coal to fire that Unit.

A. Notwithstanding the provisions of Subparagraphs B and C above or the definition of Re-Power in this Consent Decree, Tampa Electric may also elect to fuel Big Bend Unit 4 with a gaseous fuel other than or in addition to natural gas, if and only if Tampa Electric applies for and secures a PSD permit before using such fuel in this Unit, complies with all requirements issued in such a permit, and complies with all requirements of this Consent Decree applicable to Re-Powering.

35. <u>Early Reductions of NO_x from Big Bend Units 1 through 3</u>: On or before

December 31, 2001, Tampa Electric shall submit to EPA for review and comment a plan to reduce NO_x emissions from Big Bend Units 1, 2 and 3, through the expenditure of up to $3 million Project Dollars on combustion optimization using commercially available methods, techniques, systems, or equipment, or combinations thereof. Subject only to the financial limit stated in the previous sentence, for Units 1 and 2 the goal of the combustion optimization shall be to reduce the NO_x Emission Rate by at least 30% when compared against the NO_x Emissions Rate for these Units during calendar year 1998, which the United States and Tampa Electric agree was 0.86 lb/mmBTU. For Unit 3 the goal of the combustion optimization shall be to reduce the NO_x Emissions Rate by at least 15% when compared against the NO_x Emission Rate for this Unit during calendar year 1998, which the United States and Tampa Electric agree was 0.57 lb/mmBTU. If the financial limit in this Paragraph precludes designing and installing combustion controls that will meet the percentage reduction goals for the NO_x Emission Rates specified in this Paragraph for all three Units, then Tampa Electric's plan shall first maximize the Emission Rate reductions at Units 1 and 2 and then at Unit 3. Unless the United States has sought dispute resolution on Tampa Electric's plan on or before May 30, 2002, Tampa Electric shall implement all aspects of its plan at Big Bend Units 1, 2, and 3 on or before December 31, 2002. On or before April 1, 2003, Tampa Electric shall submit to EPA a report that documents the date(s) of complete implementation of the plan, the results obtained from implementing the plan, including the emission reductions or benefits achieved, and the Project Dollars expended by Tampa Electric in implementing the plan.

36. Election for Big Bend Units 1 through 3: Shutdown. Re-Power. or Continued Combustion of Coal. Tampa Electric shall advise EPA in writing, on or before May 1, 2007, whether Big Bend Units 1, 2, or 3, or any combination of them, will be Shutdown, will be Re-Powered, or will continue to be fired by coal.

37. Further NO_x Reduction Requirements if Big Bend Units 1. 2. and/or 3 Remain Coal-fired. If Tampa Electric advises EPA in writing, pursuant to Paragraph 36, above, that Tampa Electric will continue to combust coal at Units 1, 2, and/or 3, then:

A. Subject only to Subparagraphs B and D, Tampa Electric shall timely solicit contract proposals to acquire, install, and operate SCR, or other technology if approved in writing by EPA in advance, sufficient to limit the Emission Rate of NO_x to no more than 0.10 lb/mmBTU at each Unit that will combust coal. Tampa Electric shall install and operate such equipment on all Units that will continue to combust coal and shall achieve an Emission Rate of NO_x on each such Unit no less stringent than 0.10 lb/mmBTU.

A. Notwithstanding .Subparagraph A, Tampa Electric shall not be required to install SCR to limit the Emission Rate of NO_x at Units 1, 2 and/or 3 to 0.10 lb/mmBTU if the "installation cost ceiling" contained in this Paragraph will be exceeded by such installation. If Tampa Electric decides to continue burning coal at Units 1, 2 and 3, the installation cost ceiling for SCR at Units 1, 2, and 3 shall be three times the cost of installing SCR at Big Bend Unit 4 plus forty-five (45%) percent of the cost of installing SCR at Big Bend 4. If Tampa Electric decides to continue burning coal at only two Units at Big Bend, the installation cost ceiling for SCR at those two Units shall be two times the cost of installing SCR at Big Bend 4 plus forty-five (45) percent of the cost of installing SCR at Big Bend Unit 4. If Tampa Electric decides to continue burning coal at only one Unit at Big Bend, the installation cost ceiling for SCR at that Unit shall be the cost of installing SCR at Big Bend 4 plus forty five (45) percent.

A. If, based on the contract proposals obtained under Subparagraph A, Tampa Electric determines that the projected cost of proposed control equipment satisfying a 0.10 lb/mmBTU Emission Rate will not exceed the "installation cost ceiling," Tampa Electric shall install and operate such equipment on all Units that will continue to combust coal and shall achieve a NO_x Emission Rate on each Unit no less stringent than 0.10 lb/mmBTU. If, based on the contract proposals, Tampa Electric determines that the projected cost will exceed the installation cost ceiling, Tampa Electric shall so advise EPA and shall provide EPA with the basis for Tampa Electric's determination, including all documentation sufficient to replicate and evaluate Tampa Electric's cost projections.

A. Unless EPA contests Tampa Electric's determination that the installation cost ceiling will be exceeded by installing control equipment to reduce NO_x emissions to 0.10

lb/mmBTU or less, Tampa Electric shall install, at each Unit that will continue to combust coal, the NO_x control technology designed to achieve the lowest Emission Rate that can be attained within the "installation cost ceiling." Notwithstanding any provision of this Consent Decree, including the "installation cost ceiling," Tampa Electric shall install NO_x control technology that is designed to achieve an Emission Rate no less stringent than 0.15 lb/mmBTU. Each Unit combusting coal and its NO_x controls shall meet the Emission Rate for which they are designed.

A. Tampa Electric shall acquire, install, commence operating emission control equipment, and meet the applicable Emission Rate for NO_x at each of the Units to remain coal-fired, as follows: (1) for the first of the Units to remain coal-fired, or if only one Unit is to be coal-fired, on or before May 1, 2008; (2) for the second Unit, if there is one, on or before May 1, 2009; (3) for the third Unit, if there is one, on or before May 1, 2010.

38. Tampa Electric's NO_x Reduction Requirements if Tampa Electric Re-Powers Units 1, 2, and/or 3 . If, by May 1, 2007, Tampa Electric advises EPA that Tampa Electric has elected to Re-Power one or more of Units 1, 2, and 3 at Big Bend, then Tampa Electric shall complete all steps necessary to accomplish such Re-Powering in a time frame to commence operation of the Re-Powered Unit(s) no later than May 1, 2010. Any Unit(s) to be replaced by a Re-Powered Unit may continue to operate until the earlier of six months after the date the Re-Powered

Unit begins commercial operation or December 31, 2010. Tampa Electric shall timely apply for a preconstruction permit under Rule 62-212, F.A.C., prior to commencing construction of any Re-Powered Unit at Big Bend. In applying for such permit Tampa Electric shall seek, as part of the permit, provisions requiring installation of SCR or other EPA approved control technology and a NO_x Emission Rate no greater than 3.5 ppm. Tampa Electric shall operate any Unit Re-Powered under this Paragraph to meet an Emission Rate for NO_x of no greater than 3.5 ppm or the rate established in the preconstruction permit, whichever is more stringent. Notwithstanding the provisions of this Paragraph or the definition of Re-Power in this Consent Decree, Tampa Electric may also elect to fuel Units 1, 2, or 3 with a gaseous fuel other than or in addition to natural gas, if and only if Tampa Electric applies for and secures a PSD permit before using such fuel in any of these Units, complies with all requirements issued in such a permit, and complies with all requirements of this Consent Decree applicable to Re-Powering.

39. Requirements Applicable to Big Bend Units 1, 2, and/or 3 if Shutdown. If Tampa Electric elects to Shutdown one or more of Units1, 2, and 3, Tampa Electric shall complete Shutdown of the first such Unit on or before May 1, 2008; of the second Unit, if applicable, on or before May 1, 2009, and of the third Unit, if applicable, on or before May 1, 2010. Notwithstanding the requirements of this Paragraph, Tampa Electric may retain any Unit Shutdown pursuant to this Paragraph on

Reserve / Standby. If Tampa Electric later decides to restart such Unit retained on Reserve / Standby by Re-Powering it then, prior to such restart, Tampa Electric shall timely apply for a PSD permit for the Unit(s) to be Re-Powered, and Tampa Electric shall abide by the permit issued as result of that application, including installation of BACT and its corresponding Emission Rate determined at the time of the restart. Tampa Electric shall operate each Unit Re-Powered under this Paragraph to meet an Emission Rate for NO_x of no greater than 3.5 ppm or the Emission Rate established in the PSD permit, whichever is more stringent. Tampa Electric shall provide a copy of any permit application(s), proposed permit(s), and permit(s) to the United States as specified in Paragraph 82 (Notice). Upon Shutdown of a Unit under this Paragraph, Tampa Electric may never again use coal to fire that Unit. For any Unit Shutdown and placed on on Reserve / Standby under this Paragraph, and notwithstanding the definition of Re-Power in this Consent Decree, Tampa Electric also may elect to fuel such a Unit with a gaseous fuel other than or in addition to natural gas, if and only if Tampa Electric: applies for and secures a PSD permit before using such fuel in any of such Unit, complies with all requirements issued in such a permit, and complies with all requirements of this Consent Decree applicable to Re-Powering.

40. <u>Further SO_2 Reduction Requirements if Big Bend Units 1, 2, or 3 Remains Coal-fired</u>. If Tampa Electric elects under Paragraph 36 to continue combusting coal at Units 1, 2, and/or 3, Tampa Electric shall meet the following requirements.

A. Removal Efficiency or Emission Rate. Commencing on dates set forth in Subparagraph C and continuing thereafter, Tampa Electric shall operate coal-fired Units and the scrubbers that serve those Units so that emissions from the Units shall meet at least one of the following limits:

(1) the scrubber shall remove at least 95% of the SO_2 in the flue gas that entered the scrubber; or

(2) the Emission Rate for SO_2 from each Unit does not exceed 0.25 lb/mmBTU.

A. Availability Criteria. Commencing on the deadlines set in this Paragraph and continuing thereafter, Tampa Electric shall not allow emissions of SO_2 from Big Bend Units 1, 2, or 3 without scrubbing the flue gas from those Units and using other equipment designed to control SO_2 emissions. Notwithstanding the preceding sentence, to the extent that the Clean Air Act New Source Performance Standards identify circumstances during which Bend Unit 4 may operate without its scrubber, this Consent Decree shall allow Big Bend Units1, 2, and/or 3 to operate when those same circumstances are present at Big Bend Units 1, 2, and/or 3.

A. Deadlines. Big Bend Unit 3 and the scrubber(s) serving it shall be subject to the requirements of this Paragraph beginning January 1, 2010 and continuing thereafter. Until January 1, 2010, Tampa Electric shall control $S0_2$ emissions from Unit 3 as required by Paragraphs 30 and 31. Big Bend Units 1 and 2 and the scrubber(s) serving them shall be subject to the requirements of this Paragraph beginning January 1, 2013 and continuing thereafter. Until January 1, 2013, Tampa Electric shall control SO_2 emissions from Units 1 and 2 as required by Paragraphs 29 and 31.

A. Nothing in this Consent Decree shall alter requirements of NSPS, 40 C.F.R. Part 60 Subpart Da, that apply to operation of Unit 4 and the scrubber serving it.

C. BIG BEND AND GANNON -- PERMITS AND RESOLUTION OF CLAIMS

41. Timely Application for Permits. Except as otherwise stated in this Consent Decree, in any instance where otherwise applicable law or this Consent Decree requires Tampa Electric to secure a permit to authorize constructing or operating any device under this Consent Decree, Tampa Electric shall make such application in a timely manner. Such applications shall be completed and submitted to the appropriate authorities to allow sufficient time for all legally required processing and review of the permit request. Failure to comply with this provision shall bar any use by Tampa Electric of the Force Majeure provisions of this Consent Decree.

42. Title V Permits.

A.

B. On or before January 1, 2004, Tampa Electric shall apply for a Title V Permit(s), or for an amendment to an existing Title V Permit(s), to include all performance, operational, maintenance, and control technology requirements established by or determined under this Consent Decree for Gannon, including but not limited to Emission Rates, removal efficiencies, limits on fuel use (including those imposed on Re-Powered or Shutdown Units), and operation and maintenance optimization requirements.

A. On or before January 1, 2009, Tampa Electric shall apply for a Title V Permit(s), or for an amendment to an existing Title V Permit(s), to include all performance, operational, maintenance, and control technology requirements established by or determined under this Consent Decree for Big Bend, including but not limited to Emission Rates, removal efficiencies, limits on fuel use (including those imposed on Re-Powered or Shutdown Units), and operation and maintenance optimization requirements.

A. Except as this Consent Decree expressly requires otherwise, this Consent Decree shall not be construed to require Tampa Electric to apply for or obtain a permit pursuant to the Prevention of Significant Deterioration requirements of the Clean Air Act for any work performed by Tampa Electric within the scope of the Resolution of Claims provisions of Paragraphs 43 and 44, below.

43. Resolution of Past Claims - This Consent Decree resolves all of Plaintiff's civil claims for liability arising from violations of either: (1) the Prevention of Significant Deterioration or Non-Attainment provisions of Parts C and D of the Clean Air Act, 42 U.S.C. § 7401, et seq at Units at Big Bend or Gannon, or (2) 40 C.F.R. Section 60.14 at Units at Big Bend or Gannon, that :

A.

B. are alleged in the Complaint filed November 3, 1999, or in the NOV issued on that date;

A. could have been alleged by the United States in the Complaint filed November 3, 1999, or in the NOV issued on that date; or

A. have arisen from Tampa Electric's actions that occurred between November 3, 1999 and the date on which this Consent Decree is entered by the Court.

44. Resolution of Future Claims - Covenant not to Sue. The United States covenants not to sue Tampa Electric for civil claims arising from the Prevention of Significant Deterioration or Non-Attainment provisions of Parts C and D of the Clean Air Act, 42 U.S.C. § 7401 et seq., at Big Bend or Gannon Units and that are based on failure to obtain PSD or nonattainment New Source Review (NSR) permits for:

A. work that this Consent Decree expressly directs Tampa Electric to undertake; or

A. physical changes or changes in the method of operation of Big Bend or Gannon Units not required by this Consent Decree, if and only if:

A.

B. such change is commenced after Tampa Electric is implementing the plan, or the first phase of the plan if applicable, approved by EPA under Paragraph 31 (Optimizing Availability of Scrubbers),

1. such change is commenced, within the meaning of 40 C.F.R. Section 52.21(b)(9),

during the time this Consent Decree applies to the Unit at which this change has been made ;

(3) Tampa Electric is otherwise in compliance with this Consent Decree;

(4) hourly Emission Rates of NO_x, SO_2, or PM at the changed Unit(s) do not exceed their respective hourly Emission Rates prior to the change, as measured by 40 C.F.R. § 60.14(h); and

(5) in any calendar year following the change, emissions of no pollutant within the scope of Total Baseline Emissions exceed the emissions of that pollutant in the Total Baseline Emissions.

45. Separate Limitation on Resolution of Claims. Notwithstanding the provisions of Section XIII ("Termination"), the provisions of Paragraph 44 ("Resolution of Future Claims - Covenant Not to Sue") shall terminate at Gannon and Big Bend, as follows. On December 31, 2006, the provisions of Paragraph 44 shall terminate and be of no further effect as to physical changes or changes in the method of operation at Gannon. On December 31, 2012, the provisions of Paragraph 44 shall terminate and be of no further effect as to physical changes or changes in the method of operation at Big Bend. If Tampa Electric Re-Powers any Unit at Big Bend under the terms provided by this Consent Decree, then for each such Unit the provisions of Paragraph 44 shall terminate two years after each such Unit is Re-Powered or on December 31, 2012, whichever is earlier.

46. Exclusion of Certain Emission Allowances. For any and all actions taken by Tampa Electric pursuant to the terms of this Consent Decree, including but not limited to upgrading of ESPs and scrubbers, installation of NO_x controls, Re-Powering, and Shutdown, Tampa Electric shall not use or sell any resulting NO_x or SO_2 emission allowances or credits in any emission trading or marketing program of any kind; provided, however, that:

A. SO_2 credits allocated to Tampa Electric by the Administrator of EPA under the Act, due to the Re-Powering or Shutdown of Gannon, may be retained by Tampa Electric during the year in which they are allocated, but only for Tampa Electric's own use in meeting any acid rain requirement imposed under the Act. For any such allowances not used by Tampa Electric for this purpose by June 30 of the following calendar year, Tampa Electric shall not use, sell, trade, or otherwise transfer these allowances for its benefit or the benefit of a third party unless such a transfer would result in the retiring of such allowances without their ever being used.

A. If Tampa Electric decides to Re-Power any Unit at Big Bend, then Tampa Electric shall be entitled to retain for any purpose under law the difference between the emission allowances that would have resulted from installing BACT- level NO_x and SO_2 controls at the existing coal-fired Unit and the emission allowances that result from Re-Powering that Unit. Before Tampa Electric uses any allowances within the scope of this Subparagraph, Tampa Electric shall submit the calculation of the net emission allowances for approval by the United States.

A. Nothing in this Consent Decree shall preclude Tampa Electric from using or selling emission allowances arising from Tampa Electric's activities occurring prior to December 31, 1999, or Tampa Electric's activities after that date that are not related to actions required of Tampa Electric under this Consent Decree. The United States and Tampa Electric agree that the operation of the SO_2 scrubber serving Big Bend Units 1 and 2 meets the requirements of this Subparagraph, and that emission allowances resulting from the operation of this scrubber shall not be treated as an activity related to or required under this Consent Decree.

V. REPORTING AND RECORD KEEPING

47. Beginning at the end of the first calendar quarter after entry of this Consent Decree, and in addition to any other express reporting requirement in this Consent Decree, Tampa Electric shall submit to EPA a quarterly report, consistent with the form attached to this Consent Decree as the Appendix, within thirty (30) days after the end of each calendar quarter until this Consent Decree is terminated.

48. Tampa Electric's report shall be signed by Tampa Electric's Vice President, Environmental and Fuels, or, in his or her absence, Vice President, Energy Supply, or higher ranking official, and shall contain the following certification:

> I certify under penalty of law that this information was prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my directions and my inquiry of the person(s) who manage the system, or the person(s) directly responsible for gathering the information, the information submitted is, to the best of my knowledge and belief, true, accurate, and complete. I understand that there are significant penalties for making misrepresentations to

or misleading the United States.

VI. CIVIL PENALTY

49. Within thirty (30) calendar days of entry of this Consent Decree, Tampa Electric shall pay to the United States a civil penalty in the amount of $3.5 million. The civil penalty shall be paid by Electronic Funds Transfer ("EFT") to the United States Department of Justice, in accordance with current EFT procedures, referencing the USAO File Number and DOJ Case Number 90-5-2-1-06932 and the civil action case name and case number of this action. The costs of such EFT shall be Tampa Electric's responsibility. Payment shall be made in accordance with instructions provided by the Financial Litigation Unit of the U.S. Attorney's Office for the Middle District of Florida. Any funds received after 11:00 a.m. (EST) shall be credited on the next business day. Tampa Electric shall provide notice of payment, referencing the USAO File Number, DOJ Case Number 90-5-2-1- 06932, and the civil action case name and case number, to the Department of Justice and to EPA, as provided in Paragraph 82 (Notice). Failure to timely pay the civil penalty shall subject Tampa Electric to interest accruing from the date payment is due until the date payment is made at the rate prescribed by 28 U.S.C. § 1961, and shall render Tampa Electric liable for all charges, costs, fees, and penalties established by law for the benefit of a creditor or of the United States in securing payment.

VII. NO_x REDUCTION PROJECTS AND MITIGATION PROJECTS

50. Tampa Electric shall submit plans for and shall implement the NO_x Reduction and Other Mitigation Projects (referred to together as "Projects") described in this Section, and in Paragraph 35 of this Consent Decree, in compliance with the schedules and terms of this Consent Decree. In performing these Projects, Tampa Electric shall spend no less than $10 million in Project Dollars, in total, unless the Additional NO_x Reduction Project(s) selected under Paragraph 52.C is estimated to cost more than $5 million, in which case Tampa Electric shall spend no less than $10 million but no more than $11 million in Project Dollars, in total. Tampa Electric shall expend the full amount of the Project Dollars required by this Paragraph on or before May 1, 2010. Tampa Electric shall maintain for review by EPA, upon its request, all documents identifying Project Dollars spent by Tampa Electric.

51. All plans and reports prepared by Tampa Electric pursuant to the requirements of Paragraph 35 and this Section of the Consent Decree shall be publicly available without charge.

52. Tampa Electric shall submit the required plans for and complete the following Projects:

(1)

(2) Early NO_x reductions through combustion optimization as described in Paragraph 35 of this Consent Decree.

(A) Performance of Air Chemistry Work in Tampa Bay Estuary. Tampa Electric shall expend no more than $2 million Project Dollars in conducting or financing stack tests, emissions estimation, ambient air monitoring, data acquisition and analysis, and any combination thereof that: (1) is not otherwise required by law, (2) will provide data or analysis that is not already available, (3) will complement work carried out by other persons examining the air chemistry of Tampa Bay Estuary, and (4) will help close gaps in current understanding of air chemistry in the Tampa Bay Estuary. Tampa Electric shall either conduct this work itself, fund other persons already conducting such work on a non-profit basis, or both. For work Tampa Electric intends to conduct itself, the company shall describe the proposed work and a schedule for completion to EPA, in writing, at least 90 days prior to the date on which Tampa Electric intends to start such work, including an explanation of why the proposed work meets all the requirements of this Subparagraph. Unless EPA objects to the proposed work on the grounds it does not comply with the requirements of this Subparagraph, Tampa Electric shall undertake and complete the work according to the proposed schedule. If Tampa Electric elects to spend some or all of the $2 million Project Dollars to finance work to be performed by other persons or organizations, the company shall provide to EPA for review and approval a plan that describes the work to be performed, the persons or organizations conducting the work, the schedule for its completion, the schedule for Tampa Electric's payments, and an explanation of why the proposed payment(s) meets all the requirements of this Subparagraph. The plan shall be provided to EPA at least 90 days prior to the date on which Tampa Electric will begin transferring the money to finance such work. All payments to persons or organizations under such a plan shall be completed by Tampa Electric no later than June 30, 2002. Before Tampa Electric makes such payments for the benefit of any person or organization carrying out work under this Paragraph, Tampa Electric shall secure a written, signed commitment from such person to provide Tampa Electric and EPA with the results of the work.

C. Additional NO_x Reductions Project(s).

(1) General Requirement. Tampa Electric shall expend the remainder of the Project Dollars required under this Consent Decree to: (i) demonstrate innovative NO_x control technologies on any of its Units or boilers at Gannon or Big Bend not Shutdown or on Reserve / Standby; and/or (ii) reduce the NO_x Emission Rate for any Big Bend coal-combusting Unit below the lowest rate otherwise applicable to it under this Consent Decree.

(1) For any Project(s) at Gannon. If Tampa Electric elects to undertake a project on an eligible Gannon Unit(s) to demonstrate any innovative NO_x control technology, within six months after entry of this Consent Decree Tampa Electric shall submit a plan to EPA, for review and approval, which sets forth: (a) the NO_x demonstration or innovative control technology projects being proposed; (b) the anticipated cost of the projects; (c) the reduction in NO_x or other environmental benefits anticipated to result from the project, and (d) a schedule for implementation of the project providing for

commencement and completion in accordance with the requirements of this Subparagraph. . EPA shall complete its review of this plan within 60 days after receipt. If such project is approved, Tampa Electric shall complete installation of the technology no later than December 31, 2004 as part of the Re-Powering of such Units; provided, however, that nothing in this Paragraph alters Tampa Electric's obligation under Paragraph 26 of this Consent Decree.

(1) For any Project(s) at Big Bend. At least three (3) years prior to the date on which the expenditure of any Project Dollars is to commence on Big Bend under this Subparagraph C, Tampa Electric shall submit a plan to EPA for review and approval which sets forth: (a) the NO_x demonstration or innovative control technology projects being proposed; (b) the anticipated cost of the projects; (c) the reduction in NO_x or other environmental benefits anticipated to result from the project, and (d) a schedule for implementation of the project providing for commencement and completion in accordance with the requirements of this Subparagraph. If EPA approves the projects contained in the plan, Tampa Electric shall implement the project(s). Projects that would demonstrate innovative NO_x control technology or reduce the NO_x Emission Rate for any Big Bend coal-fired or Re-Powered Unit shall be operating and achieving reductions or demonstrating the performance of the innovative technology, as applicable, not later than May 1, 2010.

(1) Follow-up Report(s). Within sixty (60) days following the implementation of each EPA-approved project, Tampa Electric shall submit to EPA a report that documents the date that all aspects of the project were implemented, Tampa Electric's results in implementing the project, including the emission reductions or other environmental benefits achieved, and the Project Dollars expended by Tampa Electric in implementing the project.

VIII. STIPULATED PENALTIES

53. For purposes of this Consent Decree, within thirty days after written demand from the United States, and subject to the provisions of Sections X (Force Majeure) and XI (Dispute Resolution), Tampa Electric shall pay the following stipulated penalties to the United States for each failure by Tampa Electric to comply with the terms of this Consent Decree.

A. For failure to pay timely the civil penalty as specified in Section VI of this Consent Decree, $10,000 per day.

A. For all violations of a 24 hour Emission Rate – (1) Less than 5% in excess of limit: $4,000 per day, per violation; (2) more than 5% but less than 10% in excess of limit: $9,000 per day per violation; (3) equal to or greater than 10% in excess of limit: $27,500 per day, per violation

A. For all violations of 30-day rolling average Emission Rates – (1) Less than 5% in excess of limit: $150 per day per violation; (2) more than 5% but less than 10% in excess of limit: $300 per day per violation; (3) equal to or greater than 10% in excess of limit: $800 per day per violation. Violation of an Emission Rate that is based on a 30 day rolling average is a violation on every day of the 30 day period on which the average is based . Where a violation of a 30 day rolling monthly average Emission Rate (for the same pollutant and from the same source) recurs within periods less than 30 days, Tampa Electric shall not pay a daily stipulated penalty for any day of the recurrence for which a stipulated penalty has already been paid.

A. For all violations of a 95% removal efficiency requirement – (1) For removal efficiency less than 95% but greater than or equal to 94%, $4,000 per day, per violation; (2) for removal efficiency less than 94% but greater than or equal to 91%, $9,000 per day, per violation; (3) for removal efficiency less than 91%, $27,500 per day, per violation. For all violations of a 93% removal efficiency requirement – (1) For removal efficiency less than 93% but greater than or equal to 92%, $4,000 per day, per violation; (2) for removal efficiency less than 92% but greater than or equal to 90%, $9,000 per day, per violation; (3) for removal efficiency less than 90%, $27,500 per day, per violation;

A. Violation of deadlines for Shutdown of boilers or Units or megawatt capacity — $27,500 per day, per violation.

A. Failure to apply for the permits required by Paragraphs 26, 27, 34, 38, and

42 — $1,000 per day, per violation.

A. Failure to implement the recommendations of the PM BACT Analysis or the PM optimization study by May 1, 2004 — $5,000 per day, per violation for first 30 days; $15,000 per day, per violation, for next 30 days; $27,500 per day, per violation, thereafter.

A. Failure to commence combustion optimization at Big Bend Units 1, 2, or 3 on or before May 30, 2003 as required by Paragraph 35, $10,000 per day, per violation.

A. Failure to operate the scrubbers at Big Bend Units 1, 2, or 3 on any day except as permitted by Paragraphs 29, 30, or 31, $27,500 per day, per violation.

A. Failure to submit quarterly progress and monitoring report — $100 per day, per violation, for first ten days late, and $500 per day for each day thereafter.

A. Failure to complete timely any action or payment required by or established under Subparagraph 52(B) (Performance of Air Chemistry Work in Tampa Bay Estuary), $5,000 per day, per violation

A. Failure to perform NO_x reduction or demonstration project(s), by the deadline(s) established in Subparagraph 52.C (Additional NO_x Reductions Project(s)), $10,000 per day, per violation;

A. For failure to spend at least the number of Project Dollars required by this Consent Decree by date specified in Paragraph 50, $5,000 per day, per violation;

A. Violation of any Consent Decree prohibition on use of allowances as provided in Paragraph 46 — three times the market value of the improperly used allowance as measured at the time of the improper use.

54. Should Tampa Electric dispute its obligation to pay part or all of a stipulated penalty demanded by the United States, it may avoid the imposition of a separate stipulated penalty for the failure to pay the disputed penalty by depositing the disputed amount in a commercial escrow account pending resolution of the matter and by invoking the Dispute Resolution provisions of this Consent Decree within the time provided in this Section VIII of the Consent Decree for payment of the disputed penalty. If the dispute is thereafter resolved in Tampa Electric's favor, the escrowed amount plus accrued interest shall be returned to Tampa Electric. If the dispute is resolved in favor of the United States, it shall be entitled to the escrowed amount determined to be due by the Court, plus accrued interest. The balance in the escrow account, if any, shall be returned to Tampa Electric.

55. The United States reserves the right to pursue any other remedies to which it is entitled, including, but not limited to, a new civil enforcement action and additional injunctive relief for Tampa Electric's violations of this Consent Decree. If the United States elects to seek civil or contempt penalties after having collected stipulated penalties for the same violation, any further penalty awarded shall be reduced by the amount of the stipulated penalty timely paid or escrowed by Tampa Electric. Tampa Electric shall not be required

to remit any stipulated penalty to the United States that is disputed in compliance with

Part XI of this Consent Decree until the dispute is resolved in favor of the United

States. However, nothing in this Paragraph shall be construed to cease the accrual of the stipulated penalties until the dispute is resolved.

IX. RIGHT OF ENTRY

56. Any authorized representative of EPA or an appropriate state agency, including independent contractors, upon presentation of credentials, shall have a right of entry upon the premises of Tampa Electric's plants identified herein at any reasonable time for the purpose of monitoring compliance with the provisions of this Consent Decree, including inspecting plant equipment and inspecting and copying all records maintained by Tampa Electric required by this Consent Decree. Tampa Electric shall retain such records for a period of twelve (12) years from the date of entry of this Consent Decree. Nothing in this Consent Decree shall limit the authority of EPA to conduct tests and inspections at Tampa Electric's facilities under Section 114 of the Act, 42 U.S.C. § 7414.

X. FORCE MAJEURE

57. If any event occurs which causes or may cause a delay in complying with any provision of this Consent Decree, Tampa Electric shall notify the United States in writing as soon as practicable, but in no event later than seven (7) business days following the date Tampa Electric first knew, or within ten (10) business days following the date Tampa Electric should have known by the exercise of due

diligence, that the event caused or may cause such delay. In this notice Tampa Electric shall reference this Paragraph of this Consent Decree and describe the anticipated length of time the delay may persist, the cause or causes of the delay, the measures taken or to be taken by Tampa Electric to prevent or minimize the delay, and the schedule by which those measures will be implemented. Tampa Electric shall adopt all reasonable measures to avoid or minimize such delays.

58. Failure by Tampa Electric to comply with the notice requirements of Paragraph 57 shall render this Section X voidable by the United States as to the specific event for which Tampa Electric has failed to comply with such notice requirement. If voided, the provisions of this Section shall have no effect as to the particular event involved.

59. The United States shall notify Tampa Electric in writing regarding Tampa Electric's claim of a delay in performance within (15) fifteen business days of receipt of the Force Majeure notice provided under Paragraph 57. If the United States agrees that the delay in performance has been or will be caused by circumstances beyond the control of Tampa Electric, including any entity controlled by Tampa Electric, and that Tampa Electric could not have prevented the delay through the exercise of due diligence, the parties shall stipulate to an extension of the required deadline(s) for all requirement(s) affected by the delay for a period equivalent to the delay actually caused by such circumstances. Such stipulation shall be filed as a modification to this Consent Decree in order to be

effective. Tampa Electric shall not be liable for stipulated penalties for the period of any such delay.

60. If the United States does not accept Tampa Electric's claim of a delay in performance, to avoid the imposition of stipulated penalties Tampa Electric must submit the matter to this Court for resolution by filing a petition for determination. Once Tampa Electric has submitted the matter, the United States shall have fifteen business days to file its response. If Tampa Electric submits the matter to this Court for resolution, and the Court determines that the delay in performance has been or will be caused by circumstances beyond the control of Tampa Electric, including any entity controlled by Tampa Electric, and that Tampa Electric could not have prevented the delay by the exercise of due diligence, Tampa Electric shall be excused as to that event(s) and delay (including stipulated penalties otherwise applicable), but only for the period of time equivalent to the delay caused by such circumstances.

61. Tampa Electric shall bear the burden of proving that any delay in performance of any requirement of this Consent Decree was caused by or will be caused by circumstances beyond its control, including any entity controlled by it, and that Tampa Electric could not have prevented the delay by the exercise of due diligence. Tampa Electric shall also bear the burden of proving the duration and extent of any delay(s) attributable to such circumstances. An extension of one compliance date based on a particular event may, but will not necessarily, result in

an extension of a subsequent compliance date.

62. Unanticipated or increased costs or expenses associated with the performance of Tampa Electric's obligations under this Consent Decree shall not constitute circumstances beyond the control of Tampa Electric or serve as a basis for an extension of time under this Section. However, failure of a permitting authority to issue a necessary permit in a timely fashion may constitute a Force Majeure event where the failure of the permitting authority to act is beyond the control of Tampa Electric and Tampa Electric has taken all steps available to it to obtain the necessary permit, including, but not limited to, submitting a complete permit application, responding to requests for additional information by the permitting authority in a timely fashion, accepting lawful permit terms and conditions, and prosecuting appeals of any allegedly unlawful terms and conditions imposed by the permitting authority in an expeditious fashion.

63. The parties agree that, depending upon the circumstances related to an event and Tampa Electric's response to such circumstances, the kinds of events listed below could also qualify as Force Majeure events within the meaning of this Section X of the Consent Decree: Construction, labor, or equipment delays; natural gas and gas transportation availability delays;acts of God; and the failure of an innovative technology approved under Paragraph 26.B and 52.C.

64. Notwithstanding any other provision of this Consent Decree, this Court shall not draw any inferences nor establish any presumptions adverse to either party as a

result of Tampa Electric delivering a notice pursuant to this Section or the parties' inability to reach agreement on a dispute under this Part.

65. As part of the resolution of any matter submitted to this Court under this Section, the parties by agreement, or this Court by order, may in appropriate circumstances extend or modify the schedule for completion of work under this Consent Decree to account for the delay in the work that occurred as a result of any delay agreed to by the United States or approved by this Court. Tampa Electric shall be liable for stipulated penalties for its failure thereafter to complete the work in accordance with the extended or modified schedule.

XI. DISPUTE RESOLUTION

66. The dispute resolution procedure provided by this Section XI shall be available to resolve all disputes arising under this Consent Decree, except as provided in Section X regarding Force Majeure, or in this Section XI, provided that the party making such application has made a good faith attempt to resolve the matter with the other party.

67. The dispute resolution procedure required herein shall be invoked by one party to this Consent Decree giving written notice to another advising of a dispute pursuant to this Section XI. The notice shall describe the nature of the dispute and shall state the noticing party's position with regard to such dispute. The party receiving such a notice shall acknowledge receipt of the notice, and the parties

shall expeditiously schedule a meeting to discuss the dispute informally not later than fourteen (14) days following receipt of such notice.

68. Disputes submitted to dispute resolution under this Section shall, in the first instance, be the subject of informal negotiations between the parties. Such period of informal negotiations shall not extend beyond thirty (30) calendar days from the date of the first meeting between representatives of the United States and Tampa Electric unless the parties' representatives agree to shorten or extend this period.

69. If the parties are unable to reach agreement during the informal negotiation period, the United States shall provide Tampa Electric with a written summary of its position regarding the dispute. The written position provided by the United States shall be considered binding unless, within thirty (30) calendar days thereafter, Tampa Electric files with this Court a petition which describes the nature of the dispute and seeks resolution. The United States may respond to the petition within forty-five (45) calendar days of filing.

70. Where the nature of the dispute is such that a more timely resolution of the issue is required, the time periods set out in this Section may be shortened upon motion of one of the parties to the dispute.

71. This Court shall not draw any inferences nor establish any presumptions adverse to either party as a result of invocation of this Section or the parties' inability to reach agreement.

72. As part of the resolution of any dispute under this Section, in appropriate circumstances the parties may agree, or this Court may order, an extension or modification of the schedule for completion of work under this Consent Decree to account for the delay that occurred as a result of dispute resolution. Tampa Electric shall be liable for stipulated penalties for its failure thereafter to complete the work in accordance with the extended or modified schedule.

