

**Cedar Bay Cogeneration Facility
Air Quality Analysis
November, 1992**

ENSR

**Prepared for:
U.S. Generating Company
Bethesda, Maryland**

DRAFT (Revision 1)

ENSR Consulting and Engineering

Acton, Massachusetts

ENSR Document Number 5402-027-230

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EXECUTIVE SUMMARY

The objective of the information presented in this document is to provide data useful for assessing:

- 1) whether, on balance, the air pollutant emissions and air quality impacts of the Cedar Bay Power Plant, as proposed to be modified, and the addition of the three new yet-to-be-proposed package boilers scheduled for the SKC site necessary to provide the 640,000 lb. of steam per hour for SKC's use, will be less than the emissions and air quality impacts of the future SKC recycling operation, providing the 640,000 lb. of steam per hour for SKC's use without the power plant. This is the comparison required directly by the June 16, 1992 Order of the Siting Board.
- 2) whether, on balance, the permitted air pollutant emissions and air quality impacts of the Cedar Bay Power Plant, as proposed to be modified, and the addition of the three new yet-to-be-proposed package boilers scheduled for the SKC site at their permitted capacity, will be less than the emissions and air quality impacts of the power plant as certified;
- 3) whether, on balance, the permitted air pollutant emissions and air quality impacts of the Cedar Bay Power Plant, as modified, and the addition of any boilers on the SKC site at their permitted capacity, will be less than the emissions and air quality impacts of the future SKC recycling operation at permitted capacity without the power plant;
- 4) whether the combustion and material handling sources at the Cedar Bay cogeneration facility by itself, as proposed to be modified, would either cause or contribute to a violation of an ambient air quality standard (AAQS) or cause or contribute to a violation of the allowable PSD increments, in either the region surrounding the facility (a PSD Class II area) or the two distant PSD Class I areas. The two PSD Class I areas are the Okefenokee and Wolf Island Wilderness areas in Georgia. In addition, information is presented to provide data useful for assessing whether the Cedar Bay facility would produce air toxics concentrations above the Draft Florida No Threat Levels (NTLs); and
- 5) to provide updated information on air emission controls and emission rates. The lower air pollutant emission rates for the Cedar Bay CFB boilers, and the inclusion of a new add-on technology (selective non-catalytic reduction) require some changes to the original Air Permit. To provide the state and EPA with accurate and updated information

on the project for review of the proposed changes, ENSR, on behalf of U.S. Generating Company, developed a technical review of the air emission controls and emission rates.

The "Cedar Bay Power Plant as certified" refers to the facility as described in the Final Order and Power Plant Site Certification PA 88-24 dated February 11, 1991 and the March 28, 1991 Final Determination by the FDER, Permit No. PSD-FL-137. The "Cedar Bay Power Plant as proposed to be modified" refers to the facility as described in the Amended Petition for Modification of Certification filed with the Division of Administrative Hearings on July 22, 1992, plus further improvements proposed by the Cedar Bay Cogeneration Project.

The "future SKC Recycling Operation without the power plant" refers to the two bark and three oil-fired boilers presently at the SKC site as they would be operated should the Cedar Bay power plant not be. As currently permitted, the three power boilers would fire Grade No. 6 residual fuel oil with a maximum sulfur content of 1.0%. In this hypothetical future case, without the Cedar Bay power plant, it is ENSR's understanding that the exhausts of the three power boilers would be combined and exhausted through a newly constructed 125 foot stack to lessen susceptibility to aerodynamic downwash effects caused by nearby structures.

The addition of the three new yet-to-be-prepared package "boilers scheduled for the SKC site necessary to provide the 640,000 lb of steam for SKC's use" refers to three package boilers to be proposed by SKC capable of producing a total of 375,000 lb/hr of steam. For purposes of the technical analyses for it is assumed that the 640,000 lb/hr steam requirement is met by the Cedar Bay Power plant supplying 380,000 lb/hr and the SK package boilers supplying 260,000 lb/hr.

The addition of "the three new yet-to-be-proposed package boilers scheduled for the SKC site at their permitted capacity" refers to these same boilers producing a total of 375,000 lb/hr of steam.

