IN THE UNITED STATES DISTRICT COURT
FOR THE MIDDLE DISTRICT OF FLORIDA

UNITED STATES OF AMERICA, Plaintiff, v. TAMPA ELECTRIC COMPANY, Defendant.	)	Civil Action No.

COMPLAINT

The United States of America, by authority of the Attorney General of the United States and through the undersigned attorneys, acting at the request of the Administrator of the United States Environmental Protection Agency ("EPA"), alleges:

NATURE OF THE ACTION

1. This is a civil action brought against the Defendant pursuant to Sections 113(b)(2) and 167 of the Clean Air Act ("the Act"), 42 U.S.C. § 7413(b)(2) and 7477, for injunctive relief and the assessment of civil penalties for violations of the Prevention of Significant Deterioration ("PSD") provisions of the Act, 42 U.S.C. §§ 7470-92. Defendant modified, and thereafter operated, its electric generating units at Big Bend and Gannon, coal-fired electricity generating power plants in Hillsborough County, Florida, without first obtaining appropriate permits

authorizing this construction and without installing the best available control technology to control emissions of nitrogen oxides, sulfur dioxide, and particulate matter, as the Act requires.

2. As a result of Defendant's operation of the power plants, following these unlawful modifications and the absence of appropriate controls, massive amounts of sulfur dioxide, nitrogen oxides, and particulate matter have been, and still are being, released into the atmosphere aggravating air pollution locally and far downwind from these plants. Defendant's violations, alone and in combination with similar violations at other coal-fired electric power plants, have been significant contributors to some of the most severe environmental problems facing the nation today. An order of this Court directing this Defendant, forthwith, to install and operate the best available technology to control these pollutants, in conjunction with orders being sought in similar cases involving other coal-fired electric power plants in the Midwest and Southern United States being filed by the United States concurrent with the filing of this complaint, will produce an immediate, dramatic improvement in the quality of air breathed by millions of Americans. It will reduce illness, protect lakes and streams from further degradation due to the fallout from acid precipitation, and allow the environment to restore itself following years, and in some cases decades, of illegal emissions.

3. Sulfur dioxide, nitrogen oxides, and particulate matter when emitted into air can have adverse environmental and health impacts. Electric utility plants collectively account for about 70 percent of annual sulfur dioxide emissions and 30 percent of nitrogen oxides emissions in the United States. Sulfur dioxide ("SO_2") interacts in the atmosphere to form sulfate aerosols, which may be transported long distances through the air. Most sulfate aerosols are particles that can be inhaled. In the eastern United States, sulfate aerosols make up about 25 percent of the

inhalable particles and according to recent studies, higher levels of sulfate aerosols are associate with increased sickness and mortality from lung disorders, such as asthma and bronchitis. Lowering sulfate aerosol emissions from electric utility plants may significantly reduce the incidence and the severity of asthma and bronchitis and associated hospital admissions and emergency room visits.

4. Nitrogen Oxides ("NO_x") are major producers of ground level ozone, which scientists have long recognized as being harmful to human health. NOx, transformed into ozone, may cause decreases in lung function (especially among children who are active outdoors) and respiratory problems leading to increased hospital admissions and emergency room visits. Human lungs may be inflamed and permanently damaged by ozone. NO_x is also transformed into nitrogen dioxide ("NO_2"), a dangerous pollutant which can cause people to have difficulty breathing by constricting lower respiratory passages; it may weaken one's immune system, causing increased susceptibility to pulmonary and other forms of infections. While children and asthmatics are the primary sensitive populations, individuals suffering from bronchitis, emphysema, and other chronic pulmonary diseases are also predisposed to sensitivity to NO_2 exposure. NO_x also reacts with other pollutants and sunlight to form photochemical smog, which in turn contributes to haze and reduces visibility.

5. SO_2 and NOx interact in the atmosphere with water and oxygen to form nitric and sulfuric acids, commonly known as acid rain. Acid rain, which also comes in the form of snow or sleet, "acidifies" lakes and streams rendering them uninhabitable by aquatic life, and it damages trees at high elevations. Acid precipitation accelerates the decay of building materials and paints, including irreplaceable buildings, statues, and sculptures that are part of our nation's

cultural heritage. SO_2 and NO_x gases and their particulate matter derivatives, sulfates and nitrates, contribute to visibility degradation and impact public health. In this civil action, and i other civil actions filed concurrent with it, the United States intends to reduce dramatically the amount of SO_2 and NO_x that certain electric utility plants have been illegally releasing into the atmosphere. If the injunctive relief requested by the United States is imposed, many acidified lakes and streams will improve so that they may once again support fish and other forms of aquatic life. Visibility will improve, allowing for increased enjoyment of scenic vistas throughout the eastern half of our country. Stress to our forests from Maine to Georgia will be reduced. Deterioration of our historic buildings and monuments will be slowed. In addition, reductions in SO_2 and NO_x will reduce sulfates, nitrates, and ground level ozone, leading to improvements in public health.

6. Particulate matter is the term for solid or liquid particles found in the air. Smaller particulate matter of a diameter of 10 micro-meters or less is referred to as PM-10. Power plants are a major source of particulate matter ("PM"). Breathing PM at concentrations in excess of existing ambient air standards may increase the chances of premature death, damage to lung tissue, cancer, or respiratory disease. The elderly, children, and people with chronic lung disease, influenza, or asthma, tend to be especially sensitive to the effects of PM. PM could also make the effects of acid precipitation worse, reducing visibility and damaging man-made materials. Reductions in PM illegally released into the atmosphere by the defendant and others will significantly reduce the serious health and environmental effects caused by PM in our atmosphere.

JURISDICTION AND VENUE

7. This Court has jurisdiction of the subject matter of this action pursuant to Sections 113(b) and 167 of the Act, 42 U.S.C. §§ 7413(b) and 7477, and pursuant to 28 U.S.C. §§ 1331, 1345, and 1355.

8. Venue is proper in this District pursuant to Section 113(b) of the Act, 42 U.S.C. § 7413(b), and 28 U.S.C. § 1391(b) and (c), and 1395(a), because the Defendant resides in this District, the violations occurred in this District, and the Big Bend and Gannon facilities are located in this District.

NOTICES

9. The United States is providing notice of the commencement of this action to the State of Florida as required by Section 113(b) of the Act, 42 U.S.C. § 7413(b).

THE DEFENDANT

10. Defendant, Tampa Electric Company ("TECO"), owns and is an operator of 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 ("Unit 1"), Big Bend Unit 2 ("Unit 2"), Big Bend Unit 3 ("Unit 3"), and Big Bend Unit 4 ("Unit 4").

11. Defendant, TECO, owns and is an operator of Gannon a coal fired electric generation plant in Hillsborough County. Gannon generates electricity from six steam generating boilers which are designated as Gannon Unit 1 ("Unit 1"), Gannon Unit 2 ("Unit 2"), Gannon Unit 3 ("Unit 3"), Gannon Unit 4 ("Unit 4"), Gannon Unit 5 ("Unit 5"), and Gannon Unit 6 ("Unit 6").

12. The Defendant is a "person" within the meaning of Section 302(e) of the Act, 42 U.S.C. § 7602(e).

STATUTORY BACKGROUND

13. The Clean Air Act is designed to protect and enhance the quality of the nation's air so as to promote the public health and welfare and the productive capacity of its population. Section 101(b)(1) of the Act, 42 U.S.C. § 7401(b)(1).

The National Ambient Air Quality Standards

14. Section 109 of the Act, 42 U.S.C. § 7409, requires the Administrator of EPA to promulgate regulations establishing primary and secondary national ambient air quality standards ("NAAQS" or "ambient air quality standards") for those air pollutants ("criteria pollutants") for which air quality criteria have been issued pursuant to Section 108, 42 U.S.C. § 7408. The primary NAAQS are to be adequate to protect the public health, and the secondary NAAQS are to be adequate to protect the public welfare, from any known or anticipated adverse effects associated with the presence of the air pollutant in the ambient air.

15. Under Section 107(d) of the Act, 42 U.S.C. § 7407(d), each state is required to designate those areas within its boundaries where the air quality is better or worse than the NAAQS for each criteria pollutant, or where the air quality cannot be classified due to insufficient data. An area that meets the NAAQS for a particular pollutant is an "attainment" area. An area that does not meet the NAAQS is a "nonattainment" area. An area that cannot be classified due to insufficient data is "unclassifiable."

16. At times relevant to this complaint, Big Bend and Gannon were located in an area that had been classified as attainment or unclassifiable for NO_x, SO_2, PM-10, and PM.

The Prevention of Significant Deterioration Requirements

17. Part C of the Act, 42 U.S.C. §§ 7470-7492, sets forth requirements for the prevention of significant deterioration ("PSD") of air quality in those areas designated as either attainment or unclassifiable for purposes of meeting the NAAQS standards. These requirements are designed to protect public health and welfare, to assure that economic growth will occur in a manner consistent with the preservation of existing clean air resources and to assure that any decision to permit increased air pollution is made only after careful evaluation of all the consequences of such a decision and after public participation in the decision making process. These provisions are referred to herein as the "PSD program."

18. Section 165(a) of the Act, 42 U.S.C. § 7475(a), among other things, prohibits the construction and operation of a "major emitting facility" in an area designated as attainment unless a permit has been issued that comports with the requirements of Section 165, including the requirement that the facility install and operate the best available control technology for each pollutant subject to regulation under the Act that is emitted from the facility. Section 169(1) of the Act, 42 U.S.C. § 7479(1), designates fossil-fuel fired steam electric plants of more than two hundred and fifty million British thermal units ("BTUs") per hour heat input and that emit or have the potential to emit one hundred tons per year or more of any pollutant to be "major emitting facilities."

19. Section 169(2)(C) of the Act, 42 U.S.C. § 7479(2)(C), defines "construction" as including "modification" (as defined in Section 111(a) of the Act). "Modification" is defined in Section 111(a) of the Act, 42 U.S.C. § 7411(a), to be "any physical change in, or change in the method of operation of, a stationary source which increases the amount of any air pollutant

emitted by such source or which results in the emission of any air pollutant not previously emitted."

ENFORCEMENT PROVISIONS

20. Section 113(a)(3) of the Act, 42 U.S.C. § 7413(a)(3), provides that "Except for a requirement or prohibition enforceable under the preceding provisions of this subsection, whenever, on the basis of any information available to the Administrator, the Administrator finds that any person has violated, or is in violation of, any other requirement or prohibition of this subchapter . . . the Administrator may . . . bring a civil action in accordance with subsection (b) of this section . . . ."

21. Section 113(b)(2) of the Act, 42 U.S.C. § 7413(b)(2), authorizes the Administrator to initiate a judicial enforcement action for a permanent or temporary injunction, and/or for a civil penalty of up to $25,000 per day of violation for violations occurring on or before January 30, 1997 and $27,500 per day for each such violation occurring after January 30, 1997, pursuant to the Federal Civil Penalties Inflation Adjustment Act of 1990, 28 U.S.C. § 2461, as amended by 31 U.S.C. § 3701, against any person whenever such person has violated, or is in violation of, requirements of the Act other than those specified in Section 113(b)(1), 42 U.S.C. § 7413(b)(1), including violations of Section 165(a), 42 U.S.C. § 7475(a) and Section 111, 42 U.S.C. § 7411.

22. Section 167 of the Act, 42 U.S.C. § 7477, authorizes the Administrator to initiate an action for injunctive relief, as necessary to prevent the construction, modification or operation of a major emitting facility which does not conform to the PSD requirements.

23. At all times pertinent to this civil action, Defendant was and is the owner and operator of Big Bend and each of its four boilers, designated Units 1, 2, 3, and 4.

24. At all times pertinent to this civil action, Defendant was and is the owner and operator of Gannon and each of its six boilers, designated Units 1, 2, 3, 4, 5, and 6.

25. At all times pertinent to this civil action, Big Bend and Gannon were each a "major emitting facility" and a "major stationary source" within the meaning of the Act for NO_x, SO_2, PM-10, and PM.

FIRST CLAIM FOR RELIEF
(PSD Violations: Modifications at Big Bend)

26. Paragraphs 1 through 25 are realleged and incorporated herein by reference.

27. At various times, Defendant commenced construction of modifications, as defined in the Act, at Big Bend. These modifications included, but are not limited to: (1) replacement of steam drum internals in Units 1 and 2 in 1994 and 1991, respectively; (2) replacement of the waterwall in Unit 2 in 1994; and (3) replacement of the high temperature reheater in Unit 2 in 1994. Defendant constructed additional modifications to its plant beyond those described in this paragraph.

28. Defendant violated and continues to violate Section 165(a) and 167 of the Act, 42 U.S.C. §§ 7475(a) and 7477, by, among other things, undertaking such modifications and continuing to operate its facility without (1) obtaining a PSD permit; and (2) applying best available control technology for NOx, SO_2, and PM, as required.

29. Unless restrained by an order of this Court, these and similar violations of the Act will continue.

30. As provided in Section 113(b)(2) of the Act, 42 U.S.C. § 7413(b)(2), and Section 167 of the Act, 42 U.S.C. § 7477, the violations set forth above subject Defendant to injunctive relief and civil penalties of up to $25,000 per day for each violation prior to January 30, 1997, and $27,500 per day for each such violation after January 30, 1997, pursuant to the Federal Civil Penalties Inflation Adjustment Act of 1990, 28 U.S.C. § 2461, as amended by 31 U.S.C. § 3701.

SECOND CLAIM FOR RELIEF
(PSD Violations: Modifications at Gannon)

31. Paragraphs 1 through 25 are realleged and incorporated herein by reference.

32. At various times, Defendant commenced construction of modifications, as defined in the Act, at Gannon. These modifications included, but are not limited to: (1) replacement of the furnace floor in Unit 3 with a new design in 1996; and, (2) replacement of the cyclone in Unit 4 in 1994. Defendant constructed additional modifications to its plant beyond those described in this paragraph.

33. Defendant violated and continues to violate Section 165(a) and 167 of the Act, 42 U.S.C. §§ 7475(a) and 7477, by, among other things, undertaking such modifications and continuing to operate its facility without (1) obtaining a PSD permit; and (2) applying best available control technology for NOx, SO_2, and PM, as required.

34. Unless restrained by an order of this Court, these and similar violations of the Act will continue.

35. As provided in Section 113(b)(2) of the Act, 42 U.S.C. § 7413(b)(2), and Section 167 of the Act, 42 U.S.C. § 7477, the violations set forth above subject Defendant to injunctive relief and civil penalties of up to $25,000 per day for each violation prior to January 30, 1997,

and $27,500 per day for each such violation after January 30, 1997, pursuant to the Federal Civil Penalties Inflation Adjustment Act of 1990, 28 U.S.C. § 2461, as amended by 31 U.S.C. § 3701.

PRAYER FOR RELIEF

WHEREFORE, based upon all the allegations contained in paragraphs 1 through 35 above, the United States of America requests that this Court:

1. Permanently enjoin the Defendant from operating Units 1 through 4 of Big Bend and Units 1 through 6 at Gannon, including the construction of future modifications, except in accordance with the Clean Air Act and any applicable regulatory requirements;

2. Order Defendant to remedy its past violations by, among other things, requiring Defendant to install, as appropriate, the best available control technology on Units 1 through 4 at Big Bend and Units 1 through 6 at Gannon for each pollutant subject to regulation under the Clean Air Act;

3. Order Defendant to apply for permits for the Big Bend and Gannon facilities that are in conformity with the requirements of the PSD program;

4. Order Defendant to conduct audits of its operations to determine if any additional modifications have occurred which would require it to meet the requirements of PSD and report the results of these audits to the United States;

5. Order Defendant to take other appropriate actions to remedy, mitigate, and offset the harm to public health and the environment caused by the violations of the Clean Air Act alleged above.

6. Assess a civil penalty against the Defendant of up to $25,000 per day for each violation of the Clean Air Act and applicable regulations, and $27,500 per day for each such violation after January 30, 1997;

7. Award Plaintiff its costs of this action; and

8. Grant such other relief as the Court deems just and proper.

Respectfully Submitted,

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Phase II NOx Compliance Plan Checklist (40 CFR part 76)

Source (Plant) Name:	Date Compliance Plan Received:	
Completeness Review		
Reviewer:	☐ Complete ☐ Incomplete	Date:
Substantive Review		
Reviewer:	Recommended for Approval? ☐ Yes ☐ No	Date:

Completeness Review

Checklist Items:

Notes/Comments/Issues:

All pertinent spaces are filled in, information is legible, appropriate, (e.g. ORIS code is entered in "ORIS Code" box) and compliance plan is signed and dated. ☐ Yes ☐ No

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Substantive Review

Checklist Items:

Notes/Comments/Issues:

STEP 1:

Plant Name, State, and ORIS Code information matches affected source information in Section 4 of the Acid Rain Permit Writer's Guide or "STEP 1" of the most recent Certificate of Representation (DR form) submitted for affected source. ☐ Yes ☐ No

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Source (Plant) Name:	Date Compliance Plan Received:

Checklist Items:

Notes/Comments/Issues:

STEP 2 :

(i) For each boiler that has an EPA-approved early election plan in effect, the box in row "(c)" has been marked, <u>and</u> the box in <u>either</u> row (a) or (b) has been marked. If the boiler is a dry bottom wall-fired boiler, the box in row (a) should be marked. If the boiler is tangentially-fired, the box in row (b) should be marked. The permitting authority has verified the boiler Phase and type, and that the boiler has been flagged "EE" to indicate that EPA has approved an early election plan for the boiler (see Section 4). Note: <u>Only</u> Phase II Group 1 boilers with EPA-approved early election plans can choose this compliance option.

☐ Yes ☐ No

☐ NA

(ii) For each boiler that does <u>not</u> have an EPA-approved early election plan in effect and is <u>not</u> averaging with other boilers, <u>one</u> of the standard limit boxes (at row (a), (b), and (d) through (i)) has been chosen that appropriately corresponds with the boiler type indicated in Section 4 for that boiler.

☐ Yes ☐ No

☐ NA

(iii) Each boiler which <u>is</u> averaging with other boilers has marked the box in row (j) and is included in a Phase II NOx averaging plan submitted with the Phase II NOx Compliance Plan.

☐ Yes ☐ No

☐ NA

Source (Plant) Name:		Date Compliance Plan Received:
Checklist Items:		**Notes/Comments/Issues:**
(iv) A boiler for which the box in row (k) has been marked must also have marked the box representing the lowest of the standard limits (at rows (a), (b), and (d) through (i)) applicable to the boilers using the common stack.[1] The permitting authority has verified that every boiler identified at row (k) is emitting at a common stack (by reviewing the monitoring plan for the affected source) and that every boiler identified at row (k) has a NOx emissions limitation under title IV (see Section 4).[2]	☐ Yes ☐ No ☐ NA	

[1] For instance, if 2 boilers share a common stack, one with a 0.45 lb/mmBtu NOx limit, and the other with a 0.50 lb/mmBtu NOx limit, row (b) denoting a 0.45 lb/mmBtu NOx limit would be checked for both boilers (in addition to row (k)), since that is the lowest NOx limit for all of the boilers emitting at that stack. The 0.45 lb/mmBtu limit would also be incorporated into the Phase II permit unit pages for each boiler. This, and early election, are the only cases in which a boiler of a certain type and Phase can choose a standard limit different from the standard limit established for that type and Phase of boiler. However, the chosen limit will always be equal to or less than the limit established for that type and Phase of boiler.

[2] Contact your U.S. EPA Regional or Headquarters Acid Rain Program CEM contacts if you require assistance reviewing a monitoring plan for an affected source.

Source (Plant) Name:	Date Compliance Plan Received:

Checklist Items:		Notes/Comments/Issues:
(v) A boiler for which the box in row (l) has been marked also has the box in row (j) marked, and that boiler is included in a Phase II NOx averaging plan submitted with the Phase II NOx compliance plan. The permitting authority has verified that every boiler identified at row (l) is emitting at a common stack (by reviewing the monitoring plan for the affected source) and that every boiler identified at row (l) has a NOx emissions limitation under title IV (see Section 4).	☐ Yes ☐ No ☐ NA	
(vi) For every boiler for which row (m) has been marked, the permitting authority has confirmed with EPA Headquarters, Acid Rain Division, Source Assessment Branch ((202) 564-9180) that an apportionment method under 40 CFR 75.17(a)(2)(i)(C), (a)(2)(iii)(B), or (b)(2) has been approved.	☐ Yes ☐ No ☐ NA	
(vii) For every boiler for which row (n) has been marked, the appropriate Phase II AEL form has been attached and includes that boiler.	☐ Yes ☐ No ☐ NA	

Source (Plant) Name:	Date Compliance Plan Received:

Checklist Items:		Notes/Comments/Issues:
(ix) For every boiler for which row (o) has been marked, the permitting authority has confirmed with EPA Headquarters, Acid Rain Division, Source Assessment Branch ((202) 564-9180) that an AEL demonstration period or final AEL is currently under review for that boiler or that the boiler has an ongoing AEL demonstration period.	☐ Yes ☐ No ☐ NA	
(x) For every boiler for which row (p) has been marked, a repowering extension plan has been approved for that boiler. If the approved repowering extension plan will expire before the expiration of the Phase II acid rain permit, an additional follow-on Phase II NOx compliance option has been marked for that boiler as well.	☐ Yes ☐ No ☐ NA	

STEP 3:

The designated representative (DR) or alternate designated representative (ADR) entered at this Step has been verified as the certified DR or ADR as of the date the Phase II NOx compliance plan was signed.	☐ Yes ☐ No	

Note: The valid DR for a submission can be identified by reviewing the state copy of the appropriate DR form for an affected source, through DR information available on the World Wide Web, or by contacting either the EPA Regional acid rain contact or Acid Rain Division at EPA Headquarters.

NO_X Standard Emission Limitations Compliance Plans

Description: Under the simplest of NO_X compliance plans in the Acid Rain Program, a boiler subject to 40 CFR part 76 for which the standard emission limitation compliance option is chosen must meet the standard emissions limit in lb/mmBtu established in 40 CFR 76.5, 76.6, or 76.7 for that specific type of coal fired boiler.

Permit Revision Procedure(s): Addition of a standard emission limitation NO_X compliance plan to a Phase II acid rain permit is executed through permit modification procedures under 40 CFR 72.81 (which references requirements adopted by the State under 40 CFR subpart G and 70.7(e)(4)(ii)). This process is basically identical to requirements for the issuance of a Phase II acid rain permit and includes the provisions of 40 CFR 72.80 (c) and (d), which state that a permit revision may be submitted at any time and that the terms of the acid rain permit apply until the revision is finalized.

Inclusion in Acid Rain Permit: The boilerplate language shown below is added to the NO_X portion of unit pages in the acid rain portion of the title V permit (see also the sample acid rain permit beginning on page 10-2-3). In addition, either the NO_X compliance plan is attached and incorporated as an enforceable part of the acid rain portion of the title V permit or the language in the NO_X compliance plan is reiterated in the acid rain portion of the title V permit.

Boilerplate Language: "Pursuant to 40 CFR part 76, **[name of permitting authority]** approves a NO_X standard emission limitation compliance plan for unit **[insert unit #]**. The compliance plan is effective for calendar year **[first year compliance plan is effective]** through calendar year **[last year acid rain permit is effective]**. Under the compliance plan, this unit's annual average NO_X emission rate for each year, determined in accordance with 40 CFR part 75, shall not exceed the applicable emission limitation, under 40 CFR **[insert appropriate CFR cite and phrase from below]**

76.5(a)(1), of 0.45 lb/mmBtu for tangentially fired boilers.
76.5(a)(2), of 0.50 lb/mmBtu for wall-fired boilers.
76.6(a)(1), of 0.68 lb/mmBtu for cell burner boilers.
76.6(a)(2), of 0.86 lb/mmBtu for cyclone boilers.
76.6(a)(3), of 0.84 lb/mmBtu for wet bottom boilers.
76.6(a)(4), of 0.80 lb/mmBtu for vertically fired boilers.
76.7(a)(1), of 0.40 lb/mmBtu for tangentially fired boilers.
76.7(a)(2), of 0.46 lb/mmBtu for wall-fired boilers.

In addition, this unit 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."

Example:[1] "Pursuant to 40 CFR part 76, the State of Mind DEP approves a NO_X standard emissions limitation compliance plan for unit 3. The NO_X compliance plan is effective beginning 2000 through 2004. Under the NO_X compliance plan, this unit's annual average NO_X emissions rate for each year, determined in accordance with 40 CFR part 75, shall not exceed the applicable emission limitation, under 40 CFR 76.6(a)(3), of 0.84 lb/mmBtu for wet bottom boilers.

In addition to the described NO_X compliance plan, this unit 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."

Misc. Notes: An initial NO_X compliance plan in which a standard emission limitation is chosen is effective beginning for calendar year 2000 and continues through the last calendar year that the acid rain permit is effective. Every subsequent standard emission limitation NO_X compliance plan submitted at the time of acid rain permit renewal will be effective for the same years that the acid rain permit is effective, including any partial years.

A State that has not incorporated by reference 40 CFR part 76 and has written a State-version of the Acid Rain Program NO_X regulation must replace the cites to the federal rule with cites to its own rule, where applicable.

The boilerplate references to 40 CFR 76.5(a)(1) and (2) are for Phase I Group 1 boilers; the references to 40 CFR 76.7(a)(1) and (2) are for Phase II Group 1 boilers.

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[1] See also sample permit with NO_X language added starting on page 10-2-3.

BEST AVAILABLE COPY

Table 2 - Phase II Allowance Allocations								
			Allowances for Years 2000-2009				Years 2010 and [illegible]	
State	Plant Name	Boiler1	(A) Auction Reserve Deduction	(B) Repowering Deduction	(C)2 Total Annual Phase II	(D) 1993-1998 Auction Deduction	(E) Auction Reserve Deduction	(F) [illegible]
FL	Big Bend	BB01	352	4	12132	351	351	[illegible]
FL	Big Bend	BB02	354	4	12196	353	353	[illegible]
FL	Big Bend	BB03	332	4	11444	331	331	[illegible]
FL	Big Bend	BB04	255	3	8780	254	254	[illegible]
FL	C D McIntosh Jr	1	26	0	907	26	26	908
FL	C D McIntosh Jr	2	30	0	1029	30	30	1031
FL	C D McIntosh Jr	3	288	3	9928	287	288	9948
FL	Cape Canaveral	PCC1	123	1	4224	122	122	4232
FL	Cape Canaveral	PCC2	144	2	4961	143	144	4969
FL	Combined Cycle 1	32432	2	0	60	2	2	60
FL	Crist	1	1	0	35	1	1	35
FL	Crist	2	0	0	3	0	0	3
FL	Crist	3	0	0	4	0	0	4
FL	Crist	4	72	1	2467	71	71	2473
FL	Crist	5	70	1	2430	70	70	2435
FL	Crist	6	244	3	8396	243	243	8413
FL	Crist	7	363	4	12522	362	363	12545
FL	Crystal River	1	360	4	12425	359	360	12449
FL	Crystal River	2	415	4	14291	413	414	14320
FL	Crystal River	4	686	8	23651	684	686	23697
FL	Crystal River	5	734	9	25248	732	732	25301
FL	CT	**1	0	0	0	0	0	0
FL	CT	**2	0	0	0	0	0	0
FL	CT	**3	0	0	0	0	0	0
FL	CT	**4	0	0	0	0	0	0
FL	Cutler	PCU5	0	0	0	0	0	4
FL	Cutler	PCU6	0	0	0	0	0	9
FL	Debary	**10	20	0	705	20	20	706
FL	Debary	**7	20	0	705	20	20	706
FL	Debary	**8	20	0	705	20	20	706
FL	Debary	**9	20	0	705	20	20	706
FL	Deerhaven	**NA2	0	0	0	0	0	0
FL	Deerhaven	B1	1	0	98	1	3	114
FL	Deerhaven	B2	240	3	8268	239	239	8286
FL	Deerhaven	CT3	0	0	0	0	0	0
FL	F J Gannon	GB01	97	1	3842	97	97	3358
FL	F J Gannon	GB02	120	1	4425	120	120	4148
FL	F J Gannon	GB03	164	2	5664	164	164	5675
FL	F J Gannon	GB04	179	2	6223	179	179	6185
FL	F J Gannon	GB05	190	2	6537	189	189	6551
FL	F J Gannon	GB06	292	3	10081	292	292	10101
FL	Fort Myers	PFM1	93	1	3188	92	92	3194
FL	Fort Myers	PFM2	274	3	9457	273	274	9475
FL	G E Turner	2	2	0	543	2	2	82
FL	G E Turner	3	21	0	718	21	21	720

Table 1-1. Air Pollutant Standards and Terms

Faclility ID: 0570039 **DRAFT Permit No.:**
Permittee: BigBend

			Allowable Emissions	Equivalent Allowable Emissions	
E.U. ID#	**Description**	**Pollutant Name**	**Standard(s)**	**lbs/hour**	**tons/year**
001	Unit No. 1; Solid Fuel Steam	SO2	6.500000 lb/MMBtu	26,240.50	114,933.40
			25.000000 tons/hr	50,000.00	
			31.500000 tons/hr	63,000.00	
		PM	0.300000 lb/MMBtu	1,211.10	2,210.30
002	Unit No. 2; Solid Fuel Steam	SO2	6.500000 lb/MMBtu	25,947.00	113,766.10
			25.000000 tons/hr	50,000.00	
			31.500000 tons/hour	63,000.00	
		PM	0.300000 lb/MMBtu	1,198.80	2,187.80
003	Unit No. 3; Solid Fuel Steam	SO2	6.500000 lb/MMBtu	26,747.50	117,154.10
			25.000000 tons/hr	50,000.00	
			31.500000 tons/hr	63,000.00	
		NOX	0.700000 lb/MMBtu	2,880.50	12,616.60
		PM	0.300000 lb/MMBtu	1,234.50	2,253.00
004	Unit No. 4; Solid Fuel Steam	SO2	0.820000 lb/MMBtu	3,576.00	15,662.90
			1.200000 lb/MMBtu	5,196.00	22,758.48
		NOX	0.600000 lb/MMBtu	2,598.00	11,379.20
		PM	0.030000 lb/MMBtu	130.00	569.00
		CO	0.029000 lb/MMBtu	125.60	550.00
008	Fly Ash Silo No. 1 (Units #1	PM	0.030000 grains/dscf	5.16	22.62
			5.160000 lb/hr	5.16	22.62
			22.620000 ton/yr	5.16	22.62
009	Fly Ash Silo No. 2 (Units #1,		5.160000 lb/hr	5.16	22.62
			22.620000 tons/year	5.16	22.62
014	Fly Ash Silo No. 3 (Unit #4)		0.200000 lb/hr		
015	Solid Fuel Bunkers (all units)		0.990000 ton/yr	0.20	0.06
			0.480000 lb/hr	0.20	0.06
011	Limestone Handling and Stora			0.05	0.22
				0.65	2.84