73. The Court shall decide all disputes pursuant to applicable principles of law for resolving such disputes; provided, however, that the United States and Tampa Electric reserve their rights to argue for what the applicable standard of law should be for resolving any particular dispute. Notwithstanding the preceding sentence of this Paragraph, as to disputes arising under Paragraph 32, the Court shall sustain the position of the United States as to the BACT Analysis recommendations and the optimization study measures that should be installed and implemented, unless Tampa Electric demonstrates that the position of the United States is arbitrary or capricious.

XII. GENERAL PROVISIONS

74. Effect of Settlement. This Consent Decree is not a permit; compliance with its terms does not guarantee compliance with all applicable Federal, State or Local laws or regulations.

75. Satisfaction of all of the requirements of this Consent Decree constitutes full

settlement of and shall resolve and release Tampa Electric from all civil liability of Tampa Electric to the United States for the claims referred to in Paragraphs 43 and 44 of this Consent Decree. This Consent Decree does not apply to any claim(s) of alleged criminal liability, which are reserved.

76. In any subsequent administrative or judicial action initiated by the United States for injunctive relief or civil penalties relating to the facilities covered by this Consent Decree, Tampa Electric shall not assert any defense or claim based upon principles of waiver, res judicata, collateral estoppel, issue preclusion, claim splitting, or other defense based upon any contention that the claims raised by the United States in the subsequent proceeding were brought, or should have been brought, in the instant case; provided, however, that nothing in this Paragraph is intended to affect the enforceability of the Resolution of Claims provisions of Paragraphs 43 and 44 of this Consent Decree..

77. Other Laws. Except as specifically provided by this Consent Decree, nothing in this Consent Decree shall relieve Tampa Electric of its obligation to comply with all applicable Federal, State and Local laws and regulations. Subject to Paragraph 43 and 44, nothing contained in this Consent Decree shall be construed to prevent or limit the United States' rights to obtain penalties or injunctive relief under the Clean Air Act or other federal, state or local statutes or regulations.

78. Third Parties. This Consent Decree does not limit, enlarge or affect the rights of any party to this Consent Decree as against any third parties.

79. Costs. Each party to this action shall bear its own costs and attorneys' fees.

80. Public Documents. All information and documents submitted by Tampa Electric to the United States pursuant to this Consent Decree shall be subject to public inspection, unless subject to legal privileges or protection or identified and supported as business confidential by Tampa Electric in accordance with 40 C.F.R. Part 2.

81. Public Comments. The parties agree and acknowledge that final approval by the United States and entry of this Consent Decree is subject to the requirements of 28 C.F.R. § 50.7, which provides for notice of the lodging of this Consent Decree in the Federal Register, an opportunity for public comment, and the right of the United States to withdraw or withhold consent if the comments disclose facts or considerations which indicate that the Consent Decree is inappropriate, improper, or inadequate.

82. Notice. Unless otherwise provided herein, notifications to or communications with the United States or Tampa Electric shall be deemed submitted on the date they are postmarked and sent either by overnight mail, return receipt requested, or by certified or registered mail, return receipt requested. Except as otherwise provided herein, when written notification to or communication with the United States, EPA, or Tampa Electric is required by the terms of this Consent Decree, it shall be addressed as follows:

As to the United States of America:

For U.S. DOJ –

Chief
Environmental Enforcement Section
Environment and Natural Resources Division
U.S. Department of Justice
P.O. Box 7611, Ben Franklin Station
Washington, D.C. 20044-7611
DJ# 90-5-2-1-06932

Whitney L. Schmidt
Coordinator, Affirmative Civil Enforcement Program
Office of the United States Attorney
Middle District of Florida
400 N. Tampa Street
Tampa, FL 33602

For U.S. EPA –

Director, Air Enforcement Division
Office of Enforcement and Compliance Assurance
U.S. Environmental Protection Agency
Ariel Rios Building [2242A]
1200 Pennsylvania Avenue, N.W.
Washington, DC 20460

and

Regional Administrator
U.S. EPA Region IV
61 Forsyth Street, S.E.
Atlanta, GA 30303

As to Tampa Electric:

Sheila M. McDevitt
General Counsel
Tampa Electric Company
P.O. Box 111
Tampa, FL 333601-0111

83. Any party may change either the notice recipient or the address for providing notices to it by serving all other parties with a notice setting forth such new notice recipient or address.

84. Modification. Except as otherwise allowed by law, there shall be no modification of this Consent Decree without written approval by the United States and Tampa Electric, and approval of such modification by the Court.

85. Continuing Jurisdiction. The Court shall retain jurisdiction of this case after entry of this Consent Decree to enforce compliance with the terms and conditions of this Consent Decree and to take any action necessary or appropriate for its interpretation, construction, execution, or modification. During the term of this Consent Decree, any party may apply to the Court for any relief necessary to construe or effectuate this Consent Decree.

86. Complete Agreement. This Consent Decree constitutes the final, complete and exclusive agreement and understanding among the parties with respect to the settlement embodied in this Consent Decree. The parties acknowledge that there are no representations, agreements or understandings relating to the settlement other than those expressly contained in this Consent Decree. An Appendix is attached to and incorporated into this Consent Decree by this reference.

XIII. TERMINATION

87. Except as provided in Paragraphs 43, 44, and 45 (involving resolution of claims),

this Consent Decree shall be subject to termination upon motion by either party after Tampa Electric satisfies all requirements of this Consent Decree, including payment of all stipulated penalties that may be due, installation of control technology systems as specified herein, the receipt of all permits specified herein, securing valid Title V Permits for Gannon and Big Bend that incorporate all emission and fuel limits from this Consent Decree as well as all operational limits established under this Consent Decree, and the submission of all final reports indicating satisfaction of the requirements for implementation of all acts called for under Part VII of this Consent Decree.

88. If Tampa Electric believes it has achieved compliance with the requirements of this Consent Decree, then Tampa Electric shall so certify to the United States. Unless the United States objects in writing with specific reasons within 60 days of receipt of Tampa Electric's certification, the Court shall order that this Consent Decree be terminated on Tampa Electric's motion. If the United States objects to Tampa Electric's certification, then the matter shall be submitted to the Court for resolution under Section XI of this Consent Decree. In such case, Tampa Electric shall bear the burden of proving that this Consent Decree should be terminated.

SO ORDERED, THIS _____ DAY OF ________________ 2000.

____

UNITED STATES DISTRICT JUDGE

Signature Page for Consent Decree in United States v. Tampa Electric Company, Civ. No. 99-2524 CIV-T-23F

Steve A. Herman
Assistant Administrator for Enforcement
U.S. Environmental Protection Agency
Washington, D.C.

Bruce Buckheit

Bruce Buckheit
Director

Gregory Jaffe
Senior Enforcement Counsel

Air Enforcement Division
Office of Enforcement and Compliance Assurance
U.S. Environmental Protection Agency
Washington, D.C.

Signature Page for Consent Decree in United States v. Tampa Electric Company, Civ. No. 99-2524 CIV-T-23F

John H. Hankinson
Regional Administrator
U.S. Environmental Protection Agency (Region IV)
Atlanta, Georgia

Signature Page for Consent Decree in United States v. Tampa Electric Company,
Civ. No. 99-2524 CIV-T-23F

THROUGH ITS UNDERSIGNED REPRESENTATIVES, THE UNITED STATES AGREES AND CONSENTS TO ENTRY OF THE FOREGOING CONSENT DECREE:

FOR PLAINTIFF
UNITED STATES OF AMERICA:

______________________ Date: 2/28/00

Lois J. Schiffer
Assistant Attorney General
Environment and Natural Resources
Division
United States Department of Justice

____

W. Benjamin Fisherow
Assistant Chief
Thomas A. Mariani, Jr.
Jon A. Mueller
Senior Attorneys
Environmental Enforcement Section
United States Department of Justice
P.O. Box 7611
Washington, D.C. 20044
(202) 514-4620

Donna A. Bucella
United States Attorney for the
Middle District of Florida

By:______________________
Whitney L. Schmidt
Affirmative Civil Enforcement Coordinator
Assistant United States Attorney
United States Attorney's Office
Middle District of Florida
Florida Bar No. 0337129
Tampa, Florida 33602
(813) 274-6000
(813) 274-6198 (facsimile)

Signature Page for Consent Decree in United States v. Tampa Electric Company, Civ. No. 99-2524 CIV-T-23F

THROUGH ITS UNDERSIGNED REPRESENTATIVES, TAMPA ELECTRIC COMPANY AGREES AND CONSENTS TO ENTRY OF THE FOREGOING CONSENT DECREE

FOR TAMPA ELECTRIC COMPANY

Date: 2/29/00

John B. Ramil
President
Tampa Electric Company

Sheila M. McDevitt
General Counsel
Tampa Electric Company

-file-

INTEROFFICE MEMORANDUM

Date: 28-Mar-2000 08:41am
From: Shannon Todd
sktodd@tecoenergy.com
Dept:
Tel No:

To:	Cindy.Phillips	(Cindy.Phillips@dep.state.fl.us)
CC:	Scott.Sheplak	(Scott.Sheplak@dep.state.fl.us)
CC:	kirby	(kirby@epcjanus.epchc.org)
CC:	Greg Nelson	(gmnelson@tecoenergy.com)
CC:	Jamie Hunter	(jjhunter@tecoenergy.com)

Subject: Big Bend Title V Outstanding Issues

Cindy,

Attached for your review is a Draft list of outstanding issues from the last Big Bend Title V meeting. I have attempted to consolidate and address everything that we discussed, but this document continues to evolve. Hopefully, we can discuss this during Thursday's meeting.

Sincerely,

Shannon K. Todd
Tampa Electric Company
(813) 641-5125
fax (813) 641-5081

DRAFT

Big Bend Title V Permitting – Outstanding Issues

1. Insignificant Emission Units and/or Activities

TEC feels that the Insignificant Emissions Units and or Activities should included the following:

1. Internal combustion engines in boats, aircraft and vehicles used for transportation of passengers or freight.
1. Cold storage refrigeration equipment, except for any such equipment located at a Title V source using an ozone-depleting substance regulated under 40 CFR Part 82.
1. Vacuum pumps in laboratory operations.
1. Equipment used for steam cleaning.
1. Belt or drum sanders having a total sanding surface of five square feet or less and other equipment used exclusively on wood or plastics or their products having a density of 20 pounds per cubic foot or more.
1. Equipment used exclusively for space heating, other than boilers.
1. Laboratory equipment used exclusively for chemical or physical analyses.
1. Brazing, soldering or welding equipment.
1. One or more emergency generators located within a single facility provided:
    a. None of the emergency generators is subject to the Federal Acid Rain Program; and
    a. Total fuel consumption by all such emergency generators within the facility is limited to 32,000 gallons per year of diesel fuel, 4,000 gallons per year of gasoline, 4.4 million standard cubic feet per year of natural gas or propane, or an equivalent prorated amount if multiple fuels are used.
1. One or more heating units and general purpose internal combustion engines located within a single facility provided:
    a. None of the heating units or general purpose internal combustion engines is subject to the Federal Acid Rain Program; and
    a. Total fuel consumption by all such heating units and general purpose internal combustion engines within the facility is limited to 32,000 gallons per year of diesel fuel, 4,000 gallons per year of gasoline, 4.4 million standard cubic feet per year of natural gas or propane, or an equivalent prorated amount if multiple fuels are used.
1. Fire and safety equipment.

1. Storage Tanks
1. Degreasing units using heavier-than-air vapors exclusively, except any such unit using or emitting any substance classified as a hazardous air pollutant.
1. Turbine vapor extractors
1. Architectural coatings.
1. Surface coating operations utilizing only coatings containing 5.0 percent or less VOCs, by volume.
1. Evaporation of non-hazardous boiler chemical cleaning waste which was generated on site.
1. No. 2 fuel Oil Storage Tanks
1. Vehicle Refueling Operations
1. Molten Sulfur Storage Tanks

2. Unregulated Emissions Units and/or Activities

TEC feels that the Unregulated Emissions Units and/or Activities should include the following:

E.U. ID No.	Brief Description of Emissions Units and/or Activities
-xxx	Slag and bottom ash sources BH-001 through BH-004
	Gypsum handling and storage sources GH-001 through GH-017
	General Purpose Internal Combustion Engines
	Fugitive PM sources-on site vehicles
	Material Handling of coal and ash
	Fugitive PM sources-abrasive blasting operations

3. Flame Stabilization

Flame stabilization is defined as the use of No. 2 fuel oil to stabilize a flame during times of unexpected poor coal quality or equipment failure such as coal piping pluggage. Flame stabilization due to poor coal quality occurs when coal is wet or does not provide the necessary heat to maintain a stable flame. In this situation, No. 2 fuel oil is combusted to provide the additional required heat input to maintain a stable flame. Flame stabilization due to equipment failure occurs when coal piping is plugged or equipment is otherwise damaged that results in an inconsistent amount of coal reaching the burners. Under certain conditions, this may result in the burners intermittently seeing large amounts of fuel at one time, causing a potentially explosive flame 'puff'. In this situation, No. 2 fuel oil must be used for stabilization to prevent flame 'puffing' and ensure safe operation.

4. Injection of Nonhazardous Boiler Chemical Cleaning Waste

Boiler chemical cleaning takes place at Big Bend less than once per year. In fact, the last boiler chemical cleaning that took place was in 1993. Typically, TEC uses approximately 70,000 gallons of a mineral acid solution to clean the boiler.

5. Permitting note addition to Specific Condition B-1

Consistent with specific condition A-1, the following permitting note should be added to specific condition B-1:

{Permitting note: The heat input limitations have been placed on this permit to identify the capacity of each unit for the purposes of confirming that emissions testing is conducted within 90 to 100 percent of the unit's rated capacity (or to limit future operation to 110 percent of the test load), to establish appropriate emission limits and to aid in determining future rule applicability. Regular record keeping is not required for heat input. Instead the owner or operator is expected to determine heat input whenever emission testing is required, to demonstrate at what percentage of the rated capacity that the unit was tested. Rule 62-297.310(5), F.A.C., requires measurement of the process variables for emission tests. Such heat input determination may be based on measurements of fuel consumption by various methods including but not limited to fuel flow metering or tank drop measurements, using the heat value of the fuel determined by the fuel vendor or the owner or operator, to calculate average hourly heat input during the test.}

5. Permitting Conditions that require the inclusion of the quantity of liquid fuel combusted to determine applicable limits.

TEC requests that all such conditions be eliminated. This will remove the requirement for unnecessary paperwork. The amount of liquid fuel is insignificant when compared to the amount of solid fuel combusted. Therefore, the limits are essentially the same both before and after the consideration of the amount of liquid fuel combusted.

5. Revision of Specific Condition D.l

TEC requests that the limit on loading rate for Silo No. 2 be removed to be consistent with the permit amendment dated February 7, 1990. This amendment removed the maximum permitted loading rate limit of 11.9 tons per hour and TEC feels that the Title V permit should reflect this.

5. Abrasive Blasting

TEC requests that the maximum permitted usage of abrasive blast media in the abrasive blast booth be limited to 300 tons per year. Other abrasive blasting performed at Big Bend is done within a portable enclosure to minimize particulate emissions. TEC feels that this activity is covered in the Appendix U-1 Unregulated Emissions Units and Activities.

5. Transfer of Flyash from Tanker Trucks to Silo 3

Consistent with Subsection D, TEC requests that the following language be added to Subsection E:

Also, flyash may be pneumatically conveyed from tanker trucks to Silo No. 3.

This allows TEC to transfer flyash from Silos 1 and 2 to Silo 3 in case of an unforeseen malfunction.

5. Incorporation of Construction Permits into the Draft Title V Permit

The following two construction permits should be incorporated into the Draft Title V permit:

- Units 1 & 2 FGD Construction Permit
- CT 2 & 3 Inlet Air Fogging System Construction Permit

5. Periodic Monitoring

Consistent with periodic monitoring requirements for Crystal River Unit 2, TEC suggests the following language be incorporated into the Title V permit to address periodic monitoring for Big Bend Units 1-4:

Periodic monitoring for particulate matter shall be COMS. For any calendar quarter in which more than five percent of the COMS readings show 20% or greater opacity for Units 1, 2, 3 and 4 (excluding startup, shutdown, and malfunction periods), a steady-state particulate matter stack test shall be performed within the following calendar quarter. Due to the allowed opacity level of 60% for sootblowing and load changing periods for Units 1 and 2, periods of sootblowing and load changing shall also be excluded for those units. The stack test shall comply with all of the testing and reporting requirements contained in the preceding specific conditions and, where practicable, shall be performed while operating at conditions representative of those showing
greater than 20% opacity. Units are not required to be brought on-line solely for the purpose of performing this special test. If the unit does not operate in the following quarter, the special test may be postponed until the unit is brought back on-line. In such

cases, the special test shall be performed within 30 days.
[Rule 62-213.440, F.A.C.]

Comparing the Emissions with the Permit Limits

SO_2 Compliance Tracking

Date: 01/27/2000

Big Bend Units 1 & 2 FGD Construction Permit

	CS001 Emissions	CS0W1 Emissions	CS002 Emissions
Average Fuel Sulfur Content [lb/MMBtu]			
Actual 24-Hour SO_2 Average [lb/hr]	2,161	1,152	1,700
24-Hour SO_2 Limit Average [lb/hr]	4,294	5,695	13,000
Difference [lb/hr]	**2,133**	**4,543**	**11,300**

Current Operating Permit

BB1 + BB2 SO_2 [tons/hr]	1.66	(Not to exceed 16.5 tons/hr on a 24 hour average)
BB3 SO_2 [tons/hr]	0.85	(Not to exceed 8.5 tons/hr on a 24 hour average)
BB1 + BB2 + BB3 SO_2 [tons/hr]	2.51	(Not to exceed 25 tons/hr on a 24 hour average)

Gin TECO

2/2/00

Applying the Equation to Determine Compliance

Big Bend Units 1 & 2 SO_2 Compliance

Enter Date

01/27/2000

(mm/dd/yy)

F9 to Refresh Screen

Hour	BB1 + BB2 Percent Flue Gas Scrubbed	Percent BB3 Flue Gas Scrubbed	CS001 Hourly Limit [lb/hr]	CS001 Actual Emissions [lb/hr]	CSOW1 Hourly Limit [lb/hr]	CSOW1 Actual Emissions [lb/hr]	BB 3 Hourly Limit [lb/hr]	BB 3 Actual Emissions [lb/hr]
0	100%	100%	0.00	0.00	6,587.00	2,739.60	17,000.00	2,328.60
1	100%	100%	0.00	0.00	6,587.00	2,721.40	17,000.00	2,176.50
2	100%	100%	0.00	0.00	6,587.00	2,597.30	17,000.00	2,078.00
3	100%	100%	0.00	0.00	6,587.00	2,343.70	17,000.00	1,906.50
4	100%	100%	0.00	0.00	6,587.00	2,104.80	17,000.00	1,326.40
5	100%	100%	0.00	0.00	6,587.00	2,275.30	17,000.00	1,620.10
6	100%	100%	0.00	0.00	6,587.00	2,807.60	17,000.00	2,010.80
7	100%	100%	0.00	0.00	6,587.00	2,849.70	17,000.00	2,051.80
8	100%	100%	0.00	0.00	6,587.00	2,863.00	17,000.00	2,004.90
9	100%	100%	0.00	0.00	6,587.00	2,111.30	17,000.00	2,142.70
10	100%	100%	0.00	0.00	6,587.00	424.20	17,000.00	2,086.00
11	80%	100%	0.00	0.00	5,253.82	143.00	17,000.00	2,014.80
12	100%	100%	0.00	0.00	6,587.00	163.00	17,000.00	1,838.60
13	100%	100%	0.00	0.00	6,587.00	190.60	17,000.00	1,399.00
14	100%	100%	0.00	0.00	6,587.00	183.80	17,000.00	1,063.20
15	100%	100%	0.00	0.00	6,587.00	196.50	17,000.00	1,031.40
16	100%	100%	0.00	0.00	6,587.00	145.60	17,000.00	1,451.80
17	100%	100%	0.00	0.00	6,587.00	139.10	17,000.00	1,361.20
18	0%	100%	33,000.00	11,171.70	0.00	0.00	17,000.00	1,459.20
19	0%	100%	33,000.00	20,210.20	0.00	0.00	17,000.00	1,429.30
20	2%	100%	32,969.56	20,150.10	132.39	0.40	17,000.00	1,528.00
21	93%	100%	4,086.75	325.60	6,140.12	169.90	17,000.00	1,580.90
22	100%	100%	0.00	0.00	6,587.00	235.60	17,000.00	1,602.10
23	100%	100%	0.00	0.00	6,587.00	231.20	17,000.00	1,303.90

2/2/05

Copy to: Cindy & Chris
– file –

ENVIRONMENTAL PROTECTION COMMISSION
HILLSBOROUGH COUNTY

ADMINISTRATIVE OFFICES, LEGAL & WATER MANAGEMENT DIVISION
1900 - 9TH AVENUE
TAMPA, FLORIDA 33605
TELEPHONE (813) 272-5960
FAX (813) 272-5157

AIR MANAGEMENT DIVISION
TELEPHONE (813) 272-5530

WASTE MANAGEMENT DIVISION
TELEPHONE (813) 272-5788

WETLANDS MANAGEMENT DIVISION
TELEPHONE (813) 272-7104

MEMORANDUM

DATE: February 1, 2000

TO: Mr. Clair Fancy
Florida Department of Environmental Protection
Bureau of Air Regulations

FROM: Rob Kalch RSK **Thru:** Richard C. Kirby IV, P.E. RK

SUBJECT: Tampa Electric Company
Big Bend Station Units 1, 2, 3, and 4
Permits AO29-219924, AO29-179912, AO29-179911, and PSD-FL-040
Request for Amendment

Dear Mr. Fancy:

EPC has reviewed the letter received January 7, 2000 from James Hunter on behalf of Tampa Electric Company (TEC), requesting an amendment to permits AO29-219924, AO29-179912, AO29-179911. The amendments would allow the use of continuous emissions monitoring (CEM) to show compliance with the sulfur dioxide emission limitations outlined in the specific conditions of the operating permit(s).

EPC requests that the amendment be made part of the Title V operating permit and/or the operating permits for the facility. There is some confusion as to the validity of the operating permits referenced above. Rules 62-210.300(2)(a)(3)a, and 62-213.420(1)(b)2 seem to contradict each other. Rule 62-210.300(2)(a)(3)a, states that the operating permits are valid only 60 days after the deadline for the submission of the Title V permit application, and offers no options to extend the expiration date any further. Rule 62-213.420(1)(b)2, states that as long as an application has been submitted and is complete the operation permit is still valid. The following comments are made in the context of the operating permits referenced above.

TEC is requesting the removal of all other methods of providing proof of SO_2 emissions compliance in the permits referenced above if CEMs are used for compliance demonstration, "*In lieu of other SO_2 compliance demonstration methodologies referenced in this permit, ...*",(letter received from James Hunter, January 7, 2000). If TEC were given approval on the requested amendment, both fuel sampling and stack testing would no longer be required to prove compliance with the operating permits. Compliance verification would be based solely on the CEM data. EPC has no objection to the use of CEMs to monitor SO_2 emissions, but insists on the retention of a required annual stack test for SO_2 emissions from units 1, 2, and 3 to provide reasonable assurance the limitations contained in the permit are being met, and for reasonable assurance the CEMs are operating properly. However, while speaking to Mr. Holtom and Mr. Linero January 26, 2000, it was mentioned that the RATA might be sufficient if the method used meets the appropriate requirements, and this option is listed in the latest version of the draft Title V permit. EPC has no objection to this as long as the RATA is sufficient.

EPC is also concerned with the "range" of the analytical equipment used in the CEMs. Most analytical equipment has a finite range in which the readings are valid. If the range is exceeded, readings may still be recorded, but actual concentrations may be higher or lower.

EPC is also concerned about the sources potential to emit. For SO_2, the worst case scenario would be the failure of the FGD system. To provide reasonable assurance that the emission limit for SO_2 would be met under <u>all</u> operating conditions, we request that the testing of units 1, 2, and 3 continue to be performed under unscrubbed operating conditions, and fuel sampling be retained as a alternative to CEM use. Again the use of fuel sampling in place of CEM data, during periods of extended system malfunction, has been provided in the draft Title V permit, but not in the operating permits referenced above.

EPC has some suggested wording for the incorporation of the amendment into the operating permits that may adequately cover this situation. The addition of another subpart to the following specific conditions in the appropriate permits may be adequate.

Permit #	Specific Condition #
AO29-179912	9
AO29-219924	9
AO29-179911	12

For permits AO29-179912 and AO29-219924, Units #1 and #2;
Specific Condition 9, Part E.,

Calibrating, maintaining, and operating a continuous emissions monitoring (CEM) system in the stack(s) to measure and record the sulfur dioxide emissions from this emission unit, in a manner sufficient to demonstrate compliance with the SO_2 emission limits set forth in specific condition #4 of this permit. Compliance with the emission limits of this permit shall be based on 2-hour or 3-hour averages or 24-hour calendar day averages calculated by the CEM system expressed in units of pounds per million Btu heat input, pounds per hour, or tons per hour, as applicable.

For permits AO29-179911, Unit #3;
Specific Condition 12, Part E.,

Calibrating, maintaining, and operating a continuous emissions monitoring (CEM) system in the stack(s) to measure and record the sulfur dioxide emissions from this emission unit, in a manner sufficient to demonstrate compliance with the SO_2 emission limits set forth in specific condition #4 of this permit. The CEM requirements for unit #3 apply during the non-integrated or partially integrated mode of operation. When operated in the integrated mode the flue gas from unit #3 will be required to meet the emissions limits of unit #4. Compliance with the emission limits of this permit shall be based on 2-hour or 3-hour averages or 24-hour calendar day averages calculated by the CEM system expressed in units of pounds per million Btu heat input, pounds per hour, or tons per hour, as applicable.

The amendment would allow flexibility in the methods used for showing compliance with the SO_2 emissions limit contained in the permit, but would retain the requirement of an annual stack test for SO_2 emissions, and make provisions for alternative methods of showing compliance in case of equipment failure or malfunction.

EPC has also reviewed the letter received January 14, 2000 from James Hunter on behalf of Tampa Electric Company (TEC), requesting an amendment to permits AO29-179911 and PSD-FL-040. TEC is requesting the removal of the sulfur content limits on petcoke and the removal of the limit on vanadium content of the mineral ash for units 3 and 4.

Although units 1 and 2 currently do not have limits on the sulfur content of petcoke, the limit should be retained in the permit to make it enforceable. The basis for TEC's requested change refers back to the use of scrubbers to control the amount of SO_2 emitted into the atmosphere.

Finally, has modeling been done to evaluate the emissions of vanadium during periods of operation without the FGD system operating, or during periods of startup, shutdown, malfunction, or soot blowing? Referencing OSHA 29 CFR 1926.55, Appendix A, Pg. 29, vanadium has a threshold limit of 0.5 mg/m^3 ,as dust, for construction. Considering the typical petroleum coke analysis provided in a letter from Mr. Patrick Ho, Manager, Environmental Planning, TECO, dated August 5, 1994, the vanadium content has a range from 534.0 to 750 mg/kg (ppm), based on a petroleum coke trace metals analysis, and 1100 to 1900 ppm, based on a petroleum coke analysis. EPC is concerned that safe levels of vanadium in the ambient air might be exceeded during unusual operating conditions.

rsk

ENVIRONMENTAL PROTECTION COMMISSION
HILLSBOROUGH COUNTY

ADMINISTRATIVE OFFICES, LEGAL & WATER MANAGEMENT DIVISION
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WASTE MANAGEMENT DIVISION
TELEPHONE (813) 272-5788

WETLANDS MANAGEMENT DIVISION
TELEPHONE (813) 272-7104

MEMORANDUM

RECEIVED

JAN 20 1998

BUREAU OF AIR REGULATION

DATE: January 15, 1998

TO: Clair Fancy

FROM: Jerry Campbell JC

SUBJECT: Sulfur Dioxide Standards at Big Bend

We noted the reduced SO_2 standard of 18.75 tons of SO_2 for Units 1, 2 and 3 on a 24 hour average in the draft Title V permit. We applaud the Department's initiative and ask that you consider revisiting TEC's whole SO_2 program. The State's SO_2 limitations at Gannon and Big Bend are health based standards, that we have long felt were not practically enforceable. The complexity of their standards and their compliance methodology defies logic, and we would favor a more straightforward approach.

The attached analysis indicates what can be done using CEM data. This particular analysis was in response to the question of how often TEC operated above the 18.75 figure during two discrete quarters. The table on the front page shows there is not good correlation between CEMs data and the current methodology. Considering that the current methodology consists of composite fuel samples and voodoo statistics, we will take the continuous emission monitor data every time. Perhaps we could offer to get away from stack testing, thus providing some incentive for TEC as well.

As you consider this matter, please keep in mind we are not necessarily advocating more stringent standards. Naturally we would like to see TEC move from health-based emission limits to technology-based standards, and the Acid Rain program is probably driving them to it; but in the absence of evidence of an ambient problem, we primarily seek an enforceable standard.

Thanks for your efforts and we look forward to hearing from you.

cag

cc: Bill Thomas
Patrick Ho

AIR MANAGEMENT DIVISION
MEMORANDUM

TO: JERRY THROUGH: STERLIN
FROM: PATRICK
SUBJECT: BIG BEND'S NEW SO2 LIMIT
DATE: DECEMBER 11, 1997

I have two quarters of valid data the whole Big Bend station, 4th Quarter 1996 and 2nd Quarter 1997. During these two quarters the station exceeded the 18.75 ton/hr on a rolling 24 hour average, ˜143 hours, i.e. 143 24 hour rolling averages were exceeded. I made a comparison to what is reported in the corresponding SO2 quarterly reports. The results are in the table below. Note that the current Tampa Electric quarterly report is a daily 24 hour average, not a rolling 24 hour average hence the low number of times > 18 tons/hr.

Quarter/Month	CEM (24 rolling average > 18.75 tons/hr SO2) i.e. hours > 18.75 on a 24 hour average	Current quarterly submittals from TEC > 18 ton/hr
4th 1996/October	65	6
4th 1996/November	38	3
4th 1996/December	0	6
2nd 1997/April	0	0
2nd 1997/May	0	0
2nd 1997/June	40	10

Conclusions: The fuel sampling provides only a snap shot of the emissions and can under or over estimate the actual SO2 emissions due to coal quality variability. The best example is June 1997. If you look at the Tampa Electric submittal and compare it to the 8 ½" x 14" chart. The variability of the coal's sulfur content is evidenced by the variability of hourly SO2 emissions. On days with high coal sulfur variability, several hourly observations can be aligned vertically on the chart. On days with low coal variability the hourly readings are grouped together, e.g. April 30th through may 12th. Therefore coal sampling is not very representative of the true lb/MMBtu sulfur content of the bunkered fuel when there is high variability in the quality of the coal.

Recommendation: The 18.75 ton/hr limit should be on a rolling 24 hour average and demonstrated by CEM.

Attachments:
CEM emission charts, the red line is the 24 hour rolling average.
TEC 4th quarter 1996 and 2nd quarter 1997 SO2 reports

Print Date: 12/11/97 3:29 PM
document2

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Florida Department of Environmental Protection

Meeting Sign-In Sheet

Re: Tampa Electric Company

Date: October 15, 1998

Name	Representing	Telephone
Richard C Kirby IV	EPC Hillsborough Co.	(813) 272-5530
[illegible]	EPC Hills. Co.	(813) 272-5530
Lennon Anderson	DEP	850 921-9588
Teresa Heron	DEP-NSR	850/921-9529
Clive Holladay	DEP-NSR	850/921-8986
Jamie Hunter	Tampa Electric	813/641-5033
Theresa Watley	Tampa Electric	813/641-5034
Clair Fancy	DEP	850/488-1344
Scott Sheplak	DEP	850/488-1344

-file-

Florida Department of Environmental Protection

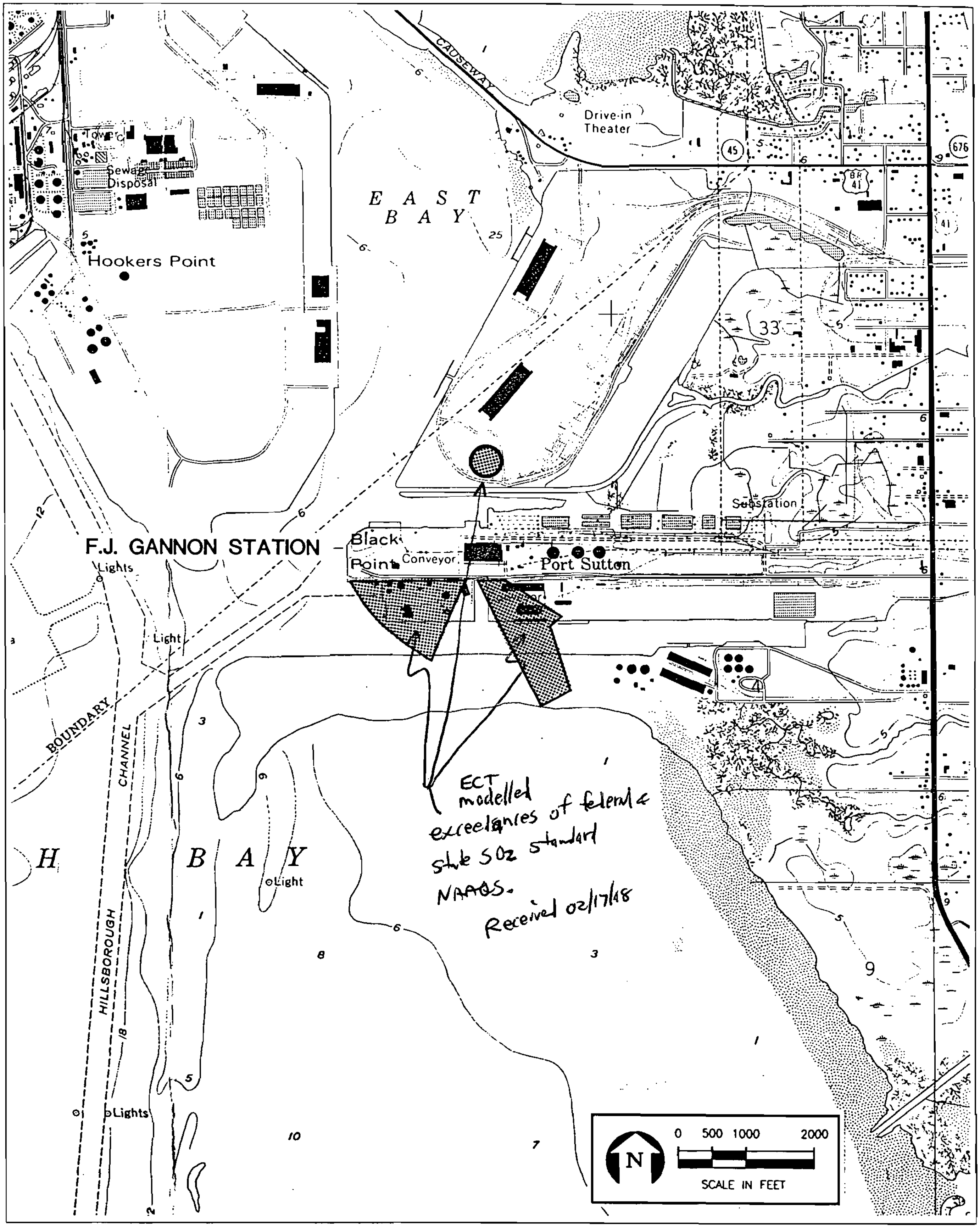
Meeting Sign-In Sheet

Re: Tampa Electric

Date: February 17, 1998

Name	Representing	Telephone
Scott Sheplak	DEP Title V Section	488-1344
CINDY PHILLIPS	DEP	921-9534
Rick Kirby	EPC Hills. Co	(813) 272-5530
STERLIN WOODARD	EPC. HILLS. Co.	(813) 272-5530
PAT COMER	DEP / OGC	(850) 488-9730
CLEVE HOLLADAY	DEP	850 488 1344
JANICE TAYLOR	TEC	813 641 5639
Larry Curtin	Holland & Knight (TEC)	850-224-7000
Lennon Anderson	DEP	850-921-9588
Clair Fancy	DEP	8509219503
Al Trbovich	Environmental Consulting & Technology	352-332-0444

98010/at

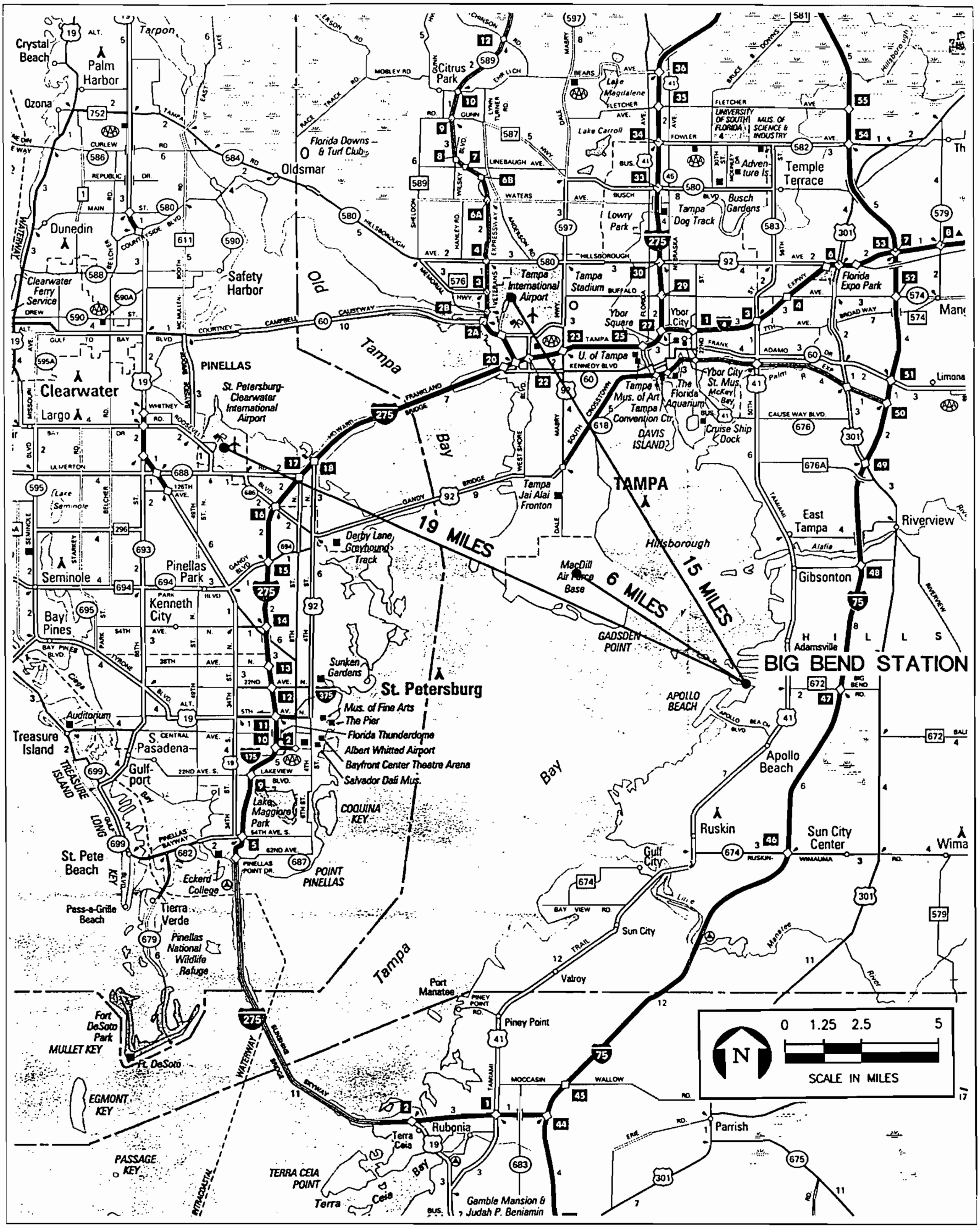


F.J. GANNON STATION IMPACT AREAS

Source: USGS Quad, Tampa, FL, 1981.