The proposed SK package boilers are capable of accommodating either fuel oil or natural gas. Not yet permitted, the current SK plans calls for No. 2 distillate fuel oil with a maximum sulfur content of 0.5% and an annual average of 0.3%.

In making the assessments for pollutant emissions, the maximum annual emissions of health criteria pollutants, other regulated pollutants, and non-regulated air toxics pollutants are compared. To compare the air quality impacts and evaluate compliance with the AAQS, PSD increments and draft NTLs, comprehensive atmospheric dispersion modeling was performed in accordance with EPA and Florida DER Guidelines.

Table ES-1 illustrates the difference in annual pollutant emissions between Cedar Bay as proposed to be modified plus the SK package boilers, and the future SKC recycling operation

TABLE ES-1

**Cedar Bay as Proposed to be Modified Plus SK Package Boilers
vs.
SKC Recycling
(Both Cases at 640,000 lb/hr Steam for SK)
Net Change in Annual Emissions Due To
Cedar Bay and SK Package Boilers**

Pollutants Category	Net Change
Health Criteria and PSD Increments	Decrease 300 tons
Total Regulated	Decrease 158 tons
Total Non-Regulated Air Toxics	Decrease 2 tons
Total Pollutants	Decrease 160 tons

(both cases at 640,000 lb/hr steam usage by to SKC). This table demonstrates the decreases achieved in the actual annual emissions of four categories of pollutants by operating the Cedar Bay facility and the SK package boilers and shutting down the SKC power and bark boilers. The health criteria and PSD increment pollutants are those for which ambient air quality standards and PSD increments have been established. The total regulated pollutants include the criteria and all PSD pollutants. Non-regulated air toxics represent twenty different compounds emitted by the sources in question which are included in the list of 751 compounds cited in Florida's Draft Air Toxics Permitting Strategy. In aggregating health criteria; PSD increment and regulated pollutants, TSP and PM-10 are treated as individual pollutants exclusive of one another. Although PM-10 are a portion of TSP, the health criteria standards address PM-10 while the PSD increments address TSP. In this context, they are also treated exclusively when comparing ambient impacts, for consistency with the standards and PSD increments.

The comparisons of annual emissions shown in the table assume that the SK package boilers always fire fuel oil. To the extent that they fire natural gas on an annual basis, any decreases shown in emissions would be greater. As shown in Table ES-1 decreases in air pollutant emissions are achieved by the Cedar Bay facility in each category.

A comparison of air quality impacts between the Cedar Bay facility, as proposed to be modified plus the SK package boilers, and the SKC recycling operation without the power plant (both cases at 640,000 lb/hr steam usage by SKC) is summarized in Table ES-2. The table summarizes the changes due to Cedar Bay as proposed to be modified and the SK package boilers for each criteria pollutant as well as total air toxics. Three values are listed for each pollutant: 1) the change to the maximum predicted concentration of the pollutant anywhere (higher, lower or insignificant); 2) the net effect on air quality on a regional basis in terms of the highest predicted pollutant concentrations (improved or degraded); and 3) the percent of locations for which modeling was performed which showed a net benefit in terms of the highest concentrations. A total of 1008 locations referred to as "model receptors" were addressed. The majority of these fall within 10 kilometers of the Cedar Bay facility, but a portion extend as far as 25 kilometers. As shown in Table ES-2, the Cedar Bay facility as proposed to be modified and the SK package boilers result in lower maximum concentrations of all criteria pollutants and total air toxics, a net improvement in the highest concentrations on a regional basis, and a net air quality benefit at virtually all locations.

A summary of the comparison of the maximum permitted annual pollutant emissions between Cedar Bay as certified and Cedar Bay as proposed to be modified plus the SK package boilers is presented in Table ES-3. This table illustrates the decrease in emissions resulting from Cedar Bay as proposed to be modified plus the SK package boilers for the four pollutant categories. As shown in the table, decreases are achieved in all four categories of pollutants.