Table 1-2. Segment Description

Faclility ID: 0570039 **DRAFT Permit No.:**
Permittee: BigBend

		Segment Information		
E.U. ID#	**EU Description**	**Segment Description**	**Max Hourly Rate**	**Max Annual Rate**
001	Unit No. 1; Solid Fuel Steam Generator	Coal and petcoke/coal blend burned in Unit No. 1.	103.50	909,510
002	Unit No. 2; Solid Fuel Steam Generator	Coal and petcoke/coal blend burned in Unit No. 2	182.10	1,595,196
003	Unit No. 3; Solid Fuel Steam Generator	Coal and petcoke/coal blend burned in Unit No. 3	190.30	1,667,383
004	Unit No. 4; Solid Fuel Steam Generator	Coal and petcoke/coal blend burned in Unit No. 4		
007	Combustion Turbine No. 1	No. 2 Distillate Fuel Oil burned in CT No. 1		10,825
005	Combustion Turbine No. 2	No. 2 Distillate Fuel Oil burned in CT No. 2	6.00	52,560
006	Combustion Turbine No. 3	No. 2 Distillate Fuel Oil burned in CT No. 3.	6.00	52,560
008	Fly Ash Silo No. 1 (Units #1 and #2)	Fly Ash Storage	44.50	389,820
009	Fly Ash Silo No. 2 (Units #1, #2, and #3)	Flyash Storage	44.50	389,820
014	Fly Ash Silo No. 3 (Unit #4)	Fly Ash Storage	44.50	389,820
015	Solid Fuel Bunkers (all units)	Fuel handled	8,000.00	4,800,000
011	Limestone Handling and Storage (all sources)	Limestone handling.	168.00	1,471,680
No Id	Fly Ash Handling and Storage Fugitives (all except silos)	Not applicable - fugitive emissions from a variety of fly ash handling sources.		
	Gypsum Handling and Storage Fugitives (all gypsum sources)	Gypsum handling.	120.00	1,051,200
010	Solid Fuel Handling and Storage Fugitives (all sources)	Solid fuel handling	4,000.00	6,228,030
No Id	Slag and Bottom Ash Handling (all sources)	Not applicable		

Table 2-1. Compliance Requirements

Facility ID: 0570039
Permittee: BigBend

DRAFT Permit No.:

			Pollutant	VE	Visible Emissions
E.U. ID#	**Description**	**Pollutant Name**	**Compliance Method**	**Type**	**Compliance Method**
001	Unit No. 1; Solid Fuel Steam Generator	SO2	Weekly composite fuel sampling and fuel analysis or continuous emissions monitoring per FDEP Rule 62-296.405(1(f)1.b., F.A.C. Deletion of current requirement to conduct an annual stack test is requested.		Annual test using EPA Reference Method 9.
			Daily composite fuel sampling and analysis per Specific Condition 9.C of permit AO29-219924. Deletion of current requirement to conduct an annual stack test is requested.		Annual test using EPA Reference Method 9.
					Annual test using EPA Reference Method 9.
		PM	Annual test using EPA reference method 5, 5B, or 17. Option to use three soot-blowing test runs to demonstrate compliance with non-soot blowing standard is requested.	S	
002	Unit No. 2; Solid Fuel Steam Generator	SO2	Weekly composite fuel sampling and fuel analysis or continuous emissions monitoring per FDEP Rule 62-296.405(1(f)1.b., F.A.C. Deletion of current requirement to conduct an annual stack test is requested.		Annual test using EPA Reference Method 9.
			Daily composite fuel sampling and analysis per Specific Condition 9.C. of permit AO29-179912. Deletion of current requirement to conduct an annual stack test is requested.		Annual test using EPA Reference Method 9.
					Annual test using EPA Reference Method 9.
		PM	Annual test using EPA reference method 5, 5B, or 17. Option to use three soot-blowing test runs to demonstrate compliance with non-soot blowing standard is requested.	S	

			Pollutant	VE	Visible Emissions
E.U. ID#	**Description**	**Pollutant Name**	**Compliance Method**	**Type**	**Compliance Method**
002	Unit No. 2; Solid Fuel Steam Generator			S	
003	Unit No. 3; Solid Fuel Steam Generator	SO2	Weekly composite fuel sampling and fuel analysis or continuous emissions monitoring per FDEP Rule 62-296.405(1(f)1.b., F.A.C. Deletion of current requirement to conduct an annual stack test is requested.		Continuous opacity monitoring system (COMS). Deletion of current annual test using EPA or FDEP Reference Method 9 is requested.
			Daily composite fuel sampling and analysis per Specific Condition 12.C. of permit AO29-179911. Deletion of current requirement to conduct an annual stack test is requested.		Continuous opacity monitoring system (COMS). Deletion of current annual test using EPA or FDEP Reference Method 9 is requested.
					Continuous opacity monitoring system (COMS). Deletion of current annual test using EPA or FDEP Reference Method 9 is requested.
		NOX	30-day rolling average to be determined using EPA Reference Method 19.	S	Continuous opacity monitoring system (COMS).
		PM	Annual test using EPA reference method 5, 5B or 17. Option to use three soot-blowing test runs to demonstrate compliance with non-soot blowing standard is requested. Testing to be conducted in stack CS-003 (non-integrated mode) or in the duct (integrated mode).		Continuous opacity monitoring system (COMS).
004	Unit No. 4; Solid Fuel Steam Generator	SO2	Continuous emissions monitoring system (CEMS). Deletion of current requirement to conduct an annual stack test is requested.		Continuous opacity monitoring system (COMS). Deletion of current annual test using EPA or FDEP Reference Method 9 is requested.

Faclility ID: 0570039 **DRAFT Permit No.:**
Permittee: BigBend

			Pollutant	VE	Visible Emissions
E.U. ID#	**Description**	**Pollutant Name**	**Compliance Method**	**Type**	**Compliance Method**
004	Unit No. 4; Solid Fuel Steam Generator	SO2	Continuous emissions monitoring system (CEMS). Deletion of current requirement to conduct an annual stack test is requested.		Continuous opacity monitoring system (COMS). Deletion of current annual test using EPA or FDEP Reference Method 9 is requested.
		NOX	EPA Reference Method 19.		
		PM	Annual test using EPA reference method 5, 5B, or 17.		
		CO	EPA Reference Method 10 once every five years.		
007	Combustion Turbine No. 1				
005	Combustion Turbine No. 2				
006	Combustion Turbine No. 3				
008	Fly Ash Silo No. 1 (Units #1 and #2)	PM	Annual visible emission test using EPA Reference Method 9 in lieu of particulate test per Specific Condition No. 3 of permit AO29-160255.	A	Annual test using EPA Reference Method 9.
					Annual test using EPA Reference Method 9.
					Annual test using EPA Reference Method 9.
					Annual test using EPA Reference Method 9.
					Annual test using EPA Reference Method 9.
					Annual test using EPA Reference Method 9.
009	Fly Ash Silo No. 2 (Units #1, #2, and #3)		Annual visible emission test using EPA Reference Method 9 in lieu of particulate test per Specific Condition No. 4 of permit AO29-161082.	A	Annual test using EPA Reference Method 9.
					Annual test using EPA Reference Method 9.

			Pollutant	VE	Visible Emissions
E.U. ID#	**Description**	**Pollutant Name**	**Compliance Method**	**Type**	**Compliance Method**
009	Fly Ash Silo No. 2 (Units #1, #2, and #3)	PM	Annual visible emission test using EPA Reference Method 9 in lieu of particulate test per Specific Condition No. 4 of permit AO29-161082.		
014	Fly Ash Silo No. 3 (Unit #4)		Annual visible emission test using EPA Reference Method 9 in lieu of particulate test per Specific Condition No. 3 of permit PSD-FL-040.	A	Annual test using EPA Reference Method 9.
015	Solid Fuel Bunkers (all units)		Visible emission test using EPA Reference Method 9 upon permit renewal in lieu of particulate test per Specific Condition No. 7 of permit AO29-163788.		EPA Reference Method 9 test upon permit renewal.
			Visible emission test using EPA Reference Method 9 upon permit renewal in lieu of particulate test per Specific Condition No. 7 of permit AO29-163788.		EPA Reference Method 9 test upon permit renewal.
			Visible emission test using EPA Reference Method 9 upon permit renewal in lieu of particulate test per Specific Condition No. 7 of permit AO29-163788.		
			Visible emission test using EPA Reference Method 9 upon permit renewal in lieu of particulate test per Specific Condition No. 7 of permit AO29-163788.		
011	Limestone Handling and Storage (all sources)		Testing for PM is not required unless opacity limits are exceeded.		Annual test using EPA Reference Method 9.
					Annual test using EPA Reference Method 9.
No Id	Fly Ash Handling and Storage Fugitives (all except silos)				

Faclility ID: 0570039 **DRAFT Permit No.:**
Permittee: BigBend

			Pollutant	VE	Visible Emissions
E.U. ID#	**Description**	**Pollutant Name**	**Compliance Method**	**Type**	**Compliance Method**
No Id	Gypsum Handling and Storage Fugitives (all gypsum sources)				
010	Solid Fuel Handling and Storage Fugitives (all sources)	PM			EPA Reference Method 9.
					EPA Reference Method 9.
No Id	Slag and Bottom Ash Handling (all sources)				

Table 2-2. Continuous Monitor Description

Facility ID: 0570039 **DRAFT Permit No.:**

Permittee: BigBend

			Continouos Monitor	
E.U. ID#	**Description**	**Pollutant Name**	**Parameter Code**	**CMS Requirement**
001	Unit No. 1; Solid Fuel Steam Generator	SO2	VE	RULE
			SO2	RULE
			NOX	RULE
			FLOW	RULE
			CO2	RULE
		PM	VE	RULE
			SO2	RULE
			NOX	RULE
			FLOW	RULE
			CO2	RULE
002	Unit No. 2; Solid Fuel Steam Generator	SO2	VE	RULE
			SO2	RULE
			NOX	RULE
			FLOW	RULE
			CO2	RULE
		PM	VE	RULE
			SO2	RULE
			NOX	RULE
			FLOW	RULE
			CO2	RULE
003	Unit No. 3; Solid Fuel Steam Generator	SO2	VE	RULE
			SO2	RULE
			NOX	RULE
			FLOW	RULE
			CO2	RULE
		NOX	VE	RULE
			SO2	RULE
			NOX	RULE
			FLOW	RULE
			CO2	RULE
		PM	VE	RULE
			SO2	RULE
			NOX	RULE
			FLOW	RULE
			CO2	RULE
004	Unit No. 4; Solid Fuel Steam Generator	SO2	SO2	RULE
			NOX	RULE

Faclility ID: 0570039 **DRAFT Permit No.:**

Permittee: BigBend

			Continouos Monitor	
E.U. ID#	**Description**	**Pollutant Name**	**Parameter Code**	**CMS Requirement**
004	Unit No. 4; Solid Fuel Steam Generator	SO2	VE	RULE
			FLOW	RULE
			CO2	RULE
		NOX	SO2	RULE
			NOX	RULE
			VE	RULE
			FLOW	RULE
			CO2	RULE
		PM	SO2	RULE
			NOX	RULE
			VE	RULE
			FLOW	RULE
			CO2	RULE
		CO	SO2	RULE
			NOX	RULE
			VE	RULE
			FLOW	RULE
			CO2	RULE
007	Combustion Turbine No. 1			
005	Combustion Turbine No. 2			
006	Combustion Turbine No. 3			
008	Fly Ash Silo No. 1 (Units #1 and #2)	PM		
009	Fly Ash Silo No. 2 (Units #1, #2, and #3)			
014	Fly Ash Silo No. 3 (Unit #4)			
015	Solid Fuel Bunkers (all units)			
011	Limestone Handling and Storage (all sources)			
No Id	Fly Ash Handling and Storage Fugitives (all except silos)			
	Gypsum Handling and Storage Fugitives (all gypsum sources)			
010	Solid Fuel Handling and Storage Fugitives (all sources)	PM		
No Id	Slag and Bottom Ash Handling (all sources)			

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 4

IN THE MATTER OF:	)	
	)	**Notice of Violation**
Tampa Electric Company	)	
	)	EPA-CAA-2000-04-0007
Big Bend and Gannon Stations	)	
	)	
	)	
Proceedings Pursuant to Section 113(a)(1) of the Clean Air Act, 42 U.S.C. §7413(a)(1)	)	

NOTICE OF VIOLATION

This Notice of Violation ("NOV") is issued to the Tampa Electric Company ("TECO") for violations of the Clean Air Act ("Act") at the coal-fired power plants identified below. TECO has embarked on a program of modifications intended to extend the useful life, regain lost generating capacity, and/or increase capacity at their coal-fired power plants.

Commencing at various times since 1977 and continuing to today, TECO has modified and operated the coal-fired power plants identified below without obtaining New Source Review ("NSR") permits authorizing the construction and operation of physical modifications of its boiler units as required by the Act. In addition, for each physical modification at these power plants, TECO has operated these modifications without installing pollution control equipment required by the Act. These violations of the Act and the State Implementation Plan ("SIP") of Florida have resulted in the release of massive amounts of Sulfur Dioxides ("SO_2"), Nitrogen Oxides ("NO_X"), and particulate matter ("PM") into the environment. Until these violations are corrected, TECO will continue to release massive amounts of illegal SO_2, NOx, and PM into the environment.

This NOV is issued pursuant to Section 113(a)(1) of the Act, as amended, 42 U.S.C.A. Sections 7401-7671q. Section 113(a) of the Act requires the Administrator of the United States Environmental Protection Agency ("EPA") to notify any person in violation of a state implementation plan or permit of the violations. The authority to issue this NOV has been delegated to the Regional Administrator for EPA Region 4 and further redelegated to the Director of the Air, Pesticides and Toxics Management Division for EPA, Region 4.

STATUTORY AND REGULATORY BACKGROUND

1. When the Clean Air Act was passed in 1970, Congress exempted existing facilities from many of its requirements. However, Congress also made it quite clear that this exemption would not last forever. As the United States Court of Appeals for the D.C. Circuit explained in Alabama Power v. Costle, 636 F.2d 323 (D.C. Cir. 1979), "the statutory scheme intends to 'grandfather' existing industries; but...this is not to constitute a perpetual immunity from all standards under the PSD program." Rather, the Act requires grandfathered facilities to install modern pollution control devices whenever the unit is proposed to be modified in such a way that its emissions may increase.

2. The NSR provisions of Parts C and D of Title I of the Act require preconstruction review and permitting for modifications of stationary sources. Pursuant to applicable regulations, if a major stationary source is planning upon making a major modification, then that source must obtain either a PSD permit or a nonattainment NSR permit, depending on whether the source is located in an attainment or a nonattainment area for the pollutant being increased above the significance level. If a major stationary source is planning on making a modification that is not major, it must obtain a general or "minor" NSR permit regardless of its location. To obtain the required permit, the source must agree to put on the best available control technology ("BACT") for an attainment pollutant or achieve the lowest achievable emission rate ("LAER") in a nonattainment area, or, in the case of a modification that is not major, must meet the emission limit called for under the applicable minor NSR program.

3. Pursuant to Part C of the Act, the Florida SIP requires that no construction or operation of a major modification of a major stationary source occur in an area designated as attainment without first obtaining a permit under 40 CFR Section 52.21 and the current Florida SIP Rule 62-212.400, Florida Administrative Code (F.A.C.). The PSD portion of the Florida SIP was originally approved by EPA on November 22, 1983 at 48 Fed. Reg. 52716, and amendments were later approved by EPA on October 20, 1994 at 59 Fed. Reg. 52916, and on January 11, 1995 at 60 Fed. Reg. 2688. No SIP-approval for PSD has been given to the State of Florida for power plants which are also subject to the Florida Power Plant Siting Act (PPSA). Rather, Florida has a fully delegated PSD program with respect to power plants subject

to the PPSA. Florida implements this delegation under 40 C.F.R. Section 52.21, whose provisions are incorporated by reference into the Florida SIP pursuant to 40 C.F.R. Section 52.530.

4. Pursuant to Part D of the Act, the Florida SIP requires that no construction or operation of a major modification of a major stationary source occur in an area designated as nonattainment without first obtaining a permit under 40 CFR Section 52.24 and the current Florida SIP Rule 62-212.500, F.A.C., as approved on November 22, 1983 at 48 Fed. Reg. 52716, and amended on October 20, 1994 at 59 Fed. Reg. 52916.

5. The Florida SIP Rule 62-212.300, F.A.C., provides that no emission unit or source subject to that rule shall be constructed without obtaining an air construction permit that meets the requirement of that rule. This rule was approved as part of the Florida SIP on October 20, 1994, at 59 Fed. Reg. 52916.

6. The SIP provisions identified in paragraphs 3, 4, and 5 above are all federally enforceable pursuant to Sections 110 and 113 of the Act.

FACTUAL BACKGROUND

7. TECO operates the Gannon Station, a fossil fuel-fired electric utility steam generating plant located at Port Sutton Road in Hillsborough County, Tampa, Florida. The plant consists of 6 boiler units with a total generating capacity of 1215 megawatts in 1998 and began operations in 1957.

8. TECO operates the Big Bend Station, a fossil fuel-fired electric utility steam generating plant located at Big Bend Station, Hillsborough County, Tampa, Florida 33619. The plant consists of 4 boiler units with a total generating capacity of 1795 megawatts in 1998 and began operations in 1971.

9. The Gannon and Big Bend Stations are both located in an area that has the following attainment/nonattainment classifications from 1980 to the present:

   For NO_2, the area has been classified as attainment from 1980 to the present.

For SO_2, the area has been classified as attainment from 1980 to the present.

For PM, the area was classified as nonattainment from 1980 to April 2, 1990, for total suspended particulate matter. The area has been designated as attainment since April 2, 1990.

For ozone, the area has been classified as nonattainment until February 5, 1996 and attainment since that date.

10. Each of the plants identified in paragraphs 7 and 8 above emits or has the potential to emit at least 100 tons per year of NOx, SO_2 and/or PM and is a stationary source under the Act.

VIOLATIONS

A. <u>Gannon Station</u>

11. On numerous occasions between 1979 and the date of this Notice, TECO has made "modifications" of the Gannon Station as defined by both 40 CFR Section 52.21 and Florida SIP Rules 62-210.200 and 62-212.400, F.A.C. These modifications included, but are not limited to, the following individual modifications or projects: replacement of the furnace floor of Unit 3 in 1996; replacement of the cyclone burners of Unit 4 in 1994; and replacement of the 2nd radiant superheater of Unit 6 in 1992.

12. For each of the modifications that occurred at the Gannon Station, TECO did not obtain a PSD permit pursuant to 40 CFR Section 52.21 and Florida SIP Rule 62-212.400, F.A.C.; a nonattainment NSR permit pursuant to 40 CFR Section 52.24 and Rule 62-212.400, F.A.C.; nor a minor source permit pursuant to Rule 62-212.300, F.A.C. In addition, for modifications after 1992, no information was provided to the permitting agency of actual emissions after the modification in accordance with 40 CFR Section 52.21(b)(21)(v) and Rule 62-210.200(12)(d), F.A.C.

13. None of the modifications fall within the "routine maintenance, repair and replacement" exemption found at 40 CFR Section 52.21(b)(2)(iii)(a) and Florida SIP Rule 62-210.200(183)(a)1.a., F.A.C. Each of these changes was an expensive capital expenditure performed infrequently at the plant that constituted the replacement and/or redesign of a

boiler component with a long useful life. In each instance, the change was performed to increase capacity, regain lost capacity, and/or extend the life of the unit. In many instances, the original component was replaced with a component that was substantially redesigned in a manner that increased emissions. That the "routine maintenance, repair and replacement" exemption does not apply where construction activity is at issue was known to the utility industry since at least 1988 when EPA issued a widely publicized applicability determination regarding utility modifications at a Wisconsin Electric Power Co. ("WEPCO") facility. EPA's interpretation of this exemption was upheld by the court of appeals in 1990. Wisconsin Electric Power Co. v. Reilly, 893 F.2d 901 (7th Cir. 1990).

14. None of these modifications fall within the "increase in hours of operation or in the production rate" exemption found at 40 CFR § 52.21(b)(2)(iii)(f), or Florida regulation 62-210.200(183)(a)2., F.A.C. This exemption is limited to stand-alone increases in operating hours or production rates, not where such increases follow or are otherwise linked to construction activity. That the hours of operation/rates of production exemption does not apply where construction activity is at issue was known to the utility industry since at least 1988 when EPA issued a widely publicized applicability determination regarding utility modifications at a Wisconsin Electric Power Co. ("WEPCO") facility. EPA's interpretation of this exemption was upheld twice by the court of appeals, in 1989 and in 1990. Puerto Rican Cement Co. v. EPA, 889 F.2D 292 (1st Cir. 1989); Wisconsin Electric Power Co. v. Reilly, 893 F.2d 901 (7th Cir. 1990).

15. None of these modifications fall within the "demand growth" exemption found at 40 CFR Section 52.21(b)(33)(ii) and Florida SIP Rule 62-210.200(12)(d), F.A.C., because for each modification a physical change was performed which resulted in the emissions increase.

16. Each of these modifications resulted in a net significant increase in emissions from Gannon Station for NO_X, SO_2 and/or PM as defined by 40 CFR Sections 52.21(b)(3) and (23) and Florida SIP Rule 62-212.400(2)(e)2., F.A.C.

17. Therefore, TECO violated and continues to violate 40 CFR Section 52.21 and Florida SIP Rule 62-212.400, F.A.C., for the prevention of significant deterioration; 40 CFR Section 52.24 and Rule 62-212.500, F.A.C., for preconstruction

review for nonattainment areas; and/or Rule 62-212.300, F.A.C., by constructing and operating modifications at the Gannon Station without the necessary permit required by the Florida SIP.

18. Each of these violations exists from the date of start of construction of the modification until the time that TECO obtains the appropriate NSR permit and operates the necessary pollution control equipment to satisfy the Florida SIP .

B. Big Bend Station

19. On numerous occasions between 1979 and the date of this Notice, TECO has made "modifications" at its Big Bend Station as defined by both 40 CFR Section 52.21 and Florida SIP Rule 62-212.400, F.A.C. These modifications included, but are not limited to, the following individual modifications or projects: replacement of steam drum internals on Units 1 and 2 in 1994 and 1991 respectively; and high temperature reheater replacement and waterwall addition for Unit 2 in 1994.

20. For each of the modifications that occurred at the Big Bend Station, TECO did not obtain a PSD permit pursuant to 40 CFR Section 52.21 and Florida SIP Rule 62-212.400, F.A.C.; a nonattainment NSR permit pursuant to 40 CFR Section 52.24 and Rule 62-212.400, F.A.C.; or a minor NSR permit pursuant to Rule 62-212.300, F.A.C. In addition, for modifications after 1992, no information was provided to the permitting agency of actual emissions after the modification as required by 40 CFR Section 52.21(b)(21)(v) and Rule 62-210.200(12)(d), F.A.C.

21. None of these modifications fall within the "routine maintenance, repair and replacement" exemption found at 40 CFR Section 52.21(b)(2)(iii)(a) and Florida SIP Rule 62-210.200(183)(a)1.a., F.A.C. Each of these changes was an expensive capital expenditure performed infrequently at the plant that constituted the replacement and/or redesign of a boiler component with a long useful life. In each instance, the change was performed to increase capacity, regain lost capacity, and/or extend the life of the unit. In many instances, the original component was replaced with a component that was substantially redesigned in a manner that increased emissions. That the "routine maintenance, repair and replacement" exemption does not apply where construction activity is at issue was known to the utility industry since at least 1988 when EPA issued a widely publicized

applicability determination regarding utility modifications at a Wisconsin Electric Power Co. ("WEPCO") facility. EPA's interpretation of this exemption was upheld by the court of appeals in 1990. Wisconsin Electric Power Co. v. Reilly, 893 F.2d 901 (7th Cir. 1990).

22. None of these modifications fall within the "increase in hours of operation or in the production rate" exemption found at 40 CFR § 52.21(b)(2)(iii)(f), or Florida regulation 62-210.200(183)(a)2., F.A.C. This exemption is limited to stand-alone increases in operating hours or production rates, not where such increases follow or are otherwise linked to construction activity. That the hours of operation/rates of production exemption does not apply where construction activity is at issue was known to the utility industry since at least 1988 when EPA issued a widely publicized applicability determination regarding utility modifications at a Wisconsin Electric Power Co. ("WEPCO") facility. EPA's interpretation of this exemption was upheld twice by the court of appeals, in 1989 and in 1990. Puerto Rican Cement Co. v. EPA, 889 F.2D 292 (1st Cir. 1989); Wisconsin Electric Power Co. v. Reilly, 893 F.2d 901 (7th Cir. 1990).

23. None of these modifications fall within the "demand growth" exemption found at 40 CFR Section 52.21(b)(33)(ii) and Florida SIP Rule 62-210.200(12)(d), F.A.C., because for each modification a physical change was performed which resulted in the emissions increase.

24. Each of these modifications resulted in a net significant increase in emissions from Big Bend Station for NO_x, SO_2 and/or PM as defined by 40 CFR Sections 52.21(b)(3) and (23) and Florida SIP Rule 62-212.400(2)(e)2., F.A.C.

25. Therefore, TECO violated and continues to violate 40 CFR Section 52.21 and Florida SIP Rule 62-212.400, F.A.C., for the prevention of significant deterioration; 40 CFR Section 52.24 and Rule 62-212.500, F.A.C., for preconstruction review for nonattainment areas; and/or Rule 62-212.300, F.A.C., by constructing and operating modifications at the Big Bend Station without the necessary permit required by the Florida SIP.

26. Each of these violations exists from the date of start of construction of the modification until the time that TECO obtains the appropriate NSR permit and operates the necessary pollution control equipment to satisfy the Florida

SIP.

ENFORCEMENT

Section 113(a)(1) of the Act provides that at any time after the expiration of 30 days following the date of the issuance of this NOV, the Regional Administrator may, without regard to the period of violation, issue an order requiring compliance with the requirements of the state implementation plan or permit, and/or bring a civil action pursuant to Section 113(b) for injunctive relief and/or civil penalties of not more than $25,000 per day for each violation on or before January 30, 1997, and no more than $27,500 per day for each violation after January 30, 1997.

OPPORTUNITY FOR CONFERENCE

Respondent may, upon request, confer with EPA. The conference will enable Respondent to present evidence bearing on the finding of violation, on the nature of violation, and on any efforts it may have taken or proposes to take to achieve compliance. Respondent has a right to be represented by counsel. A request for a conference must be made within 10 days of receipt of this NOV, and the request for a conference or other inquiries concerning the NOV should be make in writing to:

Charles V. Mikalian
Associate Regional Counsel
Environmental Accountability Division
U.S. EPA
61 Forsyth Street, SW
Atlanta, GA 30303
404-562-9575

____
Date

____
John H. Hankinson, Jr.
Regional Administrator
EPA, Region 4

Mikalian	Dion	Tommelleo	Hewson	Dubose
Spagg	Kutzman	Smith	Lynch	

Hankinson

					Acid Rain NOx	Current Acid Rain Phase I Facilities		
	Company	**Facility ID No.**	**Facility Name**	**Current NOx Limit for fees (Tons)**	**NOx Allowable Limit under Phase II**	**SO2 Limit under Phase II**	**PM Limit under Phase II**	**NOx Limit under Phase II**
Teresa	Gainesville Regional Utilities	0010006	Deerhaven Station	1938				
Bruce	Jacksonville Electric	0310001	St. John's River Power Park	4000				
Ed	City of Lakeland	1050004	C.D. McIntosh	4000				
Ed	Seminole Electric Coop.	1070025	Seminole Power Plant	4000				
Joe	Florida Power	0170004	Crystal River	4000				
Cindy	Tampa Electric	0570039	Big Bend*	4000		4000	4000	4000
Lennon	Tampa Electric	0570040	F.J. Gannon Station*	**No NOx limits now**	4000	4000	4000	
Steve	Tampa Electric	0570038	Hookers Point*			4000	1536	
Syed	Orlando Utilities	0950137	Stanton Energy	4000				
Jon	Gulf Power	0050014	Lansing Smith	**No NOx limits now**	4000			
Jon	Gulf Power	0630014	Scholz*	**No NOx limits now**	2828	4000	707	
Jon	Gulf Power	0330045	Crist*	**No NOx limits now**	4000	4000	4000	
	New Revenue:				$370,000.	500,000.	356,075.	100,000.
			*Phase I Acid Rain					**$1,326,075 Total**

Big Bend Station - Dispersion Model Stack Parameters

Emission Source	SO_2 Emission Rate		Stack Height (m)	Stack Gas Temperature (K)	Stack Gas Velocity (m/sec)	Stack Diameter (m)
	3 hr (g/sec)	24 hr & Annual† (g/sec)				
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

STD
346 → 260
24hr

62-20

BBPARAM.XLS

AMBIENT AIR QUALITY STANDARDS
SULFUR DIOXIDE

State of Florida - Rule 62-204.240(1), F.A.C.

3 - Hour Maximum	1/year	1,300 ug/m^3	(0.5 ppm)
24 - Hour Maximum	1/year	260 ug/m^3	(0.1 ppm)
Annual Arithmetic Mean		60 ug/m^3	(0.02 ppm)

United States Environmental Protection Agency - 40 CFR 50

3 - Hour Maximum	1/year	1,300 ug/m^3
24 - Hour Maximum	1/year	365 ug/m^3
Annual Arithmetic Mean		80 ug/m^3

Rule 62-204.240(1), F.A.C.
Florida's SO_2 standards.

Rule 62-296.405(1)(c)3, F.A.C.
Ambient SO_2 & boilers.

12-12

~~Scott~~ SMS 12/15
~~Cindy~~ CP 12/18

On TEC Gannon coal yard throughput increase & PSD applicability. Al will be PE and will review for PSD applicability. Herron will review application & draft conditions as he just reviewed that facility for Title V

Clair

< version dated 02/05/97 >
(FOR OFFICE USE ONLY)

Table 1-1, Summary of Air Pollutant Standards and Terms

[Facility Owner/Company Name]
[Site Name]

DRAFT Permit No.: [xxxxxxx-xxx-AV]
Facility ID No.: [xxxxxxx]

This table summarizes information for convenience purposes only. This table does not supersede any of the terms or conditions of this permit.

E.U. ID No. **Brief Description**
[-xxx]

			Allowable Emissions			Equivalent Emissions*			
Pollutant Name	Fuel(s)	Hours/Year	Standard(s)	lbs./hour	TPY	lbs./hour	TPY	Regulatory Citation(s)	See permit condition(s)

Notes:
* The "Equivelent Emissions" listed are for informational purposes only.

[electronic file name: xxxxxxx1.xls]

< version dated 02/05/97 >
(FOR OFFICE USE ONLY)

Table 2-1, Summary of Compliance Requirements

[Facility Owner/Company Name]
[Site Name]

DRAFT Permit No.: [xxxxxxx-xxx-AV]
Facility ID No.: [xxxxxxx]

This table summarizes information for convenience purposes only. This table does not supersede any of the terms or conditions of this permit.