TECO
TAMPA ELECTRIC

98010/at

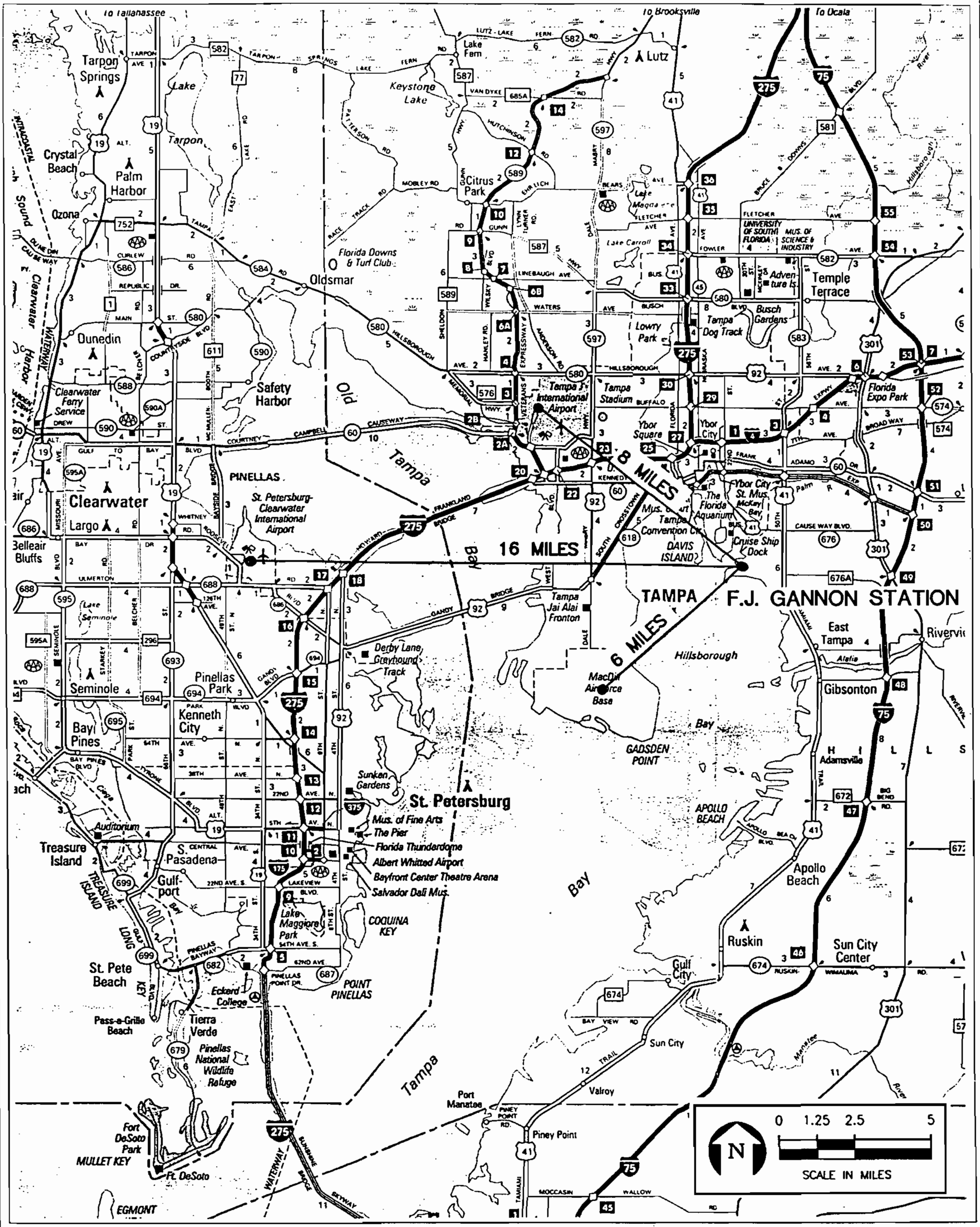


DISTANCE BETWEEN BIG BEND STATION AND SURFACE METEOROLOGY OBSERVATION STATIONS

Source: AAA, 1996.

TECO
TAMPA ELECTRIC

98010/at



DISTANCE BETWEEN F.J. GANNON STATION AND SURFACE METEOROLOGY OBSERVATION STATIONS

Source: AAA, 1996.

TECO
TAMPA ELECTRIC

-SN-

TO: Cleve Holladay
Cindy Phillips, Lennon Anderson
Pat Comer, Doug Beason

FROM: Scott Sheplak SMS
DATE: 10/9/97

Re: Tampa Electric Company (TEC) - Big Bend, Gannon

I set up a meeting on the subject company's DRAFT Title V permits for next Tuesday, October 14, 10-12 noon, in our conference room. Please advise whether or not you will be present.

TEC agreed to limit our discussion to modeling. Based on our modeling results, we reduced (TEC) - Big Bend's 24-hour SO2 average from 25 tons/hour to 18.75 tons/hour (a 25% reduction) in their DRAFT Title V permit. Modeling may be required on the TEC - Gannon facility also.

Janice Taylor, Tampa Electric Company, will be bringing their attorney - Larry Curtain from Holland & Knight and their consultant modeller - Al Trbovich from ECT.

copy to: Clair Fancy

BEST AVAILABLE COPY

TEC-

Big Bend Station - Dispersion Model Stack Parameters

Emission Source	SO_2 Emission Rate 3 hr (g/sec)	24 hr & Annual† (g/sec)	Stack Height (m)	Stack Gas Temperature (K)	Stack Gas Velocity (m/sec)	Stack Diameter (m)
Units 1 and 2, combined	5,292*	4,200†	152.1	418	28.7	7.32
Unit 3	2,646*	2,100†	152.1	426	14.6	7.32
Unit 4	447	447	152.1	342	16.7	7.32
Combustion Turbine 1	11	11	10.7	817	28.0	3.35
Combustion Turbine 2	60	60	22.9	771	35.4	5.06
Combustion Turbine 3	60	60	22.9	771	35.4	5.06

*Based on three-hour average emission cap of 31.5 tons per hour for Units 1, 2, and 3 combined, equally divided among the 3 units.

†Based on 24-hour average emission cap of 25 tons per hour for Units 1, 2, and 3 combined, equally divided among the 3 units.

Reduce Unit 1 2, 3 emissions by 25%

Or mult Units 1 2 4200 X .75 = 3150 gs^{-1} = 25,000 lbs/hr

and Unit 3 2100 X .75 = 1575 gs^{-1} = 12,500 lbs/hr

37,500 lbs/hr

or 18.75 tons/p hr 24-hour avg

346

24 hr

0.75 (25 Tons SO_2/hour) = 18.75 Tons SO_2/hour

9/29/97

BBPARAM.XLS

-file-

STATE OF FLORIDA, DEP, BUREAU OF AIR REGULATION, TITLE V SECTION

TELEPHONE CONVERSATION RECORD

TO: file

FROM: SCOTT SHEPLAK

DATE: 10/06/97 TIME: ~5p.m.

WITH: Ms. Janice Taylor

REPRESENTING: TEC- Big Bend

TELEPHONE NO.: 813/641-5039

SUBJECT: DRAFT Title V permits

SUMMARY: Would like to discuss the modelling performed on Big Bend. Tampa Electric Company will be bringing their attorney. I informed her that we would need to bring our attorney. She would like to meet with Clair Fancy. I advised that Clair may be in on the October 17 but, may not be back until November 1. She is willing to meet the week of October 13 (Wed. the 15th is not good).

She would like to know whether or not modelling will be required for TEC-Gannon.

09/10/96 14:48 P02

ENVIRONMENTAL PROTECTION COMMISSION
HILLSBOROUGH COUNTY

ADMINISTRATIVE OFFICES, LEGAL & WATER MANAGEMENT DIVISION
1900 - 9TH AVENUE
TAMPA, FLORIDA 33605
TELEPHONE (813) 272-5960
FAX (813) 272-5157
AIR MANAGEMENT DIVISION
TELEPHONE (813) 272-5530
WASTE MANAGEMENT DIVISION
TELEPHONE (813) 272-5788
WETLANDS MANAGEMENT DIVISION
TELEPHONE (813) 272-7104

M E M O R A N D U M

DATE: September 10, 1996

TO: John Brown

FROM: Rick Kirby **THRU:** Jerry Campbell
Iwan Choronenko

SUBJECT: Title V Review of TECO Facilities in Hillsborough County

The EPC has received copies of Tampa Electric Company Title V applications. The packages were received August 14 and 21, 1996 with a request that comments be provided by September 9, 1996. The actual application and some supporting documentation were provided on computer disk.

I have begun my initial review of the Big Bend facility and have already turned up several issues which should be addressed. Some of these are as follows:

1. The State sulfur dioxide standards for the Big Bend and Gannon stations do not appear to meet any of the criteria for practical enforceability. Rules 62-296.405(1)(c)2.a. and b., F.A.C. are truly not comprehensible to anyone other than a doctorate of mathematics or statistics. While we are not suggesting the standard be tightened through the Title V process, we are stating that it should be simplified so it is meaningful. TECO now has CEMs in the stacks and we should look to establishing them as the reference method with a practically enforceable standard that will pass the EPA muster. We do not see how they can provide reasonable assurance that these standards are being met or that these limits protect the ambient air quality standards. You recall we have experienced a number of sulfur dioxide violations downwind of the Gannon Station and these have not been resolved. The EPC feels very strongly about this particular issue.

2. It appears that many sources have been grouped into one emissions unit, when they may not meet the State definition of similar sources. These include fuel and other material handling.

3. Many of these units have been presented as being fugitive emissions sources when they do not meet that definition.

4. There are fuels and chemicals listed for use in boilers which have no previous permitting approval. These include used oil and non-hazardous cleaning chemicals.

5. Some emission units are not listed. EPC had previously agreed to defer permitting of a marine vessel repair and painting operation to be included in the Title V process. It was not found in this package.

Based on the above issues, I feel it is necessary to have EPC permitting engineers perform an inspection of each facility, to include a thorough air pollution source audit, as well as an in depth application and file review. Additionally, EPC has been unable to generate or access the applications for the Hookers Point and F.J. Gannon facilities. As you may be aware, FDEP data personnel came to EPC recently. On the same day, a lightning strike took out a large part of our computer system. It is still not completely functional. Cindy Phillips has graciously agreed to generate hard copies of the two remaining facilities.

I would like to close by saying that these are very complex projects. In addition to the size of each facility, there are complicating factors such as the outstanding Chapter 120 F.S. hearing request by the citizens of Apollo Beach for the latest Big Bend modification and the application for modification at the F.J. Gannon facility which may well trigger PSD. This is the largest polluter in Hillsborough County and a thorough, complete review is called for. We respectfully request that the review time given us be extended for 30 days to insure that we can properly represent the interest of the citizens.

bm

Appendix U-1, List of Unregulated Emissions Units and Activities

Tampa Electric Company
Big Bend Station

FINAL Permit No.: 0570039-002-AV

Unregulated Emissions Units and/or Activities. An emissions unit which emits no "emissions-limited pollutant" and which is subject to no unit-specific work practice standard, though it may be subject to regulations applied on a facility-wide basis (e.g., unconfined emissions, odor, general opacity) or to regulations that require only that it be able to prove exemption from unit-specific emissions or work practice standards.

The below listed emissions units and/or activities are neither 'regulated emissions units' nor 'exempt emissions units'.

E.U. ID No.	Brief Description of Emissions Units and/or Activities
-036	Slag and bottom ash sources BH-001 through BH-004
	Gypsum handling and storage sources GH-001 through GH-017
	No. 2 Fuel Oil Storage Tanks > 550 gallons
	Vehicle Refueling Operations
	Turbine Vapor Extractor

Appendix I-1, List of Insignificant Emissions Units and/or Activities

Tampa Electric Company **FINAL Permit No.:** 0570039-002-AV
Big Bend Station
Page 1 of 2

The facilities, emissions units, or pollutant-emitting activities listed in Rule 62-210.300(3)(a), F.A.C., Full Exemptions, are exempt from the permitting requirements of Chapters 62-210 and 62-4, F.A.C.; provided, however, that exempt emissions units shall be subject to any applicable emission limiting standards and the emissions from exempt emissions units or activities shall be considered in determining whether a facility containing such emissions units or activities would be subject to any applicable requirements. Emissions units and pollutant-emitting activities exempt from permitting under Rule 62-210.300(3)(a), F.A.C., are also exempt from the permitting requirements of Chapter 62-213, F.A.C., provided such emissions units and activities also meet the exemption criteria of Rule 62-213.430(6)(b), F.A.C. The below listed emissions units and/or activities are hereby exempt pursuant to Rule 62-213.430(6), F.A.C.

Brief Description of Emissions Units and/or Activities

1. Internal combustion engines in boats, aircraft and vehicles used for transportation of passengers or freight.
2. Cold storage refrigeration equipment, except for any such equipment located at a Title V source using an ozone-depleting substance regulated under 40 CFR Part 82.
3. Vacuum pumps in laboratory operations.
4. Equipment used for steam cleaning.
5. Belt or drum sanders having a total sanding surface of five square feet or less and other equipment used exclusively on wood or plastics or their products having a density of 20 pounds per cubic foot or more.
6. Equipment used exclusively for space heating, other than boilers.
7. Laboratory equipment used exclusively for chemical or physical analyses.
8. Brazing, soldering or welding equipment.
9. One or more emergency generators located within a single facility provided:
    a. None of the emergency generators is subject to the Federal Acid Rain Program; and
    b. Total fuel consumption by all such emergency generators within the facility is limited to 32,000 gallons per year of diesel fuel, 4,000 gallons per year of gasoline, 4.4 million standard cubic feet per year of natural gas or propane, or an equivalent prorated amount if multiple fuels are used.
10. One or more heating units and general purpose internal combustion engines located within a single facility provided:
    a. None of the heating units or general purpose internal combustion engines is subject to the Federal Acid Rain Program; and
    b. Total fuel consumption by all such heating units and general purpose internal combustion engines within the facility is limited to 32,000 gallons per year of diesel fuel, 4,000 gallons per year of gasoline, 4.4 million standard cubic feet per year of natural gas or propane, or an equivalent prorated amount if multiple fuels are used.
11. Fire and safety equipment.

13. Degreasing units using heavier-than-air vapors exclusively, except any such unit using or emitting any substance classified as a hazardous air pollutant.

Note: No exemption shall be granted to any emissions unit or activity if:

1. Such unit or activity would be subject to any unit-specific applicable requirement;
2. Such unit or activity, in combination with other units and activities proposed for exemption, would cause the facility to exceed any major source threshold(s) as defined in Rule 62-213.420(3)(c)1., F.A.C., unless it is acknowledged in the permit application that such units or activities would cause the facility to exceed such threshold(s); or
3. Such unit or activity would emit or have the potential to emit:

a. 500 pounds per year or more of lead and lead compounds expressed as lead;
b. 1,000 pounds per year or more of any hazardous air pollutant;
c. 2,500 pounds per year or more of total hazardous air pollutants; or
d. 5.0 tons per year or more of any other regulated pollutant.

[Rule 62-213.430(6), F.A.C]

APPENDIX TV-3, TITLE V CONDITIONS (version dated 04/30/99)

[Note: This attachment includes "canned conditions" developed from the "Title V Core List."]

{Permitting note: APPENDIX TV-3, TITLE V CONDITIONS, is distributed to the permittee only. Other persons requesting copies of these conditions shall be provided one copy when requested or otherwise appropriate.}

Chapter 62-4. F.A.C.

1. Not federally enforceable. General Prohibition. Any stationary installation which will reasonably be expected to be a source of pollution shall not be operated, maintained, or modified without the appropriate and valid permits issued by the Department, unless the source is exempted by Department rule. The Department may issue a permit only after it receives reasonable assurance that the installation will not cause pollution in violation of any of the provisions of Chapter 403, F.S., or the rules promulgated thereunder. A permitted installation may only be operated, maintained, constructed, expanded or modified in a manner that is consistent with the terms of the permit.
[Rule 62-4.030, Florida Administrative Code (F.A.C.); Section 403.087, Florida Statute (F.S.)]

2. Not federally enforceable. Procedure to Obtain Permits: Application.
(1) Any person desiring to obtain a permit from the Department shall apply on forms prescribed by the Department and shall submit such additional information as the Department by law may require.
(2) All applications and supporting documents shall be filed in quadruplicate with the Department.
(3) To ensure protection of public health, safety, and welfare, any construction, modification, or operation of an installation which may be a source of pollution shall be in accordance with sound professional engineering practices pursuant to Chapter 471, F.S. All applications for a Department permit shall be certified by a professional engineer registered in the State of Florida except when the application is for renewal of an air pollution operation permit at a minor facility as defined in Rule 62-210.200, F.A.C., or where professional engineering is not required by Chapter 471, F.S. Where required by Chapter 471 or 492, F.S., applicable portions of permit applications and supporting documents which are submitted to the Department for public record shall be signed and sealed by the professional(s) who prepared or approved them.
(4) Processing fees for air construction permits shall be in accordance with Rule 62-4.050(4), F.A.C.
(5)(a) To be considered by the Department, each application must be accompanied by the proper processing fee. The fee shall be paid by check, payable to the Department of Environmental Protection. The fee is non-refundable except as provided in Section 120.60, F.S., and in this section.
(c) Upon receipt of the proper application fee, the permit processing time requirements of Sections 120.60(2) and 403.0876, F.S., shall begin.
(d) If the applicant does not submit the required fee within ten days of receipt of written notification, the Department shall either return the unprocessed application or arrange with the applicant for the pick up of the application.
(e) If an applicant submits an application fee in excess of the required fee, the permit processing time requirements of Sections 120.60(2) and 403.0876, F.S., shall begin upon receipt, and the Department shall refund to the applicant the amount received in excess of the required fee.
(6) Any substantial modification to a complete application shall require an additional processing fee determined pursuant to the schedule set forth in Rule 62-4.050, F.A.C., and shall restart the time requirements of Sections 120.60 and 403.0876, F.S. For purposes of this Subsection, the term "substantial modification" shall mean a modification which is reasonably expected to lead to substantially different environmental impacts which require a detailed review.
(7) Modifications to existing permits proposed by the permittee which require substantial changes in the existing permit or require substantial evaluation by the Department of potential impacts of the proposed modifications shall require the same fee as a new application.
[Rule 62-4.050, F.A.C.]

3. Standards for Issuing or Denying Permits. Except as provided at Rule 62-213.460, F.A.C., the issuance of a permit does not relieve any person from complying with the requirements of Chapter 403, F.S., or Department rules.
[Rule 62-4.070(7), F.A.C.]

4. Modification of Permit Conditions.
(1) For good cause and after notice and an administrative hearing, if requested, the Department may require the permittee to conform to new or additional conditions. The Department shall allow the permittee a reasonable time to conform to the new or additional conditions and on application of the permittee the Department may grant additional time. For the purpose of this section, good cause shall include, but not be limited to, any of the following: (also, see Condition No. 38)

(a) A showing that an improvement in effluent or emission quality or quantity can be accomplished because of technological advances without unreasonable hardship.

(b) A showing that a higher degree of treatment is necessary to effect the intent and purpose of Chapter 403, F.S.

(c) A showing of any change in the environment or surrounding conditions that requires a modification to conform to applicable air or water quality standards.

(e) Adoption or revision of Florida Statutes, rules, or standards which require the modification of a permit condition for compliance.

(2) A permittee may request a modification of a permit by applying to the Department.
(3) A permittee may request that a permit be extended as a modification of the permit. Such a request must be submitted to the Department in writing before the expiration of the permit. Upon timely submittal of a request for extension, unless the permit automatically expires by statute or rule, the permit will remain in effect until final agency action is taken on the request. For construction permits, an extension shall be granted if the applicant can demonstrate reasonable assurances that, upon completion, the extended permit will comply with the standards and conditions required by applicable regulation. For all other permits, an extension shall be granted if the applicant can demonstrate reasonable assurances that the extended permit will comply with the standards and conditions applicable to the original permit. A permit for which the permit application fee was prorated in accordance with Rule 62-4.050(4)(1), F.A.C., shall not be extended. In no event shall a permit be extended or remain in effect longer than the time limits established by statute or rule.
[Rule 62-4.080, F.A.C.]

5. Renewals. Prior to one hundred eighty (180) days before the expiration of a permit issued pursuant to Chapter 62-213, F.A.C., the permittee shall apply for a renewal of a permit using forms incorporated by reference in the specific rule chapter for that kind of permit. A renewal application shall be timely and sufficient. If the application is submitted prior to 180 days before expiration of the permit, it will be considered timely and sufficient. If the renewal application is submitted at a later date, it will not be considered timely and sufficient unless it is submitted and made complete prior to the expiration of the operation permit. When the application for renewal is timely and sufficient, the existing permit shall remain in effect until the renewal application has been finally acted upon by the Department or, if there is court review of the Department's final agency action, until a later date is required by Section 120.60, F.S., provided that, for renewal of a permit issued pursuant to Chapter 62-213, F.A.C., the applicant complies with the requirements of Rules 62-213.420(1)(b)3. and 4., F.A.C.
[Rule 62-4.090(1), F.A.C.]

6. Suspension and Revocation.
(1) Permits shall be effective until suspended, revoked, surrendered, or expired and shall be subject to the provisions of Chapter 403, F.S., and rules of the Department.
(2) Failure to comply with pollution control laws and rules shall be grounds for suspension or revocation.
(3) A permit issued pursuant to Chapter 62-4, F.A.C., shall not become a vested property right in the permittee. The Department may revoke any permit issued by it if it finds that the permit holder or the permit holder's agent:

(a) Submitted false or inaccurate information in application or operational reports.

(b) Has violated law, Department orders, rules or permit conditions.

(c) Has failed to submit operational reports or other information required by Department rules.

(d) Has refused lawful inspection under Section 403.091, F.S.

[Rule 62-4.100, F.A.C.]

7. Not federally enforceable. Financial Responsibility. The Department may require an applicant to submit proof of financial responsibility and may require the applicant to post an appropriate bond to guarantee compliance with the law and Department rules.
[Rule 62-4.110, F.A.C.]

8. Transfer of Permits.
(1) Within 30 days after the sale or legal transfer of a permitted facility, an "Application for Transfer of Permit" (DEP Form 62-1.201(1)) must be submitted to the Department. This form must be completed with the notarized signatures of both the permittee and the proposed new permittee.
(2) The Department shall approve the transfer of a permit unless it determines that the proposed new permittee cannot provide reasonable assurances that conditions of the permit will be met. The determination shall be limited solely to the ability of the new permittee to comply with the conditions of the existing permit, and it shall not concern the adequacy of these permit conditions. If the Department proposes to deny the transfer, it shall provide both the permittee and the proposed new permittee a written objection to such transfer together with notice of a right to request a Chapter 120, F.S., proceeding on such determination.
(3) Within 30 days of receiving a properly completed Application for Transfer of Permit form, the Department shall issue a final determination. The Department may toll the time for making a determination on the transfer by notifying both the permittee and the proposed new permittee that additional information is required to adequately review the transfer request. Such notification shall be served within 30 days of receipt of an Application for Transfer of Permit form, completed pursuant to Rule 62-4.120(1), F.A.C. If the Department fails to take action to approve or deny the transfer within 30 days of receipt of the completed Application for Transfer of Permit form, or within 30 days of receipt of the last item of timely requested additional information, the transfer shall be deemed approved.
(4) The permittee is encouraged to apply for a permit transfer prior to the sale or legal transfer of a permitted facility. However, the transfer shall not be effective prior to the sale or legal transfer.
(5) Until this transfer is approved by the Department, the permittee and any other person constructing, operating, or maintaining the permitted facility shall be liable for compliance with the terms of the permit. The permittee transferring the permit shall remain liable for corrective actions that may be required as a result of any violations occurring prior to the sale or legal transfer of the facility.
[Rule 62-4.120, F.A.C.]

9. Plant Operation-Problems. If the permittee is temporarily unable to comply with any of the conditions of the permit due to breakdown of equipment or destruction by hazard of fire, wind or by other cause, the permittee shall immediately notify the Department. Notification shall include pertinent information as to the cause of the problem, and what steps are being taken to correct the problem and to prevent its recurrence, and where applicable, the owner's intent toward reconstruction of destroyed facilities. Such notification does not release the permittee from any liability for failure to comply with Department rules. (also, see Condition No. 10)
[Rule 62-4.130, F.A.C.]

10. For purposes of notification to the Department pursuant to Condition No. 9, Condition No. 12(8), and Rule 62-4.130, F.A.C., Plant Operation-Problems, "immediately" shall mean the same day, if during a workday (i.e., 8:00 a.m. - 5:00 p.m.), or the first business day after the incident, excluding weekends and holidays; and, for purposes of 40 CFR 70.6(a)(3)(iii)(B), "prompt" shall have the same meaning as "immediately". [also, see Conditions Nos. 9 and 12(8)]
[40 CFR 70.6(a)(3)(iii)(B)]

11. Not federally enforceable. Review. Failure to request a hearing within 14 days of receipt of notice of proposed or final agency action on a permit application or as otherwise required in Chapter 62-103, F.A.C., shall be deemed a waiver of the right to an administrative hearing.
[Rule 62-4.150, F.A.C.]

12. Permit Conditions. All permits issued by the Department shall include the following general conditions:
(1) The terms, conditions, requirements, limitations and restrictions set forth in this permit, are "permit conditions" and are binding and enforceable pursuant to Sections 403.141, 403.727, or 403.859 through 403.861, F.S. The permittee is placed on notice that the Department will review this permit periodically and may initiate enforcement action for any violation of these conditions.
(2) This permit is valid only for the specific processes and operations applied for and indicated in the approved drawings or exhibits. Any unauthorized deviation from the approved drawings, exhibits, specifications, or conditions of this permit may constitute grounds for revocation and enforcement action by the Department.
(3) As provided in subsections 403.087(6) and 403.722(5), F.S., the issuance of this permit does not convey any vested rights or any exclusive privileges. Neither does it authorize any injury to public or private property or any invasion of personal rights, nor any infringement of federal, state, or local laws or regulations. This permit is not a waiver of or approval of any other Department permit that may be required for other aspects of the total project which are not addressed in this permit.

(4) This permit conveys no title to land or water, does not constitute State recognition or acknowledgment of title, and does not constitute authority for the use of submerged lands unless herein provided and the necessary title or leasehold interests have been obtained from the State. Only the Trustees of the Internal Improvement Trust Fund may express State opinion as to title.
(5) This permit does not relieve the permittee from liability for harm or injury to human health or welfare, animal, or plant life, or property caused by the construction or operation of this permitted source, or from penalties therefore; nor does it allow the permittee to cause pollution in contravention of F.S. and Department rules, unless specifically authorized by an order from the Department.
(6) The permittee shall properly operate and maintain the facility and systems of treatment and control (and related appurtenances) that are installed and used by the permittee to achieve compliance with the conditions of this permit, as required by Department rules. This provision includes the operation of backup or auxiliary facilities or similar systems when necessary to achieve compliance with the conditions of the permit and when required by Department rules.
(7) The permittee, by accepting this permit, specifically agrees to allow authorized Department personnel, upon presentation of credentials or other documents as may be required by law and at reasonable times, access to the premises where the permitted activity is located or conducted to:

(a) Have access to and copy any records that must be kept under conditions of the permit;

(b) Inspect the facility, equipment, practices, or operations regulated or required under this permit; and,

(c) Sample or monitor any substances or parameters at any location reasonable necessary to assure compliance with this permit or Department rules. Reasonable time may depend on the nature of the concern being investigated.

(8) If, for any reason, the permittee does not comply with or will be unable to comply with any condition or limitation specified in this permit, the permittee shall immediately provide the Department with the following information: (also, see Condition No. 10)

(a) A description of and cause of noncompliance; and,

(b) The period of noncompliance, including dates and times; or, if not corrected, the anticipated time the noncompliance is expected to continue, and steps being taken to reduce, eliminate, and prevent recurrence of the noncompliance. The permittee shall be responsible for any and all damages which may result and may be subject to enforcement action by the Department for penalties or for revocation of this permit.

(9) In accepting this permit, the permittee understands and agrees that all records, notes, monitoring data and other information relating to the construction or operation of this permitted source which are submitted to the Department may be used by the Department as evidence in any enforcement case involving the permitted source arising under the F.S. or Department rules, except where such use is prescribed by Sections 403.111 and 403.73, F.S. Such evidence shall only be used to the extent it is consistent with the Florida Rules of Civil Procedure and appropriate evidentiary rules.
(10) The permittee agrees to comply with changes in Department rules and F.S. after a reasonable time for compliance; provided, however, the permittee does not waive any other rights granted by F.S. or Department rules.
(11) This permit is transferable only upon Department approval in accordance with Rule 62-4.120, F.A.C., as applicable. The permittee shall be liable for any non-compliance of the permitted activity until the transfer is approved by the Department.
(12) This permit or a copy thereof shall be kept at the work site of the permitted activity.
(14) The permittee shall comply with the following:

(a) Upon request, the permittee shall furnish all records and plans required under Department rules. During enforcement actions, the retention period for all records will be extended automatically unless otherwise stipulated by the Department.

(b) The permittee shall hold at the facility or other location designated by this permit records of all monitoring information (including all calibration and maintenance records and all original strip chart recordings for continuous monitoring instrumentation) required by the permit, copies of all reports required by this permit, and records of all data used to complete the application for this permit. These materials shall be retained at least five (5) years from the date of the sample, measurement, report, or application unless otherwise specified by Department rule.

(c) Records of monitoring information shall include:

1. the date, exact place, and time of sampling or measurements;
2. the person responsible for performing the sampling or measurements;
3. the dates analyses were performed;
4. the person responsible for performing the analyses;
5. the analytical techniques or methods used; and,
6. the results of such analyses.

(15) When requested by the Department, the permittee shall within a reasonable time furnish any information required by law which is needed to determine compliance with the permit. If the permittee becomes aware the relevant facts were not submitted or were incorrect in the permit application or in any report to the Department, such facts or information shall be corrected promptly.
[Rules 62-4.160 and 62-213.440(1)(b), F.A.C.]

13. Construction Permits.
(1) No person shall construct any installation or facility which will reasonably be expected to be a source of air or water pollution without first applying for and receiving a construction permit from the Department unless exempted by statute or Department rule. In addition to the requirements of Chapter 62-4, F.A.C., applicants for a Department Construction Permit shall submit the following as applicable:
(a) A completed application on forms furnished by the Department.
(b) An engineering report covering:
1. plant description and operations,
2. types and quantities of all waste material to be generated whether liquid, gaseous or solid,
3. proposed waste control facilities,
4. the treatment objectives,
5. the design criteria on which the control facilities are based, and,
6. other information deemed relevant.

Design criteria submitted pursuant to Rule 62-4.210(1)(b)5., F.A.C., shall be based on the results of laboratory and pilot-plant scale studies whenever such studies are warranted. The design efficiencies of the proposed waste treatment facilities and the quantities and types of pollutants in the treated effluents or emissions shall be indicated. Work of this nature shall be subject to the requirements of Chapter 471, F.S. Where confidential records are involved, certain information may be kept confidential pursuant to Section 403.111, F.S.

(c) The owners' written guarantee to meet the design criteria as accepted by the Department and to abide by Chapter 403, F.S. and the rules of the Department as to the quantities and types of materials to be discharged from the installation. The owner may be required to post an appropriate bond or other equivalent evidence of financial responsibility to guarantee compliance with such conditions in instances where the owner's financial resources are inadequate or proposed control facilities are experimental in nature.

(2) The construction permit may contain conditions and an expiration date as determined by the Secretary or the Secretary's designee.
(3) When the Department issues a permit to construct, the permittee shall be allowed a period of time, specified in the permit, to construct, and to operate and test to determine compliance with Chapter 403, F.S., and the rules of the Department and, where applicable, to apply for and receive an operation permit. The Department may require tests and evaluations of the treatment facilities by the permittee at his/her expense.
[Rule 62-4.210, F.A.C.]

14. Not federally enforceable. Operation Permit for New Sources. To properly apply for an operation permit for new sources, the applicant shall submit certification that construction was completed noting any deviations from the conditions in the construction permit and test results where appropriate.
[Rule 62-4.220, F.A.C.]

Chapters 28-106 and 62-110, F.A.C.

15. Public Notice, Public Participation, and Proposed Agency Action. The permittee shall comply with all of the requirements for public notice, public participation, and proposed agency action pursuant to Rule 62-110.106 and Rule 62-210.350, F.A.C.
[Rules 62-110.106, 62-210.350 and 62-213.430(1)(b), F.A.C.]

16. Administrative Hearing. The permittee shall comply with all of the requirements for a petition for administrative hearing or waiver of right to administrative proceeding pursuant to Rules 28-106.201, 28-106.301 and 62-110.106, F.A.C.
[Rules 28-106.201, 28-106.301 and 62-110.106, , F.A.C.]

Chapter 62-204, F.A.C.

17. Asbestos. This permit does not authorize any demolition or renovation of the facility or its parts or components which involves asbestos removal. This permit does not constitute a waiver of any of the requirements of Chapter 62-257, F.A.C., and 40 CFR Part 61, Subpart M, National Emission Standard for Asbestos, adopted and incorporated by reference in Rule 62-204.800, F.A.C. Compliance with Chapter 62-257, F.A.C., and 40 CFR 61, Subpart M, Section 61.145, is required for any asbestos demolition or renovation at the source.
[40 CFR 61; Rule 62-204.800, F.A.C.; and, Chapter 62-257, F.A.C.]

Chapter 62-210. F.A.C.

18. Permits Required. The owner or operator of any emissions unit which emits or can reasonably be expected to emit any air pollutant shall obtain an appropriate permit from the Department prior to beginning construction, modification, or initial or continued operation of the emissions unit unless exempted pursuant to Department rule or statute. All emissions limitations, controls, and other requirements imposed by such permits shall be at least as stringent as any applicable limitations and requirements contained in or enforceable under the State Implementation Plan (SIP) or that are otherwise federally enforceable. Except as provided at Rule 62-213.460, F.A.C., issuance of a permit does not relieve the owner or operator of an emissions unit from complying with any applicable requirements, any emission limiting standards or other requirements of the air pollution rules of the Department or any other such requirements under federal, state, or local law.

(1) Air Construction Permits.

(a) Unless exempt from permitting pursuant to Rule 62-210.300(3)(a) or (b), F.A.C., or Rule 62-4.040, F.A.C., an air construction permit shall be obtained by the owner or operator of any proposed new or modified facility or emissions unit prior to the beginning of construction or modification, in accordance with all applicable provisions of this chapter, Chapter 62-212, F.A.C., and Chapter 62-4, F.A.C. Except as provided under Rule 62-213.415, F.A.C., the owner or operator of any facility seeking to create or change an air emissions bubble shall obtain an air construction permit in accordance with all the applicable provisions of this chapter, Chapter 62-212, F.A.C., and Chapter 62-4, F.A.C. The construction permit shall be issued for a period of time sufficient to allow construction or modification of the facility or emissions unit and operation while the new or modified facility or emissions unit is conducting tests or otherwise demonstrating initial compliance with the conditions of the construction permit.

(b) Notwithstanding the expiration of an air construction permit, all limitations and requirements of such permit that are applicable to the design and operation of the permitted facility or emissions unit shall remain in effect until the facility or emissions unit is permanently shut down, except for any such limitation or requirement that is obsolete by its nature (such as a requirement for initial compliance testing) or any such limitation or requirement that is changed in accordance with the provisions of Rule 62-210.300(1)(b)1., F.A.C. Either the applicant or the Department can propose that certain conditions be considered obsolete. Any conditions or language in an air construction permit that are included for informational purposes only, if they are transferred to the air operation permit, shall be transferred for informational purposes only and shall not become enforceable conditions unless voluntarily agreed to by the permittee or otherwise required under Department rules.

1. Except for those limitations or requirements that are obsolete, all limitations and requirements of an air construction permit shall be included and identified in any air operation permit for the facility or emissions unit. The limitations and requirements included in the air operation permit can be changed, and thereby superseded, through the issuance of an air construction permit, federally enforceable state air operation permit, federally enforceable air general permit, or Title V air operation permit; provided, however, that:

a. Any change that would constitute an administrative correction may be made pursuant to Rule 62-210.360, F.A.C.;

b. Any change that would constitute a modification, as defined at Rule 62-210.200, F.A.C., shall be accomplished only through the issuance of an air construction permit; and

c. Any change in a permit limitation or requirement that originates from a permit issued pursuant to 40 CFR 52.21, Rule 62-204.800(10)(d)2., F.A.C., Rule 62-212.400, F.A.C., Rule 62-212.500, F.A.C., or any former codification of Rule 62-212.400 or 62-212.500, F.A.C., shall be accomplished only through the issuance of a new or revised air construction permit under Rule 62-204.800(10)(d)2., F.A.C., 62-212.400 or 62-212.500, F.A.C., as appropriate.

2. The force and effect of any change in a permit limitation or requirement made in accordance with the provisions of Rule 62-210.300(1)(b)1. F.A.C., shall be the same as if such change were made to the original air construction permit.

3. Nothing in Rule 62-210.300(1)(b), F.A.C., shall be construed as to allow operation of a facility or emissions unit without a valid air operation permit.

(2) Air Operation Permits. Upon expiration of the air operation permit for any existing facility or emissions unit, subsequent to construction or modification and demonstration of initial compliance with the conditions of the construction permit for any new or modified facility or emissions unit, or as otherwise provided in Chapter 62-210 or Chapter 62-213, the owner or operator of such facility or emissions unit shall obtain a renewal air operation permit, an initial air operation permit, or an administrative correction or revision of an existing air operation permit, whichever is appropriate, in accordance with all applicable provisions of Chapter 62-210, Chapter 62-213, and Chapter 62-4, F.A.C.

(a) Minimum Requirements for All Air Operation Permits. At a minimum, a permit issued pursuant to this subsection shall:

1. Specify the manner, nature, volume and frequency of the emissions permitted, and the applicable emission limiting standards or performance standards, if any;

2. Require proper operation and maintenance of any pollution control equipment by qualified personnel, where applicable in accordance with the provisions of any operation and maintenance plan required by the air pollution rules of the Department.

3. Contain an effective date stated in the permit which shall not be earlier than the date final action is taken on the application and be issued for a period, beginning on the effective date, as provided below.

   a. The operation permit for an emissions unit which is in compliance with all applicable rules and in operational condition, and which the owner or operator intends to continue operating, shall be issued or renewed for a five-year period, except that, for Title V sources subject to Rule 62-213.420(1)(a)1., F.A.C., operation permits shall be extended until 60 days after the due date for submittal of the facility's Title V permit application as specified in Rule 62-213.420(1)(a)1., F.A.C.

   b. Except as provided in Rule 62-210.300(2)(a)3.d., F.A.C., the operation permit for an emissions unit which has been shut down for six months or more prior to the expiration date of the current operation permit, shall be renewed for a period not to exceed five years from the date of shutdown, even if the emissions unit is not maintained in operational condition, provided:

      (i) the owner or operator of the emissions unit demonstrates to the Department that the emissions unit may need to be reactivated and used, or that it is the owner's or operator's intent to apply to the Department for a permit to construct a new emissions unit at the facility before the end of the extension period; and,

      (ii) the owner or operator of the emissions unit agrees to and is legally prohibited from providing the allowable emission permitted by the renewed permit as an emissions offset to any other person under Rule 62-212.500, F.A.C.; and,

      (iii) the emissions unit was operating in compliance with all applicable rules as of the time the source was shut down.

   c. Except as provided in Rule 62-210.300(2)(a)3.d., F.A.C., the operation permit for an emissions unit which has been shut down for five years or more prior to the expiration date of the current operation permit shall be renewed for a maximum period not to exceed ten years from the date of shutdown, even if the emissions unit is not maintained in operational condition, provided the conditions given in Rule 62-210.300(2)(a)3.b., F.A.C., are met and the owner or operator demonstrates to the Department that failure to renew the permit would constitute a hardship, which may include economic hardship.

   d. The operation permit for an electric utility generating unit on cold standby or long-term reserve shutdown shall be renewed for a five-year period, and additional five-year periods, even if the unit is not maintained in operational condition, provided the conditions given in Rules 62-210.300(2)(a)3.b.(i) through (iii), F.A.C., are met.

4. In the case of an emissions unit permitted pursuant to Rules 62-210.300(2)(a)3.b., c., and d., F.A.C., include reasonable notification and compliance testing requirements for reactivation of such emissions unit and provide that the owner or operator demonstrate to the Department prior to reactivation that such reactivation would not constitute reconstruction pursuant to Rule 62-204.800(7), F.A.C.

[Rules 62-210.300(1) & (2), F.A.C.]

19. Not federally enforceable. <u>Notification of Startup</u>. The owner or operator of any emissions unit or facility which has a valid air operation permit and which has been shut down more than one (1) year, shall notify the Department in writing of the intent to start up such emissions unit or facility, a minimum of sixty (60) days prior to the intended startup date.

   (a) The notification shall include the planned startup date, anticipated emission rates or pollutants released, changes to processes or control devices which will result in changes to emission rates, and any other conditions which may differ from the valid outstanding operation permit.

   (b) If, due to an emergency, a startup date is not known 60 days prior thereto, the owner shall notify the Department as soon as possible after the date of such startup is ascertained.

[Rule 62-210.300(5), F.A.C.]

20. <u>Emissions Unit Reclassification</u>.

(a) Any emissions unit whose operation permit has been revoked as provided for in Chapter 62-4, F.A.C., shall be deemed permanently shut down for purposes of Rule 62-212.500, F.A.C. Any emissions unit whose permit to operate has expired without timely renewal or transfer may be deemed permanently shut down, provided, however, that no such emissions unit shall be deemed permanently shut down if, within 20 days after receipt of written notice from the Department, the emissions unit owner or operator demonstrates that the permit expiration resulted from inadvertent failure to comply with the requirements of Rule 62-4.090, F.A.C., and that the owner or operator intends to continue the emissions unit in operation, and either submits an application for an air operation permit or complies with permit transfer requirements, if applicable.

(b) If the owner or operator of an emissions unit which is so permanently shut down, applies to the Department for a permit to reactivate or operate such emissions unit, the emissions unit will be reviewed and permitted as a new emissions unit.
[Rule 62-210.300(6), F.A.C.]

21. Public Notice and Comment.

(1) Public Notice of Proposed Agency Action.

(a) A notice of proposed agency action on permit application, where the proposed agency action is to issue the permit, shall be published by any applicant for:

1. An air construction permit;

2. An air operation permit, permit renewal or permit revision subject to Rule 62-210.300(2)(b), F.A.C., (i.e., a FESOP), except as provided in Rule 62-210.300(2)(b)1.b., F.A.C.; or

3. An air operation permit, permit renewal, or permit revision subject to Chapter 62-213, F.A.C., except those permit revisions meeting the requirements of Rule 62-213.412(1), F.A.C.

(b) The notice required by Rule 62-210.350(1)(a), F.A.C., shall be published in accordance with all otherwise applicable provisions of Rule 62-110.106, F.A.C. A public notice under Rule 62-210.350(1)(a)1., F.A.C., for an air construction permit may be combined with any required public notice under Rule 62-210.350(1)(a)2. or 3., F.A.C., for air operation permits. If such notices are combined, the public notice must comply with the requirements for both notices.

(c) Except as otherwise provided at Rules 62-210.350(2) and (5), F.A.C., each notice of intent to issue an air construction permit shall provide a 14-day period for submittal of public comments.

(2) Additional Public Notice Requirements for Emissions Units Subject to Prevention of Significant Deterioration or Nonattainment - Area Preconstruction Review.

(a) Before taking final agency action on a construction permit application for any proposed new or modified facility or emissions unit subject to the preconstruction review requirements of Rule 62-212.400 or 62-212.500, F.A.C., the Department shall comply with all applicable provisions of Rule 62-110.106, F.A.C., and provide an opportunity for public comment which shall include as a minimum the following:

1. A complete file available for public inspection in at least one location in the district affected which includes the information submitted by the owner or operator, exclusive of confidential records under Section 403.111, F.S., and the Department's analysis of the effect of the proposed construction or modification on ambient air quality, including the Department's preliminary determination of whether the permit should be approved or disapproved;

2. A 30-day period for submittal of public comments; and,

3. A notice, by advertisement in a newspaper of general circulation in the county affected, specifying the nature and location of the proposed facility or emissions unit, whether BACT or LAER has been determined, the degree of PSD increment consumption expected, if applicable, and the location of the information specified in paragraph 1. above; and notifying the public of the opportunity for submitting comments and requesting a public hearing.

(b) The notice provided for in Rule 62-210.350(2)(a)3:, F.A.C., shall be prepared by the Department and published by the applicant in accordance with all applicable provisions of Rule 62-110.106, F.A.C., except that the applicant shall cause the notice to be published no later than thirty (30) days prior to final agency action.

(c) A copy of the notice provided for in Rule 62-210.350(2)(a)3., F.A.C., shall also be sent by the Department to the Regional Office of the U. S. Environmental Protection Agency and to all other state and local officials or agencies having cognizance over the location of such new or modified facility or emissions unit, including local air pollution control agencies, chief executives of city or county government, regional land use planning agencies, and any other state, Federal Land Manager, or Indian Governing Body whose lands may be affected by emissions from the new or modified facility or emissions unit.

(d) A copy of the notice provided for in Rule 62-210.350(2)(a)3., F.A.C., shall be displayed in the appropriate district, branch and local program offices.

(e) An opportunity for public hearing shall be provided in accordance with Chapter 120, F.S., and Rule 62-110.106, F.A.C.

(f) Any public comments received shall be made available for public inspection in the location where the information specified in Rule 62-210.350(2)(a)1., F.A.C., is available and shall be considered by the Department in making a final determination to approve or deny the permit.

(g) The final determination shall be made available for public inspection at the same location where the information specified in Rule 62-210.350(2)(a)1., F.A.C., was made available.

(h) For a proposed new or modified emissions unit which would be located within 100 kilometers of any Federal Class I area or whose emissions may affect any Federal Class I area, and which would be subject to the preconstruction review requirements of Rule 62-212.400, F.A.C., or Rule 62-212.500, F.A.C.:

1. The Department shall mail or transmit to the Administrator a copy of the initial application for an air construction permit and notice of every action related to the consideration of the permit application.

2. The Department shall mail or transmit to the Federal Land Manager of each affected Class I area a copy of any written notice of intent to apply for an air construction permit; the initial application for an air construction permit, including all required analyses and demonstrations; any subsequently submitted information related to the application; the preliminary determination and notice of proposed agency action on the permit application; and any petition for an administrative hearing regarding the application or the Department's proposed action. Each such document shall be mailed or transmitted to the Federal Land Manager within fourteen (14) days after its receipt by the Department.

(3) Additional Public Notice Requirements for Facilities Subject to Operation Permits for Title V Sources.

(a) Before taking final agency action to issue a new, renewed, or revised air operation permit subject to Chapter 62-213, F.A.C., the Department shall comply with all applicable provisions of Rule 62-110.106, F.A.C., and provide an opportunity for public comment which shall include as a minimum the following:

1. A complete file available for public inspection in at least one location in the district affected which includes the information submitted by the owner or operator, exclusive of confidential records under Section 403.111, F.S.; and,

2. A 30-day period for submittal of public comments.

(b) The notice provided for in Rule 62-210.350(3)(a), F.A.C., shall be prepared by the Department and published by the applicant in accordance with all applicable provisions of Rule 62-110.106, F.A.C., except that the applicant shall cause the notice to be published no later than thirty (30) days prior to final agency action.

(c) The notice shall identify:

1. The facility;

2. The name and address of the office at which processing of the permit occurs;

3. The activity or activities involved in the permit action;

4. The emissions change involved in any permit revision;

5. The name, address, and telephone number of a Department representative from whom interested persons may obtain additional information, including copies of the permit draft, the application, and all relevant supporting materials, including any permit application, compliance plan, permit, monitoring report, and compliance statement required pursuant to Chapter 62-213, F.A.C. (except for information entitled to confidential treatment pursuant to Section 403.111, F.S.), and all other materials available to the Department that are relevant to the permit decision;

6. A brief description of the comment procedures required by Rule 62-210.350(3), F.A.C.;

7. The time and place of any hearing that may be held, including a statement of procedure to request a hearing (unless a hearing has already been scheduled); and,

8. The procedures by which persons may petition the Administrator to object to the issuance of the proposed permit after expiration of the Administrator's 45-day review period.

[Rule 62-210.350, F.A.C.]

22. Administrative Permit Corrections.

(1) A facility owner shall notify the Department by letter of minor corrections to information contained in a permit. Such notifications shall include:

(a) Typographical errors noted in the permit;

(b) Name, address or phone number change from that in the permit;

(c) A change requiring more frequent monitoring or reporting by the permittee;

(d) Changes listed at 40 CFR 72.83(a)(1), (2), (6), (9) and (10), hereby adopted and incorporated by reference, to Title V sources subject to emissions limitations or reductions pursuant to 42 USC ss. 7651-7651o;

(e) Changes listed at 40 CFR 72.83(a)(11), hereby adopted and incorporated by reference, to Title V sources subject to emissions limitations or reductions pursuant to 42 USC ss. 7651-7651o, provided the notification is accompanied by a copy of any EPA determination concerning the similarity of the change to those listed at Rule 62-210.360(1)(d), F.A.C.; and

(f) Any other similar minor administrative change at the source.

(2) Upon receipt of any such notification the Department shall within 60 days correct the permit and provide a corrected copy to the owner.

(3) After first notifying the owner, the Department shall correct any permit in which it discovers errors of the types listed at Rule 62-210.360(1)(a) and (b), F.A.C., and provide a corrected copy to the owner.

(4) For Title V source permits, other than general permits, a copy of the corrected permit shall be provided to EPA and any approved local air program in the county where the facility or any part of the facility is located.

(5) The Department shall incorporate requirements resulting from issuance of a new or revised construction permit into an existing Title V source permit, if the construction permit or permit revision incorporates requirements of federally enforceable preconstruction review, and if the applicant requests at the time of application that all of the requirements of Rule 62-213.430(1), F.A.C., be complied with in conjunction with the processing of the construction permit application.

[Rule 62-210.360, F.A.C.]

23. Reports.

(3) Annual Operating Report for Air Pollutant Emitting Facility.

(a) The Annual Operating Report for Air Pollutant Emitting Facility (DEP Form No. 62-210.900(5)) shall be completed each year.

(c) The annual operating report shall be submitted to the appropriate Department District or Department approved local air pollution control program office by March 1 of the following year unless otherwise indicated by permit condition or Department request.

[Rule 62-210.370(3), F.A.C.]

24. Circumvention. No person shall circumvent any air pollution control device, or allow the emission of air pollutants without the applicable air pollution control device operating properly.

[Rule 62-210.650, F.A.C.]

25. Forms and Instructions. The forms used by the Department in the stationary source control program are adopted and incorporated by reference in this section. The forms are listed by rule number, which is also the form number, with the subject, title and effective date. Forms 62-210.900(1),(3),(4) and (5), F.A.C., including instructions, are available from the Department as hard-copy documents or executable files on computer diskettes. Copies of forms (hard-copy or diskette) may be obtained by writing to the Department of Environmental Protection, Division of Air Resources Management, 2600 Blair Stone Road, Tallahassee, Florida 32399-2400. Notwithstanding the requirement of Rule 62-4.050(2), F.A.C., to file application forms in quadruplicate, if an air permit application is submitted using the Department's electronic application form, only one copy of the diskette and signature pages is required to be submitted.

(1) Application for Air Permit - Title V Source, Form and Instructions (Effective 2-11-99).

(a) Acid Rain Part (Phase II), Form and Instructions (Effective 7-1-95).

1. Repowering Extension Plan, Form and Instructions (Effective 7-1-95).
2. New Unit Exemption, Form and Instructions (Effective 7-1-95).
3. Retired Unit Exemption, Form and Instructions (Effective 7-1-95).
4. Phase II NOx Compliance Plan, Form and Instructions (Effective 1-6-98).
5. Phase II NOx Averaging Plan, Form (Effective 1-6-98).

(b) Reserved.

(5) Annual Operating Report for Air Pollutant Emitting Facility, Form and Instructions (Effective 2-11-99).

[Rule 62-210.900, F.A.C.]

Chapter 62-213. F.A.C.

26. Annual Emissions Fee. Each Title V source permitted to operate in Florida must pay between January 15 and March 1 of each year, upon written notice from the Department, an annual emissions fee in accordance with Rule 62-213.205, F.A.C., and the appropriate form and associated instructions.

[Rules 62-213.205 and 62-213.900(1), F.A.C.]

27. Annual Emissions Fee. Failure to pay timely any required annual emissions fee, penalty, or interest constitutes grounds for permit revocation pursuant to Rule 62-4.100, F.A.C.

[Rule 62-213.205(1)(g), F.A.C.]

28. Annual Emissions Fee. Any documentation of actual hours of operation, actual material or heat input, actual production amount, or actual emissions used to calculate the annual emissions fee shall be retained by the owner for a minimum of five (5) years and shall be made available to the Department upon request.

[Rule 62-213.205(1)(j), F.A.C.]

29. Annual Emissions Fee. A completed DEP Form 62-213.900(1), F.A.C., "Major Air Pollution Source Annual Emissions Fee Form", must be submitted by the responsible official with the annual emissions fee.

[Rule 62-213.205(1)(k), F.A.C.]

30. Air Operation Permit Fees. After December 31, 1992, no permit application processing fee, renewal fee, modification fee or amendment fee is required for an operation permit for a Title V source.
[Rule 62-213.205(4), F.A.C.]

31. Permits and Permit Revisions Required. All Title V sources are subject to the permit requirements of Chapter 62-213, F.A.C.
(1) No Title V source may operate except in compliance with Chapter 62-213, F.A.C.
(2) Except as provided in Rule 62-213.410, F.A.C., no source with a permit issued under the provisions of this chapter shall make any changes in its operation without first applying for and receiving a permit revision if the change meets any of the following:
(a) Constitutes a modification;
(b) Violates any applicable requirement;
(c) Exceeds the allowable emissions of any air pollutant from any unit within the source;
(d) Contravenes any permit term or condition for monitoring, testing, recordkeeping, reporting or of a compliance certification requirement;
(e) Requires a case-by-case determination of an emission limitation or other standard or a source specific determination of ambient impacts, or a visibility or increment analysis under the provisions of Chapters 62-212 or 62-296, F.A.C.;
(f) Violates a permit term or condition which the source has assumed for which there is no corresponding underlying applicable requirement to which the source would otherwise be subject;
(g) Results in the trading of emissions among units within a source except as specifically authorized pursuant to Rule 62-213.415, F.A.C.
(h) Results in the change of location of any relocatable facility identified as a Title V source pursuant to paragraph (a)-(e), (g) or (h) of the definition of "major source of air pollution" at Rule 62-210.200, F.A.C
(i) Constitutes a change at an Acid Rain Source under the provisions of 40 CFR 72.81(a)(1),(2),or (3),(b)(1) or (b)(3), hereby incorporated by reference;
(j) Constitutes a change in a repowering plan, nitrogen oxides averaging plan, or nitrogen oxides compliance deadline extension at an Acid Rain Source.
(k) Is a request for exemption pursuant to Rule 62-214.340, F.A.C.
[Rule 62-213.400(1) & (2), F.A.C.]

32. Changes Without Permit Revision. Title V sources having a valid permit issued pursuant to Chapter 62-213, F.A.C., may make the following changes without permit revision, provided that sources shall maintain source logs or records to verify periods of operation in each alternative method of operation:
(1) Permitted sources may change among those alternative methods of operation allowed by the source's permit as provided by the terms of the permit;
(2) Permitted sources may implement the terms or conditions of a new or revised construction permit if;
(a) The application for construction permit complied with the requirements of Rule 62-213.420(3) and (4), F.A.C.;
(b) The terms or conditions were subject to federally enforceable preconstruction review pursuant to Chapter 62-212, F.A.C.; and,
(c) The new or revised construction permit was issued after the Department and the applicant complied with all the requirements of Rule 62-213.430(1), F.A.C.;
(3) A permitted source may implement operating changes after the source submits any forms required by any applicable requirement and provides the Department and EPA with at least 7 days written notice prior to implementation. The source and the Department shall attach each notice to the relevant permit;
(a) The written notice shall include the date on which the change will occur, and a description of the change within the permitted source, the pollutants emitted and any change in emissions, and any term or condition becoming applicable or no longer applicable as a result of the change;
(b) The permit shield described in Rule 62-213.460, F.A.C., shall not apply to such changes;
(4) Permitted sources may implement changes involving modes of operation only in accordance with Rule 62-213.415, F.A.C.
[Rule 62-213.410, F.A.C.]

33. Immediate Implementation Pending Revision Process.
(1) Those permitted Title V sources making any change that constitutes a modification pursuant to the definition of modification at Rule 62-210.200, F.A.C., but which would not constitute a modification pursuant to 42 USC 7412(a) or to 40 CFR 52.01, 60.2, or 61.15, adopted and incorporated by reference at Rule 62-204.800, F.A.C., may implement such change prior to final issuance of a permit revision in accordance with this section, provided the change:
(a) Does not violate any applicable requirement;
(b) Does not contravene any permit term or condition for monitoring, testing, recordkeeping or reporting, or any compliance certification requirement;

(c) Does not require or change a case-by-case determination of an emission limitation or other standard, or a source-specific determination of ambient impacts, or a visibility or increment analysis under the provisions of Chapter 62-212 or 62-296, F.A.C.;

(d) Does not seek to establish or change a permit term or condition for which there is no corresponding underlying applicable requirement and that the source has assumed to avoid an applicable requirement to which the source would otherwise be subject including any federally enforceable emissions cap or federally enforceable alternative emissions limit.

(2) A Title V source may immediately implement such changes after they have been incorporated into the terms and conditions of a new or revised construction permit issued pursuant to Chapter 62-212, F.A.C., and after the source provides to EPA, the Department, each affected state and any approved local air program having geographic jurisdiction over the source, a copy of the source's application for operation permit revision. The Title V source may conform its application for construction permit to include all information required by Rule 62-213.420, F.A.C., in lieu of submitting separate application forms.

(3) The Department shall process the application for operation permit revision in accordance with the provisions of Chapter 62-213, F.A.C., except that the Department shall issue a draft permit revision or a determination to deny the revision within 60 days of receipt of a complete application for operation permit revision or, if the Title V source has submitted a construction permit application conforming to the requirements of Rule 62-213.420, F.A.C., the Department shall issue a draft permit or a determination to deny the revision at the same time the Department issues its determination on issuance or denial of the construction permit application. The Department shall not take final action until all the requirements of Rule 62-213.430(1)(a), (c), (d), and (e), F.A.C., have been complied with.

(4) Pending final action on the operation permit revision application, the source shall implement the changes in accordance with the terms and conditions of the source's new or revised construction permit.

(5) The permit shield described in Rule 62-213.460, F.A.C., shall not apply to such changes until after the Department takes final action to issue the operation permit revision.

(6) If the Department denies the source's application for operation permit revision, the source shall cease implementation of the proposed changes.

[Rule 62-213.412, F.A.C.]

34. <u>Permit Applications</u>.

(1). Duty to Apply. For each Title V source, the owner or operator shall submit a timely and complete permit application in compliance with the requirements of Rules 62-213.420, 62-4.050(1) & (2), and 62-210.900, F.A.C.

(a) Timely Application.

3. For purposes of permit renewal, a timely application is one that is submitted in accordance with Rule 62-4.090, F.A.C.

(b) Complete Application.

1. Any applicant for a Title V permit, permit revision or permit renewal must submit an application on DEP Form No. 62-210.900(1), which must include all the information specified by Rule 62-213.420(3), F.A.C., except that an application for permit revision must contain only that information related to the proposed change. The applicant shall include information concerning fugitive emissions and stack emissions in the application. Each application for permit, permit revision or permit renewal shall be certified by a responsible official in accordance with Rule 62-213.420(4), F.A.C.

2. For those applicants submitting initial permit applications pursuant to Rule 62-213.420(1)(a)1., F.A.C., a complete application shall be an application that substantially addresses all the information required by the application form number 62-210.900(1), and such applications shall be deemed complete within sixty days of receipt of a signed and certified application unless the Department notifies the applicant of incompleteness within that time. For all other applicants, the applications shall be deemed complete sixty days after receipt, unless the Department, within sixty days after receipt of a signed application for permit, permit revision or permit renewal, requests additional documentation or information needed to process the application. An applicant making timely and complete application for permit, or timely application for permit renewal as described by Rule 62-4.090(1), F.A.C., shall continue to operate the source under the authority and provisions of any existing valid permit or Florida Electrical Power Plant Siting Certification, provided the applicant complies with all the provisions of Rules 62-213.420(1)(b)3. and 4. F.A.C. Failure of the Department to request additional information within sixty days of receipt of a properly signed application shall not impair the Department's ability to request additional information pursuant to Rules 62-213.420(1)(b)3. and 4., F.A.C.

3. For those permit applications submitted pursuant to the provisions of Rule 62-213.420(1)(a)1., F.A.C., the Department shall notify the applicant if the Department becomes aware at any time during processing of the application that the application contains incorrect or incomplete information. The applicant shall submit the corrected or supplementary information to the Department within ninety days unless the applicant has requested and been granted additional time to submit the information. Failure of an applicant to submit corrected or supplementary information requested by the Department within ninety days or such additional time as requested and granted shall render the application incomplete.
4. For all applications other than those addressed at Rule 62-213.420(1)(b)3., F.A.C., should the Department become aware, during processing of any application that the application contains incorrect information, or should the Department become aware, as a result of comment from an affected State, an approved local air program, EPA, or the public that additional information is needed to evaluate the application, the Department shall notify the applicant within 30 days. When an applicant becomes aware that an application contains incorrect or incomplete information, the applicant shall submit the corrected or supplementary information to the Department. If the Department notifies an applicant that corrected or supplementary information is necessary to process the permit, and requests a response, the applicant shall provide the information to the Department within ninety days of the Department request unless the applicant has requested and been granted additional time to submit the information or, the applicant shall, within ninety days, submit a written request that the Department process the application without the information. Failure of an applicant to submit corrected or supplementary information requested by the Department within ninety days, or such additional time as requested and granted, or to demand in writing within ninety days that the application be processed without the information shall render the application incomplete. Nothing in this section shall limit any other remedies available to the Department.

[Rules 62-213.420(1)(a)3. and 62-213.420(1)(b)1., 2., 3. & 4., F.A.C.]

35. Confidential Information. Whenever an applicant submits information under a claim of confidentiality pursuant to Section 403.111, F.S., the applicant shall also submit a copy of all such information and claim directly to EPA. (also, see Condition No. 50.)
[Rule 62-213.420(2), F.A.C.]

36. Standard Application Form and Required Information. Applications shall be submitted under Chapter 62-213, F.A.C., on forms provided by the Department and adopted by reference in Rule 62-210.900(1), F.A.C. The information as described in Rule 62-210.900(1), F.A.C., shall be included for the Title V source and each emissions unit. An application must include information sufficient to determine all applicable requirements for the Title V source and each emissions unit and to evaluate a fee amount pursuant to Rule 62-213.205, F.A.C.
[Rule 62-213.420(3), F.A.C.]

37. Certification by Responsible Official (RO). In addition to the professional engineering certification required for applications by Rule 62-4.050(3), F.A.C., any application form, report, compliance statement, compliance plan and compliance schedule submitted pursuant to Chapter 62-213, F.A.C., shall contain a certification signed by a responsible official that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete.
[Rule 62-213.420(4), F.A.C.]

38. a. Permit Renewal and Expiration. Permits being renewed are subject to the same requirements that apply to permit issuance at the time of application for renewal. Permit renewal applications shall contain that information identified in Rules 62-210.900(1) and 62-213.420(3), F.A.C. Unless a Title V source submits a timely application for permit renewal in accordance with the requirements of Rule 62-4.090(1), F.A.C., the existing permit shall expire and the source's right to operate shall terminate.

b. Permit Revision Procedures. Permit revisions shall meet all requirements of Chapter 62-213, F.A.C., including those for content of applications, public participation, review by approved local programs and affected states, and review by EPA, as they apply to permit issuance and renewal, except that permit revisions for those activities implemented pursuant to Rule 62-213.412, F.A.C., need not meet the requirements of Rule 62-213.430(1)(b), F.A.C. The Department shall require permit revision in accordance with the provisions of Rule 62-4.080, F.A.C., and 40 CFR 70.7(f), whenever any source becomes subject to any condition listed at 40 CFR 70.7(f)(1), hereby adopted and incorporated by reference. The below requirements from 40 CFR 70.7(f) are adopted and incorporated by reference in Rule 62-213.430(4), F.A.C.:

o 40 CFR 70.7(f): Reopening for Cause. (also, see Condition No. 4)

(1) This section contains provisions from 40 CFR 70.7(f) that specify the conditions under which a Title V permit shall be reopened prior to the expiration of the permit. A Title V permit shall be reopened and revised under any of the following circumstances:

(i) Additional applicable requirements under the Act become applicable to a major Part 70 source with a remaining permit term of 3 or more years. Such a reopening shall be completed not later than 18 months after promulgation of the applicable requirement. No such reopening is required if the effective date of the requirement is later than the date on which the permit is due to expire, unless the original permit or any of its terms and conditions has been extended pursuant to 40 CFR 70.4(b)(10)(i) or (ii).

(ii) Additional requirements (including excess emissions requirements) become applicable to an affected source under the acid rain program. Upon approved by the Administrator, excess emissions offset plans shall be deemed to be incorporated into the permit.

(iii) The permitting authority or EPA determines that the permit contains a material mistake or that inaccurate statements were made in establishing the emissions standards or other terms or conditions of the permit.

(iv) The Administrator or the permitting authority determines that the permit must be revised or revoked to assure compliance with the applicable requirements.

(2) Proceedings to reopen and issue a permit shall follow the same procedures as apply to initial permit issuance and shall affect only those parts of the permit for which cause to reopen exists. Such reopening shall be made as expeditiously as practicable.

(3) Reopenings under 40 CFR 70.7(f)(1) shall not be initiated before a notice of such intent is provided to the Part 70 source by the permitting authority at least 30 days in advance of the date that the permit is to be reopened, except that the permitting authority may provide a shorter time period in the case of an emergency.

[Rules 62-213.430(3) & (4), F.A.C.; and, 40 CFR 70.7(f)]

39. Insignificant Emissions Units or Pollutant-Emitting Activities.

(a) All requests for determination of insignificant emissions units or activities made pursuant to Rule 62-213.420(3)(m), F.A.C., shall be processed in conjunction with the permit, permit renewal or permit revision application submitted pursuant to Chapter 62-213, F.A.C. Insignificant emissions units or activities shall be approved by the Department consistent with the provisions of Rule 62-4.040(1)(b), F.A.C. Emissions units or activities which are added to a Title V source after issuance of a permit under Chapter 62-213, F.A.C., shall be incorporated into the permit at its next renewal, provided such emissions units or activities have been exempted from the requirement to obtain an air construction permit and also qualify as insignificant pursuant to Rule 62-213.430(6), F.A.C.

(b) An emissions unit or activity shall be considered insignificant if:

1. Such unit or activity would be subject to no unit-specific applicable requirement;
2. Such unit or activity, in combination with other units or activities proposed as insignificant, would not cause the facility to exceed any major source threshold(s) as defined in Rule 62-213.420(3)(c)1., F.A.C., unless it is acknowledged in the permit application that such units or activities would cause the facility to exceed such threshold(s); and
3. Such unit or activity would not emit or have the potential to emit:
    a. 500 pounds per year or more of lead and lead compounds expressed as lead;
    b. 1,000 pounds per year or more of any hazardous air pollutant;
    c. 2,500 pounds per year or more of total hazardous air pollutants; or
    d. 5.0 tons per year or more of any other regulated pollutant.

[Rule 62-213.430(6), F.A.C.]

40. Permit Duration. Operation permits for Title V sources may not be extended as provided in Rule 62-4.080(3), F.A.C., if such extension will result in a permit term greater than five (5) years.

[Rule 62-213.440(1)(a), F.A.C.]

41. Monitoring Information. All records of monitoring information shall specify the date, place, and time of sampling or measurement and the operating conditions at the time of sampling or measurement, the date(s) analyses were performed, the company or entity that performed the analyses, the analytical techniques or methods used, and the results of such analyses.
[Rule 62-213.440(1)(b)2.a., F.A.C.]

42. Retention of Records. Retention of records of all monitoring data and support information shall be for a period of at least 5 years from the date of the monitoring sample, measurement, report, or application. Support information includes all calibration and maintenance records and all original strip-chart recordings for continuous monitoring instrumentation, and copies of all reports required by the permit.
[Rule 62-213.440(1)(b)2.b., F.A.C.]