E.U. ID No. **Brief Description**
[-xxx]

Pollutant Name or Parameter	Fuel(s)	Compliance Method	Testing Time Frequency	Frequency Base Date *	Min. Compliance Test Duration	CMS**	See permit condition(s)

Notes:
* The frequency base date is established for planning purposes only; see Rule 62-297.310, F.A.C.
**CMS [=] continuous monitoring system

[electronic file name: xxxxxxx2.xls]

Estimated HAP Emissions from Tampa Electric Co. Big Bend Station's Coal-Fired Steam Generators

	Coal Unit Size (MW)	**325**	4037	3996	4115	4330
Pollutant (tons/year)						
Arsenic		**0.081**	1.006	0.996	1.026	1.079
Cadmium		**0.00051**	0.00633	0.00627	0.00646	0.00679
Chromium		**0.086**	1.068	1.057	1.089	1.146
Lead		**0.075**	0.932	0.922	0.950	0.999
Mercury		**0.05**	0.62	0.61	0.63	0.67
Hydrogen chloride		**190**	2360	2336	2406	2531
Hydrogen fluoride		**14**	174	172	177	187
Dioxins		**0.00000014**	0.00000174	0.00000172	0.00000177	0.00000187
Nickel		**NC**	NC	NC	NC	NC
NC = Not Calculated						
Bold Numbers are the estimated emissions from utility emissions given in Table ES-2 of EPA's final interim report on emissions of hazardous air pollutants from fossil fule-fired electric utility steam generating units.						
Non-bold numbers are factored emissions based on the difference in actual MW vs. 325 MW.						

Estimated HAP Emissions from Tampa Electric Co. Big Bend Station's Coal-Fired Steam Generators

	Coal Unit Size (MW)	**325**	4037	3996	4115	4330	Total
Pollutant (tons/year)							
Arsenic		**0.081**	1.006	0.996	1.026	1.079	4.107
Cadmium		**0.00051**	0.00633	0.00627	0.00646	0.00679	0.02586
Chromium		**0.086**	1.068	1.057	1.089	1.146	4.360
Lead		**0.075**	0.932	0.922	0.950	0.999	3.803
Mercury		**0.05**	0.62	0.61	0.63	0.67	2.54
Hydrogen chloride		**190**	2360	2336	2406	2531	9633
Hydrogen fluoride		**14**	174	172	177	187	710
Dioxins		**0.00000014**	0.00000174	0.00000172	0.00000177	0.00000187	0.00000710
Nickel		**NC**	NC	NC	NC	NC	
NC = Not Calculated							
Bold Numbers are the estimated emissions from utility emissions given in Table ES-2 of EPA's final interim report on emissions of hazardous air pollutants from fossil fuel-fired electric utility steam generating units.							
Non-bold numbers are factored emissions based on the difference in actual MW vs. 325 MW.							

AIR POLLUTION CONTROL
SPECIFIC OPERATING AGREEMENT

BETWEEN THE

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

AND THE

HILLSBOROUGH COUNTY
ENVIRONMENTAL PROTECTION COMMISSION

AIR POLLUTION CONTROL
SPECIFIC OPERATING AGREEMENT
BETWEEN THE
STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
AND THE
HILLSBOROUGH COUNTY
ENVIRONMENTAL PROTECTION COMMISSION

TABLE OF CONTENTS

AIR POLLUTION CONTROL
SPECIFIC OPERATING AGREEMENT

BETWEEN THE

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

AND THE

HILLSBOROUGH COUNTY
ENVIRONMENTAL PROTECTION COMMISSION

BACKGROUND

(1) General Operating Agreements. On September 18, 1974, the Florida Department of Environmental Protection (DEP) and the Hillsborough County Environmental Protection Commission (EPC) entered into a General Operating Agreement (GOA). It was amended in 1980 and superseded by another GOA on August 13, 1981, a third GOA was executed on August 4, 1988, and is the current GOA. A copy of the GOA is on file at the EPC and the District FDEP.

(2) Special Acts. EPC was created and expanded by special acts passed in 1967, 1969, 1971, 1972, and 1973. These were repealed and superseded in 1984 by Chapter 84-446, Laws of Florida, and amended in 1987 by Chapter 87-495, Laws of Florida. The powers and duties of EPC established by these special acts are incorporated herein by reference. Copies of the Special Acts are available at the EPC or District FDEP.

(3) Objective. This Air Specific Operating Agreement (Air SOA) supersedes one executed on January 26, 1984 and November 20, 1992. The intent of this Air SOA is to formally establish the basis upon which DEP and EPC will work together to protect the air quality of Hillsborough County according to the provisions of Section 403.182, F.S., and Rule Chapter 62-209, F.A.C., which are incorporated herein by reference. Copies are available at the EPC or District FDEP.

PART I

ADMINISTRATION OF THIS AIR SPECIFIC OPERATING AGREEMENT

(1) Commencement. The renewal of this Air SOA shall become effective upon signature by both DEP and EPC. Notwithstanding Section 9.01 of the GOA, this Air SOA is entered into by the DEP Secretary and the EPC Executive Director, both of whom have the authority to execute this Air SOA and satisfy its terms and conditions.

(2) Expiration. The renewal of this Air SOA shall expire at midnight on the third anniversary of the date that this document was signed by both DEP and EPC unless both DEP and EPC state in writing an intent to renew or amend this Air SOA. Upon such written intent, this Air SOA shall remain in effect pending the execution of an agreement to extend or amend it or until terminated pursuant to Part I, Section (7).

(3) Modification. This Air SOA may be modified in writing at any time by mutual consent of DEP and EPC.

(4) Agreement Conflicts. If this Air SOA conflicts with any part of the GOA, then that part of the GOA shall not apply to DEP or EPC with respect to the air pollution control program in Hillsborough County.

(5) Severability. If any part of this Air SOA is found invalid or unenforceable by any Court, the remaining parts of this Air SOA will not be affected if DEP and EPC agree that the rights and duties of both parties contained in this Air SOA are not materially prejudiced, and if the intentions of the parties can continue to be effective.

(6) Approval of EPC Rules. The DEP determines that EPC's existing rules pertaining to air pollution control, Chapters 1-3, 1-4, and 1-8 adopted pursuant to Chapter 84-446, Laws of Florida are compatible with, or stricter or more extensive than those imposed by Chapter 403, F.S., and rules issued thereunder, and shall be enforced by DEP if it elects to exercise its jurisdiction over air pollution within the territory of EPC. This determination is not applicable to rules not listed above, or pertaining to noise pollution. This determination is also not applicable to the following EPC rules: Section 1-3.12.2 and Section 1-8.04.1.(b).

   (a) Future EPC Rules. To clarify the intent of DEP and EPC regarding the effect of Subsection 403.182(7), F.S., Sections 3.02 and 8.02 of the GOA, and Rule 62-209.400(4)(e), F.A.C., it is agreed by DEP and EPC that if EPC amends any existing ordinances or rules pertaining to air pollution control, or adopts any new rules, DEP will not enforce such amended or new rules unless and until DEP has determined that such rules are compatible with, or stricter or more extensive than those imposed by Chapter 403, F.S., and rules adopted thereunder. Prior to making such a determination, DEP is not obligated to enforce such rules if it asserts its jurisdiction, and EPC cannot use DEP's authority under Section 403.161, F.S. to enforce such amendments.

(7) Termination.

(a) Procedures. If the GOA is terminated according to Section 2.07 of the GOA by either party without cause upon written notice to the other party at least ninety days prior to the effective date of such termination, then this Air SOA shall be simultaneously terminated. EPC or DEP may terminate this Air SOA without cause by providing written notice to the other party at least 90 days prior to the effective date of such termination.

(b) Distribution of Funds. Within 90 days of termination, EPC shall refund to DEP any financial support provided by the State of Florida under Title V of the 1990 Clean Air Act Amendments for air pollution control which has not been obligated or expended by EPC for that purpose. Conversely, DEP shall pay EPC a pro rata share of any such financial support due during that budgetary period which has been obligated or funded by EPC for air pollution control before the effective date of termination. (The distribution of funds pertaining to license registration fees on vehicles shall be governed by Rule Chapter 62-209, F.A.C.)

PART II

AIR PROGRAM MANAGEMENT

(1) Budget. DEP and EPC shall annually exchange summaries of their respective approved budgets, outlining funding and staffing.

(2) Adequate Staff. DEP has determined that EPC has adequate and appropriate administration staff, financial and other resources to effectively and efficiently carry out the air program; that the program is adequate to prevent and control pollution; and that the program provides for enforcement of its requirements by appropriate administrative and judicial processes. EPC shall maintain an

adequate air permitting, monitoring, mobile source, compliance and enforcement staff to satisfy the requirements of this Air SOA. As required by Section 2.05 of the GOA, EPC's organizational chart (Attachment 1) shall be periodically updated or supplemented by EPC as necessary when there are changes of key personnel or organizational structure. For purposes of this Air SOA, an organizational chart and an alphabetical directory of EPC and DEP personnel shall be exchanged by EPC and DEP at least every year from the signing of this Air SOA.

(3) Plans. DEP and EPC shall coordinate and annually exchange their respective U.S. Environmental Protection Agency (EPA) 105 grant workplans upon request. The DARM and the EPC Air Program will cooperate with each other in the development of other activities covered by the applicable DEP rules concerning local air programs.

(a) Exchange of Data. All activities involving the preparation, review, and implementation of air programs for those functions specified in the applicable DEP rules concerning local air programs will be exchanged between DEP and EPC.

(4) Training. EPC will ensure that its employees have the requisite entry-level training and the subsequent training needed to allow its employees to properly accomplish their work assignments. As time and resources allow, EPC staff will attend the following specific training events, when held:

(a) DEP Air Program Meeting;

(b) DEP Air Permit Engineers' Specialty Meeting;

(c) DEP Air Compliance and Enforcement Specialty Meeting;

(d) EPA or TREEO Asbestos Inspector Training Course(s);

(e) DEP Visible Emissions Training Course;

(f) DEP Mobile Source Specialty Meeting;

(g) DEP Ambient Air Monitors Operators' Specialty Meeting;

(h) Florida Air Monitoring Advisory Committee Meetings:

(i) DEP Air Program - ARMS Coordinators' Workshop (annual); and

(j) DEP Enforcement Workshop (annual).

In addition, EPC is encouraged to send members of its air program staff to individual training courses such as the EPA Air Pollution Training Institute's courses, and to allow participation in other DEP air training activities, as time and resources allow.

(5) Meetings. In addition to fulfilling the requirements of Section 5.02 of the GOA, EPC will be represented as time and resources allow at the following specific meetings, when held;

(a) EPA Region IV State/Local Air Directors' Meeting (for 105 Air Grant recipients);

(b) EPA Region IV 105 Air Grant Meeting (for EPA 105 Air Grant recipients);

(c) EPA Region IV Ambient Air Monitoring Meeting;

(d) Florida Air Council Meetings;

(e) Florida Air Toxics Working Group Meetings and Region IV's Air Toxic Meeting;

(f) EPA Region IV Compliance and Enforcement;

(g) Annual Meeting of the Florida Section of the Air and Waste Management Association; and,

(h) Annual Convention of the International Air and Waste Management Association (AWMA) and the Florida Section's Annual Meeting.

EPC is encouraged to participate in the Association of Local Air Pollution Control Officials (ALAPCO).

(6) Policy Coordination. EPC and DEP will coordinate their activities regarding operations and enforcement issues. This is particularly critical when the issue involves the EPA. Any delegation or subdelegation of DEP or EPA authority to EPC shall be accepted with the understanding that the delegating authority (DEP or EPA) may require adherence to its policies and reporting formats.

(7) Program Reports. DEP and EPC will submit reports to each other as required by this agreement (or its amendments) at the frequency listed in Attachment 2.

Where possible, such reports will be made through computerized data systems. A list of these reports will be periodically updated as needed. DEP will send EPC a copy of the letter of transmittal (or another form of verification) indicating when a report has been submitted by DEP to the EPA or to another agency on behalf of EPC. A list of these reports will be periodically updated by DEP, as needed, and provided to EPC.

(8) Evaluations and Audits. DEP will periodically conduct both program performance evaluations and financial audits of EPC's implementation of those programs or activities.

(a) Purpose of Evaluations. The purpose of the performance evaluations is to determine if permit application reviews, monitoring programs, mobile-source activities, compliance efforts, and enforcement actions are being effectively conducted in accordance with state requirements and DEP policies, and that appropriate records are being maintained for all delegated state permitting actions taken, and monitoring programs, enforcement actions, and other responsibilities assumed by EPC. After the effective date of this Air SOA, records shall be maintained by EPC for at least three years. As stated in Section 7.01 of the GOA, EPC will otherwise comply with the requirements of Chapter 119, F.S.

(b) Purpose of Audits. The purpose of the financial audits is to determine if state funds received by EPC for its air program have been properly accounted for and distributed, and that appropriate records of all monetary transactions are on file. After the effective date of this Air SOA, financial records shall be maintained for at least three years. As stated in Section 7.01 of the GOA, EPC will otherwise comply with the requirements of Chapter 119, F.S.

(c) Coordination. In those instances when EPC is subject to audit by a federal agency as well as the DEP, every effort will be made to fully coordinate the audits. EPC will have adequate time to complete any DEP preaudit surveys and to comment on draft DEP audit findings. Draft DEP audit findings will be provided to the EPC Air Staff for review before releasing for general distribution.

(d) Frequency. Evaluations and audits will normally be conducted on a biennial basis in accordance with the appropriate provisions of the GOA. DEP may conduct air program evaluations or audits more or less frequently, at the DEP's discretion. To the extent feasible and appropriate, DEP will consider the availability of the needed EPC air program staff when selecting specific dates for conducting on-site visits.

(e) Schedule. The ambient air monitoring quality assurance systems audits and the air program performance evaluations will normally be conducted between January and July with the final reports completed by October of that year. Other evaluations and audits will be conducted as needed.

(9) Contracts. DEP and EPC may enter into mutually agreeable contracts for work covered under this agreement (i.e., Title V, CFC, etc.)

PART III

HILLSBOROUGH COUNTY ENVIRONMENTAL PROTECTION COMMISSION RESPONSIBILITIES

(1) Basic Air Permitting Requirements. EPC is not required by Florida law to receive applications for, process, or issue state air permits in order to be approved by the Department as a DEP-approved county air program under Rule Chapter 62-209, F.A.C. Subsection 403.182(2), F.S., states that:

> The department shall have the exclusive authority and power to require and issue permits; provided, however, that the department may delegate its power and authority to a local pollution control organization if the department finds it necessary or desirable to do so.

EPC's requirements which are compatible with, stricter, or more extensive than DEP requirements, shall be included in a state air permit if the requirements apply to stationary installations or sources that are required to obtain state air permits; with the restriction stated in Subsection 403.182(7), F.S., that:

> If any local program changes any rule, regulation, or order, whether or not of a stricter or more stringent nature, such change shall not apply to any installation or source operating at the time of such change in conformance with a currently valid [air] permit issued by DEP.

(2) Air Permitting Relationships. Each DEP-approved local air program has one or more of the following working relationships with DEP.

(a) No Delegation. Where delegation has not been granted by DEP for certain types of air permits, then the EPC will not issue state air permits for those types of sources. However, EPC shall be provided a copy of the application and related correspondence as well as notice of DEP-proposed agency action on permit applications for these sources within EPC jurisdiction. Ample time will be given to the EPC to review and comment on these permit applications to the extent that EPC chooses to do so. The absence of delegation regarding certain types of air permits does not imply the inability of EPC to do the permitting work.

(b) Partial Delegation. Before granting full delegation to issue DEP permits, DEP may grant partial delegation over selected classes or categories of sources within EPC jurisdiction. Under partial delegation, EPC should receive air permit applications on behalf of DEP, process those applications, draft permits, and submit the draft permits to DEP for final review and signature.

(c) Full Delegation. Under full delegation, EPC will receive, process, issue the intent to issue or intent to deny, and take final agency action on behalf of DEP to issue or deny certain types of air permits within EPC jurisdiction, except when an administrative hearing pursuant to Chapter 120, F.S. is held. In such a case, the recommendation of the Hearing Officer will be referred to the Secretary of DEP for final issuance or denial of the permit.

(d) Keep DEP Informed. Regardless of whether EPC has full, partial or no delegation for issuing various types of state air permits, EPC is responsible for providing DEP with a current, complete copy of all local rules which pertain to air pollution control.

(e) EPC's Status. Before execution of this Air SOA, EPC had been granted partial delegation since 1982 regarding all air sources within Hillsborough County for which it is eligible to receive such delegation. Upon signature by both EPC and DEP for renewal of this Air SOA, EPC shall have full delegation, except for those facilities listed in paragraph (3)(a) below. Further, either on July 1, 1997, or after an affected facility receives their first Title V permit from the DEP, whichever occurs last, EPC will have full delegation of sources that belong to Major Group 26 and Major Group 28 as defined in the Standard Industrial Classification Manual, except for the specific industries noted under (3)(a)6 below.

(3) Delegation of District-Level Air Permitting. As of the effective date of this delegation (as specified below), EPC will receive, process, and act on applications for state air permits for which DEP has delegated district-level air permit issuance authority to EPC in accordance with the following general procedures and specific conditions.

(a) Effective Date and Limitations. Upon signature by both EPC and DEP for renewal of this Air SOA, DEP delegates to EPC the authority and the responsibility to receive, process and take final agency action on air permits within EPC jurisdiction that otherwise would be administered by DEP's Southwest District, except for the following permits or categories of air sources:

1. Electrical power plants and waste-to-energy facilities;

2. Permits for which local air pollution programs are precluded from taking final agency action under F.S. 403.0872 except as provided in subpart (2)(e) above;

3. County-owned or operated facilities' and facilities/operations whose owner/operator would be represented by county legal staff in enforcement action;

4. PSD and NSR permits other than those covered above; and

5. General permits for area sources.

6. Cargill Fertilizer, Inc. (NEDS 0008), CF Industries, Inc. (NEDS 0005), Coronet Industries, Inc. (NEDS 0075).

(b) Revocation. In the event that the DEP Secretary determines that EPC has failed to comply with the conditions of this delegation or any relevant part of this Air SOA, EPC will have a reasonable period, not to exceed 90 days from receipt of notification referencing this section, to take corrective measures. If, in the judgment of the DEP Secretary, EPC fails to take appropriate corrective measures within the time allowed, the DEP Secretary may revoke the delegation.

(c) Training. DEP will periodically meet with EPC's air permitting staff to keep them up-to-date on DEP's air permitting practices and requirements.

(d) Performance Evaluations. The Southwest District office will annually evaluate EPC's delegated air permitting activities. DEP may also conduct performance evaluations at random.

(e) Specific Condition of Delegation. In addition to the other provisions of this Air SOA regarding air permitting, EPC shall comply with the following specific requirements as a condition of maintaining this delegation:

1. The review of the permit applications and the drafting of the specific permit conditions shall be done under the supervision of a professional engineer licensed by the State of Florida. The supervising professional engineer shall provide professional engineering certification of all technical evaluations of permit applications as required by Florida law.

2. EPC shall comply with all applicable permitting provisions of the Florida Air

and Water Pollution Control Act, Chapter 403, Florida Statutes; all applicable permitting provisions of the Florida Administrative Procedures Act, Chapter 120, Florida Statutes; and DEP permitting and air pollution control rules.

3. EPC shall follow the written permitting procedures issued by DEP's Secretary and his/her legal and program directors.

4. EPC is authorized to make determinations of whether a source is exempt under DEP's permitting and air pollution control rules because an air pollution source has an insignificant effect on air quality or the natural environment. A copy of all correspondence related to such determinations will be mailed to DARM in Tallahassee and the Southwest District Office.

5. EPC shall use permitting forms adopted by DEP. The local air program may affix its name and logo on the forms.

6. EPC shall have full access to DEP's Air Resource Management (ARMS), and shall accurately and in a timely manner enter all permit-related data as permit applications are processed and as permits are issued or denied. For purposes of PATS, a timely manner is within one working day.

7. EPC shall have the legal resources to defend its permitting decisions in Administrative Hearings under Chapter 120, F.S., or any other legal proceedings. To the extent that DEP's technical or rule interpretation or guidance is at issue, DEP will assist, at its option, EPC in such proceedings.

(4) Non-Title V Permits. EPC shall process permit applications for all Non-Title V sources within the county's jurisdiction not specifically excluded in paragraph (3)(a) above in accordance with the following guidelines.

(a) Application Review Procedures

1. DEP Procedures. When DEP receives a permit application for an air source within Hillsborough County and for which permit issuance authority has been fully delegated, DEP will forward all copies of the application and the associated fees to EPC. EPC will ascertain whether the fees remitted are correct, and retain those for which permit delegation has been granted by DEP. Pursuant to Rule 62-4.050(5)(c), F.A.C., when the EPC receives the proper fee made out to EPC, the permit processing time requirements of Sections 120.60(2) and 403.0876, F.S., shall begin.

2. EPC Procedures.

a. EPC shall write a technical evaluation for each air construction permit application it processes. The evaluation shall include, as a minimum, a brief project description, a rule applicability determination, and a summary description of the allowable and actual emissions.

b. All permit conditions in any construction permit issued by DEP that would apply to the operation permit shall be included in any operation permit issued by EPC.

c. EPC shall have full authority to make determinations regarding the correct DEP permit fees on permits for which they have full delegation. All determinations will be made pursuant to F.S. 403.087 and Rule 62-4.050 and to any written guidance as issued by the DEP's Secretary or his/her legal and program directors.

d. Within five working days of receiving an application for a state air permit with appropriate fees, EPC will enter the appropriate information into the DEP's ARMS system.

e. Within 7 days of receiving the initial application EPC will provide the Southwest District office with one copy of the state air permit application as received.

f. When EPC determines that a fee is correct for an application that EPC is to process, EPC will promptly process the check. EPC will accept a check only for a state air construction permit or a Non-Title V air operation permit application that EPC is delegated authority to issue. Checks for non-delegated Non-Title V permit applications will be forwarded to DEP's district office. Checks for non-delegated permit applications made out to EPC will be returned to the applicant with instructions to the applicant to submit the package to DEP with the appropriate fee.

g. All checks for application fees for state permits which are delegated to the EPC and not made out to EPC will be promptly returned to the applicant, with a notice to resubmit the fee check to the EPC. Pursuant to Rule 62-4.060(5)(c), F.A.C., the permit processing time requirements will begin once the fee is properly received by the EPC.

h. If the amount of submitted fee for such an application is not correct, EPC will promptly notify the applicant, and resolve the matter in accordance with DEP's air permit fee rules (which may involve returning the application and any fee submitted to the applicant for correction and reapplication).

i. A copy of all correspondence related to a permit application will be kept on file by EPC. EPC will mail to DEP a copy of its proposed agency action on such permit application at the same time that EPC mails its intent to issue (or deny) to the applicant.

j. EPC will review each application for completeness within 30 days of receipt. If the application is determined to be incomplete, a letter of incompleteness will be sent by certified mail, return receipt requested, to the applicant by EPC identifying and requesting the needed additional information.

k. When the application is determined to be complete, EPC will process the application as expeditiously as possible, and take final agency action on behalf of DEP on the complete application in accordance with the procedures and time frames that would apply to DEP, if DEP were taking final action on the application. EPC will provide DEP with a complete copy of each state air permit issued and each air permit denial issued.

(b) Distribution of Permit Fees.

1. EPC may charge its own permit application fee schedule pursuant to its own rules and enabling legislation to the extent allowed by law. However, to further good government and to avoid duplication of fees paid by the regulated public, EPC agrees to charge a single fee for fully delegated permits.

2. Since acting on an application for a state air permit is not an activity that EPC is required by statute to do, to become or remain a DEP-approved local air program pursuant to Section 403.182, F.S., DEP and EPC agree that EPC should receive specific financial compensation from DEP to cover the reasonable cost of doing this work. Therefore, DEP shall allow EPC to keep 80% of the fees for fully delegated Non-Title V permits. The remaining 20% of the fees shall be returned to the DEP on a monthly basis. Said fees shall be delivered to the DEP in Tallahassee, Office of Finance and Accounting, Attention: Revenue, twenty days following the previous month and shall consist of a single check along with the attached record, "Permit Revenue Roster."

(c) Non-Title V Permitting Reporting Requirements. EPC will report its state air permitting activities to DEP by use of the following DEP reporting systems at the frequencies shown:

1. EPC will update ARMS for sources permitted by EPC. All such permit data will be put into ARMS by EPC within 30 days of permit issuance.

2. EPC will update ARMS for all applications received, permits processed, and issued or denied by EPC. All such information will be input into PATS within five working days of any air permit action.

3. EPC is responsible for any and all inquiries in relation to ARMS and PATS entries for which they are responsible for entering.

(5) Title V Permits. EPC shall process permit applications for all Title V sources within the county's jurisdiction not specifically excluded in paragraph (3)(a) above in accordance with the following guidelines.

(a) Application Review Procedures

1. DEP Procedures. When DEP receives a permit application for an air Title V source within Hillsborough County and for which permit issuance authority has been fully delegated, DEP will forward all copies of the application and associated information to EPC. Upon receipt, EPC shall process the application in accordance with Section 403.0872, F.S., and Rules 62-213.420 and 62-213.430, F.A.C.

2. EPC Procedures

a. Within five working day of receiving an application for a Title V state air permit application, the County will enter (upload) the appropriate information into DEP's ARMS system.

b. Upon completion of the Title V draft permit, the Title V permit application, draft permit and all pertinent material shall be sent to DEP in Tallahassee for review within the appropriate time frame as determined by DEP Title V implementation procedures.

c. Any checks for Title V annual emission fees submitted to the local program will be promptly returned to the applicant with a notice to submit the check directly to DARM, Tallahassee. A copy of the notice shall be provided to the Division of Air Resources Management, the Bureau of Air Regulation, the Title V Section.

d. A copy of all correspondence related to a permit application will be kept on file by EPC. EPC will mail to the Title V Section in DEP, a copy of its intended agency action at the same time that EPC mails its intended agency action to the applicant.

e. EPC will review each Title V operation permit application for completeness in accordance with Rule 62-213.420, F.A.C. If the application is determined to be incomplete, a letter of incompleteness will be sent by certified mail, return receipt requested, to the applicant by EPC identifying and requesting the needed additional information.

f. When the application is determined to be complete, EPC will process the application as expeditiously as possible, and take final agency action on behalf of DEP on the complete application in accordance with the procedures and time frames that would apply to DEP, if DEP were processing the application. EPC will provide DEP with a complete copy of each state air permit issued and each air permit denial issued.

(b) Title V Permitting Reporting Requirements. EPC will report its state air permitting activities to DEP by use of the following DEP reporting systems at the frequencies shown:

1. EPC will update ARMS for Title V sources/emission units permitted by EPC. All such permit data will be entered into ARMS by EPC within 30 days of permit issuance.

2. EPC will update ARMS for all applications received, permits processed, and issued or denied by EPC. All such information will be input into ARMS by the time that the draft permit is submitted to the Title V Section in DARM for review.

3. EPC is responsible for any and all inquiries in relation to ARMS entries for which they are responsible for entering.

(6) General Permits for Title V Area Sources. All General Permits for Title V area sources will be processed by DEP in Tallahassee. When EPC receives a General Permit Notification Form or fees for emissions within the county, the notification form and/or fees will be promptly returned to the applicant with a notice to submit the application and check directly to DARM, Tallahassee. A copy of the notice shall be provided to the Bureau of Air Monitoring and Mobile Sources in DARM.

(7) Non Delegated Permits. EPC will assist DEP in the processing of applications for state air

permits for which it is excluded from delegation under paragraph (3)(a) above.

(a) DEP's Application Review Procedures. When DEP receives an air permit application for a source which DEP is to take final agency action, DEP will (within three working days) forward one copy to EPC for review and comment. DEP will provide EPC with sufficient opportunity to comment on the completeness of each such permit application, as well as to recommend issuance or denial. All associated incompleteness letters, intents to issue or deny, and any permits issued will be prepared and signed by DEP staff. To the extent possible, DEP will attempt to share drafts of proposed agency actions with EPC prior to taking proposed action. At a minimum, EPC will be provided with a copy of any notice of DEP-proposed agency actions within 7 days of such notices. DEP will provide EPC with a complete copy of each state air permit (or denial order) it issues for an air source within Hillsborough County.

(b) EPC's Application Review Procedures.

1. When EPC receives an application for a non-delegated state air permit for which DEP is to take final agency action, EPC will retain one copy and forward the remaining copies to DEP, along with any attendant fees, within three working days of receipt.

2. Within 22 days of receipt, EPC will review the application for completeness and notify DEP of any information that EPC would like to see addressed. If the application is ruled to be complete, based on the initial submission, then EPC may forward any information and recommendations on the permit to DEP by the 45th day. For construction permits and for operation permits for which a public notice is required, or was given, EPC may comment to DEP on the intent to issue or deny within the time frame specified in the public notice.

(c) Conflict Resolution. Although DEP has the responsibility for decisions on final agency action for all applications for non-delegated state air permits, and for all delegated permits for which a state administrative hearing is held, an effort will be made to reach an acceptable agreement if a conflict arises between EPC and DEP with respect to permit issuance or denial.

(8) Administrative Hearings and Final Agency Actions. All air permits received, processed, and acted upon by EPC on behalf of DEP will be accomplished in accordance with the appropriate state laws and DEP rules.

(a) Permit Appeals. All delegated air permitting decisions made by EPC shall be subject to the provisions of the Florida Administrative Procedure Act, Chapter 120, F.S., as if these decisions had been made by DEP. All timely petitions for formal administrative hearings on delegated air permitting applications processed by EPC shall be referred to the Division of Administrative Hearings (DOAH) for the assignment of hearing officers, if the petitions are submitted pursuant to Chapter 120 F.S. and satisfy the requirements set forth in the applicable rules of DEP. At the time of referral of a petition to DOAH, a copy of the notice of referral, the petition, and the challenged permitting decision shall be mailed to DEP's Office of General Counsel at Twin Towers Office Building, 2600 Blair Stone Road, Tallahassee, Florida 32399-2400. DEP shall have the right, if it so chooses, to intervene in the DOAH proceeding. For all hearings challenging agency action on delegated air permits, EPC shall be responsible for preparation for the hearings, appearance at the hearings, and the preparation and submittal of the proposed recommended orders to the assigned hearing officers. Prior to all final hearings, EPC attorneys shall consult with DEP attorneys regarding significant issues. All recommended orders resulting from such DOAH proceedings shall be referred to the DEP Secretary for final agency action. Exceptions and responses to exceptions shall be filed with the DEP's Office of General Counsel within the times set forth in the applicable DEP rules. Appeals of final orders entered following an administrative appeal hearing shall be the responsibility of EPC. DEP will collaborate with EPC to the extent practicable on appeals of final orders.