43. Monitoring Reports. The permittee shall submit reports of any required monitoring at least every six (6) months. All instances of deviations from permit requirements must be clearly identified in such reports.
[Rule 62-213.440(1)(b)3.a., F.A.C.]

44. Deviation from Permit Requirements Reports. The permittee shall report in accordance with the requirements of Rules 62-210.700(6) and 62-4.130, F.A.C., any deviations from permit requirements, including those attributable to upset conditions as defined in the permit. Reports shall include the probable cause of such deviations, and any corrective actions or preventive measures taken.
[Rule 62-213.440(1)(b)3.b., F.A.C.]

45. Reports. All reports shall be accompanied by a certification by a responsible official, pursuant to Rule 62-213.420(4), F.A.C.
[Rule 62-213.440(1)(b)3.c, F.A.C.]

46. If any portion of the final permit is invalidated, the remainder of the permit shall remain in effect.
[Rule 62-213.440(1)(d)1., F.A.C.]

47. It shall not be a defense for a permittee in an enforcement action that maintaining compliance with any permit condition would necessitate halting of or reduction of the source activity.
[Rule 62-213.440(1)(d)3., F.A.C.]

48. A Title V source shall comply with all the terms and conditions of the existing permit until the Department has taken final action on any permit renewal or any requested permit revision, except as provided at Rule 62-213.412(2), F.A.C.
[Rule 62-213.440(1)(d)4., F.A.C.]

49. A situation arising from sudden and unforeseeable events beyond the control of the source which causes an exceedance of a technology-based emissions limitation because of unavoidable increases in emissions attributable to the situation and which requires immediate corrective action to restore normal operation, shall be an affirmative defense to an enforcement action in accordance with the provisions and requirements of 40 CFR 70.6(g)(2) and (3), hereby adopted and incorporated by reference.
[Rule 62-213.440(1)(d)5., F.A.C.]

50. Confidentiality Claims. Any permittee may claim confidentiality of any data or other information by complying with Rule 62-213.420(2), F.A.C. (also, see Condition No. 35.)
[Rule 62-213.440(1)(d)6., F.A.C.]

51. Statement of Compliance. The permittee shall submit a statement of compliance with all terms and conditions of the permit. Such statements shall be submitted to the Department and EPA annually, or more frequently if specified by Rule 62-213.440(2), F.A.C., or by any other applicable requirement. Such statements shall be accompanied by a certification in accordance with Rule 62-213.420(4), F.A.C. The statement of compliance shall include all the provisions of 40 CFR 70.6(c)(5)(iii), incorporated by reference at Rule 62-204.800, F.A.C.

o 40 CFR 70.6(c)(5)(iii). The compliance certification shall include all of the following (provided that the identification of applicable information may cross-reference the permit or previous reports, as applicable):

(A) The identification of each term or condition of the permit that is the basis of the certification;

(B) The identification of the method(s) or other means used by the owner or operator for determining the compliance status with each term and condition during the certification period, and whether such methods or other means provide continuous or intermittent data. Such methods and other means shall include, at a minimum, the methods and means required under 40 CFR 70.6(a)(3). If necessary, the owner or operator also shall identify any other material information that must be included in the certification to comply with section113(c)(2) of the Act, which prohibits knowingly making a false certification or omitting material information;

(C) The status of compliance with the terms and conditions of the permit for the period covered by the certification, based on the method or means designated in paragraph (c)(5)(iii)(B) of this section. The certification shall identify each deviation and take it into account in the compliance certification. The certification shall also identify as possible exceptions to compliance any periods during which compliance is required and in which an excursion or exceedance as defined under part 64 of this chapter occurred; and

(D) Such other facts as the permitting authority may require to determine the compliance status of the source.

The statement shall be accompanied by a certification by a responsible official, in accordance with Rule 62-213.420(4), F.A.C. The responsible official may treat compliance with all other applicable requirements as a surrogate for compliance with Rule 62-296.320(2), Objectionable Odor Prohibited.

[Rule 62-213.440(3), F.A.C.]

52. Permit Shield. Except as provided in Chapter 62-213, F.A.C., compliance with the terms and conditions of a permit issued pursuant to Chapter 62-213, F.A.C., shall be deemed compliance with any applicable requirements in effect as of the date of permit issuance, provided that the source included such applicable requirements in the permit application. Nothing in Rule 62-213.460, F.A.C., or in any permit shall alter or affect the ability of EPA or the Department to deal with an emergency, the liability of an owner or operator of a source for any violation of applicable requirements prior to or at the time of permit issuance, or the requirements of the Federal Acid Rain Program.

{Permitting note: The permit shield is not in effect until the effective date of the permit.}

[Rule 62-213.460, F.A.C.]

53. Forms and Instructions. The forms used by the Department in the Title V source operation program are adopted and incorporated by reference in Rule 62-213.900, F.A.C. The form is listed by rule number, which is also the form number, and with the subject, title, and effective date. Copies of forms may be obtained by writing to the Department of Environmental Protection, Division of Air Resources Management, 2600 Blair Stone Road, Tallahassee, Florida 32399-2400, or by contacting the appropriate permitting authority.

(1) Major Air Pollution Source Annual Emissions Fee (AEF) Form.

[Rule 62-213.900(1), F.A.C.]

Chapter 62-256. F.A.C.

54. Not federally enforceable. Open Burning. This permit does not authorize any open burning nor does it constitute any waiver of the requirements of Chapter 62-256, F.A.C. Source shall comply with Chapter 62-256, F.A.C., for any open burning at the source.

[Chapter 62-256, F.A.C.]

Chapter 62-281. F.A.C.

55. Refrigerant Requirements. Any facility having refrigeration equipment, including air conditioning equipment, which uses a Class I or II substance (listed at 40 CFR 82, Subpart A, Appendices A and B), and any facility which maintains, services, or repairs motor vehicles using a Class I or Class II substance as refrigerant must comply with all requirements of 40 CFR 82, Subparts B and F, and with Rule 62-281.100, F.A.C. Those requirements include the following restrictions:

(1) Any facility having any refrigeration equipment normally containing 50 (fifty) pounds of refrigerant, or more, must keep servicing records documenting the date and type of all service and the quantity of any refrigerant added pursuant to 40 CFR 82.166;

(2) No person repairing or servicing a motor vehicle may perform any service on a motor vehicle air conditioner (MVAC) involving the refrigerant for such air conditioner unless the person has been properly trained and certified as provided at 40 CFR 82.34 and 40 CFR 82.40, and properly uses equipment approved pursuant to 40 CFR 82.36 and 40 CFR 82.38, and complies with 40 CFR 82.42;
(3) No person may sell or distribute, or offer for sale or distribution, any substance listed as a Class I or Class II substance at 40 CFR 82, Subpart A, Appendices A and B, except in compliance with Rule 62-281.100, F.A.C., and 40 CFR 82.34(b), 40 CFR 82.42, and/or 40 CFR 82.166;
(4) No person maintaining, servicing, repairing, or disposing of appliances may knowingly vent or otherwise release into the atmosphere any Class I or Class II substance used as a refrigerant in such equipment and no other person may open appliances (except MVACs as defined at 40 CFR 82.152) for service, maintenance or repair unless the person has been properly trained and certified pursuant to 40 CFR 82.161 and unless the person uses equipment certified for that type of appliance pursuant to 40 CFR 82.158 and unless the person observes the practices set forth at 40 CFR 82.156 and 40 CFR 82.166;
(5) No person may dispose of appliances (except small appliances, as defined at 40 CFR 82.152) without using equipment certified for that type of appliance pursuant to 40 CFR 82.158 and without observing the practices set forth at 40 CFR 82.156 and 40 CFR 82.166;
(6) No person may recover refrigerant from small appliances, MVACs and MVAC-like appliances (as defined at 40 CFR 82.152), except in compliance with the requirements of 40 CFR 82, Subpart F.
[40 CFR 82; and, Chapter 62-281, F.A.C. (Chapter 62-281, F.A.C., is not federally enforceable)]

Chapter 62-296, F.A.C.

56. Industrial, Commercial, and Municipal Open Burning Prohibited. Open burning in connection with industrial, commercial, or municipal operations is prohibited, except when:

(a) Open burning is determined by the Department to be the only feasible method of operation and is authorized by an air permit issued pursuant to Chapter 62-210 or 62-213, F.A.C.; or

(b) An emergency exists which requires immediate action to protect human health and safety; or

(c) A county or municipality would use a portable air curtain incinerator to burn yard trash generated by a hurricane, tornado, fire or other disaster and the air curtain incinerator would otherwise be operated in accordance with the permitting exemption criteria of Rule 62-210.300(3), F.A.C.

[Rule 62-296.320(3), F.A.C.]

58. Unconfined Emissions of Particulate Matter.
(4)(c)1. No person shall cause, let, permit, suffer or allow the emissions of unconfined particulate matter from any emissions unit whatsoever, including, but not limited to, vehicular movement, transportation of materials, construction, alteration, demolition or wrecking, or industrially related activities such as loading, unloading, storing or handling, without taking reasonable precautions to prevent such emission.

3. Reasonable precautions may include, but shall not be limited to the following:

a. Paving and maintenance of roads, parking areas and yards.

b. Application of water or chemicals to control emissions from such activities as demolition of buildings, grading roads, construction, and land clearing.

c. Application of asphalt, water, oil, chemicals or other dust suppressants to unpaved roads, yards, open stock piles and similar emissions units.

d. Removal of particulate matter from roads and other paved areas under the control of the owner or operator of the emissions unit to prevent reentrainment, and from buildings or work areas to prevent particulate from becoming airborne.

e. Landscaping or planting of vegetation.

f. Use of hoods, fans, filters, and similar equipment to contain, capture and/or vent particulate matter.

g. Confining abrasive blasting where possible.

h. Enclosure or covering of conveyor systems.

4. In determining what constitutes reasonable precautions for a particular facility, the Department shall consider the cost of the control technique or work practice, the environmental impacts of the technique or practice, and the degree of reduction of emissions expected from a particular technique or practice.
[Rules 62-296:320(4)(c)1., 3., & 4. F.A.C.]

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APPENDIX SS-1, STACK SAMPLING FACILITIES (version dated 10/07/96)

Stack Sampling Facilities Provided by the Owner of an Emissions Unit. This section describes the minimum requirements for stack sampling facilities that are necessary to sample point emissions units. Sampling facilities include sampling ports, work platforms, access to work platforms, electrical power, and sampling equipment support. Emissions units must provide these facilities at their expense. All stack sampling facilities must meet any Occupational Safety and Health Administration (OSHA) Safety and Health Standards described in 29 CFR Part 1910, Subparts D and E.

(a) Permanent Test Facilities. The owner or operator of an emissions unit for which a compliance test, other than a visible emissions test, is required on at least an annual basis, shall install and maintain permanent stack sampling facilities.

(b) Temporary Test Facilities. The owner or operator of an emissions unit that is not required to conduct a compliance test on at least an annual basis may use permanent or temporary stack sampling facilities. If the owner chooses to use temporary sampling facilities on an emissions unit, and the Department elects to test the unit, such temporary facilities shall be installed on the emissions unit within 5 days of a request by the Department and remain on the emissions unit until the test is completed.

(c) Sampling Ports.

1. All sampling ports shall have a minimum inside diameter of 3 inches.

2. The ports shall be capable of being sealed when not in use.

3. The sampling ports shall be located in the stack at least 2 stack diameters or equivalent diameters downstream and at least 0.5 stack diameter or equivalent diameter upstream from any fan, bend, constriction or other flow disturbance.

4. For emissions units for which a complete application to construct has been filed prior to December 1, 1980, at least two sampling ports, 90 degrees apart, shall be installed at each sampling location on all circular stacks that have an outside diameter of 15 feet or less. For stacks with a larger diameter, four sampling ports, each 90 degrees apart, shall be installed. For emissions units for which a complete application to construct is filed on or after December 1, 1980, at least two sampling ports, 90 degrees apart, shall be installed at each sampling location on all circular stacks that have an outside diameter of 10 feet or less. For stacks with larger diameters, four sampling ports, each 90 degrees apart, shall be installed. On horizontal circular ducts, the ports shall be located so that the probe can enter the stack vertically, horizontally or at a 45 degree angle.

5. On rectangular ducts, the cross sectional area shall be divided into the number of equal areas in accordance with EPA Method 1. Sampling ports shall be provided which allow access to each sampling point. The ports shall be located so that the probe can be inserted perpendicular to the gas flow.

(d) Work Platforms.

1. Minimum size of the working platform shall be 24 square feet in area. Platforms shall be at least 3 feet wide.

2. On circular stacks with 2 sampling ports, the platform shall extend at least 110 degrees around the stack.

3. On circular stacks with more than two sampling ports, the work platform shall extend 360 degrees around the stack.

4. All platforms shall be equipped with an adequate safety rail (ropes are not acceptable), toeboard, and hinged floor-opening cover if ladder access is used to reach the platform. The safety rail directly in line with the sampling ports shall be removable so that no obstruction exists in an area 14 inches below each sample port and 6 inches on either side of the sampling port.

(e) Access to Work Platform.

1. Ladders to the work platform exceeding 15 feet in length shall have safety cages or fall arresters with a minimum of 3 compatible safety belts available for use by sampling personnel.

2. Walkways over free-fall areas shall be equipped with safety rails and toeboards.

(f) Electrical Power.

1. A minimum of two 120-volt AC, 20-amp outlets shall be provided at the sampling platform within 20 feet of each sampling port.

2. If extension cords are used to provide the electrical power, they shall be kept on the plant's property and be available immediately upon request by sampling personnel.

(g) Sampling Equipment Support.

1. A three-quarter inch eyebolt and an angle bracket shall be attached directly above each port on vertical stacks and above each row of sampling ports on the sides of horizontal ducts.

a. The bracket shall be a standard 3 inch x 3 inch x one-quarter inch equal-legs bracket which is 1 and one-half inches wide. A hole that is one-half inch in diameter shall be drilled through the exact center of the horizontal portion of the bracket. The horizontal portion of the bracket shall be located 14 inches above the centerline of the sampling port.

b. A three-eighth inch bolt which protrudes 2 inches from the stack may be substituted for the required bracket. The bolt shall be located 15 and one-half inches above the centerline of the sampling port.

c. The three-quarter inch eyebolt shall be capable of supporting a 500 pound working load. For stacks that are less than 12 feet in diameter, the eyebolt shall be located 48 inches above the horizontal portion of the angle bracket. For stacks that are greater than or equal to 12 feet in diameter, the eyebolt shall be located 60 inches above the horizontal portion of the angle bracket. If the eyebolt is more than 120 inches above the platform, a length of chain shall be attached to it to bring the free end of the chain to within safe reach from the platform.

2. A complete monorail or dualrail arrangement may be substituted for the eyebolt and bracket.

3. When the sample ports are located in the top of a horizontal duct, a frame shall be provided above the port to allow the sample probe to be secured during the test.

[Rule 62-297.310(6), F.A.C.]

TABLE 297.310-1 CALIBRATION SCHEDULE
(version dated 10/07/96)

[Note: This table is referenced in Rule 62-297.310, F.A.C.]

ITEM	MINIMUM CALIBRATION FREQUENCY	REFERENCE INSTRUMENT	TOLERANCE
Liquid in glass thermometer	Annually	ASTM Hg in glass ref. thermometer or equivalent, or thermometric points	+/-2%
Bimetallic thermometer	Quarterly	Calib. liq. in glass thermometer	5 degrees F
Thermocouple	Annually	ASTM Hg in glass ref. thermometer, NBS calibrated reference and potentiometer	5 degrees F
Barometer	Monthly	Hg barometer or NOAA station	+/-1% scale
Pitot Tube	When required or when damaged	By construction or measurements in wind tunnel D greater than 16" and standard pitot tube	See EPA Method 2, Fig. 2-2 & 2-3
Probe Nozzles	Before each test or when nicked, dented, or corroded	Micrometer	+/-0.001" mean of at least three readings Max. deviation between readings .004"
Dry Gas Meter and Orifice Meter	1. Full Scale: When received, When 5% change observed, Annually 2. One Point: Semiannually	Spirometer or calibrated wet test or dry gas test meter	2%
	3. Check after each test series	Comparison check	5%

[electronic file name: 297310-1.doc]

FIGURE 1--SUMMARY REPORT--GASEOUS AND OPACITY EXCESS EMISSION AND MONITORING SYSTEM PERFORMANCE (version dated 7/96)

[Note: This form is referenced in 40 CFR 60.7, Subpart A-General Provisions]

Pollutant *(Circle One)*: SO_2 NO_X TRS H_2S CO Opacity

Reporting period dates: From ________________ to ________________

Company: ________________

Emission Limitation: ________________

Address: ________________

Monitor Manufacturer: ________________

Model No.: ________________

Date of Latest CMS Certification or Audit: ________________

Process Unit(s) Description: ________________

Total source operating time in reporting period [1]: ________________

Emission data summary [1]	CMS performance summary [1]
1. Duration of excess emissions in reporting period due to:	1. CMS downtime in reporting period due to:
a. Startup/shutdown .... ____	a. Monitor equipment malfunctions .... ____
b. Control equipment problems .... ____	b. Non-Monitor equipment malfunctions .... ____
c. Process problems .... ____	c. Quality assurance calibration .... ____
d. Other known causes .... ____	d. Other known causes .... ____
e. Unknown causes .... ____	e. Unknown causes .... ____
2. Total duration of excess emissions .... ____	2. Total CMS Downtime .... ____
3. Total duration of excess emissions x (100) / [Total source operating time] .... ____ % [2]	3. [Total CMS Downtime] x (100) / [Total source operating time] .... ____ % [2]

1 For opacity, record all times in minutes. For gases, record all times in hours.

2 For the reporting period: If the total duration of excess emissions is 1 percent or greater of the total operating time or the total CMS downtime is 5 percent or greater of the total operating time, both the summary report form and the excess emission report described in 40 CFR 60.7(c) shall be submitted.

Note: On a separate page, describe any changes since last quarter in CMS, process or controls.

I certify that the information contained in this report is true, accurate, and complete.

Name: ________________

Signature: ________________ *Date*: ________________

Title: ________________

[electronic file name: figure1.doc]

DOCUMENT III.I.6

PROCEDURES FOR STARTUP AND SHUTDOWN

PROCEDURES FOR STARTUP AND SHUTDOWN
UNITS 1 - 4

Procedures for startup and shutdown of Units 1 through 4 are as follows:

A. STARTUP

1. Boilers are purged to expel all combustible gases.

2. Ignitors are placed in service to establish an oil fire.

3. Once the air leaving the air preheater reaches 180° F, a centrally located fuel pulverizer is activated.

4. Fuel feeders and ignitors are rotated in and out of service to establish an even fire.

5. As soon as fuel fire is established, electrostatic precipitator rectifiers are added as needed to control PM emissions.

6. Following boiler stabilization at minimum load, the oil ignitors are removed and the electrostatic precipitator is placed in full service.

7. Excess emissions during startup are minimized by the following activities:

    - Opacity is continuously monitored;
    - Ignitor burner tips are checked on a regular basis to ensure the ignitors remain lit and have even oil flow;
    - An adequate supply of combustion air is maintained;
    - Combustion air is manually and continuously controlled to maintain even combustion; and
    - Precipitators are placed in service prior to load stabilization.

B. SHUTDOWN

1. After the decision for boiler shutdown is made, load and steam header pressure are reduced.

2. Ignitors are placed in service as permissives for fuel feed removal.

3. Steam turbine is "punched out" when all fuel feeders are out of service and load and steam header pressure are approximately 5 MW and 500 lbs, respectively.

4. Exhaust fans are used to expedite boiler cooling.

PROCEDURES FOR STARTUP AND SHUTDOWN
UNITS 1 - 4 (continued)

5. Excess emissions during shutdown are minimized by the following activities:

   - Opacity is continuously monitored;
   - Precipitators are removed from service only if precipitator maintenance is required; and
   - Air flow, dampers, etc., are manually adjusted.

Unit 4 FGD System

A. STARTUP

Startup of the FGD system begins with starting up the makeup water system to provide water to the pump seals and the tower demister spray headers. The next system placed in service is the limestone reagent feed system, which supplies limestone slurry to the towers for sulfur dioxide (SO_2) removal. Once an oil fired is established in the boiler, the tower absorber and quencher pumps are placed in service. Prior to the burning of coal, two towers are placed in service to scrub the flue gas. The other tower(s) are placed in service as the load increases. The gypsum handling system is started when the gypsum slurry tanks level increases due the production of gypsum in the towers from the interaction of SO_2 and calcium carbonate (limestone).

B. SHUTDOWN

Shutdown of the FGD system is less complicated than startup and begins with the removal of unneeded tower(s) as load decreases. When the unit is off-line, all towers can be removed from service and the makeup water, limestone reagent feed system, and gypsum handling systems are shutdown.

DOCUMENT III.I.7

OPERATION AND MAINTENANCE PLAN

E.U.1., UNIT NO. 1—SOLID FUEL-FIRED STEAM GENERATOR

OPERATION AND MAINTENANCE FOR PARTICULATE CONTROL

A. Process System Performance Parameters:

1. Design fuel consumption rate at maximum continuous rating: 183.5 tons fuel/hour at 11,000 Btu/lb
2. Operating pressure: 2,400 psi
3. Operating temperature: 1,000 °F
4. Maximum design steam capacity: 3,000,000 lbs/hr

B. Particulate Control Equipment Data:

1. Control equipment designator: electrostatic precipitator
2. Electrostatic precipitator manufacturer: Joy Western
3. Design flow rate: 1,408,000 ACFM
4. Primary voltage: 400 volts
5. Primary current: 245 amps
6. Secondary voltage: 55 kilovolts
7. Secondary current: 1,250 milliamps
8. Design efficiency: 99.7 percent
9. Pressure drop: <1.0 inches H_2O (average)
10. Rapper frequency: 1/1.5 min. - 1/4.0 min. (average)
11. Rapper duration: impact
12. Gas temperature: 330± 55°F (average)

C. The following observations, checks, and operations apply to this source and shall be conducted on the schedule specified:

Continuously Monitored and Recorded

Visible emissions (continuous opacity monitor [COM])

Steam pressure

Steam temperature

Steam flow

Daily Recorded and Inspected

Electrostatic Precipitator

Primary current

Secondary voltage

Secondary current

Monthly Recorded and Inspected

Fuel input (recorded)

Inspect insulator compartment heaters/blowers. Service as needed.

Observe operation of all rapper and transformer/rectifier controls. Service as needed.

D. Records of inspections, maintenance, and performance parameters shall be retained for a minimum of 2 years and shall be made available to the Florida Department of Environmental Protection or the Environmental Protection Commission of Hillsborough County upon request.

E.U.2., UNIT NO. 2—SOLID FUEL-FIRED STEAM GENERATOR

OPERATION AND MAINTENANCE FOR PARTICULATE CONTROL

A. Process System Performance Parameters:

1. Design fuel consumption rate at maximum continuous rating: 182.1 tons fuel/hour at 11,000 Btu/lb
2. Operating pressure: 2,400 psi
3. Operating temperature: 1,000 °F
4. Maximum design steam capacity: 3,000,000 lbs/hr.

B. Particulate Control Equipment Data:

1. Control equipment designator: electrostatic precipitator
2. Electrostatic precipitator manufacturer: Joy Western
3. Design flow rate: 1,312,000 ACFM
4. Primary voltage: 400 volts
5. Primary current: 257 amps
6. Secondary voltage: 45 kilovolts
7. Secondary current: 1,600 milliamps
8. Design efficiency: 99.7 percent
9. Pressure drop: < 1.0 inches H_2O (average)
10. Rapper frequency: 1/1.5 min. - 1/4.0 min. (average)
11. Rapper duration: impact
12. Gas temperature: 330± 55°F (average)

C. The following observations, checks, and operations apply to this source and shall be conducted on the schedule specified:

Continuously Monitored and Recorded

Visible emissions (COM)

Steam pressure

Steam temperature

Steam flow

Daily Recorded and Inspected

Electrostatic Precipitator

Primary current

Secondary voltage

Secondary current

Monthly Recorded or Inspection/Maintenance

Fuel input (recorded)

Inspect insulator compartment heaters/blowers. Service as needed.

Observe operation of all rapper and transformer/rectifier controls. Service as needed.

D. Records of inspections, maintenance, and performance parameters shall be retained for a minimum of 2 years and shall be made available to the Florida Department of Environmental Protection or the Environmental Protection Commission of Hillsborough County upon request.

E.U.3., UNIT NO. 3—SOLID FUEL-FIRED STEAM GENERATOR

OPERATION AND MAINTENANCE FOR PARTICULATE CONTROL

A. Process System Performance Parameters:

1. Design fuel consumption rate at maximum continuous rating: 190.3 tons fuel/hour at 11,000 Btu/lb.
2. Operating pressure: 2,250 psi.
3. Operating temperature: 1,000 °F.
4. Maximum design steam capacity: 3,100,000 lbs/hr.

B. Particulate Control Equipment Data:

1. Control equipment designator: electrostatic precipitator
2. Electrostatic precipitator manufacturer: Research Cottrell
3. Design flow rate: 1,420,000 ACFM
4. Primary voltage: 400 volts
5. Primary current: 320 amps
6. Secondary voltage: 45 kilovolts
7. Secondary current: 2,000 milliamps
8. Design efficiency: 99.7 percent
9. Pressure drop: $<$1.0 inches H_2O (average)
10. Rapper frequency: 1/1.5 min. - 1/4.0 min. (average)
11. Rapper duration: impact
12. Gas temperature: 330± 55°F (average)

C. The following observations, checks, and operations apply to this source and shall be conducted on the schedule specified:

Continuously Monitored and Recorded

Visible emissions (COM)

Steam pressure

Steam temperature

Steam flow

Daily Recorded and Inspected

Electrostatic Precipitator

Primary current

Secondary voltage

Secondary current

Monthly Recorded or Inspection/Maintenance

Fuel input (recorded)

Inspect insulator compartment heaters/blowers. Service as needed.

Observe operation of all rapper and transformer/rectifier controls. Service as needed.

D. Records of inspections, maintenance, and performance parameters shall be retained for a minimum of 2 years and shall be made available to the Florida Department of Environmental Protection or the Environmental Protection Commission of Hillsborough County upon request.

Subpart A—General Provisions

§ 60.1 Applicability.

(a) Except as provided in subparts B and C, the provisions of this part apply to the owner or operator of any stationary source which contains an affected facility, the construction or modification of which is commenced after the date of publication in this part of any standard (or, if earlier, the date of publication of any proposed standard) applicable to that facility.

(b) Any new or revised standard of performance promulgated pursuant to section 111(b) of the Act shall apply to the owner or operator of any stationary source which contains an affected facility, the construction or modification of which is commenced after the date of publication in this part of such new or revised standard (or, if earlier, the date of publication of any proposed standard) applicable to that facility.

(c) In addition to complying with the provisions of this part, the owner or operator of an affected facility may be required to obtain an operating permit issued to stationary sources by an authorized State air pollution control agency or by the Administrator of the U.S. Environmental Protection Agency (EPA) pursuant to Title V of the Clean Air Act (Act) as amended November 15, 1990 (42 U.S.C. 7661). For more information about obtaining an operating permit see part 70 of this chapter.

(d) *Site-specific standard for Merck & Co., Inc.'s Stonewall Plant in Elkton, Virginia.* (1) This paragraph applies only to the pharmaceutical manufacturing facility, commonly referred to as the Stonewall Plant, located at Route 340 South, in Elkton, Virginia ("site").

(2) Except for compliance with 40 CFR 60.49b(u), the site shall have the option of either complying directly with the requirements of this part, or reducing the site-wide emissions caps in accordance with the procedures set forth in a permit issued pursuant to 40 CFR 52.2454. If the site chooses the option of reducing the site-wide emissions caps in accordance with the procedures set forth in such permit, the requirements of such permit shall apply in lieu of the otherwise applicable requirements of this part.

(3) Notwithstanding the provisions of paragraph (d)(2) of this section, for any provisions of this part except for Subpart Kb, the owner/operator of the site shall comply with the applicable provisions of this part if the Administrator determines that compliance with the provisions of this part is necessary for achieving the objectives of the regulation and the Administrator notifies the site in accordance with the provisions of the permit issued pursuant to 40 CFR 52.2454.

[40 FR 53346, Nov. 17, 1975, as amended at 55 FR 51382, Dec. 13, 1990; 59 FR 12427, Mar. 16, 1994; 62 FR 52641, Oct. 8, 1997]

§ 60.2 Definitions.

The terms used in this part are defined in the Act or in this section as follows:

Act means the Clean Air Act (42 U.S.C. 7401 *et seq.*)

Administrator means the Administrator of the Environmental Protection Agency or his authorized representative.

Affected facility means, with reference to a stationary source, any apparatus to which a standard is applicable.

Alternative method means any method of sampling and analyzing for an air pollutant which is not a reference or equivalent method but which has been demonstrated to the Administrator's satisfaction to, in specific cases, produce results adequate for his determination of compliance.

Approved permit program means a State permit program approved by the Administrator as meeting the requirements of part 70 of this chapter or a Federal permit program established in this chapter pursuant to Title V of the Act (42 U.S.C. 7661).

Capital expenditure means an expenditure for a physical or operational change to an existing facility which exceeds the product of the applicable "annual asset guideline repair allowance percentage" specified in the latest edition of Internal Revenue Service (IRS) Publication 534 and the existing facility's basis, as defined by section 1012 of the Internal Revenue Code. However, the total expenditure for a physical or operational change to an existing facility must not be reduced by any "excluded additions" as defined in IRS Publication 534, as would be done for tax purposes.

Clean coal technology demonstration project means a project using funds appropriated under the heading 'Department of Energy-Clean Coal Technology', up to a total amount of $2,500,000,000 for commercial demonstrations of clean coal technology, or similar projects funded through appropriations for the Environmental Protection Agency.

Commenced means, with respect to the definition of *new source* in section 111(a)(2) of the Act, that an owner or operator has undertaken a continuous program of construction or modification or that an owner or operator has entered into a contractual obligation to undertake and complete, within a reasonable time, a continuous program of construction or modification.

Construction means fabrication, erection, or installation of an affected facility.

Continuous monitoring system means the total equipment, required under the emission monitoring sections in applicable subparts, used to sample and condition (if applicable), to analyze, and to provide a permanent record of emissions or process parameters.

Electric utility steam generating unit means any steam electric generating unit that is constructed for the purpose of supplying more than one-third of its potential electric output capacity and more than 25 MW electrical output to any utility power distribution system for sale. Any steam supplied to a steam distribution system for the purpose of providing steam to a steam-electric generator that would produce electrical energy for sale is also considered in determining the electrical energy output capacity of the affected facility.

Equivalent method means any method of sampling and analyzing for an air pollutant which has been demonstrated to the Administrator's satisfaction to have a consistent and quantitatively known relationship to the reference method, under specified conditions.

Excess Emissions and Monitoring Systems Performance Report is a report that must be submitted periodically by a source in order to provide data on its compliance with stated emission limits and operating parameters, and on the performance of its monitoring systems.

Existing facility means, with reference to a stationary source, any apparatus of the type for which a standard is promulgated in this part, and the construction or modification of which was commenced before the date of proposal of that standard; or any apparatus which could be altered in such a way as to be of that type.

Isokinetic sampling means sampling in which the linear velocity of the gas entering the sampling nozzle is equal to that of the undisturbed gas stream at the sample point.

Issuance of a part 70 permit will occur, if the State is the permitting authority, in accordance with the requirements of part 70 of this chapter and the applicable, approved State permit program. When the EPA is the permitting authority, issuance of a Title V permit occurs immediately after the EPA takes final action on the final permit.

Malfunction means any sudden, infrequent, and not reasonably preventable failure of air pollution control equipment, process equipment, or a process to operate in a normal or usual manner. Failures that are caused in part by poor maintenance or careless operation are not malfunctions.

Modification means any physical change in, or change in the method of operation of, an existing facility which increases the amount of any air pollutant (to which a standard applies) emitted into the atmosphere by that facility or which results in the emission of any air pollutant (to which a standard applies) into the atmosphere not previously emitted.

Monitoring device means the total equipment, required under the monitoring of operations sections in applicable subparts, used to measure and record (if applicable) process parameters.

Nitrogen oxides means all oxides of nitrogen except nitrous oxide, as measured by test methods set forth in this part.

One-hour period means any 60-minute period commencing on the hour.

Opacity means the degree to which emissions reduce the transmission of light and obscure the view of an object in the background.

Owner or operator means any person who owns, leases, operates, controls, or supervises an affected facility or a stationary source of which an affected facility is a part.

Part 70 permit means any permit issued, renewed, or revised pursuant to part 70 of this chapter.

Particulate matter means any finely divided solid or liquid material, other than uncombined water, as measured by the reference methods specified under each applicable subpart, or an equivalent or alternative method.

Permit program means a comprehensive State operating permit system established pursuant to title V of the Act (42 U.S.C. 7661) and regulations codified in part 70 of this chapter and applicable State regulations, or a comprehensive Federal operating permit system established pursuant to title V of the Act and regulations codified in this chapter.

Permitting authority means:

(1) The State air pollution control agency, local agency, other State agency, or other agency authorized by the Administrator to carry out a permit program under part 70 of this chapter; or

(2) The Administrator, in the case of EPA-implemented permit programs under title V of the Act (42 U.S.C. 7661).

Proportional sampling means sampling at a rate that produces a constant ratio of sampling rate to stack gas flow rate.

Reactivation of a very clean coal-fired electric utility steam generating unit means any physical change or change in the method of operation associated with the commencement of commercial operations by a coal-fired utility unit after a period of discontinued operation where the unit:

(1) Has not been in operation for the two-year period prior to the enactment of the Clean Air Act Amendments of 1990, and the emissions from such unit continue to be carried in the permitting authority's emissions inventory at the time of enactment;

(2) Was equipped prior to shut-down with a continuous system of emissions control that achieves a removal efficiency for sulfur dioxide of no less than 85 percent and a removal efficiency for particulates of no less than 98 percent;

(3) Is equipped with low-NO_x burners prior to the time of commencement of operations following reactivation; and

(4) Is otherwise in compliance with the requirements of the Clean Air Act.

Reference method means any method of sampling and analyzing for an air pollutant as specified in the applicable subpart.

Repowering means replacement of an existing coal-fired boiler with one of the following clean coal technologies: atmospheric or pressurized fluidized bed combustion, integrated gasification combined cycle, magnetohydrodynamics, direct and indirect coal-fired turbines, integrated gasification fuel cells, or as determined by the Administrator, in consultation with the Secretary of Energy, a derivative of one or more of these technologies, and any other technology capable of controlling multiple combustion emissions simultaneously with improved boiler or generation efficiency and with significantly greater waste reduction relative to the performance of technology in widespread commercial use as of November 15, 1990. Repowering shall also include any oil and/or gas-fired unit which has been awarded clean coal technology demonstration funding as of January 1, 1991, by the Department of Energy.

Run means the net period of time during which an emission sample is collected. Unless otherwise specified, a run may be either intermittent or continuous within the limits of good engineering practice.

Shutdown means the cessation of operation of an affected facility for any purpose.

Six-minute period means any one of the 10 equal parts of a one-hour period.

Standard means a standard of performance proposed or promulgated under this part.

Standard conditions means a temperature of 293 K (68F) and a pressure of 101.3 kilopascals (29.92 in Hg).

Startup means the setting in operation of an affected facility for any purpose.

State means all non-Federal authorities, including local agencies, interstate associations, and State-wide programs, that have delegated authority to implement: (1) The provisions of this part; and/or (2) the permit program established under part 70 of this chapter. The term State shall have its conventional meaning where clear from the context.

Stationary source means any building, structure, facility, or installation which emits or may emit any air pollutant.

Title V permit means any permit issued, renewed, or revised pursuant to Federal or State regulations established to implement title V of the Act (42 U.S.C. 7661). A title V permit issued by a State permitting authority is called a part 70 permit in this part.

Volatile Organic Compound means any organic compound which participates in atmospheric photochemical reactions; or which is measured by a reference method, an equivalent method, an alternative method, or which is determined by procedures specified under any subpart.

[44 FR 55173, Sept. 25, 1979, as amended at 45 FR 5617, Jan. 23, 1980; 45 FR 85415, Dec. 24, 1980; 54 FR 6662, Feb. 14, 1989; 55 FR 51382, Dec. 13, 1990; 57 FR 32338, July 21, 1992; 59 FR 12427, Mar. 16, 1994]

§ 60.3 Units and abbreviations.