(b) Interpretation of Rules. Legal interpretation of DEP rules shall be made by DEP. Legal interpretation of EPC rules shall be made by EPC. If, in the course of processing air permitting applications, the interpretation of a DEP rule becomes an issue, the EPC permit processor shall consult with DEP to determine the appropriate regulatory interpretation. If DEP is enforcing EPC rules, then DEP shall consult with EPC concerning the appropriate regulatory interpretation. In the event that there is litigation concerning the interpretation of DEP's rules, then DEP shall provide testimony concerning the interpretation of those rules. To the extent that litigation involves interpretation of EPC rules, EPC shall provide testimony concerning the interpretation of those rules.

(9) Title V and Non-Title V Stationary Source, and Title V Area Sources Air Compliance and Enforcement. DEP and EPC shall conduct air compliance and enforcement activities as follows:

(a) EPC's Authority. Pursuant to EPC's independent statutory authority to regulate air pollution within the county, EPC may inspect the same sources that DEP conducts compliance inspections for, and may conduct inspections of any source of air pollution more frequently than DEP. EPC may also conduct air compliance inspections for DEP on a source-by-source basis when requested to do so by DEP.

Lead Role: EPC shall be the lead agency for all air compliance and enforcement actions in Hillsborough County, except where prohibited by statute.

(b) EPA and DEP Compliance Inspections. DEP may conduct periodic air compliance inspections of utility power plants, municipal waste-to-energy facilities, phosphate plants, county-owned facilities, and other selected sources of air pollution in Hillsborough County. The EPA conducts similar periodic air compliance inspections of these types of air sources throughout Florida and all other states. The results of the DEP compliance inspections, and EPA inspections, when available to DEP, will be made available to EPC.

(c) Complaint Investigations. EPC may conduct complaint investigations concerning any potential source of air pollution within Hillsborough county, pursuant to its own authority or for DEP, upon request.

(d) EPC Enforcement Actions and Inspections. EPC may initiate air enforcement actions to correct detected violations pursuant to its own statutory authority, or for DEP upon permitting delegation or upon request. This includes inspection of certified electrical power plants, Cargill Fertilizer, Inc. (NEDS 0008), CF Industries, Inc. (NEDS 0005), and Coronet Industries, Inc. (NEDS 0075).

(e) Inspections by DEP. Pursuant to Subsection 403.182(6) F.A.C., DEP may inspect any air pollutant emitting facility or initiate enforcement against any such entity in Hillsborough County. Unless circumstances make notice inappropriate, DEP will provide prior notification to EPC.

(f) Following EPA Timely and Appropriate Guidelines. EPC agrees to follow the EPA Timely and Appropriate guidelines stipulated in the *Florida Air Enforcement Penalty Guidance* in response to significant violators.

(g) Exchange of Information. All complaints, results of inspections, results of laboratory analyses and other such material in the possession of EPC shall be made available to DEP upon request or as otherwise specified in this Air SOA (or its amendments or attachments).

(h) Concurrent Action. It is agreed that EPC will assume the enforcement lead for violations of federal, state, and local air pollution regulations within Hillsborough County. EPC will routinely discuss its enforcement actions with DEP. If discussions with EPC reflect that EPC is resolving the violation in a timely and appropriate manner as prescribed by EPA or DEP, DEP will continue to defer enforcement to EPC. If EPC is unable to resolve the violation in a timely or appropriate manner as prescribed by EPA or DEP, DEP will advise EPC of its intent to proceed with its own action. EPC will continue to provide the necessary support for DEP's action as requested. A joint or consolidated enforcement action will be considered as an alternative to a unilateral DEP action, where feasible. If enforcement actions are initiated by DEP and EPC against the same source for the same violations, then the actions should be combined as a joint or consolidated enforcement action where possible. EPC retains the right to resume an independent enforcement action should DEP fail to resolve the violation.

(i) Enforcement Guidelines. EPC penalty assessment guidelines incorporated in the most recent State/EPA Enforcement Agreement will be followed by EPC and will serve as the basis of EPC enforcement actions with respect to local, state, and federal air pollution control requirements. EPC will maintain all penalty calculations for each enforcement action in the appropriate enforcement file, and will provide information regarding those calculations to DEP upon request. Should DEP determine that inconsistencies exist, EPC will review its guidelines and work with DEP to correct those inconsistencies.

(j) EPA/DEP Air Enforcement Agreement. EPC will initiate appropriate enforcement action with respect to DEP rules in accordance with the current EPA/DEP Air Enforcement Agreement (when it applies) or other applicable EPC air enforcement policies. It is recognized that the EPA/DEP Air Enforcement Agreement is renegotiated annually.

(k) Coordination. Nothing in this agreement shall prohibit either DEP or EPC from taking enforcement action for violations of their respective rules. However, EPC must notify DEP of any action it intends to pursue under Section 403.161, F.S., when such action is initiated against a permitted source or a source requiring a DEP Air permit.

(10) Specific Compliance Monitoring of Stationary Sources. The following specific compliance monitoring activities will be conducted by EPC in cooperation with or for DEP, if requested:

(a) Conducting Stack Tests. Whenever DEP plans to conduct a stack test within the county, EPC will be notified as far in advance as practical. EPC will assist DEP in making necessary arrangements to conduct the test. DEP will be responsible for providing the air source owner with any advance notice of the test that is to be given.

(b) Reviewing Stack Tests. A summary of each stack test reported to DEP or EPC will be reviewed within 30 days of receipt, and entered into the ARMS data system by the receiving agency within 90 days after receiving the report. The receiving agency is not required to send copies of routine data to the other agency, unless requested. As part of its responsibility to monitor the compliance status of stationary sources of air pollution in the county, EPC will review each third-party stack test received on sources for which the local program is responsible, and check each for completeness, accuracy of results, and compliance with applicable DEP rules. EPC will notify the source owner of the findings of its review within 60 days of receipt of the test results, and will provide an information copy of the letter of notification to DEP's Southwest District, if requested.

(c) Sampling of Fuels and Materials. EPC will collect or assist DEP in collecting and analyzing fuel and material samples for air sources within the county, as needed, to determine compliance with DEP's air pollution control rules or permit conditions.

(d) Asbestos Compliance. EPC will conduct National Emission Standard for Hazardous Air Pollutants (NESHAP) asbestos inspections and initiate appropriate enforcement action within Hillsborough county in a manner that is consistent with state requirements and DEP guidelines on administering the NESHAP asbestos program.

(e) Gasoline Marketing and Distribution. EPC will assist DEP in ensuring compliance with DEP's volatile organic compound (VOC) air rules that apply to gasoline marketing and distribution facilities located within the county, as time and resources allow.

(f) Storage Tanks (Above and Below Ground). EPC will coordinate and implement a program to assure compliance by the owner or operator of all storage tanks (VOC and other chemicals or compounds) within the county with the requirements of DEP's air rules or air permit conditions.

(g) Open Burning and Frost Protection Rule. EPC shall enforce the provisions of Rule 62-256, F.A.C., and its complementary Chapter 1-4, Rule of EPC, and to coordinate with the Division of Forestry, the County Fire Department and the County Sheriff's Department. The DEP shall be provided copies of any agreements and any other case specific information upon request.

(h) Biological Waste Incineration Inspections. EPC shall enforce the provisions of 62-296.401, 62-297.330, and 62-297.500, F.A.C., for biological waste incinerators. EPC will conduct on-site inspections on a quarterly basis of biological waste incinerators. EPC shall maintain written reports of inspections findings using a report format previously approved by DEP. EPC shall proceed with compliance and enforcement action using the EPC penalty matrix for assessing penalties when violations occur.

(11) Stationary Source Compliance Monitoring Procedures. Compliance monitoring shall be done according to procedures established by applicable federal and state statutes, rules, and guidelines at frequencies required therein or as specified in the appropriate facility permit. Associated quality assurance/quality control techniques shall be followed.

(a) Stationary Facilities. EPC will conduct periodic on-site inspections of major and selected minor facilities and area sources which are subject to DEP air rules or air permit conditions. The frequency of these inspections will be established annually based on negotiations between EPC, DEP and, when appropriate, EPA. The established inspection frequency will be specified in the appropriate 105 Air Grant work plan or other written document agreed to by the parties involved.

(b) Continuous Emissions Monitoring Systems (CEMs). EPC will receive Excess Emissions Reports for air pollution sources located in Hillsborough County on behalf of DEP. EPC will review each Excess Emissions Report for completeness and results. Within 60 days of receipt, EPC will send a letter to the air source owner (or operator) in reply to each such Excess Emissions Report. The reply will acknowledge receipt of the Excess Emissions Report, identify any deficiencies, and request any needed additional information. EPC will provide the DEP's Southwest District with a copy of such reply if requested. All subsequent correspondence about the Excess Emissions Report will be maintained on file by EPC. Any appropriate follow-up action on the report will be initiated by EPC, ranging from a request for additional information to initiating formal air enforcement action. EPC is responsible for monitoring compliance with appropriate quality assurance procedures for continuous emission monitors (CEMs) that are required by federal or state rules. Copies of Excess Emission Reports will be provided by DEP or EPC to the other agency upon request.

(12) Stationary Source Reporting Requirements. Compliance verification data will be entered into the following DEP data bases as specified below:

(a) ARMS. Updating DEP's Air Program Information System (ARMS) for compliance data, continuous emissions monitoring data, and test results will be the responsibility of EPC. All applicable inspection and source compliance activity data (i.e., NSPS, NESHAP, major source, synthetic minor source, minor source, area source and asbestos renovation/demolition data) shall be entered into ARMS no later than the 10th of the month following any federally reportable action during the previous month. For all Title V facilities not otherwise covered, compliance data shall be entered into ARMS no later than 30 days following the month the action was complete. Continuous Emissions Monitoring (CEM) data shall be entered no later than 45 days after receipt; stack test results no later than 90 days after receipt.

(b) Data to EPA. DEP will receive copies of any case-specific air compliance and enforcement data that is submitted directly to EPA by EPC.

(13) Mobile Source Control Requirements. EPC will coordinate its efforts with DEP in developing a mobile source control program for Hillsborough County.

(a) Coordination. EPC will coordinate the transportation air quality control activities within Hillsborough county with DEP's Southwest District and with DEP's Mobile

Source Control Section. Such coordination will include, but not be limited to, the following activities: Development of Regional Impact (DRI) reviews, public information presentations, and Metropolitan Planning Organization (MPO) Technical Coordinating Committee activities.

(b) Metropolitan Planning Organization (MPO) Committee Membership. EPC will seek to maintain its status as a voting member of the MPO Technical Coordinating Committee(s) within its area. EPC will also be active in the state, county, and local community transportation planning process and will participate in DEP-sponsored mobile source meetings, public information presentations, and training sessions, as time and resources allow.

(c) Reporting Requirements. EPC and DEP's Mobile Source Control Section will provide each other with mobile source program status reports as needed.

(d) DEP/EPA Memorandum of Understanding (MOU). EPC will act for DEP within the county for the purpose of implementing the EPA/DEP Memorandum of Understanding (MOU) concerning the investigation for enforcement of EPA's misfueling and anti-tampering rules in Florida as time and resources allow.

(e) DEP Mobile Source Control Program. EPC will assist DEP and the Department of Highway Safety and Motor Vehicles (DHSMV) in implementing Florida's Clean Outdoor Air Law (COAL) in Hillsborough County, as resources allow. EPC and DEP will develop specific agreements or contracts with each other or with DHSMV, as appropriate, to define the specific work that EPC will do for or with DEP or DHSMV, and what compensation, if any, will be provided by DEP or DHSMV for such work.

(f) Mobile Source Compliance Monitoring Procedures. EPC shall enforce the provisions of Section 1-8, Rule of EPC (with the exception of those identified in Part I, (6)), the complementary provisions of Rule 62-243, F.A.C., and pursue enforcement of violations of applicable federal, state, or local rules. Compliance monitoring shall be done according to procedures established by applicable federal, state, or local rules. The frequency and distribution of compliance monitoring activities shall be established annually by the EPC, and will include inspections of motor vehicle sale/re-sale lots, motor vehicle repair facilities, fleets, parts distributors, and service stations. A minimum of one hundred (100) mobile source compliance inspections will be conducted annually. Concerning the inspection of motor vehicle sale/re-sale lots, on each lot, at least twenty (20) percent of the vehicles offered for retail sale shall be inspected, or at least ten (10) vehicles if available, whichever is greater.

EPC agrees to respond to and investigate tampered vehicle complaints in accordance with the DEP-EPA Memorandum of Understanding. This will require one or more EPA certified inspectors.

EPC shall assist with the education of law enforcement officers to enforce the highway portion of Rule 62-243, F.A.C., which prohibits operating a tampered motor vehicle on Florida streets and highways, and with Rule 62-244, F.A.C., which prohibits visible emissions from the exhaust of motor vehicles. Monthly reports of such activities shall be submitted to the Southeast District Office.

(14) Citizen Complaints. EPC will receive, respond to, and investigate complaints from citizens relating to air pollution within Hillsborough County. Citizen complaints will be investigated in a timely fashion. Records will be kept of all complaints.

(a) Referral of Complaints from DEP to EPC. DEP will refer any complaints that it receives about air pollution situations within Hillsborough County to EPC for investigation. However, DEP reserves the right to investigate certain complaints at its own discretion but will provide notice to the EPC (e.g., complaints involving sources for which DEP has a special interest). Results of DEP investigations will be made available to EPC upon request.

(b) Response by EPC. If a violation of a local, state or federal air standard, rule, or permit condition is determined to have occurred, EPC will notify the responsible person, attempt to bring about compliance, and inform the complainant of the action taken. EPC will take enforcement action in accordance with this Air SOA.

(15) General Information Requests. EPC will answer telephone inquiries and written requests from individual citizens, the news media, and other organizations for general information about air pollution or about specific program activities or air pollution situations. As time and resources allow, EPC employees will speak to schools, civic groups, and other interested organizations when requested to do so. Inquiries about DEP air rules which require interpretation and guidance will be referred to DEP for reply.

(16) Ambient Air Monitoring Programs. EPC will be responsible for calibrating, operating, maintaining, and repairing all ambient air monitoring, calibration, and data acquisition equipment utilized in the National Air Monitoring Station (NAMS), State and Local Air Monitoring Station (SLAMS) and Special Purpose Monitoring (SPM) networks within Hillsborough County. EPC will also be responsible for operating and maintaining a laboratory, or contracting for laboratory services to perform any needed analyses of air samples, and operating any Episode Monitoring Sites (EMS) designated for the county and approved by EPA. Special Purpose Monitoring desired by EPC will be the responsibility of EPC. Special Purpose Monitoring desired by DEP will be negotiated between the two agencies and will be based on the availability of equipment, staffing, and funding.

(a) Coordination. Other than for routine day-to-day operational functions, EPC will coordinate its ambient air monitoring activities with DEP. Program decisions requiring EPA approval, such as the addition, deletion, or relocation of a monitor or the exclusion of NAMS/SLAMS data, will be submitted to EPA through, and with the approval of, DEP's Bureau of Air Monitoring and Mobile Sources (BAMMS).

(b) Air Monitoring Procedures. All NAMS and SLAMS ambient air monitoring activities conducted by EPC will be performed in accordance with applicable federal regulations and the Statewide Quality Assurance Air Program Plan, using EPA and DEP-approved standard operating procedures. BAMMS will provide technical assistance to EPC, to the extent that BAMMS resources allow.

(c) Data Automation. EPC will obtain and maintain data automation equipment that can communicate with, and be linked to, DEP's computer system. EPC will expeditiously enter and verify all valid data into this system in accordance with technical guidelines provided by DEP's Air Monitoring Section.

(d) Forms. EPC will use EPA's Aerometric Information Retrieval System (AIRS) data forms or formats, as well as other DEP or EPA-required or approved forms or formats for ambient air monitoring activities as necessary.

(17) Ambient Air Monitoring Quality Assurance Program. EPC will coordinate all air monitoring quality assurance activities with DEP.

(a) Quality Assurance Procedures. EPC will conduct all ambient monitoring activities in accordance with the Statewide Quality Assurance Air Program Plan, incorporated herein by reference. This includes use of DEP Standard Operating Procedures (SOPs), which include approved EPC SOPs that have been incorporated into DEP's SOPs, and all applicable state and federal regulations and policies to ensure the acceptability of analytical results.

1. All EPC air monitoring SOPs must be approved by DEP's Air Quality Audit Section and EPA, and be incorporated into the Statewide Quality Assurance Air Program Plan, before they are used for operational purposes, except as may be provided for in the current version of that plan. BAMMS will provide quality assurance standards laboratory services on request, as resources allow. BAMMS will provide other technical assistance to EPC as resources allow.

2. EPC will participate in Florida Air Monitoring Advisory Committee meetings and assign one individual as the coordinator for their program. EPC will participate in other quality assurance meetings as needed and as resources allow.

(b) Systems and Instrument Performance Audits. EPC will participate in the annual EPA National Performance Audit Program for all criteria pollutants for which audit devices or samples are available. BAMMS will conduct an annual ambient air monitoring systems audit for EPC and utilize the process outlined in the "Quality Assurance Systems Audit Protocol." As resources allow, BAMMS will accomplish performance audits on continuous NAMS/SLAMS instruments to meet minimum federal regulations. Notice will be given if DEP is unable to continue conducting the continuous instruments performance audits. EPC will be responsible for conducting performance audits on manual samplers.

(18) Reporting Requirements.

(a) Ambient Air Data Reporting Requirements. EPC will enter all valid ambient air data collected each month into DEP's computer system according to the schedule given below. EPC will also adhere to the schedules given below for submitting missing data forms and for verifying data.

1. EPA's Aerometric Information Retrieval System (AIRS) ambient monitoring data are to be transmitted to DEP by the 20th day following the month of record for unverified data, or by the 30th day for verified data.

2. Missing data forms are to be submitted to DEP by the 20th day following the month of record for unverified data, or by the 30th day for verified data.

3. All data are to be verified in DEP computer or, if entered in verified form, checked to ensure that all data were transmitted without errors, and the verification screen is to be transmitted to DEP by the 50th day following the quarterly period of record.

4. EPC will notify DEP upon changing its data entering format from entering verified data to entering unverified data or from entering unverified data to verified data.

(b) Quality Assurance Reporting Requirements. EPC will use DEP-approved forms and will comply with DEP reporting guidance when submitting data and performing ambient air monitoring and quality assurance activities.

1. All Precision and Accuracy Data (PA Data) will be submitted to DEP's Air Quality Audit Section within 30 days after the end of the quarterly reporting period.

2. National Performance Audit Program participation results will be reported to

DEP's Air Quality Audit Section Administrator within two weeks after receipt of the results from EPA. Notification of participation will be reported on DEP's "Air Quality Assurance Monthly Submittal" form.

(19) Air Program Information System or Air Resources Management System (ARMS). EPC will access ARMS and DEP will assure sufficient availability of on-line time to accomplish the various updates required under this Air SOA. EPC will also designate an individual to serve as the agency's ARMS contact. EPC will be responsible for maintaining the ARMS users' manual, distributing information on ARMS revisions to all ARMS users in the agency, and notifying the ARMS coordinator in DEP of any systems-related problems or training needs that exist within the agency.

(20) Emission Inventories.

(a) Stationary Sources. Annual Air Operation Report data for Title V facilities and synthetic non-Title V facilities will be verified and entered into ARMS by July 1 of each year.

(b) Mobile Sources. In cooperation with the Metropolitan Planning Organizations (MPO) and the Florida Department of Transportation (FDOT), EPC will update the emissions estimates for mobile sources in Hillsborough County as required by the EPA-approved State Implementation Plan or EPA 105 Air Work plan.

(c) Area Sources Inventories. EPC will update the emissions estimates for area sources in Hillsborough County as required by the EPA-approved State Implementation Plan or EPA 105 Air Work plan.

(d) Special Emission Inventories. EPC will assist the DEP in preparing special emissions inventory reports for support of rule making and special projects.

(21) Air Pollution Emergency Episodes. DEP and EPC agree to coordinate and cooperate fully with respect to responding to emergency situations. The announcement, implementation, and enforcement of activities required to deal with an air pollution episode is the responsibility of DEP. EPC will submit relevant air quality data to DEP in a timely manner as soon as an air episode appears to be developing.

(a) Emergency Episode Action Plans. DEP will prepare and periodically review Emergency Episode Action Plans. It will also provide EPC with a copy of the plans, and notify EPC when curtailment action is to be initiated.

(b) Episode Declaration. DEP agrees to coordinate declaration of an air pollution episode with EPC. An air pollution episode can only be declared by DEP's Secretary, in accordance with the Florida Administrative Code.

(c) Implementation. EPC will maintain source surveillance during an episode and will report data on episode levels (ambient air quality data) to ensure compliance with the Emergency Episode Action Plan. EPC may communicate with any source operator within its jurisdiction during an episode; however, DEP will take the leading role in communicating any emission reduction requirements to affected air source owners within the county, and will advise EPC of such communications.

(22) Accidental Air Pollution Emissions. EPC will coordinate and cooperate with DEP and all other state and local agencies involved in accidental air pollution emissions that may be toxic or otherwise hazardous to public health and welfare. EPC will coordinate with any interested agency in any such accidental air emissions incident.

(23) State Implementation Plan (SIP) Revisions. EPC will coordinate with and assist DEP in the preparation and submittal to EPA of all SIP revisions which may affect EPC. DEP will be responsible for determining the need and relative priority for SIP revisions. EPC will periodically inform DEP of SIP revisions that should be considered and that EPC is willing to support.

(24) Proposed Federal Air Rules. EPC will copy DEP, and vice versa, on all responses to proposed federal air rules published in the Federal Register.

(25) Interpretation of Laws, Ordinances, Rules and Regulations. The governmental agency responsible for promulgating the original law, ordinance, rule or regulation will be the primary interpretative authority.

(a) EPA Regulations. EPA will interpret regulations which it originates such as NAAQS, NSPS, and NESHAP.

(b) DEP Rules. DEP will interpret the basic permitting rules adopted in Rules 62-100 through 62-199, and the air pollution control and related administrative rules adopted in Rules 62-200 through 62-299, F.A.C., except for federal rules adopted verbatim or by reference.

(c) EPC Rules. EPC will interpret rules locally adopted, other than EPA or DEP rules adopted verbatim by reference. If EPC intends to apply an EPA or DEP rule in a more stringent way than intended by the originating agency, EPC must adopt the subject rule along with its intended interpretation as a local rule. After such adoption, the rule must be submitted to DEP, as set forth in Section 6 of Part I above. The same general principle will be observed with respect to EPA-originated rules.

(d) State Implementation Plan (SIP) Revisions. SIP revisions developed by DEP are considered state-originated rules, except when EPA language is used verbatim.

(e) Requests for Interpretations. All requests for interpretation will be answered as expeditiously as possible by the originating agency. Requests for an interpretation of a DEP rule or related procedural or administrative rule, are to be referred to DEP, in writing. Requests for an interpretation of any local rule or ordinance are to be referred to EPC, in writing.

(26) Air Toxics Program. EPC will assist DEP in the development and in the implementation of a toxic air pollutant program for the State.

HILLSBOROUGH COUNTY ENVIRONMENTAL PROTECTION COMMISSION	STATE OF FLORIDA DEPARTMENT OF ENVIRONMENTAL PROTECTION
ROGER P. STEWART EXECUTIVE DIRECTOR	VIRGINIA B. WETHERELL SECRETARY
DATE: 12/13/95	DATE: 12·21·95

LIST OF ATTACHMENTS

1. EPC Organizational Charts

2. Schedule of Reports

3. Permit Revenue Roster

Air Management Division

Environmental Protection Commission

of Hillsborough County

as of November 16, 1995

- Air Division Director/39 I. Choronenko
  - Executive Sec./13 C. Green
    - Senior Sec./89 M. Howell
    - Senior Sec./99 B. Martin
  - Enf. Ops Sup. Senior. Env. Enf..Spec./65 K. Strother
    - Env. Enf. Spec. I/103 T. Berkulis
    - Env. Spec. II/28 M. Liebner
  - Tech Air Ops Asst. Dir./34 A. D'Aquila
    - Tech Ops Env. Spec.III/49 T. Payton
      - Env. Spec. II/146 M.Cummings
      - Env. Spec.I/90 R. Clark
    - MSO Env. Spec.III/09 M.Blount
      - Env. Spec.II/93 P. Cooper
        - Env. Spec. I/26 P. Shell
        - Env. Spec. I/172 B. Broer
      - Env. Spec.II/31 R. Sanford
    - Amb. Mon. Env. Spec. III/05 T. Tamanini
      - Elec. Tech. III/12 L. Nye
        - Elec. Tech. II/43 J. Dobbs
        - Elec. Tech.II/51 W. Fonda
        - Elec. Tech.I/169 R. Nichols
        - Elec. Tech.II/07 C. Lopez
        - Elec. Tech.I/170 M. Groves
        - Elec. Tech.II/37 M. Dix
      - QA/QC Env. Spec.II/68 G. Frater
        - Env. Spec. I/100 J. Criswell
  - Air Engineering Asst. Dir./115 J. Campbell
    - AT/Prgm Dev. Sr. Eng./006 L. Deken
      - Eng. II/143 B. King
      - Eng. I/75 J. Ouellette
      - NESHAP Env. Spec. II/11 N. Janis
      - Env. Spec. I/92 G. Brown
    - Air Permit P.E. II/29 R. Kirby
      - Eng. II/64 B. Kalra
      - Eng. II/173 C. Gonzalez
      - Eng. I/117 (vacant)
      - Eng. I/40 A. Harman
      - Env. Spec. I/91 K. Boyette
    - Compliance Sr Eng./86 S. Woodard
      - Eng. II/101 L. Shelton
      - Eng. I/145 N. Morera
      - Eng. I/159 (vacant)
      - Eng. I/41 C. Bruno
      - Env. Spec. I/118 R. Delgado

Printed on 11/17/95

SCHEDULE OF REPORTS

Report Title	Report Sent To	Data Maintained In	Frequency	Data Submitted	Purpose
Permitting Records	DEP	ARMS	Within 30 days of permit issuance	Electronically	Maintain source population
Compliance Inspection Records	DEP	ARMS	By the 10th of each month	Electronically	Maintain source inspection
Stack Test Results	DEP	ARMS	Within 90 days of receipt	Electronically	Maintain source test data
Permit Application Processing	DEP	ARMS	Within 5 working days	Electronically	Track applications for State permits
Source Compliance Activity Report	DEP	ARMS	By the 10th of each month	Electronically Hard Copy	Report on federally reportable violations
Asbestos Report	DEP	ARMS	By the 10th of each month	Electronically	Report on transitory asbestos projects
Continuous Emission Monitoring Data (CEM)	DEP	ARMS	Within 75 days following the calendar quarter	Electronically	Maintain CEM Data
Mobile Source Summary	DEP	PC	Monthly or as otherwise specified by DEP	Hard Copy	Program Status Report
Missing Data Report	DEP	Files	Monthly	Hard Copy	Summary of missing data from network

SCHEDULE OF REPORTS

Report Title	Report Sent To	Data Maintained In	Frequency	Data Submitted	Purpose
Edited SAROAD Data File	DEP	Sumx	Monthly	Electronically	Edited Air Monitoring data
PA Data Report	DEP	Files	Quarterly	Electronically	Information on Data Precision and Accuracy
Exceedance Report	DEP	Sumx SAROAD	As required	Hard Copy	Summary
Excess Emissions	DEP	ARMS	Annually	Electronically	Excess emissions report for SIP and NSPS CEM's
Planned Program Accomplishments	EPA		90 days following the quarter	Hard Copy	Information for grant requirements/ validation
NEDS	DEP	ARMS	Annually	Electronically	Report emission inventory for major stationary sources through ARMS
Audit Program	EPA		Semi-Annually	Hard Copy	Report on Methods 6, 7, 8, 18, 23, 25 and 26 audit results

SCHEDULE OF REPORTS

Report Title	Report Sent To	Data Maintained In	Frequency	Data Submitted	Purpose
Air Grant and Tag Fee Audit Questionnaire	EPA	Files	Annually	Hard Copy	Status of Air Program and PPA's; Audit Preparation
Expenditure Report (Air Grant)	EPA	N/A	Annually	N/A	CEL
Other Compliance Activity Reports	DEP	ARMS	Within 30 days of the month of the action	Electronically	Track all other compliance activities
Title V Activities Report and Invoice	DEP	N/A	Quarterly	Hard Copy	Title V Contract Monitoring
Expenditure Report (Tag Fee)	DEP	N/A	Annually	N/A	CEL
EPA Data Transfer	DERM		Quarterly	Hard Copy	Inform DERM of stationary source permitting, compliance and enforcement data submitted to the EPA on the behalf of EPC

PERMIT REVIEW ROSTER

COUNTY NAME ______________________________
AIR PERMIT FEES COLLECTED FOR THE MONTH AND YEAR OF__________

Permit Number	Applicant Name	AO or AC	Permit Subtype	Total Fee

Total = __________

(State's Portion) 20% = __________

Submit to:
Supervisor of Revenue
Finance & Accounting
Department of Environmental Protection
2600 Blair Stone Road
Tallahassee, Florida 32399

Page ___ of ___

Current TECO Big Bend Permits

old id	new id	permit no.	Name	Description		Nameplate rating	emission point
1		29-219924	Unit No. 1	4037 MMBTU/hr coal-fired steam generator	"wet" bottom boiler manf. by Riley Stoker Corp. opposed-fired turbo boiler	445.5 MW	Shared stack with unit 2
2		29-179912	Unit No. 2	3996 MMBTU/hr coal-fired steam generator	"wet" bottom boiler manf. by Riley Stoker Corp. opposed-fired turbo boiler		dry ESP
3		29-179911	Unit No. 3	4115 MMBTU/hr coal-fired steam generator	"wet" bottom boiler manf. by Riley Stoker Corp. opposed-fired turbo boiler	445.5 MW	dry ESP
4		PSD-FL-040	Unit No. 4	4330 MMBTU/hr coal-fired steam generator			
7		29-160257	CT 1	integrated simple cycle, single shaft, 3 bearing fired w/ no. 2 fuel		16 MW	
5		29-174596	CT 2	integrated simple cycle, single shaft, 3 bearing fired w/ no. 2 fuel		77 MW	peaking & emergency only
6		29-174611	CT 3	integrated simple cycle, single shaft, multi-bearing fired w/ no. 2 fuel		78 MW 70.4	peaking & emergency only
8		29-160255	Flyash Silo #1 Baghouse	Serving units 1 & 2			
18		"	Flyash Silo # 1 Truck Loadout	Serving units 1 & 2			
9		29-161082	Flyash Silo #2 Baghouse	Serving units 1, 2 and/or 3, only two units at any time			
19		"	Flyash Silo # 2 Truck Loadout	Serving units 1, 2 and/or 3, only two units at any time			
15		29-163788	Unit 1 coal bunker				Roto-Clone
16		"	Unit 2 coal bunker				Roto-Clone
17		"	Unit 3 coal bunker				Roto-Clone

10 BIG BEND COAL YARD PA79-12 PSD-FL 040
11 TUCK UNLOADING OF LIMESTONE
12 LIMESTONE SILO W/2 BAGHOUSES (1 IS 100% BACKUP)
13 " " 'B' "
14 FLYASH SILO FOR UNIT #4

CT #1 : $173 \times 10^6 \frac{Btu}{hr}$ vs. $\frac{3413 \frac{Btu}{hr} \times 10^3}{MW} \times 16\ MW = 54.6 \times 10^6 \frac{Btu}{hr}$

#2 $950 \times 10^6 \frac{Btu}{hr}$ vs. $\frac{3413 \frac{Btu}{hr} \times 10^3}{MW} \times 77\ MW = 262.8 \times 10^6 \frac{Btu}{hr}$

#3 $950 \times 10^6 \frac{Btu}{hr}$ vs. $\frac{3413 \frac{Btu}{h} \times 10^3}{MW} \times 70.4\ MW = 240.3 \times 10^6 \frac{Btu}{hr}$

$\times 78\ MW = 266.2 \times 10^6 \frac{Btu}{hr}$

N:\OPAPM\DATA\HISPMT

excel OFFICE

401HC270039

1996 TEN-YEAR PLAN
STATE OF FLORIDA

FLORIDA ELECTRIC POWER COORDINATING GROUP, INC.

UTILITIES' EXISTING GENERATING FACILITIES
AS OF JANUARY 1, 1996

(1) PLANT NAME AND UNIT NO.	(2)	(3) LOCATION	(4) UNIT TYPE	(5) PRIMARY FUEL: FUEL TYPE	(6) PRIMARY FUEL: TRANSP. METHOD	(7) ALTERNATE FUEL: FUEL TYPE	(8) ALTERNATE FUEL: TRANSP. METHOD	(9) COM'L IN-SERVICE MO.	(9) COM'L IN-SERVICE YEAR	(10) EXPTD RTRMNT MO.	(10) EXPTD RTRMNT YEAR	(11) GEN MAX NAMEPLATE kW	(12) NET CAPABILITY - MW SUMMER	(13) NET CAPABILITY - MW WINTER	(14) STATUS
TAMPA ELECTRIC COMPANY															
BIG BEND	ST1	HILLSBOROUGH	FS	C	WA	—		10	1970	—	—	445,500	421	431	
BIG BEND	GT1	HILLSBOROUGH	GT	LO	WA	—	TK	2	1969	—	—	18,000	15	17	
BIG BEND	GT2	HILLSBOROUGH	GT	LO	WA	—	TK	11	1974	—	—	78,750	65	85	
BIG BEND	GT3	HILLSBOROUGH	GT	LO	WA	—	TK	11	1974	—	—	78,750	65	85	
BIG BEND	ST2	HILLSBOROUGH	FS	C	WA	—	—	4	1973	—	—	445,500	421	431	
BIG BEND	ST3	HILLSBOROUGH	FS	C	WA	—	—	5	1976	—	—	445,500	430	439	
BIG BEND	ST4	HILLSBOROUGH	FS	C	WA	—	—	2	1985	—	—	486,000	439	444	
GANNON	1	HILLSBOROUGH	FS	C	WA	—	RR	9	1957	—	—	125,000	119	119	
GANNON	2	HILLSBOROUGH	FS	C	WA	—	RR	11	1958	—	—	125,000	119	119	
GANNON	3	HILLSBOROUGH	FS	C	WA	—	RR	10	1960	—	—	179,520	155	155	
GANNON	4	HILLSBOROUGH	FS	C	WA	—	RR	11	1963	—	—	187,500	189	189	
GANNON	5	HILLSBOROUGH	FS	C	WA	—	RR	11	1965	—	—	239,360	227	232	
GANNON	6	HILLSBOROUGH	FS	C	WA	—	RR	10	1967	—	—	445,500	362	392	
GANNON	GT1	HILLSBOROUGH	GT	LO	WA	—	TK	3	1969	—	—	18,000	15	17	
HOOKERS POINT	1	HILLSBOROUGH	FS	HO	WA	—	—	7	1948	1	2003	33,000	32	34	
HOOKERS POINT	2	HILLSBOROUGH	FS	HO	WA	—	—	6	1950	1	2003	34,500	32	34	
HOOKERS POINT	3	HILLSBOROUGH	FS	HO	WA	—	—	8	1950	1	2003	34,500	32	34	
HOOKERS POINT	4	HILLSBOROUGH	FS	HO	WA	—	—	10	1953	1	2003	49,000	41	43	
HOOKERS POINT	5	HILLSBOROUGH	FS	HO	WA	—	—	5	1955	1	2003	81,600	67	67	
DINNER LAKE	1	HIGHLANDS	FS	NG	PL	HO	TK	12	1966	—	—	12,650	11	11	M
PHILLIPS PLANT	CW1	HIGHLANDS	CCW	LO	—	—	—	6	1983	—	—	3,600	3	3	M
PHILLIPS PLANT	IC1	HIGHLANDS	D	HO	TK	LO	—	6	1983	—	—	21,350	17	17	
PHILLIPS PLANT	IC2	HIGHLANDS	D	HO	TK	LO	—	6	1983	—	—	21,350	17	17	
PHILLIPS PLANT	IC5	HIGHLANDS	D	LO	—	—	—	1	1956	—	—	600	1	1	M
TOTAL:													3,280	3,401	

Emissions Unit Information Section 3

Unit No. 3: Solid Fuel Steam Generator

Pollutant Information Section 2

NOx

Allowable Emissions 1

1. Basis for Allowable Emissions Code :	RULE
2. Future Effective Date of Allowable Emissions :	
3. Requested Allowable Emissions and Units :	0.7000 lb/MMBtu
4. Equivalent Allowable Emissions :	2,880.5000 lb/hour 12,616.6000 tons/year
5. Method of Compliance : 30-day rolling average to be determined using EPA Reference Method 19.	
Method of Compliance Code :	
Frequency Base Date (DD-MON-YYYY) :	
Compliance Test Frequency :	
Regulation :	
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Allowable rate of 0.7 lb/MMBtu based on a 30-day rolling average. FDEP Rule 62-296.405(1)(d)4., F.A.C.	

Emissions Unit Information Section 4

Unit No. 4; Solid Fuel Steam Generator

Pollutant Information Section 2

NO_x

Allowable Emissions 1

1. Basis for Allowable Emissions Code :	RULE
2. Future Effective Date of Allowable Emissions :	
3. Requested Allowable Emissions and Units :	0.6000 lb/MMBtu
4. Equivalent Allowable Emissions :	2,598.0000 lb/hour 11,379.2000 tons/year
5. Method of Compliance : EPA Reference Method 19.	
Method of Compliance Code :	
Frequency Base Date (DD-MON-YYYY) :	
Compliance Test Frequency :	
Regulation :	
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Allowable emission rate of 0.6 lb/MMBtu is on a thirty-day rolling average. FDEP Rule 62-212.410, F.A.C., (BACT).	

Emissions Unit Information Section 4

Unit No. 4; Solid Fuel Steam Generator

Pollutant Information Section 4

CO

Allowable Emissions 1

1. Basis for Allowable Emissions Code :	RULE			
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :	0.0300	lb/MMBtu		
4. Equivalent Allowable Emissions :	~~125.6000~~	lb/hour	550.0000	tons/year
5. Method of Compliance : EPA Reference Method 10 once every five years.				
Method of Compliance Code :				
Frequency Base Date (DD-MON-YYYY) :				
Compliance Test Frequency :				
Regulation :				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : FDEP Rule 62-212.410, F.A.C., (BACT)				

Latest data in ARMS?

Table 1-2. Segment Description

Facility ID: 0570039 **DRAFT Permit No.:**

Permittee: BigBend

		Segment Information		
E.U. ID#	**EU Description**	**Segment Description**	**Max Hourly Rate**	**Max Annual Rate**
001	Unit No. 1; Solid Fuel Steam Generator	Coal burned in Unit No. 1.	103.50	909,510
002	Unit No. 2; Solid Fuel Steam Generator	Coal and petcoke/coal blend burned in Unit No. 2	182.10	1,595,196
003	Unit No. 3; Solid Fuel Steam Generator	Coal and petcoke/coal blend burned in Unit No. 3	190.30	1,667,383
004	Unit No. 4; Solid Fuel Steam Generator	Coal and petcoke/coal blend burned in Unit No. 4		
007	Combustion Turbine No. 1	No. 2 Distillate Fuel Oil burned in CT No. 1		10,825
005	Combustion Turbine No. 2	No. 2 Distillate Fuel Oil burned in CT No. 2	6.00	52,560
006	Combustion Turbine No. 3	No. 2 Distillate Fuel Oil burned in CT No. 3.	6.00	52,560
008	Fly Ash Silo No. 1 (Units #1 and #2)	Fly Ash Storage	44.50	389,820
009	Fly Ash Silo No. 2 (Units #1, #2, and #3)	Flyash Storage	44.50	389,820
014	Fly Ash Silo No. 3 (Unit #4)	Fly Ash Storage	44.50	389,820
015	Solid Fuel Bunkers (all units)	Fuel handled	8,000.00	4,800,000
011	Limestone Handling and Storage (all sources)	Limestone handling.	168.00	1,471,680
No	Fly Ash Handling and Storage Fugitives (all except silos)	Not applicable - fugitive emissions from a variety of fly ash handling sources.		
No Id	Gypsum Handling and Storage Fugitives (all gypsum sources)	Gypsum handling.	120.00	1,051,200
010	Solid Fuel Handling and Storage Fugitives (all sources)	Solid fuel handling	4,000.00	6,228,030
No Id	Slag and Bottom Ash Handling (all sources)	Not applicable		

F. VISIBLE EMISSIONS INFORMATION

Emissions Unit Information Section 3

Unit No. 3; Solid Fuel Steam Generator

Visible Emissions Limitation : Visible Emissions Limitation 1

1. Visible Emissions Subtype :	VE		
2. Basis for Allowable Opacity :	RULE		
3. Requested Allowable Opacity :			
Normal Conditions :		20	%
Exceptional Conditions :		27	%
Maximum Period of Excess Opacity Allowed :		6	min/hour
4. Method of Compliance : Continuous opacity monitoring system (COMS). Deletion of current annual test using EPA or FDEP Reference Method 9 is requested.			
5. Visible Emissions Comment : FDEP Rule 62-296.405(1)(a), F.A.C.			
Compliance Test Frequency :			
Frequency Base Date (DD-MON-YYYY) :			
COM Required?			
Regulation :			

F. VISIBLE EMISSIONS INFORMATION

Emissions Unit Information Section 4

Unit No. 4; Solid Fuel Steam Generator

Visible Emissions Limitation : Visible Emissions Limitation 1

1. Visible Emissions Subtype : VE	
2. Basis for Allowable Opacity : RULE	
3. Requested Allowable Opacity : Normal Conditions : 20 % Exceptional Conditions : 27 % Maximum Period of Excess Opacity Allowed : 6 min/hour	
4. Method of Compliance : Continuous opacity monitoring system (COMS). Deletion of current annual test using EPA or FDEP Reference Method 9 is requested.	
5. Visible Emissions Comment : 40 CFR Part 60, Subpart Da, 60.42a(b).. Opacity standards do not apply during periods of startup, shutdown, and malfunction per 40 CFR Part 60, Subpart A, 60.112(c).	
Compliance Test Frequency :	
Frequency Base Date (DD-MON-YYYY) :	
COM Required?	
Regulation :	

Emissions Unit Information Section 1

Unit No. 1; Solid Fuel Steam Generator

Pollutant Information Section 1 SO_2

Allowable Emissions 1

1. Basis for Allowable Emissions Code :	RULE			
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :	6.5000	lb/MMBtu		
4. Equivalent Allowable Emissions :	26,240.5000	lb/hour	114,933.4000	tons/year

5. Method of Compliance :

Weekly composite fuel sampling and fuel analysis or continuous emissions monitoring per FDEP Rule 62-296.405(1(f)1.b., F.A.C.
Deletion of current requirement to conduct an annual stack test is requested. No 62-297.310(7)(a)4.b.

Method of Compliance Code :	
Frequency Base Date (DD-MON-YYYY) :	
Compliance Test Frequency :	
Regulation :	

6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) :

Hourly rate is a two-hr average.
FDEP Rule 62-296.405(1)(c)2.b., F.A.C.

Emissions Unit Information Section 1

Unit No. 1; Solid Fuel Steam Generator

Pollutant Information Section 1 SO_2

Allowable Emissions 2

1. Basis for Allowable Emissions Code :	RULE			
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :	25.0000	tons/hr		
4. Equivalent Allowable Emissions :	50,000.0000	lb/hour		tons/year
5. Method of Compliance : Daily composite fuel sampling and analysis per Specific Condition 9.C of permit AO29-219924. Deletion of current requirement to conduct an annual stack test is requested.				
Method of Compliance Code :				
Frequency Base Date (DD-MON-YYYY) :				
Compliance Test Frequency :				
Regulation :				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Hourly rate represents total emissions from Units 1, 2, and 3 for a 24-hour average period. FDEP Rule 62-296.405(1)(c)2.b., F.A.C.				

Emissions Unit Information Section I

Unit No. 1: Solid Fuel Steam Generator

Pollutant Information Section I

SO_2

Allowable Emissions 3

1. Basis for Allowable Emissions Code :	RULE		
2. Future Effective Date of Allowable Emissions :			
3. Requested Allowable Emissions and Units :	31.5000	tons/hr	
4. Equivalent Allowable Emissions :	63,000.0000	lb/hour	tons/year
5. Method of Compliance : Daily composite fuel sampling and analysis per Specific Condition 9.C of permit AO29-219924. Deletion of current requirement to conduct an annual stack test is requested.			
Method of Compliance Code :			
Frequency Base Date (DD-MON-YYYY) :			
Compliance Test Frequency :			
Regulation :			
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Hourly rate represents total emissions from Units 1, 2, and 3 for a three-hour average period. FDEP Rule 62-296.405(1)(c)2.b., F.A.C.			

Emissions Unit Information Section 2

Unit No. 2; Solid Fuel Steam Generator

Pollutant Information Section 1

SO_2

Allowable Emissions 3

1. Basis for Allowable Emissions Code : RULE	
2. Future Effective Date of Allowable Emissions :	
3. Requested Allowable Emissions and Units : 31.5000 tons/hour	
4. Equivalent Allowable Emissions : 63,000.0000 lb/hour	tons/year
5. Method of Compliance : Daily composite fuel sampling and analysis per Specific Condition 9.C. of permit AO29-179912. Deletion of current requirement to conduct an annual stack test is requested.	
Method of Compliance Code :	
Frequency Base Date (DD-MON-YYYY) :	
Compliance Test Frequency :	
Regulation :	
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Hourly rate represents total emissions from Units 1, 2, and 3 for a 3-hour average period. FDEP Rule 62-296.405(1)(c)2.b., F.A.C.	

Emissions Unit Information Section 2

Unit No. 2: Solid Fuel Steam Generator

Pollutant Information Section 1

SO_2

Allowable Emissions 2

1. Basis for Allowable Emissions Code :	RULE	
2. Future Effective Date of Allowable Emissions :		
3. Requested Allowable Emissions and Units :	25.0000	tons/hr
4. Equivalent Allowable Emissions :	50,000.0000 lb/hour	tons/year
5. Method of Compliance : Daily composite fuel sampling and analysis per Specific Condition 9.C. of permit AO29-179912. Deletion of current requirement to conduct an annual stack test is requested.		
Method of Compliance Code :		
Frequency Base Date (DD-MON-YYYY) :		
Compliance Test Frequency :		
Regulation :		
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Hourly rate represents total emissions from Units 1, 2, and 3 for a 24-hr average period. FDEP Rule 62-296.405(1)(c)2.b., F.A.C.		

Emissions Unit Information Section 2

Unit No. 2; Solid Fuel Steam Generator

SO_2

Pollutant Information Section 1

Allowable Emissions 1

1. Basis for Allowable Emissions Code :	RULE			
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :	6.5000	lb/MMBtu		
4. Equivalent Allowable Emissions :	25,947.0000	lb/hour	113,766.1000	tons/year
5. Method of Compliance : Weekly composite fuel sampling and fuel analysis or continuous emissions monitoring per FDEP Rule 62-296.405(1(f)1.b., F.A.C. Deletion of current requirement to conduct an annual stack test is requested.				
Method of Compliance Code :				
Frequency Base Date (DD-MON-YYYY) :				
Compliance Test Frequency :				
Regulation :				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Hourly rate is a two-hr average. FDEP Rule 62-296.405(1)(c)2.b., F.A.C.				

Emissions Unit Information Section 3

Unit No. 3; Solid Fuel Steam Generator

SO_2

Pollutant Information Section 1

Allowable Emissions 1

1. Basis for Allowable Emissions Code :	RULE
2. Future Effective Date of Allowable Emissions :	
3. Requested Allowable Emissions and Units :	6.5000 lb/MMBtu
4. Equivalent Allowable Emissions :	26,747.5000 lb/hour 117,154.1000 tons/year
5. Method of Compliance : Weekly composite fuel sampling and fuel analysis or continuous emissions monitoring per FDEP Rule 62-296.405(1(f)1.b., F.A.C. Deletion of current requirement to conduct an annual stack test is requested.	
Method of Compliance Code :	
Frequency Base Date (DD-MON-YYYY) :	
Compliance Test Frequency :	
Regulation :	
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Hourly rate is a two-hr average. FDEP Rule 62-296.405(1)(c)2.b., F.A.C.	

Emissions Unit Information Section 3

Unit No. 3; Solid Fuel Steam Generator

Pollutant Information Section 1 SO_2

Allowable Emissions 2

1. Basis for Allowable Emissions Code :	RULE
2. Future Effective Date of Allowable Emissions :	
3. Requested Allowable Emissions and Units :	25.0000 tons/hr
4. Equivalent Allowable Emissions :	50,000.0000 lb/hour tons/year
5. Method of Compliance : Daily composite fuel sampling and analysis per Specific Condition 12.C. of permit AO29-179911. Deletion of current requirement to conduct an annual stack test is requested.	
Method of Compliance Code :	
Frequency Base Date (DD-MON-YYYY) :	
Compliance Test Frequency :	
Regulation :	
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Hourly rate represents total emissions from Units 1, 2, and 3 for a 24-hour average period. FDEP Rule 62-296.405(1)(c)2.b., F.A.C.	

Emissions Unit Information Section 3

Unit No. 3: Solid Fuel Steam Generator

Pollutant Information Section 1

SO_2

Allowable Emissions 3

1. Basis for Allowable Emissions Code :	RULE
2. Future Effective Date of Allowable Emissions :	
3. Requested Allowable Emissions and Units :	31.5000 tons/hr
4. Equivalent Allowable Emissions :	63,000.0000 lb/hour tons/year
5. Method of Compliance : Daily composite fuel sampling and analysis per Specific Condition 12.C. of permit AO29-179911. Deletion of current requirement to conduct an annual stack test is requested.	
Method of Compliance Code :	
Frequency Base Date (DD-MON-YYYY) :	
Compliance Test Frequency :	
Regulation :	
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Hourly rate represents total emissions from Units 1, 2, and 3 for a 3-hour average period. FDEP Rule 62-296.405(1)(c)2.b., F.A.C.	

Emissions Unit Information Section 4

Unit No. 4; Solid Fuel Steam Generator

Pollutant Information Section 1 SO_2

Allowable Emissions 1

1. Basis for Allowable Emissions Code :	RULE
2. Future Effective Date of Allowable Emissions :	
3. Requested Allowable Emissions and Units :	0.8200 lb/MMBtu
4. Equivalent Allowable Emissions :	3,576.0000 lb/hour 15,662.9000 tons/year
5. Method of Compliance : Continuous emissions monitoring system (CEMS). Deletion of current requirement to conduct an annual stack test is requested.	
Method of Compliance Code :	
Frequency Base Date (DD-MON-YYYY) :	
Compliance Test Frequency :	
Regulation :	
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Allowable emission rate of 0.82 lb/MMBtu is on a thirty-day rolling average. FDEP Rule 62-212.410, F.A.C. (BACT).	

Emissions Unit Information Section 4

Unit No. 4; Solid Fuel Steam Generator

Pollutant Information Section 1 SO_2

Allowable Emissions 2

1. Basis for Allowable Emissions Code :	RULE
2. Future Effective Date of Allowable Emissions :	
3. Requested Allowable Emissions and Units :	1.2000 lb/MMBtu
4. Equivalent Allowable Emissions :	5,196.0000 lb/hour 22,758.4800 tons/year
5. Method of Compliance : Continuous emissions monitoring system (CEMS). Deletion of current requirement to conduct an annual stack test is requested.	
Method of Compliance Code :	
Frequency Base Date (DD-MON-YYYY) :	
Compliance Test Frequency :	
Regulation :	
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Allowable emission rate of 1.2 lb/MMBtu is a maximum two hour average. 40 CFR Part 60, Subpart Da.	

Emissions Unit Information Section 1

Unit No. 1; Solid Fuel Steam Generator

Pollutant Information Section 2

PM

Allowable Emissions 1

1. Basis for Allowable Emissions Code :	RULE
2. Future Effective Date of Allowable Emissions :	
3. Requested Allowable Emissions and Units :	0.3000 lb/MMBtu
4. Equivalent Allowable Emissions :	1,211.1000 lb/hour 2,210.3000 tons/year
5. Method of Compliance : Annual test using EPA reference method 5, 5B, or 17. Option to use three soot-blowing test runs to demonstrate compliance with non-soot blowing standard is requested.	
Method of Compliance Code :	
Frequency Base Date (DD-MON-YYYY) :	
Compliance Test Frequency :	
Regulation :	
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : 0.3 lb/MMBtu applicable during soot blowing (3 hrs/day). 0.1 lb/MMBtu two-hour average during non-soot blowing. FDEP Rules 62-210.700(3) and 62-296.405(1)(b), F.A.C.	

Emissions Unit Information Section 2

Unit No. 2; Solid Fuel Steam Generator

Pollutant Information Section 2

PM

Allowable Emissions 1

1. Basis for Allowable Emissions Code :	RULE			
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :	0.3000	lb/MMBtu		
4. Equivalent Allowable Emissions :	1,198.8000	lb/hour	2,187.8000	tons/year
5. Method of Compliance : Annual test using EPA reference method 5, 5B, or 17. Option to use three soot-blowing test runs to demonstrate compliance with non-soot blowing standard is requested.				
Method of Compliance Code :				
Frequency Base Date (DD-MON-YYYY) :				
Compliance Test Frequency :				
Regulation :				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : 0.3 lb/MMBtu during soot blowing (3 hrs/day). 0.1 lb/MMBtu during non-soot blowing. FDEP Rules 62-210.700(3) and 62-296.405(1)(b), F.A.C.				

Emissions Unit Information Section 3

Unit No. 3; Solid Fuel Steam Generator

Pollutant Information Section 3

PM

Allowable Emissions 1

1. Basis for Allowable Emissions Code :	RULE			
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :	0.3000	lb/MMBtu		
4. Equivalent Allowable Emissions :	1,234.5000	lb/hour	2,253.0000	tons/year
5. Method of Compliance : Annual test using EPA reference method 5, 5B or 17. Option to use three soot-blowing test runs to demonstrate compliance with non-soot blowing standard is requested. Testing to be conducted in stack CS-003 (non-integrated mode) or in the duct (integrated mode).				
Method of Compliance Code :				
Frequency Base Date (DD-MON-YYYY) :				
Compliance Test Frequency :				
Regulation :				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : 0.3 lb/MMBtu during soot blowing (3 hrs/day). 0.1 lb/MMBtu during non-soot blowing. FDEP Rules 62-210.700(3) and 62-296.405(1)(b)., F.A.C.				

Emissions Unit Information Section 4

Unit No. 4; Solid Fuel Steam Generator

Pollutant Information Section 3 PM

Allowable Emissions 1

1. Basis for Allowable Emissions Code :	RULE			
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :	0.0300	lb/MMBtu		
4. Equivalent Allowable Emissions :	130.0000	lb/hour	569.0000	tons/year
5. Method of Compliance : Annual test using EPA reference method 5, 5B, or 17.				
Method of Compliance Code :				
Frequency Base Date (DD-MON-YYYY) :				
Compliance Test Frequency :				
Regulation :				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : FDEP Rule 62-212.410, F.A.C. (BACT).				

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]

125.6 lb/hr and 550 tpy. However, Permit No. PSD-FL-040 (October 9, 1985 Modification) limits the CO emissions to 124 lb/hr, which equates to 543 tpy. Please explain this discrepancy.

25. The maximum hourly rate of No. 2 distillate fuel oil burned in Combustion Turbine No. 1 is listed as 1.2357 thousand gallons per hour and the maximum annual burning rate is listed as 10,825 thousand gallons per year, which would indicate that the turbine operates 8760 hours per year. However, construction permit AC-29-2209 limits the hours of operation of Combustion Turbine No. 1 to 10 hrs/day, 365 days a year which equates to 3650 hours per year. Please explain this discrepancy.

26. The maximum hourly rate of No. 2 distillate fuel oil burned in Combustion Turbine No. 2 is listed as 6.00 thousand gallons per hour and the maximum annual burning rate is listed as 52,560 thousand gallons per year, which would indicate that the turbine operates 8760 hours per year. However, construction permit AC-29-2210 limits the hours of operation of Combustion Turbine No. 2 to 10 hrs/day, 365 days a year which equates to 3650 hours per year. Please explain this discrepancy.

27. In the application, Table A-1, "Summary of Federal EPA Regulatory Applicability and Corresponding Requirements for Big Bend Station" states that 40 CFR 76.5(g) applies to Steam Generator No. 4 and "Beginning January 1, 1995, NO_x emissions shall not exceed 0.45 lb/MMBtu on an annual average basis for tangentially fired boilers." However, 40 CFR 75.6(g) actually states "Beginning January 1, 2000, the owner or operator of a Group I, Phase II coal-fired utility unit with a tangentially fired boiler or a wall-fired boiler shall be subject to the emission limitations in paragraph (a) of this section." Is this a correct rule cite and/or statement of applicability? Is Steam Generator Unit No. 4 a tangentially fired boiler or a dry bottom wall-fired boiler? The Source Classification Code (SCC) listed in the application for Steam Generator Unit No. 4 is 1-01-002-02 which designates an Electric Generation External Combustion Boiler, Pulverized Coal: Dry Bottom (Bituminous Coal). However, if Unit No. 4 is tangentially fired, the more appropriate SCC would be 1-01-002-12 which designates an Electric Generation External Combustion Boiler, Pulverized Coal: Dry Bottom (Tangential)(Bituminous Coal). Also, if it is tangentially fired, why is Unit No. 4 not listed in "Table 1 - Phase I Tangentially Fired Units," 40 CFR 76 Appendix A?

28. Though referenced in the Emissions Unit Supplemental Information sections for Steam Generator Units No. 2, 3 and 4, supplemental information section III.I.11, Alternative Modes of Operation (Emissions Trading), was not included with the application. Please submit this section if it is applicable.

Fly Ash Handling and Storage Sources

1. Based on the process weight table found in Rule 62-296.320(4)2., F.A.C., the allowable particulate matter emission rate for Fly Ash Silo No. 1 is 139.15 tons/year. However, in order to waive the requirement for stack testing and comply instead with a 5% opacity standard, the potential to emit particulate matter must be less than 100 tons/year.

The application requests, and the current permit reflects, an allowable emission limitation of 22.62 tons/year based on a baghouse emission factor of 0.03 gr/dscf. The application states that the 0.03 gr/dscf factor is "Typical baghouse exit loading: ECT, 1995." Please provide additional information to document the source of this emission factor. Is this factor based on stack testing, vendor's guarantee, or some other data?

EXISTING GENERATING FACILITIES

(1) Plant	(2) Unit No.	(3) Location	(4) Type	(5) Fuel Pri	(6) Fuel Alt	(7) Com'l In-Service Mo/Yr	(8) Exptd Retrmnt Mo/Yr	(9) Gen Max Nameplate kW	(10) Net Capability Summer MW	(11) Net Capability Winter MW	(12) Fuel Transp Pri	(13) Fuel Transp Alt
TAMPA ELECTRIC COMPANY												
Big Bend	1	Hillsborough County	CT	LO	-	01/69	Unk	18000	14	14	WA	
	2-3		CT	LO	-	11/74	Unk	157500	130	130	WA	
	1		FS	C	-	10/70	Unk	445500	367	367	WA	
	2		FS	C	-	04/73	Unk	445500	337	337	WA	
	3		FS	C	-	05/76	Unk	445500	375	375	WA	
	4											
Gannon	1	Hillsborough County	CT	LO	-	01/69	Unk	18000	14	14	WA	
	1		FS	HO	-	08/57	Unk	125000	103	103	WA	
	2		FS	HO	-	10/58	Unk	125000	108	108	WA	
	3		FS	HO	-	08/60	Unk	179520	150	150	WA	
	4		FS	HO	-	07/63	Unk	187500	169	169	WA	
	5		FS	C	-	09/65	Unk	239360	218	218	RR/WA	
	6		FS	C	-	09/67	Unk	414000	337	337	RR/WA	
Hookers Point	1	Hillsborough County	FS	HO	-	07/48	Unk	33000	24	24	WA	
	2		FS	HO	-	06/50	Unk	34500	24	24	WA	
	3		FS	HO	-	08/50	Unk	34500	24	24	WA	
	4		FS	HO	-	10/53	Unk	49000	38	38	WA	
	5		FS	HO	-	05/55	Unk	81600	67	67	WA	
TOTAL								3032980	2499	2499		

Joint participation units are denoted by (nnnP) where nnn = total summer net MW rating.

This equation shall be used and the calculations completed for each of the Units No. 1, No. 2, and No. 3. This information shall be submitted to the Environmental Protection Commission of Hillsborough County (EPCHC) on a quarterly basis no later than 45 days following the calendar quarter. If an exceedance of this standard occurs, then the permittee shall report this event to the EPCHC within 24 hours of the determination.

(4) Adhering to the study, previously submitted, that demonstrates by a statistical analysis that the 31.5 tons of SO2 per hour on a three-hour average is being met. This study provides reasonable assurance that a daily sample can be used to demonstrate compliance with the 3-hour emission cap.

[AO29-219924, AO29-179912, and AO29-179911]

A.15. Compliance with nitrogen oxides emission ~~limit~~ at all hourly emission rates for Unit No. 3 shall be demonstrated continuously based upon a 30-day rolling average. The methodology to be used to calculate the 30-day rolling average will follow the criteria set forth in 40 CFR 60, Subpart Da. The calculations shall be consistent with the equations in 40 CFR 60, Appendix A, Reference Method 19, Section 4.2. Data collected during boiler operating days will be used to calculate the 30-day rolling average except during periods of start-up, shutdown, or malfunction, consistent with the provisions of Rule 62-210.700, F.A.C. 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. The continuous emission monitor 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.16. Test procedures shall meet all applicable requirements of Chapter 62-297, F.A.C.