Used in this part are abbreviations and symbols of units of measure. These are defined as follows:

(a) System International (SI) units of measure:

A—ampere
g—gram
Hz—hertz
J—joule
K—degree Kelvin
kg—kilogram
m—meter
m^3—cubic meter
mg—milligram—10^{-3} gram
mm—millimeter—10^{-3} meter
Mg—megagram—10^6 gram
mol—mole
N—newton
ng—nanogram—10^{-9} gram
nm—nanometer—10^{-9} meter
Pa—pascal
s—second
V—volt
W—watt
Ω—ohm
μg—microgram—10^{-6} gram

(b) Other units of measure:

Btu—British thermal unit
°C—degree Celsius (centigrade)
cal—calorie
cfm—cubic feet per minute
cu ft—cubic feet
dcf—dry cubic feet
dcm—dry cubic meter
dscf—dry cubic feet at standard conditions
dscm—dry cubic meter at standard conditions
eq—equivalent
°F—degree Fahrenheit
ft—feet
gal—gallon
gr—grain
g-eq—gram equivalent
hr—hour
in—inch
k—1,000
l—liter
lpm—liter per minute
lb—pound
meq—milliequivalent
min—minute
ml—milliliter
mol. wt.—molecular weight
ppb—parts per billion
ppm—parts per million
psia—pounds per square inch absolute
psig—pounds per square inch gage
°R—degree Rankine
scf—cubic feet at standard conditions
scfh—cubic feet per hour at standard conditions
scm—cubic meter at standard conditions
sec—second
sq ft—square feet
std—at standard conditions

(c) Chemical nomenclature:

CdS—cadmium sulfide
CO—carbon monoxide
CO_2—carbon dioxide
HCl—hydrochloric acid
Hg—mercury
H_2O—water
H_2S—hydrogen sulfide
H_2SO_4—sulfuric acid
N_2—nitrogen
NO—nitric oxide
NO_2—nitrogen dioxide
NO_x—nitrogen oxides
O_2—oxygen
SO_2—sulfur dioxide
SO_3—sulfur trioxide
SO_x—sulfur oxides

(d) Miscellaneous:

A.S.T.M.—American Society for Testing and Materials

[42 FR 37000, July 19, 1977; 42 FR 38178, July 27, 1977]

§ 60.4 Address.

(a) All requests, reports, applications, submittals, and other communications to the Administrator pursuant to this part shall be submitted in duplicate to the appropriate Regional Office of the U.S. Environmental Protection Agency to the attention of the Director of the Division indicated in the following list of EPA Regional Offices.

Region I (Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, Vermont), Director, Air Management Division, U.S. Environmental Protection Agency, John F. Kennedy Federal Building, Boston, MA 02203.

Region II (New Jersey, New York, Puerto Rico, Virgin Islands), Director, Air and Waste Management Division, U.S. Environmental Protection Agency, Federal Office Building, 26 Federal Plaza (Foley Square), New York, NY 10278.

Region III (Delaware, District of Columbia, Maryland, Pennsylvania, Virginia, West Virginia), Director, Air and Waste Management Division, U.S. Environmental Protection Agency, Curtis Building, Sixth and Walnut Streets, Philadelphia, PA 19106.

Region IV (Alabama, Florida, Georgia, Kentucky, Mississippi, North Carolina, South Carolina, Tennessee), Director, Air and Waste Management Division, U.S. Environmental Protection Agency, 345 Courtland Street, NE., Atlanta, GA 30365.

Region V (Illinois, Indiana, Michigan, Minnesota, Ohio, Wisconsin), Director, Air and Radiation Division, U.S. Environmental Protection Agency, 77 West Jackson Boulevard, Chicago, IL 60604-3590.

Region VI (Arkansas, Louisiana, New Mexico, Oklahoma, Texas): Director; Air, Pesticides, and Toxics Division; U.S. Environmental Protection Agency, 1445 Ross Avenue, Dallas, TX 75202.

Region VII (Iowa, Kansas, Missouri, Nebraska), Director, Air and Toxics Division, U.S. Environmental Protection Agency, 726 Minnesota Avenue, Kansas City, KS 66101.

Region VIII (Colorado, Montana, North Dakota, South Dakota, Utah, Wyoming), Director, Air and Waste Management Division, U.S. Environmental Protection Agency, 1860 Lincoln Street, Denver, CO 80295.

Region IX (American Samoa, Arizona, California, Guam, Hawaii, Nevada), Director, Air and Waste Management Division, U.S. Environmental Protection Agency, 215 Fremont Street, San Francisco, CA 94105.

Region X (Alaska, Oregon, Idaho, Washington), Director, Air and Waste Management Division, U.S. Environmental Protection Agency, 1200 Sixth Avenue, Seattle, WA 98101.

(b) Section 111(c) directs the Administrator to delegate to each State, when appropriate, the authority to implement and enforce standards of performance for new stationary sources located in such State. All information required to be submitted to EPA under paragraph (a) of this section, must also be submitted to the appropriate State Agency of any State to which this authority has been delegated (provided, that each specific delegation may except sources from a certain Federal or State reporting requirement). The appropriate mailing address for those States whose delegation request has been approved is as follows:

(A) [Reserved]

(B) State of Alabama, Air Pollution Control Division, Air Pollution Control Commission, 645 S. McDonough Street, Montgomery, AL 36104.

(C) State of Alaska, Department of Environmental Conservation, Pouch O, Juneau, AK 99811.

(D) Arizona:

Arizona Department of Health Services, 1740 West Adams Street, Phoenix, AZ 85007.

Maricopa County Department of Health Services, Bureau of Air Pollution Control, 1825 East Roosevelt Street, Phoenix, AZ 85006.

Pima County Health Department, Air Quality Control District, 151 West Congress, Tucson, AZ 85701.

Pima County Air Pollution Control District, 151 West Congress Street, Tucson, AZ 85701.

(1) The following table lists the specific source and pollutant categories that have been delegated to the air pollution control agencies in Arizona. A star (*) is used to indicate each category that has been delegated.

EC01JN92.000

EC01JN92.001

(E) State of Arkansas: Chief, Division of Air Pollution Control, Arkansas Department of Pollution Control and Ecology, 8001 National Drive, P.O. Box 9583, Little Rock, AR 72209.

(F) California:

Amador County Air Pollution Control District, P.O. Box 430, 810 Court Street, Jackson, CA 95642

Bay Area Air Pollution Control District, 939 Ellis Street, San Francisco, CA 94109.

Butte County Air Pollution Control District, P.O. Box 1229, 316 Nelson Avenue, Oroville, CA 95965

Calaveras County Air Pollution Control District, Government Center, El Dorado Road, San Andreas, CA 95249

Colusa County Air Pollution Control District, 751 Fremont Street, Colusa, CA 95952

El Dorado Air Pollution Control District, 330 Fair Lane, Placerville, CA 95667

Fresno County Air Pollution Control District, 1221 Fulton Mall, Fresno, CA 93721

Glenn County Air Pollution Control District, P.O. Box 351, 720 North Colusa Street, Willows, CA 95988

Great Basin Unified Air Pollution Control District, 157 Short Street, Suite 6, Bishop, CA 93514

Imperial County Air Pollution Control District, County Services Building, 939 West Main Street, El Centro, CA 92243

Kern County Air Pollution Control District, 1601 H Street, Suite 250, Bakersfield, CA 93301

Kings County Air Pollution Control District, 330 Campus Drive, Hanford, CA 93230

Lake County Air Pollution Control District, 255 North Forbes Street, Lakeport, CA 95453

Lassen County Air Pollution Control District, 175 Russell Avenue, Susanville, CA 96130

Madera County Air Pollution Control District, 135 W. Yosemite Avenue, Madera, CA 93637.

Mariposa County Air Pollution Control District, Box 5, Mariposa, CA 95338

Mendocino County Air Pollution Control District, County Courthouse, Ukiah, CA 95482.

Merced County Air Pollution Control District, P.O. Box 471, 240 East 15th Street, Merced, CA 95340

Modoc County Air Pollution Control District, 202 West 4th Street, Alturas, CA 96101

Monterey Bay Unified Air Pollution Control, 1164 Monroe Street, Suite 10, Salinas, CA 93906

Nevada County Air Pollution Control District, H.E.W. Complex, Nevada City, CA 95959

North Coast Unified Air Quality Management District, 5630 South Broadway, Eureka, CA 95501

Northern Sonoma County Air Pollution Control District, 134 "A" Avenue, Auburn, CA 95448

Placer County Air Pollution Control District, 11491 "B" Avenue, Auburn, CA 95603

Plumas County Air Pollution Control District, P.O. Box 480, Quincy, CA 95971

Sacramento County Air Pollution Control District, 3701 Branch Center Road, Sacramento, CA 95827.

San Bernardino County Air Pollution Control District, 15579-8th, Victorville, CA 92392

San Diego County Air Pollution Control District, 9150 Chesapeake Drive, San Diego, CA 92123.

San Joaquin County Air Pollution Control District, 1601 E. Hazelton Street (P.O. Box 2009) Stockton, CA 95201.

San Luis Obispo County Air Pollution Control District, P.O. Box 637, San Luis Obispo, CA 93406

Santa Barbara County Air Pollution Control District, 315 Camino del Rimedio, Santa Barbara, CA 93110

Shasta County Air Pollution Control District, 2650 Hospital Lane, Redding, CA 96001

Sierra County Air Pollution Control District, P.O. Box 286, Downieville, CA 95936

Siskiyou County Air Pollution Control District, 525 South Foothill Drive, Yreka, CA 96097

South Coast Air Quality Management District, 9150 Flair Drive, El Monte, CA 91731

Stanislaus County Air Pollution Control District, 1030 Scenic Drive, Modesto, CA 95350

Sutter County Air Pollution Control District, Sutter County Office Building, 142 Garden Highway, Yuba City, CA 95991

Tehama County Air Pollution Control District, P.O. Box 38, 1760 Walnut Street, Red Bluff, CA 96080

Tulare County Air Pollution Control District, County Civic Center, Visalia, CA 93277

Tuolumne County Air Pollution Control District, 9 North Washington Street, Sonora, CA 95370

Ventura County Air Pollution Control District, 800 South Victoria Avenue, Ventura, CA 93009

Yolo-Solano Air Pollution Control District, P.O. Box 1006, 323 First Street, #5, Woodland, CA 95695

(1) The following table lists the specific source and pollutant categories that have been delegated to the air pollution control agencies in California. A star (*) is used to indicate each category that has been delegated.

EC01JN92.002

EC01JN92.004

EC01JN92.005

(EE) State of New Hampshire, Air Resources Division, Department of Environmental Services, 64 North Main Street, Caller Box 2033, Concord, NH 03302-2033.

(FF) State of New Jersey: New Jersey Department of Environmental Protection, Division of Environmental Quality, Enforcement Element, John Fitch Plaza, CN-027, Trenton, NJ 08625.

(I) The following table lists the specific source and pollutant categories that have been delegated to the states in Region II. The (X) symbol is used to indicate each category that has been delegated.

	Subpart	State			
		New Jersey	New York	Puerto Rico	Virgin Islands
D	Fossil-Fuel Fired Steam Generators for Which Construction Commenced After August 17, 1971 (Steam Generators and Lignite Fired Steam Generators).	X	X	X	X
Da	Electric Utility Steam Generating Units for Which Construction Commenced After September 18, 1978.	X		X	
Db	Industrial-Commercial-Institutional Steam Generating Units	X	X	X	X
E	Incinerators	X	X	X	X
F	Portland Cement Plants	X	X	X	X
G	Nitric Acid Plants	X	X	X	X
H	Sulfuric Acid Plants	X	X	X	X
I	Asphalt Concrete Plants	X	X	X	X
J	Petroleum Refineries—(All Categories)	X	X	X	X
K	Storage Vessels for Petroleum Liquids Constructed After June 11, 1973, and prior to May 19, 1978.	X	X	X	X
Ka	Storage Vessels for Petroleum Liquids Constructed After May 18, 1978.	X	X	X	
L	Secondary Lead Smelters	X	X	X	X
M	Secondary Brass and Bronze Ingot Production Plants	X	X	X	X
N	Iron and Steel Plants	X	X	X	X
O	Sewage Treatment Plants	X	X	X	X
P	Primary Copper Smelters	X	X	X	X
Q	Primary Zinc Smelters	X	X	X	X
R	Primary Lead Smelters	X	X	X	X

	Subpart	State			
		New Jersey	New York	Puerto Rico	Virgin Islands
S	Primary Aluminum Reduction Plants	X	X	X	X
T	Phosphate Fertilizer Industry: Wet Process Phosphoric Acid Plants.	X	X	X	X
U	Phosphate Fertilizer Industry: Superphosphoric Acid Plants	X	X	X	X
V	Phosphate Fertilizer Industry: Diammonium Phosphate Plants	X	X	X	X
W	Phosphate Fertilizer Industry: Triple Superphosphate Plants	X	X	X	X
X	Phosphate Fertilizer Industry: Granular Triple Superphosphate	X	X	X	X
Y	Coal Preparation Plants	X	X	X	X
Z	Ferroally Production Facilities	X	X	X	X
AA	Steel Plants: Electric Arc Furnaces	X	X	X	X
AAa	Electric Arc Furnaces and Argon-Oxygen Decarburization Vessels in Steel Plants.	X	X	X	
BB	Kraft Pulp Mills	X	X	X	
CC	Glass Manufacturing Plants	X	X	X	
DD	Grain Elevators	X	X	X	
EE	Surface Coating of Metal Furniture	X	X	X	
GG	Stationary Gas Turbines	X	X	X	
HH	Lime Plants	X	X	X	
KK	Lead Acid Battery Manufacturing Plants	X	X		
LL	Metallic Mineral Processing Plants	X	X	X	
MM	Automobile and Light-Duty Truck Surface Coating Operations	X	X		
NN	Phosphate Rock Plants	X	X		
PP	Ammonium Sulfate Manufacturing Plants	X	X		
QQ	Graphic Art Industry Publication Rotogravure Printing	X	X	X	X
RR	Pressure Sensitive Tape and Label Surface Coating Operations.	X	X	X	
SS	Industrial Surface Coating: Large Appliances	X	X	X	
TT	Metal Coil Surface Coating	X	X	X	
UU	Asphalt Processing and Asphalt Roofing Manufacture	X	X	X	
VV	Equipment Leaks of Volatile Organic Compounds in Synthetic Organic Chemical Manufacturing Industry.	X		X	
WW	Beverage Can Surface Coating Industry	X	X	X	
XX	Bulk Gasoline Terminals	X	X	X	
FFF	Flexible Vinyl and Urethane Coating and Printing	X	X	X	
GGG	Equipment Leaks of VOC in Petroleum Refineries	X		X	
HHH	Synthetic Fiber Production Facilities	X		X	
JJJ	Petroleum Dry Cleaners	X	X	X	
KKK	Equipment Leaks of VOC from Onshore Natural Gas Processing Plants.				
LLL	Onshore Natural Gas Processing Plants; SO_2 Emissions		X		
OOO	Nonmetallic Mineral Processing Plants		X	X	
PPP	Wool Fiberglass Insulation Manufacturing Plants		X	X	

(GG) State of New Mexico: Director, New Mexico Environmental Improvement Division, Health and Environment Department, 1190 St. Francis Drive, Santa Fe, NM 87503.

(i) The City of Albuquerque and Bernalillo County: Director, The Albuquerque Environmental Health Department, The City of Albuquerque, P.O. Box 1293, Albuquerque, NM 87103.

(HH) New York: New York State Department of Environmental Conservation, 50 Wolf Road Albany, New York 12233, attention: Division of Air Resources.

(II) North Carolina Environmental Management Commission, Department of Natural and Economic Resources, Division of Environmental Management, P.O. Box 27687, Raleigh, NC 27611. Attention: Air Quality Section.

(JJ) State of North Dakota, State Department of Health and Consolidated Laboratories, Division of Environmental Engineering, State Capitol, Bismarck, ND 58505.

EDITORIAL NOTE: For a table listing Region VIII's NSPS delegation status, see paragraph (c) of this section.

(KK) State of Ohio:

(i) Medina, Summit and Portage Counties; Director, Akron Regional Air Quality Management District, 177 South Broadway, Akron, OH 44308.

(ii) Stark County: Air Pollution Control Division, 420 Market Avenue North, Canton, Ohio 44702–3335.

(iii) Butler, Clermont, Hamilton, and Warren Counties: Air Program Manager, Hamilton County Department of Environmental Services, 1632 Central Parkway, Cincinnati, Ohio 45210.

(iv) Cuyahoga County: Commissioner, Department of Public Health & Welfare, Division of Air Pollution Control, 1925 Saint Clair, Cleveland, Ohio 44114.

(v) Belmont, Carroll, Columbiana, Harrison, Jefferson, and Monroe Counties: Director, North Ohio Valley Air Authority

(NOVAA), 814 Adams Street, Steubenville, OH 43952.

(vi) Clark, Darke, Greene, Miami, Montgomery, and Preble Counties: Director, Regional Air Pollution Control Agency (RAPCA) 451 West Third Street, Dayton, Ohio 45402.

(vii) Lucas County and the City of Rossford (in Wood County): Director, Toledo Environmental Services Agency, 26 Main Street, Toledo, OH 43605.

(viii) Adams, Brown, Lawrence, and Scioto Counties: Engineer-Director, Air Division, Portsmouth City Health Department, 740 Second Street, Portsmouth, OH 45662.

(ix) Allen, Ashland, Auglaize, Crawford, Defiance, Erie, Fulton, Hancock, Hardin, Henry, Huron, Marion, Mercer, Ottawa, Paulding, Putnam, Richland, Sandusky, Seneca, Van Wert, Williams, Wood (except City of Rossford), and Wyandot Counties: Ohio Environmental Protection Agency, Northwest District Office, Air Pollution Control, 347 Dunbridge Rd., Bowling Green, Ohio 43402.

(x) Ashtabula, Holmes, Lorain, and Wayne Counties: Ohio Environmental Protection Agency, Northeast District Office, Air Pollution Unit, 2110 East Aurora Road, Twinsburg, OH 44087.

(xi) Athens, Coshocton, Gallia, Guernsey, Hocking, Jackson, Meigs, Morgan, Muskingum, Noble, Perry, Pike, Ross, Tuscarawas, Vinton, and Washington Counties: Ohio Environmental Protection Agency, Southeast District Office, Air Pollution Unit, 2195 Front Street, Logan, OH 43138.

(xii) Champaign, Clinton, Highland, Logan, and Shelby Counties: Ohio Environmental Protection Agency, Southwest District Office, Air Pollution Unit, 401 East Fifth Street, Dayton, Ohio 45402-2911.

(xiii) Delaware, Fairfield, Fayette, Franklin, Knox, Licking, Madison, Morrow, Pickaway, and Union Counties: Ohio Environmental Protection Agency, Central District Office, Air Pollution Control, 3232 Alum Creek Drive, Columbus, Ohio, 43207-3417.

(xiv) Geauga and Lake Counties: Lake County General Health District, Air Pollution Control, 105 Main Street, Painesville, OH 44077.

(xv) Mahoning and Trumbull Counties: Mahoning-Trumbull Air Pollution Control Agency, 9 West Front Street, Youngstown, OH 44503.

(LL) State of Oklahoma, Oklahoma State Department of Health, Air Quality Service, P.O. Box 53551, Oklahoma City, OK 73152.

(i) Oklahoma City and County: Director, Oklahoma City-County Health Department, 921 Northeast 23rd Street, Oklahoma City, OK 73105.

(ii) Tulsa County: Tulsa City-County Health Department, 4616 East Fifteenth Street, Tulsa, OK 74112.

(MM) State of Oregon, Department of Environmental Quality, Yeon Building, 522 S.W. Fifth, Portland, OR 97204.

(i)—(viii) [Reserved]

(ix) Lane Regional Air Pollution Authority, 225 North Fifth, Suite 501, Springfield, OR 97477.

(NN) (a) City of Philadelphia: Philadelphia Department of Public Health, Air Management Services, 500 S. Broad Street, Philadelphia, PA 19146.

(b) Commonwealth of Pennsylvania: Department of Environmental Resources, Post Office Box 2063, Harrisburg, PA 17120.

(c) Allegheny County: Allegheny County Health Department, Bureau of Air Pollution Control, 301 Thirty-ninth Street, Pittsburgh, PA 15201.

(OO) State of Rhode Island, Division of Air and Hazardous Materials, Department of Environmental Management, 291 Promenade Street, Providence, RI 02908.

(PP) State of South Carolina, Office of Environmental Quality Control, Department of Health and Environmental Control, 2600 Bull Street, Columbia, SC 29201.

(QQ) State of South Dakota, Department of Water and Natural Resources, Office of Air Quality and Solid Waste, Joe Foss Building, 523 East Capitol, Pierre, SD 57501-3181.

EDITORIAL NOTE: For a table listing Region VIII's NSPS delegation status, see paragragh (c) of this section.

(RR) Division of Air Pollution Control, Tennessee Department of Public Health, 256 Capitol Hill Building, Nashville, TN 37219.

Knox County Department of Air Pollution, City/County Building, Room L222, 400 Main Avenue, Knoxville, TN 37902.

Air Pollution Control Bureau, Metropolitan Health Department, 311 23rd Avenue North, Nashville, TN 37203.

(SS) State of Texas, Texas Air Control Board, 6330 Highway 290 East, Austin, TX 78723.

(TT) State of Utah, Department of Health, Bureau of Air Quality, 288 North 1460 West, P.O. Box 16690, Salt Lake City, UT 84113-0690.

EDITORIAL NOTE: For a table listing Region VIII's NSPS delegation status, see paragraph (c) of this section.

(UU) State of Vermont, Air Pollution Control Division, Agency of Natural Resources, Building 3 South, 103 South Main Street, Waterbury, VT 05676.

(VV) Commonwealth of Virginia, Virginia State Air Pollution Control Board, Room 1106, Ninth Street Office Building, Richmond, VA 23219.

(WW)(i) Washington: Washington Department of Ecology, Post Office Box 47600, Olympia, WA 98504.

(ii) Benton-Franklin Counties Clean Air Authority (BFCCAA), 650 George Washington Way, Richland, WA 99352.

(iii) Northwest Air Pollution Authority (NWAPA), 302 Pine Street, #207, Mt. Vernon, WA 98273-3852.

(iv) Olympic Air Pollution Control Authority (OAPCA), 909 Sleater-Kinney Rd. SE - Suite 1, Lacey, WA 98503.

(v) Puget Sound Air Pollution Control Authority (PSAPCA), 110 Union Street, Suite 500, Seattle, WA 98101.

(vi) Southwest Air Pollution Control Authority (SWAPCA), 1308 N.E. 134th Street, Suite D, Vancouver, WA 98685-2747.

(vii) Spokane County Air Pollution Control Authority (SCAPCA), West 1101 College Avenue, Health Building, Room 403, Spokane, WA 99201.

(viii) [Reserved]

(ix) The following is a table indicating the delegation status of the New Source Performance Standards for the State of Washington.

DELEGATION OF AUTHORITY—NEW SOURCE PERFORMANCE STANDARDS STATE OF WASHINGTON

Subpart	Description	WDOE [1]	BFCCAA [2]	NWAPCA [3]	OAPCA [4]	PSAPCA [5]	SWAPCA [6]	SCAPCA [7]
A	General Provisions	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93
D	Fossil-Fuel-Fired Steam Generators	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93
Da	Electric Utility Steam Generating Units	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93
Db	Industrial-Commercial-Institutional Steam Generating Units	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93
Dc	Small Industrial-Commercial-Institutional Steam Generating Units	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93
E	Incinerators	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93
Ea	Municipal Waste Combustion	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93
F	Portland Cement Plants	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93
G	Nitric Acid Plants	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93
H	Sulfuric Acid Plants	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93
I	Asphalt Concrete Plants	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93
J	Petroleum Refineries	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93
K	Petroleum Liquid Storage Vessels 6/11/73–5/19/78	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93
Ka	Petroleum Liquid Storage Vessels After 5/18/78–7/23/84	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93
Kb	Volatile Organic Liquid Storage Vessels After 7/23/84	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93
L	Secondary Lead Smelters	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93
M	Brass & Bronze Ingot Production Plants	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93
N	Iron & Steel Plants: BOPF Particulate	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93
Na	Iron & Steel Plants: BOPF, Hot Metal & Skimming Stations	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93
O	Sewage Treatment Plants	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93
P	Primary Copper Smelters	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93
Q	Primary Zinc Smelters	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93
R	Primary Lead Smelters	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93
S	Primary Aluminum Reduction Plants	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93
T	Wet Process Phosphoric Acid Plants	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93
U	Superphosphoric Acid Plants	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93
V	Diammonium Phosphate Plants	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93
W	Triple Superphosphate Plants	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93
X	Granular Triple Superphosphate Storage Facilities	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93
Y	Coal Preparation Plants	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93
Z	Ferroalloy Production Facilities	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93
AA	Steel Plant Electric Arc Furnaces 10/21/74–8/17/83	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93
AAa	Steel Plant Electric Arc Furnaces & Argon-Oxygen Decarburization Vessels after 8/7/83.	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93
BB	Kraft Pulp Mills	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93
CC	Glass Manufacturing Plants	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93
DD	Grain Elevators	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93
EE	Surface Coating of Metal Furniture	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93
GG	Stationary Gas Turbines	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93
HH	Lime Manufacturing Plants	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93
KK	Lead-Acid Battery Manufacturing Plant	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93
LL	Metallic Mineral Processing Plants	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93
MM	Automobile & Light Duty Truck Surface Coating Operations	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93
NN	Phosphate Rock Plants	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93
PP	Ammonium Sulfate Manufacture	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93
QQ	Graphic Arts Industry: Publication Rotogravure Printing	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93

DELEGATION OF AUTHORITY—NEW SOURCE PERFORMANCE STANDARDS STATE OF WASHINGTON—Continued

Subpart	Description	WDOE[1]	BFCCAA[2]	NWAPCA[3]	OAPCA[4]	PSAPCA[5]	SWAPCA[6]	SCAPCA[7]
RR	Pressure Sensitive Tape & Label Surface Coating Operations	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93
SS	Industrial Surface Coating: Large Appliances	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93
TT	Metal Coil Surface Coating	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93
UU	Asphalt Processing & Asphalt Roofing Manufacturer	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93
VV	SOCMI Equipment Leaks (VOC)	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93
WW	Beverage Can Surface Coating Operations	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93
XX	Bulk Gasoline Terminals	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93
AAA	Residential Wood Heaters	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93
BBB	Rubber Tire Manufacturing	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93
DDD	Polymer Manufacturing Industry (VOC)	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93
FFF	Flexible Vinyl and Urethane Coating and Printing	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93
GGG	Equipment Leaks of VOC in Petroleum Refineries	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93
HHH	Synthetic Fiber Production Facilities	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93
III	VOC Emissions from SOCMI Air Oxidation Unit Processes	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93
JJJ	Petroleum Dry Cleaners	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93
KKK	VOC Emissions from Onshore Natural Gas Production	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93
LLL	Onshore Natural Gas Production (SO2)	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93
NNN	VOC Emissions from SOCMI Distillation Facilities	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93
OOO	Nonmetallic Mineral Processing Plants	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93
PPP	Wool Fiberglass Insulation Manufacturing Plants	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93
QQQ	VOC Emissions from Petroleum Refinery Wastewater Systems	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93
SSS	Magnetic Tape Coating Facilities	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93
TTT	Surface Coating of Plastic Parts for Business Machines	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93
UUU	Calciners & Dryers In Mineral Industries	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93
VVV	Polymeric Coating of Support Substrates Facilities	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93	01/01/93

[1] WDOE—State of Washington Department of Ecology.
[2] BFCCAA—Benton Franklin Counties Clean Air Authority.
[3] NWAPCA—Northwest Air Pollution Control Authority.
[4] OAPCA—Olympic Air Pollution Control Authority.
[5] PSAPCA—Puget Sound Air Pollution Control Agency.
[6] SWAPCA—Southwest Air Pollution Control Authority.
[7] SCAPCA—Spokane County Air Pollution Control Authority.

(XX) State of West Virginia: Air Pollution Control Commission, 1558 Washington Street East, Charleston, WV 25311.

(YY) Wisconsin—Wisconsin Department of Natural Resources, P.O. Box 7921, Madison, WI 53707.

(ZZ) State of Wyoming, Department of Environmental Quality, Air Quality Division, Herschler Building, 122 West 25th Street, Cheyenne, WY 82002.

EDITORIAL NOTE: For a table listing Region VIII's NSPS delegation status, see paragraph (c) of this section.

(AAA) Territory of Guam: Guam Environmental Protection Agency, Post Office Box 2999, Agana, Guam 96910.

(1) The following table lists the specific source and pollutant categories that have been delegated to the air pollution control agency in Guam. A star (*) is used to indicate each category that has been delegated.

EC01JN92.006

EC01JN92.007

(BBB) Commonwealth of Puerto Rico: Commonwealth of Puerto Rico Environmental Quality Board, P.O. Box 11488, Santurce, PR 00910, Attention: Air Quality Area Director (see table under §60.4(b)(FF)(1)).

(CCC) U.S. Virgin Islands: U.S. Virgin Islands Department of Conservation and Cultural Affairs, P.O. Box 578, Charlotte Amalie, St. Thomas, VI 00801.

(c) The following is a table indicating the delegation status of New Source Performance Standards for Region VIII.

DELEGATION STATUS OF NEW SOURCE PERFORMANCE STANDARDS

[(NSPS) for Region VIII]

Subpart	CO	MT[1]	ND	SD[1]	UT[1]	WY
A—General Provisions	(*)	(*)	(*)	(*)	(*)	(*)
D—Fossil Fuel Fired Steam Generators	(*)	(*)	(*)	(*)	(*)	(*)
Da—Electric Utility Steam Generators	(*)	(*)	(*)	(*)	(*)	(*)
Db—Industrial-Commercial—Institutional Steam Generators	(*)	(*)	(*)	(*)	(*)	(*)
Dc—Industrial-Commercial—Institutional Steam Generators	(*)	(*)	(*)	(*)	(*)	
E—Incinerators	(*)	(*)	(*)	(*)	(*)	(*)
Ea—Municipal Waste Combustors	(*)	(*)	(*)	(*)	(*)	(*)
F—Portland Cement Plants	(*)	(*)	(*)	(*)	(*)	(*)
G—Nitric Acid Plants	(*)	(*)	(*)		(*)	(*)
H—Sulfuric Acid Plants	(*)	(*)	(*)		(*)	(*)
I—Asphalt Concrete Plants	(*)	(*)	(*)	(*)	(*)	(*)
J—Petroleum Refineries	(*)	(*)	(*)		(*)	(*)
K—Petroleum Storage Vessels (after 6/11/73 & prior to 5/19/78)	(*)	(*)	(*)	(*)	(*)	(*)
Ka—Petroleum Storage Vessels (after 5/18/78 & prior to 7/23/84)	(*)	(*)	(*)	(*)	(*)	(*)
Kb—Petroleum Storage Vessels (after 7/23/84)	(*)	(*)	(*)	(*)	(*)	(*)
L—Secondary Lead Smelters	(*)	(*)	(*)		(*)	(*)
M—Secondary Brass & Bronze Production Plants	(*)	(*)	(*)		(*)	(*)
N—Primary Emissions from Basic Oxygen Process Furnaces (after 6/11/73)	(*)	(*)	(*)		(*)	(*)
Na—Secondary Emissions from Basic Oxygen Process Furnaces (after 1/20/83)	(*)	(*)	(*)		(*)	(*)
O—Sewage Treatment Plants	(*)	(*)	(*)	(*)	(*)	(*)
P—Primary Copper Smelters	(*)	(*)	(*)		(*)	(*)

DELEGATION STATUS OF NEW SOURCE PERFORMANCE STANDARDS—Continued

[(NSPS) for Region VIII]

Subpart	CO	MT [1]	ND	SD [1]	UT [1]	WY
Q—Primary Zinc Smelters	(*)	(*)	(*)		(*)	(*)
R—Primary Lead Smelters	(*)	(*)	(*)		(*)	(*)
S—Primary Aluminum Reduction Plants	(*)	(*)	(*)		(*)	(*)
T—Phosphate Fertilizer Industry: Wet Process Phosphoric Plants	(*)	(*)	(*)		(*)	(*)
U—Phosphate Fertilizer Industry: Superphosphoric Acid Plants	(*)	(*)	(*)		(*)	(*)
V—Phosphate Fertilizer Industry: Diammonium Phosphate Plants	(*)	(*)	(*)		(*)	(*)
W—Phosphate Fertilizer Industry: Triple Superphosphate Plants	(*)	(*)	(*)		(*)	(*)
X—Phosphate Fertilizer Industry: Granular Triple Superphosphate Storage Facilities	(*)	(*)	(*)		(*)	(*)
Y—Coal Preparation Plants	(*)	(*)	(*)	(*)	(*)	(*)
Z—Ferroalloy Production Facilities	(*)	(*)	(*)		(*)	(*)
AA—Steel Plants: Electric Arc Furnaces (10/21/74–8/17/83)	(*)	(*)	(*)		(*)	(*)
AAa—Steel Plants: Electric Arc Furnaces and Argon-Oxygen Decarburization Vessels (after 8/7/83)	(*)	(*)	(*)		(*)	(*)
BB—Kraft Pulp Mills	(*)	(*)	(*)		(*)	(*)
CC—Glass Manufacturing Plants	(*)	(*)	(*)		(*)	(*)
DD—Grain Elevator	(*)	(*)	(*)	(*)	(*)	(*)
EE—Surface Coating of Metal Furniture	(*)	(*)	(*)		(*)	(*)
GG—Stationary Gas Turbines	(*)	(*)	(*)	(*)	(*)	(*)
HH—Lime Manufacturing Plants	(*)	(*)	(*)	(*)	(*)	(*)
KK—Lead-Acid Battery Manufacturing Plants	(*)	(*)	(*)		(*)	(*)
LL—Metallic Mineral Processing Plants	(*)	(*)	(*)	(*)	(*)	(*)
MM—Automobile & Light Duty Truck Surface Coating Operations	(*)	(*)	(*)		(*)	(*)
NN—Phosphate Rock Plants	(*)	(*)	(*)		(*)	(*)
PP—Ammonium Sulfate Manufacturing	(*)	(*)	(*)		(*)	(*)
QQ—Graphic Arts Industry: Publication Rotogravure Printing	(*)	(*)	(*)	(*)	(*)	(*)
RR—Pressure Sensitive Tape & Label Surface Coating	(*)	(*)	(*)	(*)	(*)	(*)
SS—Industrial Surface Coating: Large Applications	(*)	(*)	(*)		(*)	(*)
TT—Metal Coil Surface Coating	(*)	(*)	(*)		(*)	(*)
UU—Asphalt Processing & Asphalt Roofing Manufacture	(*)	(*)	(*)		(*)	(*)
VV—Synthetic Organic Chemicals Manufacturing: Equipment Leaks of VOC	(*)	(*)	(*)	(*)	(*)	(*)
WW—Beverage Can Surface Coating Industry	(*)	(*)	(*)		(*)	(*)
XX—Bulk Gasoline Terminals	(*)	(*)	(*)	(*)	(*)	(*)
AAA—Residential Wood Heaters	(*)	(*)	(*)	(*)	(*)	(*)
BBB—Rubber Tires	(*)	(*)	(*)		(*)	(*)
DDD—VOC Emissions from Polymer Manufacturing Industry	(*)	(*)	(*)		(*)	(*)
FFF—Flexible Vinyl & Urethane Coating & Printing	(*)	(*)	(*)		(*)	(*)
GGG—Equipment Leaks of VOC in Petroleum Refineries	(*)	(*)	(*)		(*)	(*)
HHH—Synthetic Fiber Production	(*)	(*)	(*)		(*)	(*)
III—VOC Emissions from the Synthetic Organic Chemical Manufacturing Industry Air Oxidation Unit Processes		(*)	(*)		(*)	(*)
JJJ—Petroleum Dry Cleaners	(*)	(*)	(*)	(*)	(*)	(*)
KKK—Equipment Leaks of VOC from Onshore Natural Gas Processing Plants	(*)	(*)	(*)		(*)	(*)
LLL—Onshore Natural Gas Processing: SO_2 Emissions	(*)	(*)	(*)		(*)	(*)
NNN—VOC Emissions from the Synthetic Organic Chemical Manufacturing Industry Distillation Operations	(*)	(*)	(*)	(*)	(*)	(*)
OOO—Nonmetallic Mineral Processing Plants	(*)	(*)	(*)	(*)	(*)	(*)
PPP—Wool Fiberglass Insulation Manufacturing Plants	(*)	(*)	(*)		(*)	(*)
QQQ—VOC Emissions from Petroleum Refinery Wastewater Systems	(*)	(*)	(*)		(*)	(*)
RRR—VOC Emissions from Synthetic Organic Chemical Manufacturing Industry (SOCMI) Reactor Processes	(*)		(*)		(*)	
SSS—Magnetic Tape Industry	(*)	(*)	(*)	(*)	(*)	(*)

DELEGATION STATUS OF NEW SOURCE PERFORMANCE STANDARDS—Continued
[(NSPS) for Region VIII]

Subpart	CO	MT[1]	ND	SD[1]	UT[1]	WY
TTT—Plastic Parts for Business Machine Coatings	(*)	(*)	(*)		(*)	(*)
UUU—Calciners and Dryers in Mineral Industries	(*)		(*)		(*)	
VVV—Polymeric Coating of Supporting Substrates	(*)	(*)	(*)		(*)	(*)
WWW—Municipal Solid Waste Landfills			(*)		(*)	

(*) Indicates approval of state regulation.
[1] Indicates approval of New Source Performance Standards as part of the State Implementation Plan (SIP).