[Rule 62-296.401(1)(e)5., F.A.C.]

<u>Continuous Emissions Monitoring Requirements</u>.

A.17. For Units. No. 1, No. 2, and No. 3, Tampa Electric Company (TEC) shall operate, calibrate, and maintain a continuous monitoring system for continuously monitoring opacity. For Unit No. 3, TEC shall also operate calibrate, and maintain a continuous monitoring system for continuously monitoring nitrogen oxides (expressed as NO_2). In addition, when the emissions from Unit No. 3 are controlled by the Unit No. 4 flue gas desulfurization equipment, TEC shall operate calibrate, and maintain a continuous monitoring system for continuously monitoring sulfur dioxide. 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.18. An oxygen or carbon dioxide continuous monitoring system shall be operated for Unit

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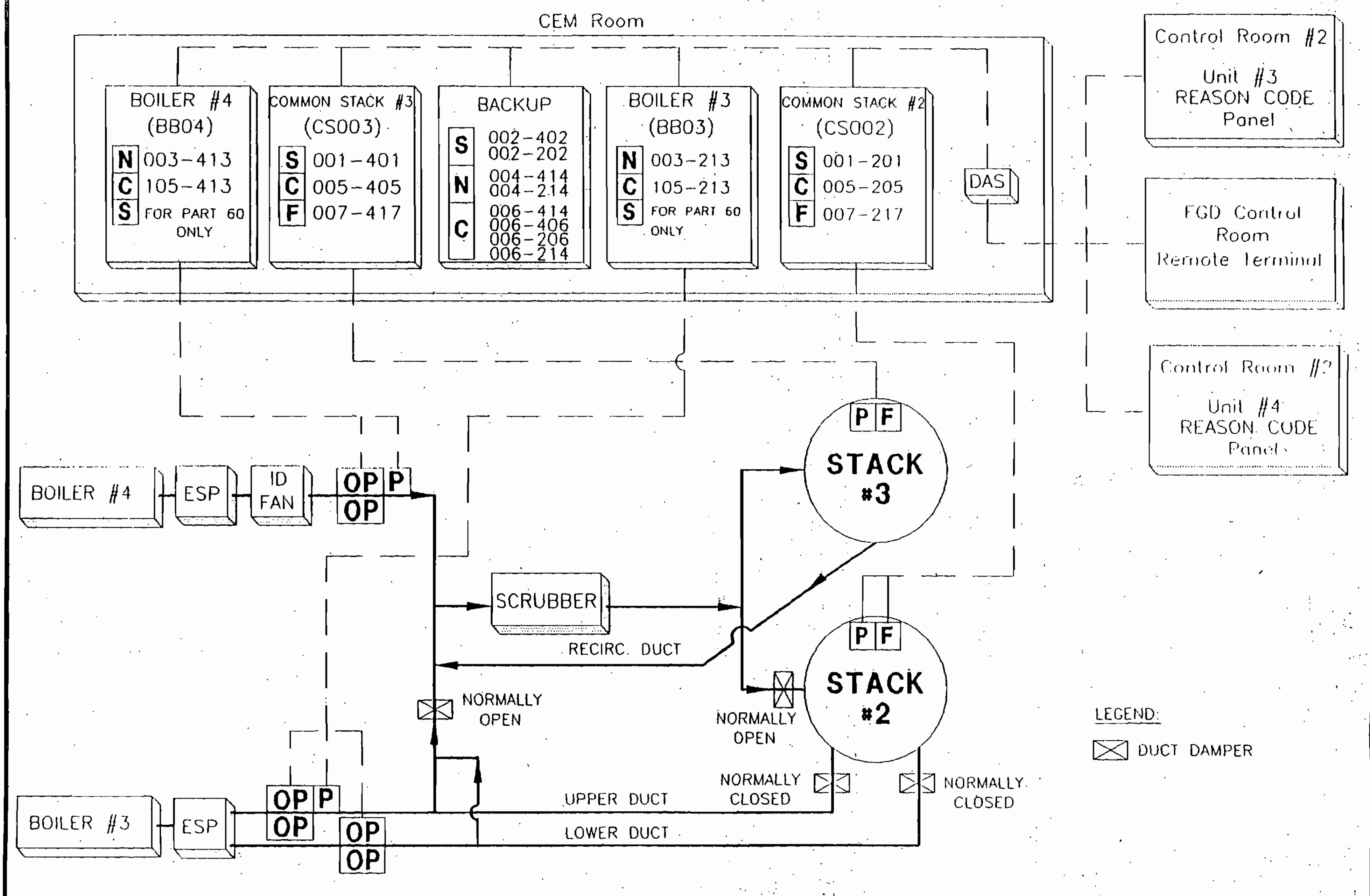

TAMPA ELECTRIC
A TECO ENERGY COMPANY

CEM SYSTEM
BLOCK DIAGRAM
UNITS NO.3 AND NO.4-BIG BEND STATION

DESIGNED BY	CHECKED BY	APPROVED BY
CW/JFM	CW	DC
DATE 03/95	JOB NO. B42-77	
FILE NAME		DWG. NO.

Arsenic								
Facility ID	EU ID	Desc	SCC	1995 (ton)	MMbtu/ton	EF	Unit	TPY
570039	1	UNIT #1 COAL FIRED BOILER W/RESEARCH-COTRELL ESP	10100201	1234582	12	0.000538	lb/MMbtu	3.985231
570039	2	UNIT #2 RILEY-STOKER COAL FIRED BOILER W/ ESP	10100201	1217160	12	0.000538	lb/MMbtu	3.928992
570039	3	UNIT #3 RILEY-STOKER COAL-FIRED BOILER W/ ESP	10100201	1103856	12	0.000538	lb/MMbtu	3.563247
570039	4	UNIT #4 COAL-FIRED BOILER W/ BELCO ESP PSD-FL-040	10100212	1335623	11	NA		
Chromium								
Facility ID	EU ID	Desc	SCC	1995 (ton)	MMbtu/ton	EF	Unit	TPY
570039	1	UNIT #1 COAL FIRED BOILER W/RESEARCH-COTRELL ESP	10100201	1234582	12	0.00102	lb/MMbtu	7.555642
570039	2	UNIT #2 RILEY-STOKER COAL FIRED BOILER W/ ESP	10100201	1217160	12	0.00102	lb/MMbtu	7.449019
570039	3	UNIT #3 RILEY-STOKER COAL-FIRED BOILER W/ ESP	10100201	1103856	12	0.00102	lb/MMbtu	6.755599
570039	4	UNIT #4 COAL-FIRED BOILER W/ BELCO ESP PSD-FL-040	10100212	1335623	11	NA		

Bit. coal 21 to 28 $\frac{MMBtu}{TON}$

4 4330 $\frac{MMBtu}{hr}$
1 4037
2 3996
3 4115

$$\frac{16{,}478 \frac{MMBtu}{hr}}{25 \frac{MMBtu}{ton}} = 659.12 \frac{TON}{hr} \qquad 15{,}819 \frac{ton}{24\,hr}$$

coal

x 8760 = 5,773,891

coal/pet coke

for 21 $\frac{MMBtu}{ton}$; 785 $\frac{TONS}{hr}$

6,873,680

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: ____

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ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 60

[FRL-5854-5]

RIN-2060-AE56

Proposed Revision of Standards of Performance for Nitrogen Oxide Emissions From New Fossil-Fuel Fired Steam Generating Units; Proposed Revisions to Reporting Requirements for Standards of Performance for New Fossil-Fuel Fired Steam Generating Units

AGENCY: Environmental Protection Agency (EPA).

ACTION: Proposed revisions.

SUMMARY: Pursuant to section 407(c) of the Clean Air Act, the EPA has reviewed the emission standards for nitrogen oxides (NO_x) contained in the standards of performance for new electric utility steam generating units and industrial-commercial-institutional steam generating units. This document presents EPA's findings and proposes revisions to the existing NO_x standards.

The proposed changes to the existing standards for NO_x emissions reduce the numerical NO_x emission limits for both utility and industrial steam generating units to reflect the performance of best demonstrated technology. The proposal also changes the format of the revised NO_x emission limit for electric utility steam generating units to an output-based format to promote energy efficiency and pollution prevention.

As a separate activity, EPA has also reviewed the quarterly sulfur dioxide, NO_x, and opacity emission reporting requirements of the utility and industrial steam

generating unit regulations contained in 40 CFR part 60, subpart Da and Db. This document proposes to allow owners or operators of affected facilities to meet the quarterly reporting requirements of both regulations by means of electronic reporting, in lieu of submitting written compliance reports.

DATES: Comments. Comments on the proposed revisions must be received on or before (insert date 60 days from publication date in the Federal Register) at the address noted below.

Public Hearing. A public hearing will be held, if requested, to provide interested persons an opportunity for oral presentations of data, views, or arguments concerning the proposed revisions. If anyone contacts the EPA requesting to speak at a public hearing by (3 weeks after proposal), a public hearing will be held on (about 30 days after proposal) beginning at 9:00 a.m. The public hearing is only for the oral presentations of comments with the EPA asking clarifying questions. Persons interested in attending the hearing should call Ms. Donna Collins at (919) 541-5578 to verify that a hearing will occur.

Request to Speak at Hearing. Persons wishing to present oral testimony must contact EPA by (3 weeks after proposal).

ADDRESSES: Interested parties may submit written comments (in duplicate if possible) to Public Docket No. A-92-71 at the following address: U.S. Environmental Protection Agency, Air and Radiation Docket and Information Center (6102), 401 M Street, S.W., Washington, D.C. 20460. The Agency requests that a separate copy also be sent to the contact person listed below. The docket is located at the above address in Room M-1500, Waterside Mall (ground floor), and may be inspected from 8:30 a.m. to 4 p.m., Monday through Friday. Materials related to this rulemaking are available upon request from the Air and Radiation Docket and Information Center by calling (202) 260-7548 or 7549. The FAX number for the Center is (202) 260-4400. A reasonable fee may be charged for copying docket materials.

Comments and data also may be submitted electronically by sending electronic mail (e-mail) to: a-and-r-docket@epamail.epa.gov. Electronic comments must be submitted as an ASCII file avoiding the use of special characters and any form of encryption. Comments and data also will be accepted on disks in WordPerfect in 5.1 file format or ASCII file format. All comments and data in electronic form must be identified by the docket number A-92-71. No Confidential Business Information (CBI) should be submitted through e-mail. Electronic comments on this proposed rule may be filed online at many Federal Depository Libraries.

Public Hearing. If a public hearing is held, it will be held at EPA's Office of Administration Auditorium, Research Triangle Park, North Carolina. Persons wishing to present oral testimony should notify Ms. Donna Collins, Combustion Group (MD-13), U.S. Environmental Protection

Agency, Research Triangle Park, North Carolina 27711, telephone number (919) 541-5578, FAX number (919) 541-5450.

Technical Support Documents. The technical support documents summarizing information gathered during the review may be obtained from the docket; from the EPA library (MD-35), Research Triangle Park, North Carolina 27711, telephone number (919) 541-2777, FAX number (919) 541-0804; or from the National Technical Information Services, 5285 Port Royal Road, Springfield, Virginia 22161, telephone number (703) 487-4650. Please refer to "New Source Performance Standards, Subpart Da - Technical Support for Proposed Revisions to NO_x Standard", EPA-453/R-94-012 or "New Source Performance Standards, Subpart Db - Technical Support for Proposed Revisions to NO_x Standard", EPA-453/R-95-012.

Docket. Docket No. A-92-71, containing supporting information used in developing the proposed revisions, is available for public inspection and copying from 8:30 a.m. to 12:00 p.m. and 1:00 to 3:00 p.m., Monday through Friday, at EPA's Air Docket Section, Waterside Mall, Room 1500, 1st Floor, 401 M Street, S.W., Washington, D.C. 20460. A reasonable fee may be changed for copying docket materials, including printed paper versions of electronic comments which do not include any information claimed as CBI.

FOR FURTHER INFORMATION CONTACT: For information concerning specific aspects of this proposal, contact Mr. James

Eddinger, Combustion Group, Emission Standards Division (MD-13), U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711, telephone number (919) 541-5426.

SUPPLEMENTARY INFORMATION: The following outline is provided to aid in locating information in this notice.

This notice is also available on the Technology Transfer Network (TTN), one of the EPA's electronic bulletin boards. The TTN provides information and technology exchange in various areas of air pollution control. The service is free, except for the cost of a phone call. Dial (919) 541-5742 for up to a 14,400 bps modem. The TTN is also accessible via the Internet at "ttnwww.rtpnc.epa.gov." If more information on the TTN is needed, call the HELP line at (919) 541-5384.

I. Background

Title IV of the Clean Air Act (the Act), as amended in 1990, authorizes the EPA to establish an acid rain program to reduce the adverse effects of acidic deposition on natural resources, ecosystems, materials, visibility, and public health. The principal sources of the acidic compounds are emissions of sulfur dioxide (SO_2) and NO_x from the combustion of fossil fuels. Section 407(c) of the Act requires the EPA to revise standards of performance previously promulgated under section 111 for NO_x emissions from fossil-fuel fired steam generating units, including both electric utility and nonutility units. These revised standards of performance are to reflect improvements in methods for the reduction of NO_x emissions.

The current standards for NO_x emissions from fossil-fuel fired steam generating units, which were promulgated under section 111 of the Act, are contained in the new source performance standards (NSPS) for electric utility steam generating units (40 CFR 60.40a, subpart Da) and for industrial-commercial-institutional steam generating units (40 CFR 60.40b, subpart Db).

The current NO_x standards for new utility steam generating units were promulgated on June 11, 1979 (44 FR 33580). The NSPS apply to electric utility steam generating units capable of firing more than 73 megawatts (MW)(250 million Btu/hour) heat input of fossil fuel, for which construction or modification commenced after September 18, 1978. The current NSPS also apply to industrial cogeneration facilities that sell more than 25 MW of electrical output and more than one-third of their potential output capacity to any utility power distribution system. The current NO_x standards for new electric utility steam generating units are fuel-specific and were based on combustion modification techniques. At the time the NSPS was promulgated, the most effective combustion modification techniques for reducing NO_x emissions from utility steam generating units were judged to be combinations of staged combustion [overfire air (OFA)], low excess air (LEA), and reduced heat release rate.

The NSPS for NO_x emissions for industrial steam generating units was promulgated on November 25, 1986 (51 FR 42768). The NSPS apply to industrial steam generating units with a heat input capacity greater than 29 MW (100 million Btu/hour), for which construction, modification, or reconstruction commenced after June 19, 1984. The NO_x standards promulgated for industrial steam generating units are fuel- and boiler-specific and were based on the performance of LEA and LEA-staged combustion modification techniques.

II. Proposed Revisions

Standards of performance for new sources established under section 111 of the Act are to reflect the application of the best system of emission reduction which (taking into consideration the cost of achieving such emission reduction, any nonair quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated. This level of control is commonly referred to as best demonstrated technology (BDT).

The proposed standards would revise the NO_x emission limits for steam generating units in subpart Da (Electric Utility Steam Generating Units) and subpart Db (Industrial-Commercial-Institutional Steam Generating Units). Only those electric utility and industrial steam generating units for which construction, modification, or reconstruction is commenced after (insert date of publication in Federal Register) would be affected by the proposed revisions.

The NO_x emission limit proposed in today's notice for subpart Da units is 170 nanograms per joule (ng/J) [1.35 lb/megawatt-hour (MWh)] net energy output regardless of fuel type. For subpart Db units, the NO_x emission limit being proposed is 87 ng/J (0.20 lb/million Btu) heat input from the combustion of any gaseous fuel, liquid fuel, or solid fuel; however, for low heat release rate units firing natural gas or distillate oil, the current NO_x emission limit of 43 ng/J (0.10 lb/million Btu) heat input is unchanged.

Compliance with the proposed NO_x emission limit is determined on a 30-day rolling average basis, which is the same requirement as the one currently in subparts Da and Db.

The proposed revisions to the quarterly SO_2, NO_x, and opacity reporting requirements of subparts Da and Db would allow electronic quarterly reports to be submitted in lieu of the written reports currently required under sections 60.49a and 60.49b. The electronic reporting option would be available to any affected facility under subpart Da or Db, including units presently regulated under those subparts. Each electronic quarterly report would be submitted no later than 30 days after the end of the calendar quarter. The format of the electronic report would be consistent with the electronic data reporting (EDR) format specified by the Administrator under section 75.64(d) for use in the Title IV Acid Rain Program. Each electronic report would be accompanied by a certification statement from the owner or operator indicating whether compliance with the applicable emission standards and minimum data requirements was achieved during the reporting period.

III. Rationale for Proposed Revisions

A. Performance of NO_x Control Technology

The control technologies that are commercially available for reducing NO_x emissions can be grouped into one of two fundamentally different techniques: combustion control and flue gas treatment. Generally, combustion controls reduce NO_x emissions by suppressing NO_x formation during the combustion process. Flue gas treatment controls are add-on controls that reduce NO_x emissions after combustion has occurred.

Combustion control techniques generally employed on wall-fired pulverized coal (PC) fired units include low NO_x burners (LNB) (i.e., burners that incorporate LEA and air staging within the burner) or LNB with OFA. For tangentially-fired PC units, combustion control techniques generally employed include LNB (i.e., a low NO_x configured coal and air nozzle array and injection of a portion of the combustion air through air nozzles above, but essentially within the same waterwall hole as the coal and air nozzle array) or LNB with separated OFA (i.e., LNB with additional air nozzles above but outside the waterwall hole that includes the coal and air nozzle array). For control of fluidized bed combustion (FBC) and stoker steam generating units, air staging is the form of combustion control employed.

Another group of combustion control techniques are based on the use of clean fuels (i.e., natural gas). Commercially available gas-based control techniques are reburning and cofiring with coal or oil. In reburning, natural gas is injected above the primary combustion zone to create a fuel-rich zone to reduce burner-generated NO_X to molecular nitrogen (N_2) and water vapor. It is necessary to add overfire air above the reburning zone to complete combustion of the reburning fuel. Natural gas cofiring consists of injecting and combusting natural gas near or concurrently with the main oil or coal fuel.

Two commercially available flue gas treatment technologies for reducing NO_X emissions from fossil fuel-fired steam generating units are selective noncatalytic reduction (SNCR) and selective catalytic reduction (SCR). In SNCR, ammonia (NH_3) or urea is injected into the flue gas to reduce NO_X to N_2 and water. The SCR utilizes injection of NH_3 into the flue gas in the presence of a catalyst. The catalyst promotes reactions that convert NO_X to N_2 and water at higher removal efficiencies and lower flue gas temperatures than required for SNCR.

Application of flue gas treatment technologies on coal-fired boilers in the United States (U.S.) has grown considerably during the past two years. However, both SNCR and SCR technologies have been applied widely to commercial-scale gas- and oil-fired steam generating units. Both technologies have been applied to coal-fired steam generating units outside the U.S. The SCR technology has been implemented on coal-fired steam generating units in Germany and Japan over the past 15 years and has achieved substantially reduced NO_x emission levels. A recent EPA report notes that there are 72 coal-fired plants (137 units) in Germany, 28 coal-fired plants (40 units) in Japan, 9 coal-fired plants (29 units) in Italy, and 8 coal-fired plants (10 units) in other European countries using SCR (See EPA report, "Performance of SCR Technology for NO_x Emissions at Coal-Fired Electric Utility Units in the United States and Western Europe").

The SCR technology is currently being applied on seven coal-fired steam generating units in the U.S. These applications are described in Table 1.

TABLE 1. FULL-SCALE SCR EXPERIENCE ON COAL-FIRED UNITS IN THE U.S.

Plant and Unit No.	State	Size (MWe)	Year Online
Birchwood 1	VA	245	1996
Carney's Point 1	NJ	140	1994
Carney's Point 2	NJ	140	1994
Indiantown	FL	370	1996
Logan 1	NJ	230	1994

Merrimack 2	NH	320	1995
Stanton 2	FL	460	1996

The SNCR technology has been applied in the U.S. to a number of coal-fired utility and industrial steam generating units. Each of these control technologies is discussed in the technical support documents.

The performance of combustion controls applied to subpart Da coal-fired steam generating units was evaluated through statistical analyses of continuous emission monitoring (CEM) data obtained from operators of conventional and FBC electric utility steam generating units. The objective of the analyses was to assess long-term NO_x emission levels that can be achieved continuously using combustion controls. For the data analyses, individual steam generating units were selected to represent the primary coal types and furnace configurations (PC and FBC) used in this source category. The procedures used to select individual steam generating units for statistical analyses, the statistical analyses that were performed, and the results of the statistical analyses for six sets of data reflecting recent operating experience for subpart Da units using combustion controls are described in the technical support document for the subpart Da revision. The results indicate that the achievable NO_x emissions from each steam generating unit are lower than the current standard.[1]

The performance of combustion controls applied to stoker coal-fired steam generating units was not evaluated using a detailed statistical analyses of CEM data. However, long-term NO_x emission data obtained from four subpart Da stoker units with combustion controls (i.e., air staging) were typically between 0.48 and 0.53 lb/million Btu heat input. In stoker steam generating units, a minimum amount of undergrate air must be used to provide adequate mixing and cooling. Since the use of air staging reduces undergrate air flow, there may be a limit to the degree of air staging used in stoker units and consequently to the NO_x reduction that can be achieved.

A statistical analysis of combustion controls applied to gas- and oil-fired utility steam generating units was also not performed since: (1) there are no known operating subpart Da natural gas- or oil-fired utility units; (2) there are pre-NSPS utility steam generating units burning these fuels that have been retrofit with combustion controls, but long-term CEM data for these units were

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It should be noted that CEM data submitted to EPA under 40 CFR part 75 were not available during the development of the technical support document. However, a preliminary examination of these data shows that the average 30-day rolling NO_x emission rates were as low as 0.22 lb/million Btu heat input from conventional PC units applying only LNB.

unavailable during the development of the technical support document.

The NO_x control performances of both flue gas treatment technologies (i.e., SNCR and SCR) were evaluated based on short-term test data from retrofit installations and permitted conditions for new units. Long-term CEM data were used to evaluate SNCR for FBC boilers and SCR for pulverized coal-fired units. The flue gas treatment NO_x control technology currently receiving the most attention in the U.S. is SCR for conventional coal-fired utility steam generating units.

Short-term test results of SNCR applied to fossil-fuel fired utility boilers were obtained on 2 conventional coal-fired, 7 FBC, 2 oil-fired, and 10 gas-fired applications. For the conventional coal-fired units, the NO_x reductions varied from 30 to 60 percent at full load, with NO_x emission levels from 0.5 to 0.76 lb/million Btu. These units were originally uncontrolled pre-NSPS units. The NO_x emissions from the seven FBC units ranged from 0.03 to 0.1 lb/million Btu at full load conditions. For oil-fired units, the NO_x emissions varied from 0.14 to 0.17 lb/million Btu, depending on the NH_3/NO_x ratio. This corresponds to NO_x removal efficiencies of 48 to 56 percent from uncontrolled levels. For gas-fired boilers, NO_x emissions ranged from 0.07 to 0.10 lb/million Btu at full load conditions or about 10 to

40 percent reduction in NO_x emissions. One utility company reported information on the retrofit of 16 gas/oil-fired steam generating units indicating a 25 to 30 percent reduction in NO_x emissions from combustion-controlled levels.

For evaluating the performance of SCR, short-term test results were obtained from pilot-scale installations at two coal-fired and one oil-fired steam generating unit, and from commercial-scale installations at two coal-fired and two gas-fired steam generating units. Permitted conditions for six new coal-fired facilities and two new gas-fired facilities equipped with SCR systems also were obtained. In addition, long-term CEM NO_x emission data for full-scale SCR applications at five pulverized coal-fired units with SCR were obtained. To date, EPA is not aware of any full-scale SCR applications on oil-firing steam generating units in the U.S.

For the pilot-scale coal-fired demonstrations, the project results indicate that 75 to 80 percent NO_x reductions from uncontrolled levels were achieved.

Commercial-scale SCR installations on coal-fired units currently operating in the U.S. are designed for NO_x reductions between 50 and 63 percent from combustion control levels, with design and permitted NH_3 slip levels (i.e., amount of unreacted NH_3 in exhaust gas) of 5 ppm or less.

Short-term test results obtained from new installations range from 0.10 to 0.15 lb/million Btu. The long-term CEM data obtained from two of these coal-fired units have been evaluated using statistical analyses. The results indicate that the estimated achievable NO_x emission rate from both units is 0.142 lb/million Btu heat input, on a 30-day rolling average basis. Further, the EPA recently analyzed long-term CEM data from five new U.S. coal-fired units. All units operated below their permitted NOx emission levels, which were no greater than 0.17 lb/million Btu (EPA report "Performance of Selective Catalytic Reduction Technology for NOx Emissions at Coal-Fired Electric Utility Units in the United States and Western Europe"). Currently, EPA does not have CEM data available for a coal-fired U.S. unit that just started up (Birchwood Unit 1). However, in a recent public forum (cite: presentation by David Gallaspy, VP Asia Pacific Rim, Southern Electric International, at the 5th Annual CCT Conference, Tampa, Florida, Jan. 7-10, 1997) the operating utility stated that this unit is achieving 0.15 to 0.16 lb/million Btu with combustion controls alone and 0.07 to 0.08 lb/million Btu with the addition of SCR.

Permitted NO_x emission levels (30-day rolling average) for new coal-fired utility steam generating units equipped with SCR typically range from 0.15 lb/million Btu for pulverized coal-fired units to 0.25 lb/million Btu for stoker units.

For gas-fired steam generating units equipped with SCR, no permitted NO_x emission levels were available for gas-fired utility steam generating units equipped with SCR; however, permitted NO_x levels range from 0.01 to 0.03 lb/million Btu for new gas-fired industrial steam generating units equipped with SCR. No permitted NO_x levels were available for new oil-fired steam generating units, either utility or industrial, equipped with SCR.

B. Control Technology Costs

The annualized costs and cost effectiveness of the NO_x control options for utility steam generating units are given in Table 2. The cost algorithms and assumptions used to estimate capital and annualized costs and the model boilers developed for analyses are described in the technical support documents.[2] (For SCR and SNCR costs, refer to the Draft Technical Report "Cost Estimates for Selected Applications of NO_x Control Technologies on Stationary Combustion Boilers," March 1996.)

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[2] Note that updated costs of SNCR and SCR applications have been presented in the document "Cost Estimates for Selected Applications of NO_x Control Technologies on Stationary Combustion Boilers," March 1996. These updated costs are shown in Table 2.

TABLE 2. ANNUALIZED COSTS AND INCREMENTAL COST EFFECTIVENESS (OVER THE BASELINE) OF NO_x CONTROLS ON UTILITY STEAM GENERATING UNITS (1995 Dollars)[3]

Steam Generating Unit Type	SNCR		SCR	
	Total Annualized Costs (mills/kwh)	Cost Effectiveness ($/ton NO_x Removed)	Total Annualized Costs (mills/kwh)	Cost Effectiveness ($/ton NO_x Removed)
Gas	0.5 - 0.8	1,600 - 3,100	0.55 - 1.1	1,400 - 2,700
Oil	0.7 - 1.0	1,150 - 1,600	0.95 - 1.7	1,550 - 2,700
Coal	1.2 - 1.7	1,170 - 1,630	2.1 - 3.3	1,460 - 2,270

The costs are presented in ranges to reflect the range of sizes (100 to 1,000 MW) of the modeled units. The costs presented are based on a capacity factor of 0.65. The costs for SNCR and SCR with combustion controls are for retrofit installations and these costs for new boilers might be lower than the costs shown in Table 2. (It is not expected that gas- and oil-fired units would utilize SCR to meet the proposed revised standards and, thus, these units would not incur the costs associated with SCR use.) The cost effectiveness listed for each control option represents the incremental cost-effectiveness of applying that technology over the baseline (i.e., NO_x levels being achieved with technologies installed to meet the current NSPS).

[3] In Table 2, the SNCR and SCR costs are for applications on wall-fired boilers, designed to achieve a NO_x emission limit of 0.15 lb/million Btu. The baseline NO_x levels used in determining the cost-effectiveness estimates were: (1) 0.45 lb/million Btu for coal-fired boilers, (2) 0.25 lb/million Btu for gas-fired boilers, and (3) 0.30 lb/million Btu for oil-fired boilers.

The main differences between industrial steam generating units and utility steam generating units are that industrial steam generating units tend to be smaller and tend to operate at lower capacity factors. The differences between industrial and utility steam generating units would be reflected in the cost impacts of the various NO_x control technologies. Smaller sized and lower capacity factor units tend to have higher cost on a per unit output basis. The annualized costs and cost effectiveness of the NO_X control options, based on a model boiler analysis, for industrial steam generating units are given in Table 3.

The costs are presented in ranges to reflect the range of sizes (100 to 1,000 million Btu per hour) and capacity factors (0.1 to 0.6) of the modeled units. The cost effectiveness listed for each control option represents the

TABLE 3. ANNUALIZED COSTS AND INCREMENTAL COST EFFECTIVENESS (OVER THE BASELINE) OF NO_x CONTROLS ON INDUSTRIAL STEAM GENERATING UNITS (1995 Dollars)

Fuel Type	SNCR		SCR	
	Annualized Costs (expressed as % of steam costs)	Cost Effectiveness ($/ton NO_x Removed)	Annualized Costs (expressed as % of steam costs)	Cost Effectiveness ($/ton NO_x Removed)
Gas/Distillate Oil	1.5 - 47.3	3,400 - 95,300	5.4 - 108.5	6,200 - 147,900
Residual Oil	2.2 - 47.5	1,080 - 23,700	6.6 - 113.0	2,500 - 43,100
Coal	1.9 - 15.2	550 - 4,710	10.3 - 45.2	1,590 - 8,700

incremental cost-effectiveness of applying that technology over the baseline (i.e., NO_x levels being achieved with technologies installed to meet the current NSPS).

C. Regulatory Approach

In selecting a regulatory approach for formulating revised standards to limit NO_x emissions from new fossil fuel fired steam generating units, the performance and cost of the NO_x control technologies discussed above were considered. The technical basis selected for establishing revised NO_x emission limits is the performance of SCR (in combination with combustion controls). The regulatory approach adopted to revise the current fuel/boiler-specific standards would establish for both utility and industrial steam generating units one emission standard which would be based on the performance of SCR on coal-fired units in combination with combustion controls. This uniform standard would be applicable regardless of fossil fuel type or boiler type.

This regulatory approach differs from the historical approach to establishing NO_x emission limits for fossil fuel-fired steam generating units, in which different emission limits are developed for different combinations of fuel (gas, oil, coal) and boiler types, based on the performance of a particular control technology applied to each fuel/boiler type combination. The current subparts Da and Db standards for NO_x emissions are based on this approach. Under this new regulatory approach, the focus is on controlling NO_x emissions from the generation of electricity or steam based on BDT without regard to specific type of steam generating equipment. This approach provides an incentive to consider both fuel/boiler type combination and control technology when developing a NO_x control strategy. Since the basis selected for the revisions is the high NO_x removal performance of SCR, the relationship between boiler NO_x emissions and boiler design, fuel, and operation is of lesser concern than if the basis was the performance of combustion controls. Under the Clean Air Act Amendments of 1990, the definition of "Best Available Control Technology" was revised to include clean fuels. The definition of "continuous system of emission reduction" under section 111 also allows EPA to consider clean fuels because the term includes any process for production or operation of any source which is inherently low polluting or non-polluting. Under this regulatory approach, an emission limit is developed based on the performance of the cleanest fuel so long as there is a technology which allows other fuels to comply with that limit while providing cost-effective NO_x reductions. This approach addresses the primary regulatory concern, NO_x, but also can result in lower carbon dioxide (CO_2), air toxics, particulate, and SO_2 emissions, as well as lower solid waste and waste water discharges.

The EPA's analysis shows that SCR can reduce NO_x emissions from coal-fired units to 0.15 lb/million Btu heat input. For oil-fired units, SNCR in combination with combustion controls would be able to achieve this NO_x level. New gas-fired units may require some degree of SNCR if improved combustion controls alone are unable to achieve this level.

In light of the cost considerations associated with the application of flue gas treatment over the range of industrial gas-fired and distillate oil-fired units, a higher uniform NO_x emission limit of 0.20 lb/million Btu heat input was selected for industrial steam generating units. Under EPA's regulatory approach, new gas-fired and distillate oil-fired units would not require any additional controls over those required under the current NSPS. Based on EPA's cost impact analysis, it is estimated that by establishing the NO_x level at 0.20 lb/million Btu rather than at 0.15 lb/million Btu, the annual nationwide control costs for new industrial steam generating units will be reduced substantially, about 70 percent, since the revision would result in no additional controls on gas- and distillate oil-fired units. Since these gas and distillate oil-fired units tend to be smaller in size and operated at lower capacity factors than coal-fired industrial units, they tend to have much higher cost-effectiveness values associated with the application of flue gas treatment than do coal-fired units.

The single emission limitation approach would expand the control options available by allowing the use of clean fuels as a method for reducing NO_x emissions. Since projected new utility steam generating units are predominantly coal-fired, the use of clean fuels (i.e., natural gas) as a method of reducing NO_x emissions from these coal-fired steam generating units may give the regulated community a more cost-effective option than the application of SCR. Similarly, for industrial units, the use of clean fuels as a method of reducing emissions may be a cost-effective approach for coal-fired and residual oil-fired industrial steam generating units.

Summary of Analyses. In order to determine the appropriate form and level of control for the proposed revisions, EPA performed extensive analyses of the potential national impacts associated with the revised standards. These analyses examined the potential incremental national environmental and cost impacts resulting from EPA's regulatory approach in the fifth year following proposal of the revised standards. The environmental impacts of the revised standards were examined by projecting NO_x emissions for each planned utility boiler and industrial boiler. The cost impact analysis of the regulatory approach included an estimation of the unit capital expenditures for air pollution control equipment, as well as operating and maintenance expenses associated with the equipment. These costs were examined both in terms of annualized costs and percent of boiler output. The regulatory approach also was examined in terms of cost per ton of NO_x removed.

The regulatory baseline used for the national impact analyses consists of permitted levels for the planned utility steam generating units and the existing NSPS applicable to industrial steam generating units (i.e., subpart Db). The projected 5-year utility boiler population was based on information obtained from two published reports which list planned utility units. Utility owners and regulatory agencies were contacted to update these projections and to determine the permitted NO_x emission levels for these units. It is estimated that a total of 17 new boilers will be built over the 5-year period, which would become subject to the revised subpart Da NO_x standard. For the industrial boiler category, sales data and projected growth rates were used to estimate the number, capacity, fuel type, and capacity factor of the industrial units expected to be built during a 5-year period. The analysis projects that 381 new industrial steam generating units will be constructed over the 5-year period under the regulatory baseline. This projected total would consist of 293 natural gas- or distillate oil-fired units, 66 residual oil-fired units, and 22 coal-fired units.

Shown in Table 4 are the annualized costs, NO_x reduction (tons/year), and cost effectiveness ($/ton of NO_x removed) for the utility and industrial steam generating units regulated under EPA's regulatory approach. Note that the cost effectiveness is the average incremental costs per ton of NO_x removed over the baseline (i.e., current NSPS). The cost effectiveness is determined by dividing the change in annualized cost by the change in annual emissions, as compared to the current standards.

TABLE 4. SUMMARY OF NATIONAL IMPACTS FOR UTILITY AND INDUSTRIAL STEAM GENERATING UNITS

Impacts	Units	Utility Steam Generating Units	Industrial Steam Generating Units
Annualized Costs: Total	$million/year	40	41
Range	% of boiler output	0 - 4.3	0 - 11.8
Average	% of boiler output	2.0	1.8
NO_X Reduction	Tons/year	25,840	19,980
Cost Effectiveness			
Range	$/Ton NO_X Removed	0 - 3,240	0 - 4,800
Average	$/Ton NO_X Removed	1,510	2,030

As shown in Table 4, under EPA's regulatory approach, national NO_x emissions would be reduced by about 41,560 megagrams (Mg) (45,800 tons) per year. These NO_x reductions on utility and industrial units will be obtained at an average cost effectiveness of about $1,770/ton of NO_x removed.

D. Revised Standard for Electric Utility Steam Generating Units (Subpart Da)

All known operating utility steam generating units currently subject to subpart Da are coal-fired and use some form of combustion control to comply with applicable emission limits. However, six recently installed conventional PC units and some FBC units use add-on NO_x controls. Most new electric utility steam generating units are projected to burn coal. Consequently, the NO_x studies used to develop the proposed revision have concentrated on the combustion of coal.

The current NO_x standards for subpart Da were based on combustion control techniques and are fuel-specific. When these limits were promulgated in 1979, the most effective combustion control techniques for reducing NO_x emissions from utility steam generating units were judged to be combinations of staged combustion, LEA, and reduced heat release rate.

Currently, SCR is considered to be the most effective NO_x control technology for new electric utility steam generating units. Based on available performance data and cost analyses, the Administrator has concluded that the application of SCR represents the best demonstrated system of continuous emission reduction (taking into consideration the cost of achieving such emission reduction, any nonair quality health and environmental impact, and energy requirements). Consequently, SCR was chosen as the basis for revising the NO_x emission limits due to its relatively high NO_x removal efficiency.

The national average cost effectiveness of additional NO_x control under this regulatory approach is about $1,500/ton NO_x removed. Further, under EPA's regulatory approach, the cost of the installation and operation of the additional NO_x control equipment does not result in any significant adverse economic impacts.

A benefit associated with the use of EPA's regulatory approach as the basis for the revised NO_x standard is that the approach expands the control options available by allowing the use of clean fuels as a method for reducing NO_x emissions. Since projected new utility steam generating units are predominantly coal-fired, the use of clean fuels (i.e., natural gas) can be a method of achieving cost effective emission reductions from these coal-fired steam generating units.

Based on available performance data and cost analyses, the Administrator is proposing today a revised NO_x emission limit for electric utility steam generating units that applies regardless of fuel type and which is based on coal-firing and the performance of SCR control technology in combination with combustion controls. The analysis shows that SCR can reduce NO_x emissions from coal-fired units to 0.15 lb/million Btu heat input or less. This NO_x emission level reflects about a 75 percent reduction in NO_x emissions over the current subpart Da limits for coal-fired units. This NO_x emission level also reflects about a 50 and 25 percent reduction in NO_x emissions over the current subpart Da limits for oil-fired and gas-fired units, respectively.

Regarding the revised NO_x emission limitation, the Administrator sought to achieve the best balance between control technology and environmental, economic, and energy considerations. In selecting a single emission limitation for electric utility steam generating units that would be applicable regardless of fuel type, the Administrator sought not to limit the control options available for compliance, but to provide flexibility for cheaper and less energy intensive control technologies (i.e., by allowing the use of clean fuels for reducing NO_x emissions). Available gas-based control techniques are cofiring with coal or oil, reburning, and switching to gas as the principal fuel. The clean fuel approach fits well with pollution prevention which is one of the EPA's highest priorities. Because natural gas is essentially free of sulfur and nitrogen and without inorganic matter typically present in coal and oil, SO_2, NO_x, inorganic particulate, and air toxic compound emissions can be dramatically reduced, depending on the degree of natural gas use. With these environmental advantages, gas-based control techniques would be viewed as a sound alternative to flue gas treatment technologies for coal or oil burning.

The fuel cost differential between gas and coal is one of the main concerns with the application of gas-based technologies for the reduction of NO_x from coal-fired boilers. Access to gas supply (proximity to pipeline) and long-term gas availability are additional concerns that may limit natural gas use solely for NO_x control. Therefore, selection of SCR in combination with combustion controls as the basis for the proposed revised NO_x limitation is appropriate since this technology is expected to be an important part of the compliance mix for coal-fired boilers. Again, for new oil-fired units, SNCR in combination with combustion controls would be able to achieve the proposed limit. New gas-fired units may require some degree of SNCR if improved combustion controls alone are unable to achieve the revised limitation which reflects a 25 percent reduction in NO_x emissions over the current NO_x standard for gas-fired utility units.

Output-Based Format. The EPA has established pollution prevention as one of the its highest priorities. One of the opportunities for pollution prevention lies in simply using energy efficient technologies to minimize the generation of emissions. The EPA investigated ways to promote energy efficiency in utility plants by changing the manner in which it regulates flue gas NO_x emissions (see EPA white paper, "Use of Output-based Emission Limits in NOx Regulations"). Therefore, in an effort to promote energy efficiency in utility steam generating facilities, the Administrator is proposing an output-based standard, which is a revised format, for subpart Da.

Traditionally, utility NO_x emissions have been controlled on the basis of boiler input energy (lb of NO_x/million Btu heat input). However, input-based limitations allow units with low operating efficiency to emit more NO_x per megawatt (MWe) of electricity produced than more efficient units. Considering two units of equal capacity, under current regulations, the less efficient unit will emit more NO_x because it uses more fuel to produce the same amount of electricity. One way to regulate mass emissions of NO_x and plant efficiency is to express the NO_x emission standard in terms of output energy. Thus, an output-based emission standard would provide a regulatory incentive to enhance unit operating efficiency and reduce NO_x emissions. Two of the possible output-based formats considered for the revised NO_x standard were: (1) mass of NO_x emitted per gross boiler steam output (lb NO_x/million Btu heat output), and (2) mass of NO_x emitted per net energy output [lb NO_x/megawatt-hour(MWh)]. The criteria used for selecting the format were ease in monitoring and compliance testing and ability to promote energy efficiency.

The objective of an output-based standard is to establish a NO_x emission limit in a format that incorporates the effects of plant efficiency. Additionally, the limit should be in a format that is practical to implement. Thus, the format selected must satisfy the following: (1) provide flexibility in promotion of plant efficiency; (2) permit measurement of parameters related to stack NO_x emissions and plant efficiency, on a continuous basis; and (3) be suitable for equitable application on a variety of power plant configurations.

The option of lb NO_x/million Btu steam output accounts only for boiler efficiency and ignores both the turbine cycle efficiency and the effects of energy consumption internal to the plant. The boiler efficiency is mainly dependent on fuel characteristics. Beyond the selection of fuels, plant owners have little control over boiler efficiency. This option, therefore, does not meet the first criterion, because it provides the owners with minimal opportunities for promoting energy efficiency at their respective plants.

The second output-based format option of lb NO_x/MWh net meets all three criteria. In this case, the net plant energy output represents the energy exported out of the plant to other sources. This energy output takes into account all internal energy consumption and losses for the plant. An emission limit based on this format, therefore, provides the owners with all possible opportunities for promoting energy efficiency at their respective plants. This option would require continuous measurement of the mass rate of NO_x emissions and net plant energy output. The net energy output can include both electrical and thermal (process steam) outputs. Both of these energy outputs are relatively easy to measure accurately, and currently are measured routinely in power plants. Further, since this option does take into account the auxiliary power requirements, an emission limit based on this format can be applied equitably on a variety of power plant configurations.

Based on this analysis, an emission limit format based on mass of NO_x emissions per net plant energy output is selected for the proposed output-based standard. Because electrical output, measured directly in MW, is the main energy output at all power plants, it is desirable to use a format in "lb NO_x/MWh net." The EPA, however, requests comments on the selected format of "lb NO_x/MWh net" since a format of "lb NO_x/MWh gross" may be more equitable in light of the varying auxiliary power requirements that may exist at power plants. At cogeneration plants, energy output is associated with electricity and process steam; however, the useful heat (Btu/hr) present in steam can be converted to MW.

Compliance with the output-based emission limit would require continuous measurement of plant operating parameters associated with the mass rate of NO_x emissions and net energy outputs. In the case of cogeneration plants where process steam is an output product, means would have to be provided to measure the process steam flow conditions and to determine the useful heat energy portion of the process steam that is interchangeable with electrical output.

Instrumentation already exists in power plants to conduct these measurements since the instrumentation is required to support current emission regulations and normal plant operation. Consequently, compliance with the output-based emission limit is not expected to require any additional instrumentation. A current federal regulation (40 CFR Part 75) requires measurements of both NO_x concentration and flue gas flow rate (for calculating mass rate of NO_x emissions), whereas metering of net electrical output must be provided to account for net electrical sendout from the plant. Therefore, no additional instrumentation is required for conventional utility applications to comply with the output-based emission limit.

However, additional signal input wiring and programming is expected to be required to convert the above measurements into the compliance format (lb NO_x/MWh net).

For cogeneration units, steam is also generated for process use. The energy content of this process steam also must be considered in determining compliance with the output-based standard. This can be accomplished by measuring the total heat content of each process steam source (from the measured flow, pressure, and temperature) and then calculating the useful energy output. If the equivalent electrical energy (useful heat) content of the process steam is expressed in the form of curves, no new instrumentation is required. The information from these curves can be programmed into the plant monitoring system and the equivalent electrical energy for each process steam source can be calculated. This equivalent electrical energy (MW) can be added to the plant's actual net electrical output (MW) to arrive at the plant's total net energy output (MW). This total net energy output (MW) used with the mass rate of NO_x emissions (lb/h), yields the NO_x emissions (lb/MWh net) for compliance.

Since all the reported data obtained throughout the development of the revised standards are in the current format of lb/million Btu heat <u>input</u>, EPA applied an efficiency factor to the current format to develop the output-based NO_x limit. The efficiency factor approach was selected because the alternative of converting all the reported data in the database to an output-basis would require extensive data gathering and analyses. Applying a baseline net efficiency would essentially convert the selected heat input-based NO_x level to an output-based emission limit. The EPA solicits comment on this format approach.

The output-based standard must be referenced to a baseline efficiency. Most existing electric utility steam generating plants fall in the range of 24 to 38 percent efficiency. However, newer units (both coal- and gas-fired) operate around 38 percent efficiency; therefore, 38 percent was selected as the baseline efficiency. The EPA requests comment on: (1) whether 38 percent is an appropriate baseline efficiency, (2) how often the baseline efficiency should be reviewed and revised in order to account for future improvements in electric generation technology, and (3) whether a 30-day rolling average is sufficient to account for any operating efficiency variability.

The efficiency of electric utility steam generating units usually is expressed in terms of heat rate, which is the ratio of heat input, based on higher heating value (HHV) of the fuel, to the energy (i.e., electrical) output. The heat rate of a utility steam generating unit operating at 38 percent efficiency is 9.5 joules per watt hour (9,000 Btu per kilowatt hour).

The efficiency of a steam generating plant refers to its net efficiency. This is the net useful work performed divided by the fuel heat input, taking into account the energy requirements for auxiliaries (e.g., fans, soot blowers, pumps, fuel handling and preparation systems) and emission control equipment. For conventional electric utility units, the total useful work performed is the net electrical output (i.e., net busbar power leaving the plant) from the turbine/generator set. Determination of the net efficiency of a cogeneration unit includes the net electrical output and the useful work achieved by the energy (i.e., steam) delivered to an industrial process. Under a Federal Energy Regulatory Commission (FERC) regulation, the efficiency of cogeneration units is determined from "...the useful power output plus one half the useful thermal output ...," 18 CFR Part 292, §205. Therefore, to determine the process steam energy contribution to net plant output, a 50 percent credit of the process steam heat was selected.

This proposed rulemaking does not include a specific methodology or methodologies for determining the unit net output. The EPA intends to specify such methods in the final rule. Consequently, the EPA requests comment on: (1) the specific methodology or methodologies appropriate and verifiable for determining the net output of a steam generating unit; and (2) whether a fixed percentage credit of 50 percent is representative of the useful heat in varying quality of process steam flows. In addition, the EPA solicits comment on whether the output-based standard in the proposed rule will promote energy efficiency improvements. The EPA acknowledges that a supplemental notice may be necessary should a specific methodology for determining the unit net output be decided upon prior to finalizing this rule.

Based on the analysis showing that SCR can reduce NO_x emissions from coal-fired units to 0.15 lb/million Btu heat input or less, the calculation of an equivalent output-based standard is straight forward using the baseline net plant efficiency. The output-based NO_x standard is computed by using the following equation:

$$E_o(\text{lb/MWh}) = E_i(\text{lb/million Btu}) * n * 1000 \text{ kwh/MWh}$$

Using an input-based emission level (E_i) of 0.15 lb/million Btu and a baseline net efficiency (n) of 9,000 Btu/kwh, the resulting output-based limit (E_o) is 1.35 lb/MWh. Based on the available performance data, cost analysis, and the above calculation, the Administrator is proposing today a revised NO_x emission limit for new electric utility steam generating units of 1.35 lb of NO_x/MWh net.

E. Industrial-Commercial-Institutional Steam Generating Units (Subpart Db)

The NO_x standard promulgated in 1986 for industrial steam generating units is based on the performance of LEA and LEA-staged combustion modification techniques. The NO_x control technology examined for revising the current NSPS is SCR in combination with combustion controls. Currently, SCR is considered to be the most effective NO_x control technology for new industrial steam generating units. Based on available performance data and cost analyses, the Administrator has concluded that the application of SCR represents the best demonstrated system of continuous emission reduction (taking into consideration the cost of achieving such emission reduction, any nonair quality health and environmental impact, and energy requirements) for coal- and residual oil-fired industrial steam generating units.

Under EPA's regulatory approach, the national average cost effectiveness of additional NO_x control is about \$2,000/ton NO_x with a total nationwide increase in annualized costs of about \$40 million. Further, EPA's economic impacts analysis indicates that revised standards based on the adopted regulatory approach would increase product prices by less than 1 percent if all steam cost increases were passed through to product prices. Consequently, the economic impacts of standards based on

EPA's regulatory approach are not expected to be significant.

As discussed above for utility steam generating units, a benefit associated with the selection of EPA's regulatory approach as the basis for the revised NO_x standard is that this regulatory approach expands the control options available by allowing the use of clean fuels as a method for reducing NO_x emissions. The use of clean fuels (i.e., natural gas) may be a cost-effective method of reducing emissions from the coal- and residual oil-fired industrial steam generating units.

Based on available performance data and cost analyses, the Administrator is proposing a revised NO_x emission limit for industrial steam generating units which is applicable regardless of fuel or boiler type, except for one boiler/fuel category. The proposed revision is based on coal-firing and the performance of SCR control technology in combination with combustion controls.

Regarding the revised NO_x emission limitation for industrial units, the Administrator again sought to achieve the best balance between control technology and environmental, economic, and energy considerations and not to limit the control options, but to provide flexibility for cheaper and less energy-intensive control technologies. Due to the cost considerations associated with the application of flue gas treatment on the range of industrial gas-fired and distillate oil-fired units, the Administrator is proposing for industrial steam generating units a revised NO_x emission limit of 0.20 lb/million Btu heat input, except for the category of low heat release rate units firing natural gas or distillate oil which retains the current NO_x emission limit of 0.10 lb/million Btu heat input. The revised limit is the same as the current NO_x emission limit for the category of high heat release rate units firing natural gas or distillate oil. Therefore, under the revised limit, new gas-fired and distillate oil-fired units would not require any additional controls over that required under the current NSPS. Based on the cost impact analysis, it is estimated that by establishing the revised limit at 0.20 lb/million Btu rather than at 0.15 lb/million Btu, the annual nationwide control costs for new industrial steam generating units will be reduced substantially, about 70 percent lower, since the revision would result in no additional controls on gas- and distillate oil-fired units. This revised limit reflects about a 50 to 70 percent reduction in NO_x emissions over the current subpart Db limits for coal-fired and residual oil-fired units.

For low heat release rate steam generating units firing fuel mixtures that include natural gas or distillate oil, the NO_x emission limit would be determined by proration of the NO_x standards based on the respective amounts of each fuel fired when the mixture contains more than 20 percent, based on heat input, of natural gas or distillate oil. Low heat release rate steam generating units firing fuel mixtures that include 20 percent or less of natural gas or distillate oil are subject to the NO_x emission limit of 0.20 lb/million Btu heat input since the use of natural gas or distillate oil in these units is considered to be a clean fuel-based NO_x control technique.

Again, in selecting a single emission limitation that would be applicable regardless of fuel type and boiler type, the Administrator sought to expand the control options available by allowing the use of clean fuels as a method for reducing NO_x emissions. The use of clean fuels (i.e., natural gas) as a method of reducing emissions from these coal-fired and residual oil-fired industrial steam generating units may be a cost-effective approach.

Because the fuel cost differential between gas and coal and access to gas supply (proximity to pipeline) are concerns that may limit natural gas use solely for NO_x control, the control option of SCR in combination with combustion controls that was selected as the basis for the revised NO_x limitation is appropriate since this technology is expected to be an important part of the compliance mix. For residual oil-fired units, SNCR in combination with combustion controls would be able to achieve the proposed limit.

Consideration of an Output-Based Format. This proposed rulemaking for industrial steam generating units does not include an output-based format as is included in today's proposed NO_x revision for electric utility steam generating units. As stated in the discussion on the proposed revision to the utility NSPS, the Administrator has established pollution prevention as one of the EPA's highest priorities. One of the opportunities for pollution prevention lies in simply using energy efficient technologies to avoid generating emissions. In an effort to promote energy efficiency in industrial steam generating facilities, a revised output-based format for the proposed NO_x emission limit was investigated.

The two output-based formats considered were lb NO_x/MWh and lb NO_x/million Btu steam output, the same formats considered for utility steam generating units. The option of lb/MWh, selected for utility units, is more easily understood for utility applications generating only, or mostly, electricity but is unreasonable for industrial units supplying only steam (no electricity generation). The other output-based format option of lb/million Btu steam output would be based on steam output from the boiler and could be applicable to all new industrial boilers. However, this output-based format option, as previously discussed, provides the owners with only minimal opportunities for promoting energy efficiency at their respective facilities. In addition, an output-based format would require additional hardware and software monitoring requirements for measuring the stack gas flow rate (for determining the mass rate of NO_x emissions), steam production rate, steam quality, and condensate return conditions. Instrumentation to conduct these measurements may not generally exists at industrial facilities as they do at utility plants.

The EPA intends to continue to investigate appropriate output-based formats for industrial units which would promote energy efficiency. Consequently, the EPA requests comment on: (1) the specific methodology or methodologies appropriate and verifiable for determining the net energy output of an industrial steam generating unit, (2) the frequency at which the unit's net output or efficiency should be documented, and (3) whether an output-based standard for industrial steam generating units will promote efficiency improvements.

F. Alternate Standard for Consideration

Because of the fundamental change in the format of the NO_x NSPS for electric utility units, the EPA anticipates that there will be numerous concerns and comments concerning the proposed output-based standard. Therefore, the

Administrator is proposing as an alternate to the output-based standard, a traditionally formatted standard of 0.15 lb/million Btu heat input. This input-based NO_x level served as the basis for developing the output-based standard being proposed today. The EPA's preference is to specify an output-based standard in the final rule, but also is proposing the input-based emission level as an alternate in case public comments and/or findings warrant reconsideration of promulgating an output-based standard. Therefore, the EPA also solicits comment on the input-based emission level selected as the basis for the output-based standard, which is achievable using SCR.

The majority of the electric utility steam generators regulated under subpart Da are also regulated under the Title IV Acid Rain Program of the Clean Air Act. The Acid Rain Continuous Emission Monitoring Regulation (40 CFR part 75) requires affected units to install, operate, maintain and quality-assure continuous monitoring systems for SO_2, NO_x, flow rate, CO_2, and opacity. Section 75.64 of part 75 requires quarterly reporting of SO_2, NO_x, and CO_2 emissions in a standardized EDR format specified by the Administrator. The EDR reporting format has been used successfully for Acid Rain Program implementation since 1994. The EDR data from calendar year 1995 were used by the EPA to determine the compliance status of the Phase I-affected Acid Rain units with respect to their allowable annual SO_2 emissions.

At the present time, there is an initiative underway in the Eastern United States to establish an emission trading program for NO_x. The program is called the Ozone Transport Commission (OTC) NO_x Budget Program. Beginning in 1998, the largest sources of NO_x in 13 eastern States will be required to account for their NO_x emissions during the ozone season. Many of the sources in the NO_x Budget Program are electric utility steam generators which are also regulated under NSPS subpart Da and under 40 CFR part 75. Many other NO_x Budget Program sources are regulated under NSPS subpart Db. To implement the NO_x Budget Program, emission data from the affected sources will be submitted electronically, in the EDR format specified under 40 CFR part 75.

At present, any Acid Rain-affected or NO_x Budget Program-affected steam generating unit which is also regulated under NSPS subpart Da or Db must meet the reporting requirements of NSPS in addition to the Acid Rain or NO_x Budget Program reporting requirements. For example, the owner or operator of a subpart Da utility unit would have to submit written NSPS compliance reports each quarter for SO_2, NO_x, and opacity, in addition to the electronic report in EDR format required by part 75.

In many instances, the data reported to meet the requirements of NSPS, the Acid Rain Program, and the OTC NO_x Budget Program are generated by the same CEM systems. The CEM data are manipulated in different ways for the different programs, but very often the NSPS, Acid Rain, and OTC reports are derived from the same data. In view of this, EPA believes it is worthwhile to explore the possibility of consolidating or streamlining the reporting requirements for steam generating units subject to these programs.

The EPA has evaluated different ways in which the reporting burden might be reduced for units subject both to NSPS subpart Da or Db and to other program(s) such as the Acid Rain or NO_x Budget Program (see Docket Item #II-B-11; "Assessment of Consolidating NSPS Subpart Da and Part 75 Reporting Requirements;" February 25, 1997). The Agency has concluded that the best way to accomplish this would be to allow the SO_2, NO_x, and opacity reports currently required under subpart Da or Db to be submitted electronically in the part 75 EDR format, in lieu of written reports. To implement this electronic reporting option, special EDR record types would have to be created to accommodate the compliance information required by subparts Da and Db.

The EPA believes that in order to derive the full benefit from the electronic reporting option in today's proposal, it should be made available to all subpart Da and

Db affected facilities, including units presently regulated under those subparts, and including affected units that are not regulated under part 75 or the NO_x Budget Program. Today's proposal, therefore, amends §§ 60.49a and 60.49b to allow the owner or operator of any subpart Da or Db facility to choose the electronic reporting option.

IV. Modification and Reconstruction Provisions

Existing steam generating units that are modified or reconstructed after today would be subject to today's revision and to the requirements in the General Provisions (40 CFR 60.14 and 60.15), which apply to all NSPS. Few, if any, changes typically made to existing steam generating units would be expected to bring such steam generating units under the proposed NO_x revisions.

A modification is any physical or operational change to an existing facility which results in an increase in emissions, 40 CFR Part 60, §60.14. Changes to an existing facility which do not result in an increase in emissions, either because the nature of the change has no effect on emissions or because additional control technology is employed to offset an increase in emissions, are not considered modifications. In addition, certain changes have been exempted under the General Provisions (40 CFR §60.14). These exemptions include production increases resulting from an increase in the hours of operation, addition or replacement of equipment for emission control (as long as the replacement does not increase emissions), and use of an alternative fuel if the existing facility was designed to accommodate it, 40 CFR §60.14.

Rebuilt steam generating units would become subject to the proposed NO_x revision under the reconstruction provisions, regardless of changes in emission rate, if the fixed capital cost of reconstruction exceeds 50 percent of the cost of an entirely new steam generating unit of comparable design and if it is technologically and economically feasible to meet the applicable standard, 40 CFR §60.15.

V. Summary of Considerations Made in Developing the Rule

The Clean Air Act was created, in part, "...to protect and enhance the quality of the Nation's air resources so as to promote the health and welfare and the productive capacity of its population..." As such, this regulation protects the public health by reducing emissions of NO_x from electric utility and industrial facilities. Nitrogen oxides can cause lung tissue damage, can increase respiratory illness, and are a primary contributor to acid rain and ground level ozone formation. The proposed revisions will substantially reduce NO_x emissions to the levels achievable using BDT.

The alternatives considered in the development of these proposed revisions are based on emission and operating data received from operating utility and industrial facilities and permitted information for planned utility and industrial facilities. The EPA met with industry representatives several times to discuss these data and information. In addition, equipment vendors, State regulatory authorities, and environmental groups had opportunity to comment on the background information that was prepared for the proposed revisions. Of major concern to the industry was the actual numerical limits of the revisions, and whether they would, in effect, dictate the use of only one control option. By using a regulatory approach that expands NO_x control options, the EPA is proposing revised NO_x limits that address their concern.

Another major concern expressed by the utility industry was the potential impact of the revision on existing utility units. Under the General Provisions (40 CFR 60, subpart A) for standards of performance for new stationary sources, an affected facility is defined as a unit which commences construction, modification, or reconstruction after the date of publication of the proposed rulemaking. To date, no existing utility unit has become subject to subpart Da under either the modification or reconstruction provision.

In the revisions, EPA has made an effort to minimize the impacts on monitoring, recordkeeping, and reporting requirements. The proposal does alter the monitoring and recordkeeping requirements (for NO_x only) currently listed in subpart Da by incorporating by reference the monitoring provisions of the Acid Rain Regulation (40 CFR parts 72, 73, 75, 77, and 78). However, 40 CFR part 75 already requires new electric utility steam generating units to comply with these monitoring requirements. In addition, requirements for monitoring of net output, both electrical and process steam, is being added but these are routinely measured by utility boiler owners and operators. Accordingly, the averaging period (i.e., 30-day rolling average) and reporting requirements of subpart Da are not being changed or replaced by incorporating the monitoring provisions of the Acid Rain Regulation. The proposal has no anticipated impact on monitoring, recordkeeping, and reporting requirements for new electric utility steam generating units. This proposal does not alter the monitoring, recordkeeping, or reporting requirements currently listed in subpart Db.