[40 FR 18169, Apr. 25, 1975]

EDITORIAL NOTE: For FEDERAL REGISTER citations affecting § 60.4 see the List of CFR Sections Affected appearing in the Finding Aids section of this volume.

§ 60.5 Determination of construction or modification.

(a) When requested to do so by an owner or operator, the Administrator will make a determination of whether action taken or intended to be taken by such owner or operator constitutes construction (including reconstruction) or modification or the commencement thereof within the meaning of this part.

(b) The Administrator will respond to any request for a determination under paragraph (a) of this section within 30 days of receipt of such request.

[40 FR 58418, Dec. 16, 1975]

§ 60.6 Review of plans.

(a) When requested to do so by an owner or operator, the Administrator will review plans for construction or modification for the purpose of providing technical advice to the owner or operator.

(b)(1) A separate request shall be submitted for each construction or modification project.

(2) Each request shall identify the location of such project, and be accompanied by technical information describing the proposed nature, size, design, and method of operation of each affected facility involved in such project, including information on any equipment to be used for measurement or control of emissions.

(c) Neither a request for plans review nor advice furnished by the Administrator in response to such request shall (1) relieve an owner or operator of legal responsibility for compliance with any provision of this part or of any applicable State or local requirement, or (2) prevent the Administrator from implementing or enforcing any provision of this part or taking any other action authorized by the Act.

[36 FR 24877, Dec. 23, 1971, as amended at 39 FR 9314, Mar. 8, 1974]

§ 60.7 Notification and record keeping.

(a) Any owner or operator subject to the provisions of this part shall furnish the Administrator written notification or, if acceptable to both the Administrator and the owner or operator of a source, electronic notification, as follows:

(1) A notification of the date construction (or reconstruction as defined under § 60.15) of an affected facility is commenced postmarked no later than 30 days after such date. This requirement shall not apply in the case of mass-produced facilities which are purchased in completed form.

(2) [Reserved]

(3) A notification of the actual date of initial startup of an affected facility postmarked within 15 days after such date.

(4) A notification of any physical or operational change to an existing facility which may increase the emission rate of any air pollutant to which a standard applies, unless that change is specifically exempted under an applicable subpart or in § 60.14(e). This notice shall be postmarked 60 days or as soon as practicable before the change is

commenced and shall include information describing the precise nature of the change, present and proposed emission control systems, productive capacity of the facility before and after the change, and the expected completion date of the change. The Administrator may request additional relevant information subsequent to this notice.

(5) A notification of the date upon which demonstration of the continuous monitoring system performance commences in accordance with § 60.13(c). Notification shall be postmarked not less than 30 days prior to such date.

(6) A notification of the anticipated date for conducting the opacity observations required by § 60.11(e)(1) of this part. The notification shall also include, if appropriate, a request for the Administrator to provide a visible emissions reader during a performance test. The notification shall be postmarked not less than 30 days prior to such date.

(7) A notification that continuous opacity monitoring system data results will be used to determine compliance with the applicable opacity standard during a performance test required by § 60.8 in lieu of Method 9 observation data as allowed by § 60.11(e)(5) of this part. This notification shall be postmarked not less than 30 days prior to the date of the performance test.

(b) Any owner or operator subject to the provisions of this part shall maintain records of the occurrence and duration of any startup, shutdown, or malfunction in the operation of an affected facility; any malfunction of the air pollution control equipment; or any periods during which a continuous monitoring system or monitoring device is inoperative.

(c) Each owner or operator required to install a continuous monitoring device shall submit excess emissions and monitoring systems performance report (excess emissions are defined in applicable subparts) and-or summary report form (see paragraph (d) of this section) to the Administrator semiannually, except when: more frequent reporting is specifically required by an applicable subpart; or the Administrator, on a case-by-case basis, determines that more frequent reporting is necessary to accurately assess the compliance status of the source. All reports shall be postmarked by the 30th day following the end of each six-month period. Written reports of excess emissions shall include the following information:

(1) The magnitude of excess emissions computed in accordance with § 60.13(h), any conversion factor(s) used, and the date and time of commencement and completion of each time period of excess emissions. The process operating time during the reporting period.

(2) Specific identification of each period of excess emissions that occurs during startups, shutdowns, and malfunctions of the affected facility. The nature and cause of any malfunction (if known), the corrective action taken or preventative measures adopted.

(3) The date and time identifying each period during which the continuous monitoring system was inoperative except for zero and span checks and the nature of the system repairs or adjustments.

(4) When no excess emissions have occurred or the continuous monitoring system(s) have not been inoperative, repaired, or adjusted, such information shall be stated in the report.

(d) The summary report form shall contain the information and be in the format shown in figure 1 unless otherwise specified by the Administrator. One summary report form shall be submitted for each pollutant monitored at each affected facility.

(1) If the total duration of excess emissions for the reporting period is less than 1 percent of the total operating time for the reporting period and CMS downtime for the reporting period is less than 5 percent of the total operating time for the reporting period, only the summary report form shall be submitted and the excess emission report described in § 60.7(c) need not be submitted unless requested by the Administrator.

(2) If the total duration of excess emissions for the reporting period is 1 percent or greater of the total operating time for the reporting period or the total CMS downtime for the reporting period is 5 percent or greater of the total operating time for the reporting period, the summary report form and

the excess emission report described in §60.7(c) shall both be submitted.

FIGURE 1—SUMMARY REPORT—GASEOUS AND OPACITY EXCESS EMISSION AND MONITORING SYSTEM PERFORMANCE

Pollutant (Circle One—SO_2/NO_X/TRS/H_2S/CO/Opacity)

Reporting period dates: From ________ to ________
Company:
Emission Limitation ________
Address:
Monitor Manufacturer and Model No. ________
Date of Latest CMS Certification or Audit ________
Process Unit(s) Description:
Total source operating time in reporting period[1] ________

Emission data summary[1]		CMS performance summary[1]	
1. Duration of excess emissions in reporting period due to:		1. CMS downtime in reporting period due to:	
a. Startup/shutdown	....	a. Monitor equipment malfunctions	....
b. Control equipment problems	....	b. Non-Monitor equipment malfunctions	....
c. Process problems	....	c. Quality assurance calibration	....
d. Other known causes	....	d. Other known causes	....
e. Unknown causes	....	e. Unknown causes	....
2. Total duration of excess emission	....	2. Total CMS Downtime	....
3. Total duration of excess emissions × (100) [Total source operating time].	%[2]	3. [Total CMS Downtime] × (100) [Total source operating time].	%[2]

[1] For opacity, record all times in minutes. For gases, record all times in hours.
[2] For the reporting period: If the total duration of excess emissions is 1 percent or greater of the total operating time or the total CMS downtime is 5 percent or greater of the total operating time, both the summary report form and the excess emission report described in §60.7(c) shall be submitted.

On a separate page, describe any changes since last quarter in CMS, process or controls. I certify that the information contained in this report is true, accurate, and complete.

____
Name

____
Signature

____
Title

____
Date

(e)(1) Notwithstanding the frequency of reporting requirements specified in paragraph (c) of this section, an owner or operator who is required by an applicable subpart to submit excess emissions and monitoring systems performance reports (and summary reports) on a quarterly (or more frequent) basis may reduce the frequency of reporting for that standard to semiannual if the following conditions are met:

(i) For 1 full year (e.g., 4 quarterly or 12 monthly reporting periods) the affected facility's excess emissions and monitoring systems reports submitted to comply with a standard under this part continually demonstrate that the facility is in compliance with the applicable standard;

(ii) The owner or operator continues to comply with all recordkeeping and monitoring requirements specified in this subpart and the applicable standard; and

(iii) The Administrator does not object to a reduced frequency of reporting for the affected facility, as provided in paragraph (e)(2) of this section.

(2) The frequency of reporting of excess emissions and monitoring systems performance (and summary) reports may be reduced only after the owner or operator notifies the Administrator in writing of his or her intention to make such a change and the Administrator does not object to the intended change. In deciding whether to approve a reduced frequency of reporting, the Administrator may review information concerning the source's entire previous performance history during the required recordkeeping period prior to the intended change, including performance test results, monitoring data, and evaluations of an owner or operator's conformance with operation and maintenance requirements. Such information may be used by the Administrator to make a judgment about the source's potential for noncompliance in the future. If the Administrator disapproves the owner or operator's request to reduce the frequency of reporting, the Administrator will notify the owner or operator in writing within 45 days after receiving notice of the

owner or operator's intention. The notification from the Administrator to the owner or operator will specify the grounds on which the disapproval is based. In the absence of a notice of disapproval within 45 days, approval is automatically granted.

(3) As soon as monitoring data indicate that the affected facility is not in compliance with any emission limitation or operating parameter specified in the applicable standard, the frequency of reporting shall revert to the frequency specified in the applicable standard, and the owner or operator shall submit an excess emissions and monitoring systems performance report (and summary report, if required) at the next appropriate reporting period following the noncomplying event. After demonstrating compliance with the applicable standard for another full year, the owner or operator may again request approval from the Administrator to reduce the frequency of reporting for that standard as provided for in paragraphs (e)(1) and (e)(2) of this section.

(f) Any owner or operator subject to the provisions of this part shall maintain a file of all measurements, including continuous monitoring system, monitoring device, and performance testing measurements; all continuous monitoring system performance evaluations; all continuous monitoring system or monitoring device calibration checks; adjustments and maintenance performed on these systems or devices; and all other information required by this part recorded in a permanent form suitable for inspection. The file shall be retained for at least two years following the date of such measurements, maintenance, reports, and records, except as follows:

(1) This paragraph applies to owners or operators required to install a continuous emissions monitoring system (CEMS) where the CEMS installed is automated, and where the calculated data averages do not exclude periods of CEMS breakdown or malfunction. An automated CEMS records and reduces the measured data to the form of the pollutant emission standard through the use of a computerized data acquisition system. In lieu of maintaining a file of all CEMS subhourly measurements as required under paragraph (f) of this section, the owner or operator shall retain the most recent consecutive three averaging periods of subhourly measurements and a file that contains a hard copy of the data acquisition system algorithm used to reduce the measured data into the reportable form of the standard.

(2) This paragraph applies to owners or operators required to install a CEMS where the measured data is manually reduced to obtain the reportable form of the standard, and where the calculated data averages do not exclude periods of CEMS breakdown or malfunction. In lieu of maintaining a file of all CEMS subhourly measurements as required under paragraph (f) of this section, the owner or operator shall retain all subhourly measurements for the most recent reporting period. The subhourly measurements shall be retained for 120 days from the date of the most recent summary or excess emission report submitted to the Administrator.

(3) The Administrator or delegated authority, upon notification to the source, may require the owner or operator to maintain all measurements as required by paragraph (f) of this section, if the Administrator or the delegated authority determines these records are required to more accurately assess the compliance status of the affected source.

(g) If notification substantially similar to that in paragraph (a) of this section is required by any other State or local agency, sending the Administrator a copy of that notification will satisfy the requirements of paragraph (a) of this section.

(h) Individual subparts of this part may include specific provisions which clarify or make inapplicable the provisions set forth in this section.

[36 FR 24877, Dec. 28, 1971, as amended at 40 FR 46254, Oct. 6, 1975; 40 FR 58418, Dec. 16, 1975; 45 FR 5617, Jan. 23, 1980; 48 FR 48335, Oct. 18, 1983; 50 FR 53113, Dec. 27, 1985; 52 FR 9781, Mar. 26, 1987; 55 FR 51382, Dec. 13, 1990; 59 FR 12428, Mar. 16, 1994; 59 FR 47265, Sep. 15, 1994; 64 FR 7463, Feb. 12, 1999]

§ 60.8 Performance tests.

(a) Within 60 days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial startup of such facility and at such other times as may be required by the Administrator under section 114 of the Act, the owner or operator of such facility shall conduct performance test(s) and furnish the Administrator a written report of the results of such performance test(s).

(b) Performance tests shall be conducted and data reduced in accordance with the test methods and procedures contained in each applicable subpart unless the Administrator (1) specifies or approves, in specific cases, the use of a reference method with minor changes in methodology, (2) approves the use of an equivalent method, (3) approves the use of an alternative method the results of which he has determined to be adequate for indicating whether a specific source is in compliance, (4) waives the requirement for performance tests because the owner or operator of a source has demonstrated by other means to the Administrator's satisfaction that the affected facility is in compliance with the standard, or (5) approves shorter sampling times and smaller sample volumes when necessitated by process variables or other factors. Nothing in this paragraph shall be construed to abrogate the Administrator's authority to require testing under section 114 of the Act.

(c) Performance tests shall be conducted under such conditions as the Administrator shall specify to the plant operator based on representative performance of the affected facility. The owner or operator shall make available to the Administrator such records as may be necessary to determine the conditions of the performance tests. Operations during periods of startup, shutdown, and malfunction shall not constitute representative conditions for the purpose of a performance test nor shall emissions in excess of the level of the applicable emission limit during periods of startup, shutdown, and malfunction be considered a violation of the applicable emission limit unless otherwise specified in the applicable standard.

(d) The owner or operator of an affected facility shall provide the Administrator at least 30 days prior notice of any performance test, except as specified under other subparts, to afford the Administrator the opportunity to have an observer present. If after 30 days notice for an initially scheduled performance test, there is a delay (due to operational problems, etc.) in conducting the scheduled performance test, the owner or operator of an affected facility shall notify the Administrator (or delegated State or local agency) as soon as possible of any delay in the original test date, either by providing at least 7 days prior notice of the rescheduled date of the performance test, or by arranging a rescheduled date with the Administrator (or delegated State or local agency) by mutual agreement.

(e) The owner or operator of an affected facility shall provide, or cause to be provided, performance testing facilities as follows:

(1) Sampling ports adequate for test methods applicable to such facility. This includes (i) constructing the air pollution control system such that volumetric flow rates and pollutant emission rates can be accurately determined by applicable test methods and procedures and (ii) providing a stack or duct free of cyclonic flow during performance tests, as demonstrated by applicable test methods and procedures.

(2) Safe sampling platform(s).

(3) Safe access to sampling platform(s).

(4) Utilities for sampling and testing equipment.

(f) Unless otherwise specified in the applicable subpart, each performance test shall consist of three separate runs using the applicable test method. Each run shall be conducted for the time and under the conditions specified in the applicable standard. For the purpose of determining compliance with an applicable standard, the arithmetic means of results of the three runs shall apply. In the event that a sample is accidentally lost or conditions occur in which one of the three runs must be discontinued because of forced shutdown, failure of an irreplaceable portion of the sample train, extreme meteorological conditions, or other circumstances, beyond the owner or operator's control, compliance may, upon the Administrator's approval, be determined using the arithmetic mean of the results of the two other runs.

[36 FR 24877, Dec. 23, 1971, as amended at 39 FR 9314, Mar. 8, 1974; 42 FR 57126, Nov. 1, 1977; 44 FR 33612, June 11, 1979; 54 FR 6662, Feb. 14, 1989; 54 FR 21344, May 17, 1989; 64 FR 7463, Feb. 12, 1999]

§ 60.9 Availability of information.

The availability to the public of information provided to, or otherwise obtained by, the Administrator under this part shall be governed by part 2 of this chapter. (Information submitted voluntarily to the Administrator for the purposes of §§ 60.5 and 60.6 is governed by §§ 2.201 through 2.213 of this chapter and not by § 2.301 of this chapter.)

§ 60.10 State authority.

The provisions of this part shall not be construed in any manner to preclude any State or political subdivision thereof from:

(a) Adopting and enforcing any emission standard or limitation applicable to an affected facility, provided that such emission standard or limitation is not less stringent than the standard applicable to such facility.

(b) Requiring the owner or operator of an affected facility to obtain permits, licenses, or approvals prior to initiating construction, modification, or operation of such facility.

§ 60.11 Compliance with standards and maintenance requirements.

(a) Compliance with standards in this part, other than opacity standards, shall be determined in accordance with performance tests established by § 60.8, unless otherwise specified in the applicable standard.

(b) Compliance with opacity standards in this part shall be determined by conducting observations in accordance with Reference Method 9 in appendix A of this part, any alternative method that is approved by the Administrator, or as provided in paragraph (e)(5) of this section. For purposes of determining initial compliance, the minimum total time of observations shall be 3 hours (30 6-minute averages) for the performance test or other set of observations (meaning those fugitive-type emission sources subject only to an opacity standard).

(c) The opacity standards set forth in this part shall apply at all times except during periods of startup, shutdown, malfunction, and as otherwise provided in the applicable standard.

(d) At all times, including periods of startup, shutdown, and malfunction, owners and operators shall, to the extent practicable, maintain and operate any affected facility including associated air pollution control equipment in a manner consistent with good air pollution control practice for minimizing emissions. Determination of whether acceptable operating and maintenance procedures are being used will be based on information available to the Administrator which may include, but is not limited to, monitoring results, opacity observations, review of operating and maintenance procedures, and inspection of the source.

(e)(1) For the purpose of demonstrating initial compliance, opacity observations shall be conducted concurrently with the initial performance test required in § 60.8 unless one of the following conditions apply. If no performance test under § 60.8 is required, then opacity observations shall be conducted within 60 days after achieving the maximum production rate at which the affected facility will be operated but no later than 180 days after initial startup of the facility. If visibility or other conditions prevent the opacity observations from being conducted concurrently with the initial performance test required under § 60.8, the source owner or operator shall reschedule the opacity observations as soon after the initial performance test as possible, but not later than 30 days thereafter, and shall advise the Administrator of the rescheduled date. In these cases, the 30-day prior notification to the Administrator required in § 60.7(a)(6) shall be waived. The rescheduled opacity observations shall be conducted (to the extent possible) under the same operating conditions that existed during the initial performance test conducted under § 60.8. The visible emissions observer shall determine whether visibility or other conditions prevent the opacity observations from being made concurrently with the initial performance test in accordance with procedures contained in Reference Method 9 of appendix B of this part. Opacity readings of portions of plumes which contain condensed, uncombined water vapor shall not be used for purposes of determing compliance with opacity standards. The owner or operator of an affected facility shall make available, upon request by the Administrator, such records as may be necessary to determine the conditions under which the visual observations were made and shall provide evidence indicating proof of current visible observer emission certification. Except as provided in paragraph (e)(5) of this section, the results of continuous monitoring by transmissometer which indicate that the opacity at the time visual observations were made was not in excess of the standard are probative but not conclusive evidence of the actual opacity of an emission, provided that the source shall meet the burden of proving that the instrument used meets (at the time of the alleged violation) Performance Specification 1 in appendix B of this part, has been properly maintained and (at the time of the alleged violation) that the resulting data have not been altered in any way.

(2) Except as provided in paragraph (e)(3) of this section, the owner or operator of an affected facility to which an opacity standard in this part applies shall conduct opacity observations in accordance with paragraph (b) of this section, shall record the opacity of emissions, and shall report to the Administrator the opacity results along with the results of the initial performance test required under § 60.8. The inability of an owner or operator to secure a visible emissions observer shall not be considered a reason for not conducting the opacity observations concurrent with the initial performance test.

(3) The owner or operator of an affected facility to which an opacity standard in this part applies may request the Administrator to determine and to record the opacity of emissions from the affected facility during the initial performance test and at such times as may be required. The owner or operator of the affected facility shall report the opacity results. Any request to the Administrator to determine and to record the opacity of emissions from an affected facility shall be included in the notification required in § 60.7(a)(6). If, for some reason, the Administrator cannot determine and record the opacity of emissions from the affected facility during the performance test, then the provisions of paragraph (e)(1) of this section shall apply.

(4) An owner or operator of an affected facility using a continuous opacity monitor (transmissometer) shall record the monitoring data produced during the initial performance test required by § 60.8 and shall furnish the Administrator a written report of the monitoring results along with Method 9 and § 60.8 performance test results.

(5) An owner or operator of an affected facility subject to an opacity standard may submit, for compliance purposes, continuous opacity monitoring system (COMS) data results produced during any performance test required under § 60.8 in lieu of Method 9 observation data. If an owner or operator elects to submit COMS data for compliance with the opacity standard, he shall notify the Administrator of that decision, in writing, at least 30 days before any performance test required under § 60.8 is conducted. Once the owner or operator of an affected facility has notified the Administrator to that effect, the COMS data results will be used to determine opacity compliance during subsequent tests required under § 60.8 until the owner or operator notifies the Administrator, in writing, to the contrary. For the purpose of determining compliance with the opacity standard during a performance test required under § 60.8 using COMS data, the minimum total time of COMS data collection shall be averages of all 6-minute continuous periods within the duration of the mass emission performance test. Results of the COMS opacity determinations shall be submitted along with the results of the performance test required under § 60.8. The owner or operator of an affected facility using a COMS for compliance purposes is responsible for demonstrating that the COMS meets the requirements specified in § 60.13(c) of this part, that

the COMS has been properly maintained and operated, and that the resulting data have not been altered in any way. If COMS data results are submitted for compliance with the opacity standard for a period of time during which Method 9 data indicates noncompliance, the Method 9 data will be used to determine opacity compliance.

(6) Upon receipt from an owner or operator of the written reports of the results of the performance tests required by § 60.8, the opacity observation results and observer certification required by § 60.11(e)(1), and the COMS results, if applicable, the Administrator will make a finding concerning compliance with opacity and other applicable standards. If COMS data results are used to comply with an opacity standard, only those results are required to be submitted along with the performance test results required by § 60.8. If the Administrator finds that an affected facility is in compliance with all applicable standards for which performance tests are conducted in accordance with § 60.8 of this part but during the time such performance tests are being conducted fails to meet any applicable opacity standard, he shall notify the owner or operator and advise him that he may petition the Administrator within 10 days of receipt of notification to make appropriate adjustment to the opacity standard for the affected facility.

(7) The Administrator will grant such a petition upon a demonstration by the owner or operator that the affected facility and associated air pollution control equipment was operated and maintained in a manner to minimize the opacity of emissions during the performance tests; that the performance tests were performed under the conditions established by the Administrator; and that the affected facility and associated air pollution control equipment were incapable of being adjusted or operated to meet the applicable opacity standard.

(8) The Administrator will establish an opacity standard for the affected facility meeting the above requirements at a level at which the source will be able, as indicated by the performance and opacity tests, to meet the opacity standard at all times during which the source is meeting the mass or concentration emission standard. The Administrator will promulgate the new opacity standard in the FEDERAL REGISTER.

(f) Special provisions set forth under an applicable subpart shall supersede any conflicting provisions in paragraphs (a) through (e) of this section.

(g) For the purpose of submitting compliance certifications or establishing whether or not a person has violated or is in violation of any standard in this part, nothing in this part shall preclude the use, including the exclusive use, of any credible evidence or information, relevant to whether a source would have been in compliance with applicable requirements if the appropriate performance or compliance test or procedure had been performed.

[38 FR 28565, Oct. 15, 1973, as amended at 39 FR 39873, Nov. 12, 1974; 43 FR 8800, Mar. 3, 1978; 45 FR 23379, Apr. 4, 1980; 48 FR 48335, Oct. 18, 1983; 50 FR 53113, Dec. 27, 1985; 51 FR 1790, Jan. 15, 1986; 52 FR 9781, Mar. 26, 1987; 62 FR 8328, Feb. 24, 1997]

§ 60.12 Circumvention.

No owner or operator subject to the provisions of this part shall build, erect, install, or use any article, machine, equipment or process, the use of which conceals an emission which would otherwise constitute a violation of an applicable standard. Such concealment includes, but is not limited to, the use of gaseous diluents to achieve compliance with an opacity standard or with a standard which is based on the concentration of a pollutant in the gases discharged to the atmosphere.

[39 FR 9314, Mar. 8, 1974]

§ 60.13 Monitoring requirements.

(a) For the purposes of this section, all continuous monitoring systems required under applicable subparts shall be subject to the provisions of this section upon promulgation of performance specifications for continuous monitoring systems under appendix B to this part and, if the continuous monitoring system is used to demonstrate compliance with emission limits on a continuous basis, appendix F to this part, unless otherwise specified in an applicable subpart or by the Administrator. Appendix F is applicable December 4, 1987.

(b) All continuous monitoring systems and monitoring devices shall be installed and operational prior to conducting performance tests under §60.8. Verification of operational status shall, as a minimum, include completion of the manufacturer's written requirements or recommendations for installation, operation, and calibration of the device.

(c) If the owner or operator of an affected facility elects to submit continous opacity monitoring system (COMS) data for compliance with the opacity standard as provided under §60.11(e)(5), he shall conduct a performance evaluation of the COMS as specified in Performance Specification 1, appendix B, of this part before the performance test required under §60.8 is conducted. Otherwise, the owner or operator of an affected facility shall conduct a performance evaluation of the COMS or continuous emission monitoring system (CEMS) during any performance test required under §60.8 or within 30 days thereafter in accordance with the applicable performance specification in appendix B of this part. The owner or operator of an affected facility shall conduct COMS or CEMS performance evaluations at such other times as may be required by the Administrator under section 114 of the Act.

(1) The owner or operator of an affected facility using a COMS to determine opacity compliance during any performance test required under §60.8 and as described in §60.11(e)(5) shall furnish the Administrator two or, upon request, more copies of a written report of the results of the COMS performance evaluation described in paragraph (c) of this section at least 10 days before the performance test required under §60.8 is conducted.

(2) Except as provided in paragraph (c)(1) of this section, the owner or operator of an affected facility shall furnish the Administrator within 60 days of completion two or, upon request, more copies of a written report of the results of the performance evaluation.

(d)(1) Owners and operators of all continuous emission monitoring systems installed in accordance with the provisions of this part shall check the zero (or low-level value between 0 and 20 percent of span value) and span (50 to 100 percent of span value) calibration drifts at least once daily in accordance with a written procedure. The zero and span shall, as a minimum, be adjusted whenever the 24-hour zero drift or 24-hour span drift exceeds two times the limits of the applicable performance specifications in appendix B. The system must allow the amount of excess zero and span drift measured at the 24-hour interval checks to be recorded and quantified, whenever specified. For continuous monitoring systems measuring opacity of emissions, the optical surfaces exposed to the effluent gases shall be cleaned prior to performing the zero and span drift adjustments except that for systems using automatic zero adjustments. The optical surfaces shall be cleaned when the cumulative automatic zero compensation exceeds 4 percent opacity.

(2) Unless otherwise approved by the Administrator, the following procedures shall be followed for continuous monitoring systems measuring opacity of emissions. Minimum procedures shall include a method for producing a simulated zero opacity condition and an upscale (span) opacity condition using a certified neutral density filter or other related technique to produce a known obscuration of the light beam. Such procedures shall provide a system check of the analyzer internal optical surfaces and all electronic circuitry including the lamp and photodetector assembly.

(e) Except for system breakdowns, repairs, calibration checks, and zero and span adjustments required under paragraph (d) of this section, all continuous monitoring systems shall be in continuous operation and shall meet minimum frequency of operation requirements as follows:

(1) All continuous monitoring systems referenced by paragraph (c) of this section for measuring opacity of emissions shall complete a minimum of one cycle of sampling and analyzing for each successive 10-second period and one cycle of data recording for each successive 6-minute period.

(2) All continuous monitoring systems referenced by paragraph (c) of this section for measuring emissions, except opacity, shall complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period.

(f) All continuous monitoring systems or monitoring devices shall be installed such that representative measurements of emissions or process parameters from the affected facility are obtained. Additional procedures for location of continuous monitoring systems contained in the applicable Performance Specifications of appendix B of this part shall be used.

(g) When the effluents from a single affected facility or two or more affected facilities subject to the same emission standards are combined before being released to the atmosphere, the owner or operator may install applicable continuous monitoring systems on each effluent or on the combined effluent. When the affected facilities are not subject to the same emission standards, separate continuous monitoring systems shall be installed on each effluent. When the effluent from one affected facility is released to the atmosphere through more than one point, the owner or operator shall install an applicable continuous monitoring system on each separate effluent unless the installation of fewer systems is approved by the Administrator. When more than one continuous monitoring system is used to measure the emissions from one affected facility (e.g., multiple breechings, multiple outlets), the owner or operator shall report the results as required from each continuous monitoring system.

(h) Owners or operators of all continuous monitoring systems for measurement of opacity shall reduce all data to 6-minute averages and for continuous monitoring systems other than opacity to 1-hour averages for time periods as defined in § 60.2. Six-minute opacity averages shall be calculated from 36 or more data points equally spaced over each 6-minute period. For continuous monitoring systems other than opacity, 1-hour averages shall be computed from four or more data points equally spaced over each 1-hour period. Data recorded during periods of continuous system breakdown, repair, calibration checks, and zero and span adjustments shall not be included in the data averages computed under this paragraph. For owners and operators complying with the requirements in § 60.7(f) (1) or (2), data averages must include any data recorded during periods of monitor breakdown or malfunction. An arithmetic or integrated average of all data may be used. The data may be recorded in reduced or nonreduced form (e.g., ppm pollutant and percent O_2 or ng/J of pollutant). All excess emissions shall be converted into units of the standard using the applicable conversion procedures specified in subparts. After conversion into units of the standard, the data may be rounded to the same number of significant digits as used in the applicable subparts to specify the emission limit (e.g., rounded to the nearest 1 percent opacity).

(i) After receipt and consideration of written application, the Administrator may approve alternatives to any monitoring procedures or requirements of this part including, but not limited to the following:

(1) Alternative monitoring requirements when installation of a continuous monitoring system or monitoring device specified by this part would not provide accurate measurements due to liquid water or other interferences caused by substances with the effluent gases.

(2) Alternative monitoring requirements when the affected facility is infrequently operated.

(3) Alternative monitoring requirements to accommodate continuous monitoring systems that require additional measurements to correct for stack moisture conditions.

(4) Alternative locations for installing continuous monitoring systems or monitoring devices when the owner or operator can demonstrate that installation at alternate locations will enable accurate and representative measurements.

(5) Alternative methods of converting pollutant concentration measurements to units of the standards.

(6) Alternative procedures for performing daily checks of zero and span drift that do not involve use of span gases or test cells.

(7) Alternatives to the A.S.T.M. test methods or sampling procedures specified by any subpart.

(8) Alternative continuous monitoring systems that do not meet the design or performance requirements in Performance Specification 1, appendix B, but adequately demonstrate a definite and consistent relationship between its measurements and the measurements of opacity by a system complying with the requirements in Performance Specification 1. The Administrator may require that such demonstration be performed for each affected facility.

(9) Alternative monitoring requirements when the effluent from a single affected facility or the combined effluent from two or more affected facilities are released to the atmosphere through more than one point.

(j) An alternative to the relative accuracy test specified in Performance Specification 2 of appendix B may be requested as follows:

(1) An alternative to the reference method tests for determining relative accuracy is available for sources with emission rates demonstrated to be less than 50 percent of the applicable standard. A source owner or operator may petition the Administrator to waive the relative accuracy test in section 7 of Performance Specification 2 and substitute the procedures in section 10 if the results of a performance test conducted according to the requirements in § 60.8 of this subpart or other tests performed following the criteria in § 60.8 demonstrate that the emission rate of the pollutant of interest in the units of the applicable standard is less than 50 percent of the applicable standard. For sources subject to standards expressed as control efficiency levels, a source owner or operator may petition the Administrator to waive the relative accuracy test and substitute the procedures in section 10 of Performance Specification 2 if the control device exhaust emission rate is less than 50 percent of the level needed to meet the control efficiency requirement. The alternative procedures do not apply if the continuous emission monitoring system is used to determine compliance continuously with the applicable standard. The petition to waive the relative accuracy test shall include a detailed description of the procedures to be applied. Included shall be location and procedure for conducting the alternative, the concentration or response levels of the alternative RA materials, and the other equipment checks included in the alternative procedure. The Administrator will review the petition for completeness and applicability. The determination to grant a waiver will depend on the intended use of the CEMS data (e.g., data collection purposes other than NSPS) and may require specifications more stringent than in Performance Specification 2 (e.g., the applicable emission limit is more stringent than NSPS).

(2) The waiver of a CEMS relative accuracy test will be reviewed and may be rescinded at such time following successful completion of the alternative RA procedure that the CEMS data indicate the source emissions approaching the level of the applicable standard. The criterion for reviewing the waiver is the collection of CEMS data showing that emissions have exceeded 70 percent of the applicable standard for seven, consecutive, averaging periods as specified by the applicable regulation(s). For sources subject to standards expressed as control efficiency levels, the criterion for reviewing the waiver is the collection of CEMS data showing that exhaust emissions have exceeded 70 percent of the level needed to meet the control efficiency requirement for seven, consecutive, averaging periods as specified by the applicable regulation(s) [e.g., § 60.45(g) (2) and (3), § 60.73(e), and § 60.84(e)]. It is the responsibility of the source operator to maintain records and determine the level of emissions relative to the criterion on the waiver of relative accuracy testing. If this criterion is exceeded, the owner or operator must notify the Administrator within 10 days of such occurrence and include a description of the nature and cause of the increasing emissions. The Administrator will review the notification and may rescind the waiver and require the owner or operator to conduct a relative accuracy test of the

CEMS as specified in section 7 of Performance Specification 2.

[40 FR 46255, Oct. 6, 1975; 40 FR 59205, Dec. 22, 1975, as amended at 41 FR 35185, Aug. 20, 1976; 48 FR 13326, Mar. 30, 1983; 48 FR 23610, May 25, 1983; 48 FR 32986, July 20, 1983; 52 FR 9782, Mar. 26, 1987; 52 FR 17555, May 11, 1987; 52 FR 21007, June 4, 1987; 64 FR 7463, Feb. 12, 1999]

§ 60.14 Modification.

(a) Except as provided under paragraphs (e) and (f) of this section, any physical or operational change to an existing facility which results in an increase in the emission rate to the atmosphere of any pollutant to which a standard applies shall be considered a modification within the meaning of section 111 of the Act. Upon modification, an existing facility shall become an affected facility for each pollutant to which a standard applies and for which there is an increase in the emission rate to the atmosphere.

(b) Emission rate shall be expressed as kg/hr of any pollutant discharged into the atmosphere for which a standard is applicable. The Administrator shall use the following to determine emission rate:

(1) Emission factors as specified in the latest issue of "Compilation of Air Pollutant Emission Factors," EPA Publication No. AP-42, or other emission factors determined by the Administrator to be superior to AP-42 emission factors, in cases where utilization of emission factors demonstrate that the emission level resulting from the physical or operational change will either clearly increase or clearly not increase.

(2) Material balances, continuous monitor data, or manual emission tests in cases where utilization of emission factors as referenced in paragraph (b)(1) of this section does not demonstrate to the Administrator's satisfaction whether the emission level resulting from the physical or operational change will either clearly increase or clearly not increase, or where an owner or operator demonstrates to the Administrator's satisfaction that there are reasonable grounds to dispute the result obtained by the Administrator utilizing emission factors as referenced in paragraph (b)(1) of this section. When the emission rate is based on results from manual emission tests or continuous monitoring systems, the procedures specified in appendix C of this part shall be used to determine whether an increase in emission rate has occurred. Tests shall be conducted under such conditions as the Administrator shall specify to the owner or operator based on representative performance of the facility. At least three valid test runs must be conducted before and at least three after the physical or operational change. All operating parameters which may affect emissions must be held constant to the maximum feasible degree for all test runs.