Representatives from other EPA offices and programs are included in the regulatory development process as members of the Work Group. The Work Group is involved in the regulatory development process, and must review and concur with the regulation before proposal and promulgation. Therefore, the EPA believes that the implications to other EPA offices and programs have been adequately considered during the development of these revisions.

VI. Summary of Cost, Environmental, Energy, and Economic Impacts

The cost, environmental, energy, and economic impacts of the proposed revisions are expressed as incremental differences between the impacts of utility and industrial steam generating units complying with the proposed revisions and these units complying with current emission standards (i.e., subpart Da and Db or States' permitted limits).

The revised NO_x standards may increase the capital costs for new steam generating units because the implementation of either SNCR or SCR requires additional hardware.

The EPA estimates that 17 new utility steam generating units and 381 new industrial steam generating units will be constructed over the next 5 years and thus would be subject to the revised standards. The nationwide increase in annualized costs in the 5th year following proposal for the projected new electric utility steam generating units subject to the revised standards is estimated to be about $40 million for utility steam generating units. This impact assumes that all planned coal-fired units remain coal-fired and employ SCR. This represents an increase of about 1.3 mills/kwh in annual costs, or about a 2 percent increase in the cost of generating electricity for these units.

The nationwide increase in annualized costs for new industrial steam generating units subject to the revised standards would be about $41 million in the 5th year following proposal. This is based on the assumption that no affected unit switches fuel type as the result of the revision. This represents an average increase of about 2 percent in the cost of producing steam for new units.

The cost effectiveness of the revised NO_x standards over the existing standards for electric utility units is projected to be about $1,650/Mg ($1,500/ton) of NO_x removed. For industrial-commercial-institutional units, the cost effectiveness of the revised NO_x standards over the existing standards is projected to be about $2,200/Mg ($2,000/ton) of NO_x removed.

The primary environmental impact resulting from the revised NO_x standards is reductions in the quantity of NO_x emitted from new steam generating units subject to the proposed revisions to the NSPS. Estimated baseline NO_x emissions from these new steam generating units are 39,500 Mg/year (43,600 tons/year) from utility steam generating units and 58,400 Mg/year (64,400 tons/year) from industrial steam generating units in the 5th year. The revised standards are projected to reduce baseline NO_x emissions by 23,000 Mg/year (25,800 tons/year) from utility steam generating units and 18,000 Mg/year (20,000 tons/year) from industrial steam generating units in the 5th year after proposal. This represents an approximate 42 percent reduction in the growth of NO_x emissions from new utility and industrial steam generating units subject to these revised standards.

National secondary impacts for increased NH_3 emissions are estimated to be about 300 tons/year from utility steam generating units and about 420 tons/year from industrial steam generating units due to the NH_3 slip from SCR or SNCR systems. Ammonia slip tends to be higher from SNCR systems.

There are additional energy requirements associated with SCR systems. Electrical energy is required for booster fans used to overcome the pressure drop across the SCR reactor and related ductwork. This energy requirement is estimated at about 0.4 percent of the boiler output (and was not specifically incorporated into the determination of the baseline operating efficiency of 38 percent).

The goal of the economic impact analysis was to estimate the market response to the proposed changes to the existing standards for NO_x emissions for both utility and industrial steam generating units. The analysis did not quantitatively address the possibility of changing technology, fuel, or capacity utilization in response to the proposed revisions. Therefore, costs and projected impacts may be overestimated.

For utilities, cost estimates for affected facilities expected to be built between 1996 and 2000 were used to project year by year price and quantity changes. The price changes were estimated by assuming that the production weighted average cost changes for the entire industry are passed on to consumers. These estimates resulted in price increases of between 0.01 percent in 1996 and 0.02 percent in 2000. Because the demand for electricity is inelastic, these price changes are projected to result in 0.002 percent (1996) and 0.004 percent (2000) decreases in electricity sales. These numbers are quite small on an industry-wide basis. The price changes on a facility basis, if the cost were completely passed on to the consumer, would be as high as 6 percent; 9 of the 13 facilities would be 1 percent or less. Because the rate structure of utilities generally has reflected the average costs for a utility which includes multiple facilities, such a price increase is unlikely. Therefore, the market impacts for electricity generation are estimated to be small.

For industrial boilers, data by industry for fuel type, furnace type, capacity, and capacity utilization were combined with projections of boiler sales to estimate the number and type of boilers to be replaced. The analysis assumes that a boiler will be replaced with a boiler of the same fuel type, technology, capacity, and capacity utilization. The analysis modeled the response of a firm faced with an added pollution control cost for boiler replacement as a decision concerning the timing of the replacement. The firm replaces an existing boiler when operating costs have increased enough to make the installation of a new boiler cheaper than continuing to operate the old boiler. Added pollution control costs for a new boiler leads the firm to defer the replacement of the existing boiler until the increased cost of operation makes replacement even with the additional pollution control costs the cheaper option. The average replacement delay was very long for small, low-capacity utilization boilers requiring control. Replacement delay may be viewed as an indicator of the severity of impact. For these boilers, the assumption that they will be replaced by a boiler of the same type, size, fuel type, and capacity utilization is questionable in the absence of the proposed revision and even more unlikely in the face of the proposed revision that would add to the cost of small, low-capacity utilization boilers. For affected boilers, the annual compliance cost as a share of annual steam costs ranges from 3 percent for the largest high-capacity utilization residual oil boiler to over 100 percent for the smallest low-capacity utilization spreader stoker boilers.

For industrial boilers, net additions to steam capacity were also estimated. The U.S. Department of Energy's Industrial Demand Module of the National Energy Modeling System (NEMS) was used with U.S. Department of Commerce projections to estimate steam demand through 2010. The yearly increase in demand for steam for each industry corresponds to the required new steam generating capacity needed. The new generating capacity is assumed to reflect estimates of the existing distribution of boilers for that industry by fuel, furnace type, furnace size, and capacity utilization. This leads to an estimate of new capacity affected by the proposed changes in the standards, which ranges from 45 percent for primary metals to 51 percent for paper. The control costs are small for the affected portion of each industry compared to the size of value of shipments for the affected portion. These percentages range from 0.002 percent for miscellaneous manufacturing to 0.8 percent for the paper industry.

The annualized social costs estimated in the economic impact analysis include costs of more stringent control for projected new utility boilers, industrial replacement boilers, and additions to industrial boiler net capacity. For the utility boilers, the estimated cost is $40 million dollars which includes both the control cost ($39 million) and a loss to consumers because of reduced electricity purchases ($1 million). The cost of replacing industrial boilers ($26 million) includes both the higher cost associated with delaying replacement and the higher control cost after replacement. Estimated control costs for projected net new boiler capacity is $49 million. Because of the number of markets involved, no estimates of market changes were made for industries affected by the proposed revision. Therefore, the losses to consumers from reduced purchases of the final goods due to increased costs of steam from industrial boilers were not developed. The assumptions that replacement industrial boilers would be the same as the boilers they replace in the absence of the proposed revisions and that no affected boilers would respond to the proposed revision by changing size, fuel, type, or capacity utilization of affected boilers lead to higher cost estimates. Impacts on fuel markets such as coal are not quantified.

VII. Request for Comments

The Administrator requests comments on all aspects of the proposed revisions. All significant comments received will be considered in the development and selection of the final revisions. The EPA specifically solicits comment on whether, and on what basis, the output-based standard being proposed for electric utility steam generating units under subpart Da should be applied to industrial steam generating units under subpart Db to promote energy efficiency. The EPA recognizes that there are a multitude of applications for which industrial units provide steam, such as basic plant heating and air conditioning, drying, process heating, etc. In addition, industrial units often supply steam for more than one application. As such, the net efficiency of industrial steam generating units can cover a wide range depending on what fraction of the energy delivered to the process actually is used. Unlike utility applications, many industrial applications utilize the heat of condensation. Thus, industrial units would have a much higher net efficiency than a utility application (e.g., 38 percent). Therefore, the output-based standard, as proposed for subpart Da, would be inappropriate for industrial units.

Consequently, the EPA specifically requests comments and information on: (1) how to encourage energy efficiency in industrial applications; (2) whether an output-based format should be applied to industrial steam generating units; (3) the range of net efficiencies applicable to various industrial applications; (4) whether a generic or separate output-based standards should be developed for different industrial applications; (5) the appropriate baseline efficiency; and (6) how the net efficiency of an industrial unit should be determined. For example, the comments might outline the mechanisms or approaches used by industrial facilities to determine the efficiency of various process applications or what fraction of the energy delivered to the process is actually used. Specific comments are requested from all interested parties including State agencies, Federal agencies, environmental groups, industry associations, and individual citizens. Written comments must be addressed to the Air Docket Section address given in the ADDRESSES section of this preamble, and must refer to Docket No. A-92-71.

VIII. Administrative Requirements

A. Public Hearing

A public hearing will be held, if requested, to discuss the proposed revisions in accordance with section 307(d)(5) of the Clean Air Act. Persons wishing to make oral presentations on the proposed revisions should contact EPA at the address given in the ADDRESSES section of this preamble. Oral presentations will be limited to 15 minutes each. Any member of the public may file a written statement before, during, or within 30 days after the hearing. Written statements must be addressed to the Air Docket Section address given in the ADDRESSES section of this preamble, and must refer to Docket No. A-92-71.

A verbatim transcript of the hearing and written statements will be available for public inspection and copying during normal working hours at the EPA's Air Docket Section in Washington, D.C. (see ADDRESSES section of this preamble).

B. Docket

The docket is an organized and complete file of all the information submitted to, or otherwise considered by, EPA in the development of this proposed rulemaking. The principal purposes of the docket are: (1) to allow interested parties to readily identify and locate documents so that they can intelligently and effectively participate in the rulemaking process, and (2) to serve as the record in case of judicial review (except for interagency review materials).

C. Clean Air Act Procedural Requirements

1. Administrator's Listing-Section 111. As prescribed by section 111(b)(1)(A) of the Act, establishment of standards of performance for electric utility steam generating units and industrial-commercial-institutional steam generating units was preceded by the Administrator's determination that these sources contribute significantly to air pollution which may reasonably be anticipated to endanger public health or welfare.

2. Periodic Review-Section 111. This regulation will be reviewed again 8 years from the date of promulgation of

any revisions to the standard resulting from this proposal as required by the Act. The review will include an assessment of the need for integration with other programs, enforceability, improvements in emission control technology, and reporting requirements.

3. External Participation-Section 117. In accordance with section 117 of the Act, publication of this review was preceded by consultation with independent experts. The Administrator will welcome comments on all aspects of the proposed revisions, including economic and technical issues.

4. Economic Impact Analysis-Section 317. Section 317 of the Act requires the EPA to prepare an economic impact assessment for any emission standards under section 111 of the Act. An economic impact assessment was prepared for the proposed revision to the standards. In the manner described above under the discussions of the impacts of, and rationale for, the proposed revision to the standards, the EPA considered all aspects of the assessments in proposing the revision to the standards. The economic impact assessment is included in the docket listed at the beginning of today's notice under SUPPLEMENTARY INFORMATION.

D. Office of Management and Budget Reviews

1. Paperwork Reduction Act. The proposed revisions contain no changes to the information collection requirements of the current NSPS. Those requirements were

previously submitted for approval by the Office of Management and Budget (OMB) during the original development of the NSPS.

2. Executive Order 12866. Under Executive Order 12866 (58 FR 51735, Oct. 4, 1994), the Agency must determine whether the regulatory action is "significant" and, therefore, subject to OMB review and the requirements of the Executive Order. The Order defines "significant" regulatory action as one that is likely to lead to a rule that may: (1) have an annual effect on the economy of $100 million or more, or adversely and materially affecting a sector of the economy, productivity, competition, jobs, the environment, public health or safety, or State, local, or tribal governments or communities; (2) create a serious inconsistency or otherwise interfere with an action taken or planned by another agency; (3) materially alter the budgetary impact of entitlements, grants, user fees, or loan programs or the rights and obligation of recipients thereof; (4) raise novel legal or policy issues arising out of legal mandates, the President's priorities, or the principles set forth in the Executive Order.

Pursuant to the terms of Executive Order 12866, EPA has determined that this rule is a "significant regulatory action" because this action may have an annual effect on the economy of $100 million or more. As such, this action was submitted to OMB for review. Changes made in response to OMB suggestions or recommendations will be documented in the public record.

3. <u>Regulatory Flexibility Act.</u> The Regulatory Flexibility Act (RFA) requires EPA to give special consideration to the impact of regulation on small businesses, small organizations, and small governmental units. The major purpose of the RFA is to keep paperwork and regulatory requirements from getting out of proportion to the scale of the entities being regulated, without compromising the objectives of, in this case, the Clean Air Act. The RFA specifies that EPA must prepare an initial regulatory flexibility analysis if a proposed regulation will have a significant economic impact on a substantial number of small entities. The Agency certifies that the rule will not have a significant impact on a substantial number of small entities.

Firms in the electric services industry (SIC 4911) are classified as small by the U.S. Small Business Administration if the firm produces less than four million megawatts a year. For the time period of the analysis (1996 to 2000) one projected new utility boiler may be affected and small. Of the 13 projected new utility boilers, 10 are known to not be small, and 2 of the remaining 3 are not expected to incur additional control costs due to the regulation. The size of the owning entity is unknown for the remaining utility boiler. That boiler also has the smallest cost in mills/kwh (0.07) of the 11 projected units to have additional control costs. Therefore, no significant small business impacts are anticipated for the utility boilers.

Regarding industrial boilers, EPA expects that some small businesses may face additional pollution control costs. It is difficult to project the number of industrial steam generating units that will both incur control costs under the regulation and be owned by a small entity. Since the rule only affects new sources, and plans for new industrial boilers are not available (as they are for electric utilities), linking new projected boilers to size of owning entity is difficult. The projection of 381 new boilers has 293 of the boilers incurring no costs because they are projected to be either gas-fired or distillate-oil-fired units that would require no additional control. Some of the 88 remaining boilers which are projected to incur costs in complying with the regulation may be owned by small entities. The size of the owning entity and the size of the boiler are not related in any simple way, but smaller entities may be more likely to have a smaller boiler. The proposed applicability size cut off of 100 million Btu/hour heat input for industrial boilers would be expected to result in fewer small entities being affected. Since only 88 industrial boilers are expected to incur any costs and many of them are likely to be owned by large entities, EPA projects that fewer than 88 of these boilers will be owned by small entities.

The information used for economic impact analysis for the proposed rule matches boiler size and fuel type to various industries. These data overestimate the share of boilers that are residual-oil-fired and coal-fired, but the data are nonetheless useful for estimating the potential economic impact of the rule on small entities in terms of cost-to-sales ratio. This analysis estimates costs as a percent of value of shipments (closely related to sales) for affected facilities. The average control cost as a percentage of value of shipments for all affected facilities is .07 percent. The range of average control cost across industries varies from a low of .004 percent for primary metals to a high of .8 percent for the paper industry. Although the cost varies by industry, boiler size, and fuel, it is unlikely that any affected small entities will have a control cost to sales ratio of greater than one percent. Based on these estimates, EPA certifies that the rule will not have a significant impact on a substantial number of small entities.

4. <u>Unfunded Mandates Act of 1995.</u> Under section 202 of the Unfunded Mandates Reform Act of 1995 ("Unfunded Mandates Act"), signed into law on March 22, 1995, EPA must

prepare a statement to accompany any proposed rule where the estimated costs to State, local, or tribal governments, or to the private sector, will be $100 million or more in any one year. Under section 205, EPA must select the most cost-effective, least costly, or least burdensome alternative that achieves the objective of the rule and is consistent with statutory requirements. Section 203 requires EPA to establish a plan for informing and advising any small governments that may be significantly impacted by the rule.

The unfunded mandates statement under section 202 must include: (1) a citation of the statutory authority under which the rule is proposed; (2) an assessment of the costs and benefits of the rule, including the effect of the mandate on health, safety and the environment, and the federal resources available to defray the costs; (3) where feasible, estimates of future compliance costs and disproportionate impacts upon particular geographic or social segments of the nation or industry; (4) where relevant, an estimate of the effect on the national economy;

and, (5) a description of EPA's prior consultation with State, local, and tribal officials.

Since this proposed rule is estimated to impose costs to the private sector in excess of $100 million, EPA has prepared the following statement with respect to these impacts.

a. Statutory authority.

The statutory authority for this rulemaking is identified and described in Sections I and VII of the preamble. As required by section 205 of the Unfunded Mandates Act, and as described more fully in Section III of this preamble, EPA has chosen to propose a rule that is the least burdensome alternative for regulation of these sources that meets the statutory requirements under the Act.

b. Costs and benefits.

As described in section VI of the preamble, the estimate of annual social cost for the regulation is $40 million for utility boilers and $41 million for industrial boilers in the year 2000. Certain simplifying assumptions, such as no fuel switching in response to the proposed rule, may have resulted in a significant overestimation of these costs.

The pollution control costs will not impose direct costs for State, local, and tribal governments. Indirectly, these entities face increased costs in the form of higher prices for electricity and the goods produced in the facilities requiring new industrial boilers that would be subject to this proposed rule. There are no federal funds available to assist State, local, or tribal governments with these indirect costs.

Because this regulation affects boilers as they are constructed (or modified), the emission reductions attributable to the regulation increase year by year until all existing boilers have been replaced. In the year 2000, the NO_x emission reduction relative to the baseline for utility boilers is estimated to be 26,000 tons per year. In the year 2000, the NO_x emission reduction relative to the baseline for industrial boilers that represent net additions to existing capacity is estimated to be 20,000 tons per year. Emissions reductions from replacement boilers are not quantified because of difficulties in characterizing emission rates for the boilers being replaced and the inability of the replacement model to predict selection of different types of boilers in both the baseline case and in response to the proposed regulation. A qualitative analysis of industrial boiler replacement raises the possibility that replacement delay due to the proposed revision may keep some boilers continuing to emit at a higher level than they would in the baseline case where they would be replaced by a lower emitting boiler.

Reducing emissions of NO_x has the potential to benefit society in a number of ways. Emissions of NO_x result in a wide range of damages, ranging from human health effects to impacts on ecosystems. They not only contribute to ambient levels of potentially harmful nitrogen compounds, but they also have important precursor effects. In combination with volatile organic compounds (VOCs), they contribute to the formation of ground level ozone. Along with emissions of sulfur oxides, they are also precursors to particulate matter and acidic deposition.

See Table 5 for a summary of linkages between NO_x emissions and damage categories.

TABLE 5. LINKAGES BETWEEN NO_x EMISSIONS AND DAMAGE CATEGORIES: STRENGTH OF THE EVIDENCE

	Direct Effects	Precursor Effects		
	Ambient NO_x Levels	Ambient Ozone Levels	Ambient Particulate Matter	Acid Deposition
Human Health				
Acute Morbidity	√√√	√√√	√√√	√
Chronic Morbidity	√√	√	√√√	
Mortality		√	√√√	
Ecosystems				
Terrestrial	√√√[4]	√√		√√
Aquatic	√√			√√√
Commercial Biological Systems[5]				

4 Evidence indicates that NO_x can have both positive and negative effects in this category.

5 Evidence for this category relates specifically to certain commercial crop or tree types rather than to the more general terrestrial damages that are covered in the separate ecosystems category

Agriculture	√	√√√		
Forestry		√√		√
Visibility	√√		√√√	
Materials	√√√		√√√	√√√

√ = weak evidence
√√ = limited evidence
√√√ = strong evidence

Benefits are only qualitatively addressed in the regulatory impacts analysis (RIA) because of difficulties in physically locating the not yet built boilers and translating their emission reductions into changes in ambient concentrations of nitrogen compounds, ozone concentrations, and particulate matter concentrations.

c. Future and disproportionate costs.

The rule is not expected to have any disproportionate budgetary effects on any particular region of the nation, any State, local, or tribal government, or urban or rural or other type of community. Only very small increases in electricity prices are estimated. See section VII C. 4 of the preamble for more detail.

d. Effects on national economy.

Significant effects on the national economy from this proposed rule are not anticipated. See section VIII C. 4 of the preamble for more detail.

e. Consultation with government officials.

The Unfunded Mandates Act requires that EPA describe the extent of the Agency's prior consultation with affected State, local, and tribal officials, summarize the officials' comments or concerns, and summarize EPA's response to those comments or concerns. In addition, section 203 of the Act requires that EPA develop a plan for informing and advising small governments that may be significantly or uniquely impacted by a proposal.

In the development of this rule, the EPA has provided small governments (State, local, and tribal) the opportunity to comment on this regulatory program. A fact sheet which summarized the regulatory program, the control options being considered, preliminary revisions, and the projected impacts was forwarded to seven trade associations representing State, local, and tribal governments. A meeting was held for interested parties to discuss and provide comments on the program. Written comments also were requested. The main comments received dealt with the need to consider the impacts of the revisions on small units and facilities. Commenters also stated that the requirement for an integrated resource plan is unnecessary and burdensome for small operators and may constitute an unfunded mandate. In response to this concern, EPA removed the requirement for an integrated resource plan from this rulemaking. In response to the concern regarding the cost impacts on small industrial steam generating units, EPA is proposing a higher NO_x emission limit for industrial units than it is proposing today for utility units. The revised limit for industrial units effectively results in no additional controls for gas and distillate oil-fired industrial units over that required to comply with the current emission limits. As described in sections VIII D.3 and D.4.c of the preamble, the impacts on small businesses and governments have been analyzed and indicate that small governments are not significantly impacted by this rule and thus no plan is required.

F. Miscellaneous

LIST OF SUBJECTS IN 40 CFR PART 60

Environmental protection, Air pollution control, Intergovernmental relations, Incorporation by reference, Reporting and recordkeeping requirements, Electric utility steam generating units, Industrial-commercial-institutional steam generating units.

VII. Statutory Authority

The statutory authority for this proposal is provided by sections 101, 111, 114, 301, and 407 of the Clean Air Act, as Amended; 42 U.S.C. 7401, 7411, 7414, 7601, and 7651f.

7/1/97 ____________

Dated Administrator

PART 60 - [AMENDED]

It is proposed to amend 40 CFR Subpart Da as follows:

* * * * *

1. In §60.41a, the list of definitions is revised to add the following definitions:

Net output means the net useful work performed by the steam generated taking into account the energy requirements for auxiliaries and emission controls. For units generating only electricity, the net useful work performed is the net electrical output (i.e., net busbar power leaving the plant) from the turbine/generator set. For cogeneration units, the net useful work performed is the net electrical output plus one half the useful thermal output (i.e., steam delivered to an industrial process).

* * * * *

2. In §60.44a, paragraphs (a) and (c) are revised to read as indicated below. Paragraph (d) is added that reads as follows:

60.44a Standard for nitrogen oxides.

(a) On and after the date on which the initial performance test required to be conducted under §60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility, except as provided under paragraphs (b) and (d) of this section, * * *

* * * * *

(c) Except as provided under paragraph (d) of this section, * * *

(d) On and after the date on which the initial performance test required to be conducted under §60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility for which construction, modification, or reconstruction commenced after (date of publication in the Federal Register) any gases which contain nitrogen oxides in excess of 170 nanograms per joule (1.35 pounds per megawatt-hour) net energy output.

* * * * *

3. In 60.47a, paragraph(k) is added that reads as follows:

(k) The procedures specified in paragraphs (k)(1) through (k)(3) of this section shall be used to determine compliance with the output-based standard under 60.44a(d).

(1) The owner or operator of an affected facility with electricity generation shall install, calibrate, maintain, and operate a wattmeter; measure net electrical output in megawatt-hour on a continuous basis; and record the output of the monitor.

(2) The owner or operator of an affected facility with process steam generation shall install, calibrate, maintain, and operate meters for steam flow, temperature, and pressure; measure net process steam output in joules per hour (or Btu per hour) on a continuous basis; and record the output of the monitor.

(3) For affected facilities generating process steam in combination with electrical generation, the net energy output is determined from the net electrical output measured in (k)(1) plus 50 percent of the net thermal output of the process steam measured in paragraph (k)(2).

* * * * *

4. Section 60.49a (i) is revised and a new paragraph (j) is added, to read as follows:

(i) Except as provided in paragraph (j) of this section, the owner or operator of an affected facility shall submit the written reports required under this section * * *

(j) The owner or operator of an affected facility may submit electronic quarterly reports for SO_2 and/or NO_x and/or opacity in lieu of submitting the written reports required under paragraphs (b) and (h) of this section. The format of each quarterly electronic report shall be consistent with the electronic data reporting format specified by the Administrator under § 75.64 (d) of this chapter. The electronic report(s) shall be submitted no later than 30 days after the end of the calendar quarter and shall be accompanied by a certification statement from the owner or operator, indicating whether compliance with the applicable emission standards and minimum data requirements of this subpart was achieved during the reporting period.

PART 60 - [AMENDED]

It is proposed to amend 40 CFR Subpart Db as follows:

* * * * *

1. In §60.44b, paragraphs (a), (b), (c), and (e) are revised to read as indicated below. Paragraph (l) is added that reads as follows:

60.44b Standard for nitrogen oxides.

(a) Except as provided under paragraphs (k) and (l) of this section, * * *

(b) Except as provided under paragraphs (k) and (l) of this section, * * *

(c) Except as provided under paragraph (l) of this section, * * *

* * * * *

(e) Except as provided under paragraph (l) of this section, * * *

* * * * *

(1) On and after the date on which the initial performance test is completed or is required to be completed under §60.8 of this part, whichever date comes first, no owner or operator of an affected facility which commenced construction, modification, or reconstruction after (date of publication in the Federal Register) shall cause to be discharged into the atmosphere from that affected facility any gases that contain nitrogen oxides (expressed as NO_2) in excess of the following limits:

(1) If the affected facility combusts coal, oil, or natural gas, or a mixture of these fuels, or with any other fuels: a limit of 86 ng/J (0.20 lb/million Btu) heat input; or

(2) If the affected facility has a low heat release rate and combusts natural gas or distillate oil in excess of 30 percent of the heat input from the combustion of all fuels, a limit determined by use of the following formula:

$$E_n = [(0.10 * H_{go})+(0.20 * H_r)]/(H_{go}+H_r)$$

where:

E_n is the NO_x emission limit, (lb/million Btu),

H_{go} is the heat input from combustion of natural gas or distillate oil, and

H_r is the heat input from combustion of any other fuel.

2. A new paragraph (u) is added to Section 60.49b, to read as follows:

(u) The owner or operator of an affected facility may submit electronic quarterly reports for SO_2 and/or NO_x and/or opacity in lieu of submitting the written reports required under paragraphs (h),(i),(j),(k) or (l) of this section. The format of each quarterly electronic report shall be consistent with the electronic data reporting format specified by the Administrator under § 75.64 (d) of this chapter. The electronic report(s) shall be submitted no later than 30 days after the end of the calendar quarter and shall be accompanied by a certification statement from the owner or operator, indicating whether compliance with the applicable emission standards and minimum data requirements of this subpart was achieved during the reporting period.

BILLING CODE: 6560-50-P

New Source Review

Pollution Control Project (PCP) Exemption From PSD

Basis for PSD Applicability

Modifications to Major Facilities.

The modification would result in a **significant net emissions increase** of any pollutant regulated under the Act. [Rule 62-212.400(2)(d)4.a(ii)]

Significant Net Emissions Increase.

A significant net emissions increase of a pollutant regulated under the Act is a net emissions increase equal to or greater than the applicable significant emission rate listed in **Table 212.400-2**, Regulated Air Pollutants - Significant Emission Rates. [Rule 62-212.400(2)(e)2]

TABLE 212.400-2

SIGNIFICANT EMISSION RATES (TPY)	
Carbon monoxide	100
Nitrogen oxides	40
Sulfur dioxide	40
VOC	40
PM/PM10	25/15

Also SAM (7), Fluorides (3), TRS, Mercury, Etc.

PCP Exemption to PSD

Pollution Control Project Exemption.

A pollution control project that is being added, replaced, or used **at an existing electric utility steam generating unit** and that meets the requirements of **40CFR52.21(b)(2) (iii)(h)** shall not be subject to the preconstruction review requirements of this rule.
[Rule 62-212.400(2)(a)2, FAC]

40CFR52.21(b)(2) (iii)(h)

The addition, replacement or use of a pollution control project **at an existing electric utility steam generating unit**, **<u>unless</u>** the Administrator determines such addition, replacement, or use renders the unit less environmentally beneficial, or except (1) When the Administrator has reason to believe that the pollution control project would result in a significant net increase in representative actual annual emissions of any criteria pollutant over levels used for that source in the most recent air quality impact analysis in the area conducted for the purpose of title I if any, and (2) The Administrator determines the increase will cause or contribute to a violation of any national ambient air quality standard or PSD increment, or visibility limitation.

Definition of PCP

40CFR52.21(b)(32)

Any activity or project undertaken at an existing electric steam generating unit for purposes of reducing emissions from such unit. Such activities and projects are limited to:

(I) The **installation of conventional or innovative pollution control technology**, including but not limited to advanced flue gas desulfurization, sorbent injection for sulfur dioxide control and nitrogen oxides control and electrostatic precipitators;

(2) An activity or project to accommodate **switching to a fuel which is less polluting** than the fuel in use prior to the activity or project, including, but not limited to natural gas or coal reburning, or the co-firing of natural gas and other fuel for the purpose of controlling emissions;

(3) A permanent clean coal technology demonstration project (including clean coal repowering)

Examples of PCPs (?)

- SO_2 Scrubber at TEC - Big Bend Units 1 and 2
- Powder River Basin Coal - TEC Gannon to reduce NO_x
- Co-firing of Natural Gas FPC - Anclote
- Big Reductions (1000s) Small collateral increases (100s)

Big Bend Unit 1 and 2 Scrubber

- Defined as PCP. Reductions in 10,000s
- Don't forget the "unless" provision
- Possible Violations of NAAQS
- How???
- On/off Scrubber
- Overscrub at Big Bend in xs of "1.2"
- Shift allowances to Gannon in 1,000s

Gannon Coalyard Throughput

- Increase to compensate for use of lower Btu PRB coal to lower NOx.
- PRB coal lower in sulfur too
- Expect >10,000 TPY decrease in NOx
- Expect 1-7,000 TPY increase in SO2!!
- >>40 TPY. Why?? How?? “unless”
- Allowances - Big Bend (burn petcoke?)

Anclote Gas Co-firing

- Sure looks like it by definition! But what was purpose? Economic or Environmental?
- Historical oil = 1-1.5 % S. Wanted to co-fire correspondingly higher sulfur fuel oil > 2.5%
- No quantification of increases and decreases.
- Got them to agree to take 1.5% S limit on fuel oil. Purpose of gas use - environmental.
- Got commitment to always use gas at low load. Control Acid Smut fallout.

Conclusions

- Limited <u>only</u> to power industry
- Even obvious PCPs require scrutiny
- New Source Review Reform will rescind PCP exemption or expand applicability
- EPA has a memo applying PCPs to other industries. July, 1994.
- Be careful. It contravenes our rules and is not one of our Guidances. Call!!