(c) The addition of an affected facility to a stationary source as an expansion to that source or as a replacement for an existing facility shall not by itself bring within the applicability of this part any other facility within that source.

(d) [Reserved]

(e) The following shall not, by themselves, be considered modifications under this part:

(1) Maintenance, repair, and replacement which the Administrator determines to be routine for a source category, subject to the provisions of paragraph (c) of this section and § 60.15.

(2) An increase in production rate of an existing facility, if that increase can be accomplished without a capital expenditure on that facility.

(3) An increase in the hours of operation.

(4) Use of an alternative fuel or raw material if, prior to the date any standard under this part becomes applicable to that source type, as provided by § 60.1, the existing facility was designed to accommodate that alternative use. A facility shall be considered to be designed to accommodate an alternative fuel or raw material if that use could be accomplished under the facility's construction specifications as amended prior to the change. Conversion to coal required for energy considerations, as specified in section 111(a)(8) of the Act, shall not be considered a modification.

(5) The addition or use of any system or device whose primary function is the reduction of air pollutants, except

when an emission control system is removed or is replaced by a system which the Administrator determines to be less environmentally beneficial.

(6) The relocation or change in ownership of an existing facility.

(f) Special provisions set forth under an applicable subpart of this part shall supersede any conflicting provisions of this section.

(g) Within 180 days of the completion of any physical or operational change subject to the control measures specified in paragraph (a) of this section, compliance with all applicable standards must be achieved.

(h) No physical change, or change in the method of operation, at an existing electric utility steam generating unit shall be treated as a modification for the purposes of this section provided that such change does not increase the maximum hourly emissions of any pollutant regulated under this section above the maximum hourly emissions achievable at that unit during the 5 years prior to the change.

(i) Repowering projects that are awarded funding from the Department of Energy as permanent clean coal technology demonstration projects (or similar projects funded by EPA) are exempt from the requirements of this section provided that such change does not increase the maximum hourly emissions of any pollutant regulated under this section above the maximum hourly emissions achievable at that unit during the five years prior to the change.

(j)(1) Repowering projects that qualify for an extension under section 409(b) of the Clean Air Act are exempt from the requirements of this section, provided that such change does not increase the actual hourly emissions of any pollutant regulated under this section above the actual hourly emissions achievable at that unit during the 5 years prior to the change.

(2) This exemption shall not apply to any new unit that:

(i) Is designated as a replacement for an existing unit;

(ii) Qualifies under section 409(b) of the Clean Air Act for an extension of an emission limitation compliance date under section 405 of the Clean Air Act; and

(iii) Is located at a different site than the existing unit.

(k) The installation, operation, cessation, or removal of a temporary clean coal technology demonstration project is exempt from the requirements of this section. A *temporary clean coal control technology demonstration project*, for the purposes of this section is a clean coal technology demonstration project that is operated for a period of 5 years or less, and which complies with the State implementation plan for the State in which the project is located and other requirements necessary to attain and maintain the national ambient air quality standards during the project and after it is terminated.

(l) The reactivation of a very clean coal-fired electric utility steam generating unit is exempt from the requirements of this section.

[40 FR 58419, Dec. 16, 1975, amended at 43 FR 34347, Aug. 3, 1978; 45 FR 5617, Jan. 23, 1980; 57 FR 32339, July 21, 1992]

§ 60.15 Reconstruction.

(a) An existing facility, upon reconstruction, becomes an affected facility, irrespective of any change in emission rate.

(b) "Reconstruction" means the replacement of components of an existing facility to such an extent that:

(1) The fixed capital cost of the new components exceeds 50 percent of the fixed capital cost that would be required to construct a comparable entirely new facility, and

(2) It is technologically and economically feasible to meet the applicable standards set forth in this part.

(c) "Fixed capital cost" means the capital needed to provide all the depreciable components.

(d) If an owner or operator of an existing facility proposes to replace components, and the fixed capital cost of the new components exceeds 50 percent of the fixed capital cost that would be required to construct a comparable entirely new facility, he shall notify the Administrator of the proposed replacements. The notice must be postmarked 60 days (or as soon as practicable) before construction of the replacements is commenced and must include the following information:

(1) Name and address of the owner or operator.

(2) The location of the existing facility.

(3) A brief description of the existing facility and the components which are to be replaced.

(4) A description of the existing air pollution control equipment and the proposed air pollution control equipment.

(5) An estimate of the fixed capital cost of the replacements and of constructing a comparable entirely new facility.

(6) The estimated life of the existing facility after the replacements.

(7) A discussion of any economic or technical limitations the facility may have in complying with the applicable standards of performance after the proposed replacements.

(e) The Administrator will determine, within 30 days of the receipt of the notice required by paragraph (d) of this section and any additional information he may reasonably require, whether the proposed replacement constitutes reconstruction.

(f) The Administrator's determination under paragraph (e) shall be based on:

(1) The fixed capital cost of the replacements in comparison to the fixed capital cost that would be required to construct a comparable entirely new facility;

(2) The estimated life of the facility after the replacements compared to the life of a comparable entirely new facility;

(3) The extent to which the components being replaced cause or contribute to the emissions from the facility; and

(4) Any economic or technical limitations on compliance with applicable standards of performance which are inherent in the proposed replacements.

(g) Individual subparts of this part may include specific provisions which refine and delimit the concept of reconstruction set forth in this section.

[40 FR 58420, Dec. 16, 1975]

§ 60.16 Priority list.

PRIORITIZED MAJOR SOURCE CATEGORIES

Priority Number[1]	*Source Category*
1.	Synthetic Organic Chemical Manufacturing Industry (SOCMI) and Volatile Organic Liquid Storage Vessels and Handling Equipment
	(a) SOCMI unit processes
	(b) Volatile organic liquid (VOL) storage vessels and handling equipment
	(c) SOCMI fugitive sources
	(d) SOCMI secondary sources
2.	Industrial Surface Coating: Cans
3.	Petroleum Refineries: Fugitive Sources
4.	Industrial Surface Coating: Paper
5.	Dry Cleaning
	(a) Perchloroethylene
	(b) Petroleum solvent
6.	Graphic Arts
7.	Polymers and Resins: Acrylic Resins
8.	Mineral Wool (Deleted)
9.	Stationary Internal Combustion Engines
10.	Industrial Surface Coating: Fabric
11.	Industrial-Commercial-Institutional Steam Generating Units.
12.	Incineration: Non-Municipal (Deleted)
13.	Non-Metallic Mineral Processing
14.	Metallic Mineral Processing
15.	Secondary Copper (Deleted)
16.	Phosphate Rock Preparation
17.	Foundries: Steel and Gray Iron
18.	Polymers and Resins: Polyethylene
19.	Charcoal Production
20.	Synthetic Rubber
	(a) Tire manufacture
	(b) SBR production
21.	Vegetable Oil
22.	Industrial Surface Coating: Metal Coil
23.	Petroleum Transportation and Marketing
24.	By-Product Coke Ovens
25.	Synthetic Fibers
26.	Plywood Manufacture
27.	Industrial Surface Coating: Automobiles
28.	Industrial Surface Coating: Large Appliances
29.	Crude Oil and Natural Gas Production
30.	Secondary Aluminum
31.	Potash (Deleted)
32.	Lightweight Aggregate Industry: Clay, Shale, and Slate[2]
33.	Glass
34.	Gypsum
35.	Sodium Carbonate
36.	Secondary Zinc (Deleted)
37.	Polymers and Resins: Phenolic
38.	Polymers and Resins: Urea-Melamine
39.	Ammonia (Deleted)
40.	Polymers and Resins: Polystyrene
41.	Polymers and Resins: ABS-SAN Resins
42.	Fiberglass
43.	Polymers and Resins: Polypropylene
44.	Textile Processing
45.	Asphalt Processing and Asphalt Roofing Manufacture
46.	Brick and Related Clay Products
47.	Ceramic Clay Manufacturing (Deleted)
48.	Ammonium Nitrate Fertilizer
49.	Castable Refractories (Deleted)
50.	Borax and Boric Acid (Deleted)
51.	Polymers and Resins: Polyester Resins
52.	Ammonium Sulfate

PRIORITIZED MAJOR SOURCE CATEGORIES—Continued

Priority Number[1]	Source Category
53.	Starch
54.	Perlite
55.	Phosphoric Acid: Thermal Process (Deleted)
56.	Uranium Refining
57.	Animal Feed Defluorination (Deleted)
58.	Urea (for fertilizer and polymers)
59.	Detergent (Deleted)
	Other Source Categories
	Lead acid battery manufacture[3]
	Organic solvent cleaning[3]
	Industrial surface coating: metal furniture[3]
	Stationary gas turbines[4]
	Municipal solid waste landfills[4]

[1] Low numbers have highest priority, e.g., No. 1 is high priority, No. 59 is low priority.
[2] Formerly titled "Sintering: Clay and Fly Ash".
[3] Minor source category, but included on list since an NSPS is being developed for that source category.
[4] Not prioritized, since an NSPS for this major source category has already been promulgated.

[47 FR 951, Jan. 8, 1982, as amended at 47 FR 31876, July 23, 1982; 51 FR 42796, Nov. 25, 1986; 52 FR 11428, Apr. 8, 1987; 61 FR 9919, Mar. 12, 1996]

§ 60.17 Incorporations by reference.

The materials listed below are incorporated by reference in the corresponding sections noted. These incorporations by reference were approved by the Director of the Federal Register on the date listed. These materials are incorporated as they exist on the date of the approval, and a notice of any change in these materials will be published in the FEDERAL REGISTER. The materials are available for purchase at the corresponding address noted below, and all are available for inspection at the Office of the Federal Register, 800 North Capitol Street, NW., suite 700, Washington, DC and at the Library (MD-35), U.S. EPA, Research Triangle Park, NC.

(a) The following materials are available for purchase from at least one of the following addresses: American Society for Testing and Materials (ASTM), 1916 Race Street, Philadelphia, Pennsylvania 19103; or the University Microfilms International, 300 North Zeeb Road, Ann Arbor, MI 48106.

(1) ASTM D388-77, Standard Specification for Classification of Coals by Rank, incorporation by reference (IBR) approved for §§ 60.41(f); 60.45(f)(4)(i), (ii), (vi); 60.41a; 60.41b; 60.41c; 60.25(b), (c).

(2) ASTM D3178-73, Standard Test Methods for Carbon and Hydrogen in the Analysis Sample of Coal and Coke, IBR approved January 27, 1983 for § 60.45(f)(5)(i).

(3) ASTM D3176-74, Standard Method for Ultimate Analysis of Coal and Coke, IBR approved January 27, 1983, for § 60.45(f)(5)(i); appendix A to part 60, Method 19.

(4) ASTM D1137-53 (Reapproved 1975), Standard Method for Analysis of Natural Gases and Related Types of Gaseous Mixtures by the Mass Spectrometer, IBR approved January 27, 1983 for § 60.45(f)(5)(i).

(5) ASTM D1945-64 (Reapproved 1976), Standard Method for Analysis of Natural Gas by Gas Chromatography, IBR approved January 27, 1983 for § 60.45(f)(5)(i).

(6) ASTM D1946-77, Standard Method for Analysis of Reformed Gas by Gas Chromatography, IBR approved for §§ 60.45(f)(5)(i), 60.18(c)(3)(i), 60.18(f), 60.614(d)(2)(ii), 60.614(d)(4), 60.664(d)(2)(ii), 60.664(d)(4), 60.564(f), 60.704(d)(2)(ii) and 60.704(d)(4).

(7) ASTM D2015-77, Standard Test Method for Gross Calorific Value of Solid Fuel by the Adiabatic Bomb Calorimeter, IBR approved January 27, 1983 for § 60.45(f)(5)(ii); § 60.46(g); appendix A to part 60, Method 19.

(8) ASTM D1826-77, Standard Test Method for Calorific Value of Gases in Natural Gas Range by Continuous Recording Calorimeter, IBR approved January 27, 1983, for §§ 60.45(f)(5)(ii); 60.46(g); 60.296(f); appendix A to part 60, Method 19.

(9) ASTM D240-76, Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter, IBR approved January 27, 1983, for § 60.46(g); 60.296(f); appendix A to part 60, Method 19.

(10) ASTM D396-78, Standard Specification for Fuel Oils, IBR approved for §§ 60.40b; 60.41b; 60.41c; 60.111(b); 60.111a(b).

(11) ASTM D2880-78, Standard Specification for Gas Turbine Fuel Oils, IBR approved January 27, 1983 for §§ 60.111(b), 60.111a(b), 60.335(b)(2).

(12) ASTM D975-78, Standard Specification for Diesel Fuel Oils, IBR approved January 27, 1983 for §§ 60.111(b), 60.111a(b).

(13) ASTM D323-82, Test Method for Vapor Pressure of Petroleum Products (Reid Method), IBR approved April 8, 1987 for §§ 60.111(l), 60.111a(g), 60.111b(g), and 60.116b(f)(2)(ii).

(14) ASTM A99-76, Standard Specification for Ferromanganese, IBR approved January 27, 1983 for § 60.261.

(15) ASTM A483-64 (Reapproved 1974), Standard Specification for Silicomanganese, IBR approved January 27, 1983 for § 60.261.

(16) ASTM A101-73, Standard Specification for Ferrochromium, IBR approved January 27, 1983 for § 60.261.

(17) ASTM A100-69 (Reapproved 1974), Standard Specification for Ferrosilicon, IBR approved January 27, 1983 for § 60.261.

(18) ASTM A482-76, Standard Specification for Ferrochromesilicon, IBR approved January 27, 1983 for § 60.261.

(19) ASTM A495-76, Standard Specification for Calcium-Silicon and Calcium Manganese-Silicon, IBR approved January 27, 1983 for § 60.261.

(20) ASTM D 1072-80, Standard Method for Total Sulfur in Fuel Gases, IBR approved July 31, 1984 for § 60.335(b)(2).

(21) ASTM D2986-71 (Reapproved 1978), Standard Method for Evaluation of Air, Assay Media by the Monodisperse DOP (Dioctyl Phthalate) Smoke Test, IBR approved January 27, 1983 for appendix A to part 60, Method 5, par. 3.1.1; Method 12, par. 4.1.1; Method 17, par. 3.1.1.

(22) ASTM D 1193-77, Standard Specification for Reagent Water, for appendix A to part 60, Method 6, par. 3.1.1; Method 7, par. 3.2.2; Method 7C, par. 3.1.1; Method 7D, par. 3.1.1; Method 8, par. 3.1.3; Method 12, par. 4.1.3; Method 25D, par. 3.2.2.4; Method 26A, par. 3.1.1; Method 29, pars. 4.2.2., 4.4.2., and 4.5.6.; Method 14A, par. 7.1.

(23) [Reserved]

(24) ASTM D2234-76, Standard Methods for Collection of a Gross Sample of Coal, IBR approved January 27, 1983, for appendix A to part 60, Method 19.

(25) ASTM D3173-73, Standard Test Method for Moisture in the Analysis Sample of Coal and Coke, IBR approved January 27, 1983, for appendix A to part 60, Method 19.

(26) ASTM D3177-75, Standard Test Methods for Total Sulfur in the Analysis Sample of Coal and Coke, IBR approved January 27, 1983, for appendix A to part 60, Method 19.

(27) ASTM D2013-72, Standard Method of Preparing Coal Samples for Analysis, IBR approved January 27, 1983, for appendix A to part 60, Method 19.

(28) ASTM D270-65 (Reapproved 1975), Standard Method of Sampling Petroleum and Petroleum Products, IBR approved January 27, 1983, for appendix A to part 60, Method 19.

(29) ASTM D737-85, Standard Test Method for Air Permeability of Textile Fabrics, IBR approved January 27, 1983 for §61.23(a).

(30) ASTM D1475-60 (Reapproved 1980), Standard Test Method for Density of Paint, Varnish, Lacquer, and Related Products, IBR approved January 27, 1983 for § 60.435(d)(1), appendix A to part 60, Method 24, par. 2.1, and Method 24A, par. 2.2.

(31) ASTM D2369-81, Standard Test Method for Volatile Content of Coatings, IBR approved January 27, 1983 for appendix A to part 60, Method 24.

(32) ASTM D3792-79, Standard Method for Water Content of Water-Reducible Paints by Direct Injection Into a Gas Chromatograph, IBR approved January 27, 1983 for appendix A to part 60, Method 24, par. 2.3.

(33) ASTM D4017-81, Standard Test Method for Water in Paints and Paint Materials by the Karl Fischer Titration Method, IBR approved January 27, 1983 for appendix A to part 60, Method 24, par. 2.4.

(34) ASTM E169-63 (Reapproved 1977), General Techniques of Ultraviolet Quantitative Analysis, IBR approved for § 60.485(d), § 60.593(b), and § 60.632(f).

(35) ASTM E168-67 (Reapproved 1977), General Techniques of Infrared Quantitative Analysis, IBR approved for § 60.485(d), § 60.593(b), and § 60.632(f).

(36) ASTM E260-73, General Gas Chromatography Procedures, IBR approved for § 60.485(d), § 60.593(b), and § 60.632(f).

(37) ASTM D2879-83, Test Method for Vapor Pressure—Temperature Relationship and Initial Decomposition Temperature of Liquids by Isoteniscope, IBR approved April 8, 1987 for §§ 60.485(e), 60.111b(f)(3), 60.116b(e)(3)(ii), and 60.116b(f)(2)(i).

(38) ASTM D2382-76, Heat of Combustion of Hydrocarbon Fuels by Bomb Calorimeter [High-Precision Method], IBR approved for §§ 60.18(f), 60.485(g), 60.614(d)(4), 60.664(d)(4), and 60.564(f), and 60.704(d)(4).

(39) ASTM D2504-67 (Reapproved 1977), Noncondensable Gases in C_3 and Lighter Hydrocarbon Products by Gas Chromatography, IBR approved for § 60.485(g).

(40) ASTM D86-78, Distillation of Petroleum Products, IBR approved for § 60.593(d), § 60.633(h), and § 60.562-2(d).

(41) [Reserved]

(42) ASTM D 3031-81, Standard Test Method for Total Sulfur in Natural Gas by Hydrogenation, IBR approved July 31, 1984 for § 60.335(b)(2).

(43) ASTM D 4084-82, Standard Method for Analysis of Hydrogen Sulfide in Gaseous Fuels (Lead Acetate Reaction Rate Method), IBR approved July 31, 1984 for § 60.335(b)(2).

(44) ASTM D 3246-81, Standard Method for Sulfur in Petroleum Gas by Oxidative Microcoulometry, IBR approved July 31, 1984 for § 60.335(b)(2).

(45) ASTM D2584-68, Standard Test Method for Ignition Loss of Cured Reinforced Resins, IBR approved February 25, 1985 for § 60.685(e).

(46) ASTM D3431-80, Standard Test Method for Trace Nitrogen in Liquid Petroleum Hydrocarbons (Microcoulometric Method), IBR approved November 25, 1986, for appendix A to part 60, Method 19.

(47) ASTM D129-64 (reapproved 1978), Standard Test Method for Sulfur in Petroleum Products (General Bomb Method), IBR approved for appendix A to part 60, Method 19.

(48) ASTM D1552-83, Standard Test Method for Sulfur in Petroleum Products (High Temperature Method), IBR approved for appendix A to part 60, Method 19.

(49) ASTM D1835-86, Standard Specification for Liquefied Petroleum (LP) Gases, to be approved for § 60.41b.

(50) ASTM D1835-86, Standard Specification for Liquefied Petroleum (LP) Gases, IBR approved for §§ 60.41b; 60.41c.

(51) ASTM D4057-81, Standard Practice for Manual Sampling of Petroleum and Petroleum Products. IBR approved for appendix A to part 60, Method 19.

(52) ASTM D4239-85, Standard Test Methods for Sulfur in the Analysis Sample of Coal and Coke Using High Temperature Tube Furnace Combustion Methods. IBR approved for appendix A to part 60, Method 19.

(53) ASTM D2016-74 (Reapproved 1983), Standard Test Methods for Moisture Content of Wood * * * for appendix A, Method 28.

(54) ASTM D4442-84, Standard Test Methods for Direct Moisture Content Measurement in Wood and Wood-base Materials * * * for appendix A, Method 28.

(55) [Reserved]

(56) ASTM D129-64 (Reapproved 1978), Standard Test Method for Sulfur in Petroleum Products (General Bomb Method), IBR approved August 17, 1989, for § 60.106(j)(2).

(57) ASTM D1552-83, Standard Test Method for Sulfur in Petroleum Products (High-Temperature Method), IBR approved August 17, 1989, for § 60.106(j)(2).

(58) ASTM D2622-87, Standard Test Method for Sulfur in Petroleum Products by X-Ray Spectrometry, IBR approved August 17, 1989, for § 60.106(j)(2).

(59) ASTM D1266-87, Standard Test Method for Sulfur in Petroleum Products (Lamp Method), IBR approved August 17, 1989, for § 60.106(j)(2).

(60) ASTM D2908-74, Standard Practice for Measuring Volatile Organic Matter in Water by Aqueous-Injection Gas Chromatography, IBR approved for § 60.564(j).

(61) ASTM D3370-76, Standard Practices for Sampling Water, IBR approved for § 60.564(j).

(62) ASTM D4457-85 Test Method for Determination of Dichloromethane and 1,1,1-Trichloroethane in Paints and Coatings by Direct Injection into a Gas Chromatograph, IBR approved for appendix A, Method 24.

(63) ASTM D 5403-93 Standard Test Methods for Volatile Content of Radiation Curable Materials, IBR approved September 11, 1995 for Method 24 of Appendix A.

(b) The following material is available for purchase from the Association of Official Analytical Chemists, 1111 North 19th Street, Suite 210, Arlington, VA 22209.

(1) AOAC Method 9, Official Methods of Analysis of the Association of Official Analytical Chemists, 11th edition, 1970, pp. 11-12. IBR approved January 27, 1983 for §§ 60.204(d)(2), 60.214(d)(2), 60.224(d)(2), 60.234(d)(2).

(c) The following material is available for purchase from the American Petroleum Institute, 1220 L Street NW., Washington, DC 20005.

(1) API Publication 2517, Evaporation Loss from External Floating Roof Tanks, Second Edition, February 1980, IBR approved January 27, 1983, for §§ 60.111(i), 60.111a(f), 60.111a(f)(1) and 60.116b(e)(2)(i).

(d) The following material is available for purchase from the Technical Association of the Pulp and Paper Industry (TAPPI), Dunwoody Park, Atlanta, GA 30341.

(1) TAPPI Method T624 os-68, IBR approved January 27, 1983 for § 60.285(d)(4).

(e) The following material is available for purchase from the Water Pollution Control Federation (WPCF), 2626 Pennsylvania Avenue NW., Washington, DC 20037.

(1) Method 209A, Total Residue Dried at 103-105 ° C, in Standard Methods for the Examination of Water and Wastewater; 15th Edition, 1980, IBR approved February 25, 1985 for § 60.683(b).

(f) The following material is available for purchase from the following address: Underwriter's Laboratories, Inc. (UL), 333 Pfingsten Road, Northbrook, IL 60062.

(1) UL 103, Sixth Edition revised as of September 3, 1986, Standard for Chimneys, Factory-built, Residential Type and Building Heating Appliance.

(g) The following material is available for purchase from the following address: West Coast Lumber Inspection Bureau, 6980 SW. Barnes Road, Portland, OR 97223.

(1) West Coast Lumber Standard Grading Rules No. 16, pages 5-21 and 90 and 91, September 3, 1970, revised 1984.

(h) The following material is available for purchase from the American Society of Mechanical Engineers (ASME), 345 East 47th Street, New York, NY 10017.

(1) ASME QRO-1-1994, Standard for the Qualification and Certification of Resource Recovery Facility Operators, IBR approved for §§ 60.56a, 60.54b(a), and 60.54b(b).

(2) ASME PTC 4.1-1964 (Reaffirmed 1991), Power Test Codes: Test Code for Steam Generating Units (with 1968 and 1969 Addenda), IBR approved for §§ 60.46b, 60.58a(h)(6)(ii), and 60.58b(i)(6)(ii).

(3) ASME Interim Supplement 19.5 on Instruments and Apparatus: Application, Part

II of Fluid Meters, 6th Edition (1971), IBR approved for §§ 60.58a(h)(6)(ii) and 60.58b(i)(6)(ii).

(i) Test Methods for Evaluating Solid Waste, Physical/Chemical Methods," EPA Publication SW-846 Third Edition (November 1986), as amended by Updates I (July, 1992), II (September 1994), IIA (August, 1993), and IIB (January, 1995). Test Method are incorporated by reference for appendix A to part 60, Method 29, pars. 2.2.1; 2.3.1; 2.5; 3.3.12.1; 3.3.12.2; 3.3.13; 3.3.14; 5.4.3; 6.2; 6.3; 7.2.1; 7.2.3; and Table 29-2. The Third Edition of SW-846 and Updates I, II, IIA, and IIB (document number 955-001-00000-1) are available from the Superintendent of Documents, U.S. Government Printing Office, Washington, DC 20402, (202) 512-1800. Copies may be obtained from the Library of the U.S. Environmental Protection Agency, 401 M Street, SW., Washington, DC 20460.

(j) Standard Methods for the Examination of Water and Wastewater, 16th edition, 1985. Method 303F Determination of Mercury by the Cold Vapor Technique. This document may be obtained from the American Public Health Association, 1015 18th Street, NW., Washington, DC 20036, and is incorporated by reference for Method 29, pars 5.4.3; 6.3; and 7.2.3 of appendix A to part 60.

(k) This material is available for purchase from the American Hospital Association (AHA) Service, Inc., Post Office Box 92683, Chicago, Illinois 60675-2683. You may inspect a copy at EPA's Air and Radiation Docket and Information Center (Docket A-91-61, Item IV-J-124), Room M-1500, 401 M Street SW., Washington, DC.

(1) An Ounce of Prevention: Waste Reduction Strategies for Health Care Facilities. American Society for Health Care Environmental Services of the American Hospital Association. Chicago, Illinois. 1993. AHA Catalog No. 057007. ISBN 0-87258-673-5. IBR approved for § 60.35e and § 60.55c.

(l) This material is available for purchase from the National Technical Information Services, 5285 Port Royal Road, Springfield, Virginia 22161. You may inspect a copy at EPA's Air and Radiation Docket and Information Center (Docket A-91-61, Item IV-J-125), Room M-1500, 401 M Street SW., Washington, DC.

(1) OMB Bulletin No. 93-17: Revised Statistical Definitions for Metropolitan Areas. Office of Management and Budget, June 30, 1993. NTIS No. PB 93-192-664. IBR approved for § 60.31e.

[48 FR 3735, Jan. 27, 1983]

EDITORIAL NOTE: For FEDERAL REGISTER citations affecting § 60.17, see the List of CFR Sections Affected in the Finding Aids section of this volume.

§ 60.18 General control device requirements.

(a) *Introduction.* This section contains requirements for control devices used to comply with applicable subparts of parts 60 and 61. The requirements are placed here for administrative convenience and only apply to facilities covered by subparts referring to this section.

(b) *Flares.* Paragraphs (c) through (f) apply to flares.

(c)(1) Flares shall be designed for and operated with no visible emissions as determined by the methods specified in paragraph (f), except for periods not to exceed a total of 5 minutes during any 2 consecutive hours.

(2) Flares shall be operated with a flame present at all times, as determined by the methods specified in paragraph (f).

(3) An owner/operator has the choice of adhering to either the heat content specifications in paragraph (c)(3)(ii) of this section and the maximum tip velocity specifications in paragraph (c)(4) of this section, or adhering to the requirements in paragraph (c)(3)(i) of this section.

(i)(A) Flares shall be used that have a diameter of 3 inches or greater, are nonassisted, have a hydrogen content of 8.0 percent (by volume), or greater, and are designed for and operated with an exit velocity less than 37.2 m/sec (122 ft/sec) and less than the velocity, V_{max}, as determined by the following equation:

$V_{max}=(X_{H2}-K_1)*K_2$

Where:

V_{max}=Maximum permitted velocity, m/sec.

K_1=Constant, 6.0 volume-percent hydrogen.

K_2=Constant, 3.9(m/sec)/volume-percent hydrogen.

X_{H2}=The volume-percent of hydrogen, on a wet basis, as calculated by using the American Society for Testing and Materials (ASTM) Method D1946–77. (Incorporated by reference as specified in § 60.17).

(B) The actual exit velocity of a flare shall be determined by the method specified in paragraph (f)(4) of this section.

(ii) Flares shall be used only with the net heating value of the gas being combusted being 11.2 MJ/scm (300 Btu/scf) or greater if the flare is steam-assisted or air-assisted; or with the net heating value of the gas being combusted being 7.45 MJ/scm (200 Btu/scf) or greater if the flare is nonassisted. The net heating value of the gas being combusted shall be determined by the methods specified in paragraph (f)(3) of this section.

(4)(i) Steam-assisted and nonassisted flares shall be designed for and operated with an exit velocity, as determined by the methods specified in paragraph (f)(4) of this section, less than 18.3 m/sec (60 ft/sec), except as provided in paragraphs (c)(4) (ii) and (iii) of this section.

(ii) Steam-assisted and nonassisted flares designed for and operated with an exit velocity, as determined by the methods specified in paragraph (f)(4), equal to or greater than 18.3 m/sec (60 ft/sec) but less than 122 m/sec (400 ft/sec) are allowed if the net heating value of the gas being combusted is greater than 37.3 MJ/scm (1,000 Btu/scf).

(iii) Steam-assisted and nonassisted flares designed for and operated with an exit velocity, as determined by the methods specified in paragraph (f)(4), less than the velocity, V_{max}, as determined by the method specified in paragraph (f)(5), and less than 122 m/sec (400 ft/sec) are allowed.

(5) Air-assisted flares shall be designed and operated with an exit velocity less than the velocity, V_{max}, as determined by the method specified in paragraph (f)(6).

(6) Flares used to comply with this section shall be steam-assisted, air-assisted, or nonassisted.

(d) Owners or operators of flares used to comply with the provisions of this subpart shall monitor these control devices to ensure that they are operated and maintained in conformance with their designs. Applicable subparts will provide provisions stating how owners or operators of flares shall monitor these control devices.

(e) Flares used to comply with provisions of this subpart shall be operated at all times when emissions may be vented to them.

(f)(1) Reference Method 22 shall be used to determine the compliance of flares with the visible emission provisions of this subpart. The observation period is 2 hours and shall be used according to Method 22.

(2) The presence of a flare pilot flame shall be monitored using a thermocouple or any other equivalent device to detect the presence of a flame.

(3) The net heating value of the gas being combusted in a flare shall be calculated using the following equation:

EC01JN92.008

where:

H_T=Net heating value of the sample, MJ/scm; where the net enthalpy per mole of offgas is based on combustion at 25 °C and 760 mm Hg, but the standard temperature for determining the volume corresponding to one mole is 20 °C;

EC01JN92.009

C_i=Concentration of sample component i in ppm on a wet basis, as measured for organics by Reference Method 18 and measured for hydrogen and carbon monoxide by ASTM D1946-77 (Incorporated by reference as specified in § 60.17); and

H_i=Net heat of combustion of sample component i, kcal/g mole at 25 °C and 760 mm Hg. The heats of combustion may be determined using ASTM D2382-76 (incorporated by reference as specified in § 60.17) if published values are not available or cannot be calculated.

(4) The actual exit velocity of a flare shall be determined by dividing the volumetric flowrate (in units of standard temperature and pressure), as determined by Reference Methods 2, 2A, 2C, or 2D as appropriate; by the unobstructed (free) cross sectional area of the flare tip.

(5) The maximum permitted velocity, V_{max}, for flares complying with paragraph (c)(4)(iii) shall be determined by the following equation.

$$\text{Log}_{10}(V_{max})=(H_T+28.8)/31.7$$

V_{max}=Maximum permitted velocity, M/sec

28.8=Constant

31.7=Constant

H_T=The net heating value as determined in paragraph (f)(3).

(6) The maximum permitted velocity, V_{max}, for air-assisted flares shall be determined by the following equation.

$$V_{max}=8.706+0.7084\ (H_T)$$

V_{max}=Maximum permitted velocity, m/sec

8.706=Constant

0.7084=Constant

H_T=The net heating value as determined in paragraph (f)(3).

[51 FR 2701, Jan. 21, 1986, as amended at 63 FR 24444, May 4, 1998]

§ 60.19 General notification and reporting requirements.

(a) For the purposes of this part, time periods specified in days shall be measured in calendar days, even if the word "calendar" is absent, unless otherwise specified in an applicable requirement.

(b) For the purposes of this part, if an explicit postmark deadline is not specified in an applicable requirement for the submittal of a notification, application, report, or other written communication to the Administrator, the owner or operator shall postmark the submittal on or before the number of days specified in the applicable requirement. For example, if a notification must be submitted 15 days before a particular event is scheduled to take place, the notification shall be postmarked on or before 15 days preceding the event; likewise, if a notification must be submitted 15 days after a particular event takes place, the notification shall be delivered or postmarked on or before 15 days following the end of the event. The use of reliable non-Government mail carriers that provide indications of verifiable delivery of information required to be submitted to the Administrator, similar to the postmark provided by the U.S. Postal Service, or alternative means of delivery, including the use of electronic media, agreed to by the permitting authority, is acceptable.

(c) Notwithstanding time periods or postmark deadlines specified in this part for the submittal of information to the Administrator by an owner or operator, or the review of such information by the Administrator, such time periods or deadlines may be changed by mutual agreement between the owner or operator and the Administrator. Procedures governing the implementation of this provision are specified in paragraph (f) of this section.

(d) If an owner or operator of an affected facility in a State with delegated authority is required to submit periodic reports under this part to the State, and if the State has an established timeline for the submission of periodic reports that is consistent with the reporting frequency(ies) specified for such facility under this part, the owner or operator may change the dates by which periodic reports under this part shall be submitted (without changing the frequency of reporting) to be consistent with the State's schedule by mutual agreement between the owner or operator and the State. The allowance in the previous sentence applies in each State beginning 1 year after the affected facility is required to be in compliance with the applicable subpart in this part. Procedures governing the implementation of this provision are specified in paragraph (f) of this section.

(e) If an owner or operator supervises one or more stationary sources affected by standards set under this part and standards set under part 61, part 63, or both such parts of this chapter, he/she may arrange by mutual agreement between the owner or operator and the Administrator (or the State with an approved permit program) a common schedule on which periodic reports required by each applicable standard shall be submitted throughout the year. The allowance in the previous sentence applies in each State beginning 1 year after the stationary source is required to be in compliance with the applicable subpart in this part, or 1 year after the stationary source is required to be in compliance with the applicable 40 CFR part 61 or part 63 of this chapter standard, whichever is latest. Procedures governing the implementation of this provision are specified in paragraph (f) of this section.

(f)(1)(i) Until an adjustment of a time period or postmark deadline has been approved by the Administrator under paragraphs (f)(2) and (f)(3) of this section, the owner or operator of an affected facility remains strictly subject to the requirements of this part.

(ii) An owner or operator shall request the adjustment provided for in paragraphs (f)(2) and (f)(3) of this section each time he or she wishes to change an applicable time period or postmark deadline specified in this part.

(2) Notwithstanding time periods or postmark deadlines specified in this part for the submittal of information to the Administrator by an owner or operator, or the review of such information by the Administrator, such time periods or deadlines may be changed by mutual agreement between the owner or operator and the Administrator. An owner or operator who wishes to request a change in a time period or postmark deadline for a particular requirement shall request the adjustment in writing as soon as practicable before the subject activity is required to take place. The owner or operator shall include in the request whatever information he or she considers useful to convince the Administrator that an adjustment is warranted.

(3) If, in the Administrator's judgment, an owner or operator's request for an adjustment to a particular time period or postmark deadline is warranted, the Administrator will approve the adjustment. The Administrator will notify the owner or operator in writing of approval or disapproval of the request for an adjustment within 15 calendar days of receiving sufficient information to evaluate the request.

(4) If the Administrator is unable to meet a specified deadline, he or she will notify the owner or operator of any significant delay and inform the owner or operator of the amended schedule.

[59 FR 12428, Mar. 16, 1994, as amended at 64 FR 7463, Feb. 12, 1998]