TABLE ES-2

**Cedar Bay as Proposed to be Modified Plus SK Package Boilers
vs.
SKC Recycling
(Both Cases at 640,000 lb/hr Steam)
Air Quality Changes Due to Cedar Bay Plus SK Package Boilers**

Pollutant	Change to Maximum Concentration	Net Regional Air Quality Effect	Percent of Locations with Air Quality Benefit
3-hour SO ₂	Lower	Improved	98.4
24-hour SO ₂	Lower	Improved	98.4
Annual SO ₂	Lower	Improved	99.6
24-hour PM-10	Lower	Improved	99.7
Annual PM-10	Lower	Improved	99.7
1-hour CO	Lower	Improved	99.7
8-hour CO	Lower	Improved	99.7
Annual NO ₂	Lower	Improved	99.7
24-hour Pb	Lower	Improved	94.8
Annual Pb	Lower	Improved	74.8
8-hour Air Toxics	Lower	Improved	99.7
24-hour Air Toxics	Lower	Improved	99.7
Annual Air Toxics	Lower	Improved	99.6

TABLE ES-3

**Cedar Bay as Certified vs. Cedar Bay as Proposed to be Modified Plus
SK Package Boilers
Net Change in Permitted Annual Emissions Due to
Cedar Bay as Modified Plus SK Package Boilers**

Pollutants Category	Net Change
Health Criteria and PSD Increments	Decrease 1,443 tons
Total Regulated	Decrease 2,618 tons
Total Non Regulated Air Toxics	Decrease 34 tons
Total Pollutants	Decrease 2,652 tons

A summary of the differences in air quality impacts at permitted capacity between Cedar Bay as certified and Cedar Bay as proposed to be modified plus the SK package boilers is presented in Table ES-4. Lower maximum concentrations are shown to result from Cedar Bay as modified for most pollutants with the exception of SO₂. However, highest SO₂ concentrations are shown to improve on a regional basis, as is the case for all other pollutants as well, with a significant percent of locations experiencing a benefit. Impacts of CO are insignificant in each case, so a meaningful comparison cannot be made.

Table ES-5a summarizes the comparison of maximum permitted emissions between Cedar Bay as proposed to be modified plus the SK package boilers, and the SKC recycling operation. This table shows an increase in each of the four pollutant categories. However, these changes do not account for substantial additional decreases that will occur due to the shutdown of recovery boilers, lime kilns and smelt dissolving tanks at SKC as a result of SKC converting to a recycling operation.

According to preliminary estimates provided by KBN Engineering and Applied Sciences in documentation being prepared in support of the PSD permit application for the SK package boilers, substantial decreases over baseline emissions will be achieved, these are listed in Table ES-5b. As shown in the table, the overall result is a net decrease in the first three pollutant categories. Decreases in non-regulated air toxics were not estimated for the application, but these would also offset the increases shown in Table 5a to some extent.

Notwithstanding the above increases, as shown in Table ES-6, maximum pollutant concentrations are lower, a net regional air quality benefit results and the vast majority of locations experience a benefit with the Cedar Bay facility as proposed to be modified, compared to the SKC recycling operation.

Table ES-7 summarizes the results of the modeling for compliance with AAQS, PSD increments and Draft Air Toxics NTLs. For the applicable AAQS and PSD increment pollutants the predicted compliance status is listed. "Compliance" indicates that an evaluation of all major sources in Duval County in addition to Cedar Bay demonstrates compliance with the standard. "Insignificant Impacts" indicates that no evaluation of the standard was performed since Cedar Bay impacts were insignificant. "Does not cause or contribute to a violation" indicates that all major sources in Duval County were modeled but only those total concentrations to which the Cedar Bay facility contributed a significant concentration were evaluated, and those concentrations were predicted to be below the standards. As shown in the table, the predicted compliance status for each criteria pollutant and standard is favorable. For the draft No Threat Levels, the Cedar Bay facility,

TABLE ES-4

**Cedar Bay as Certified vs. Cedar Bay as Modified Plus SK Package Boilers
Air Quality Changes Due to Cedar Bay as Modified Plus SK Package Boilers**

Pollutant	Change to Maximum Concentration	Net Regional Air Quality Effect	Percent of Locations with Air Quality Benefit
3-hour SO ₂	Higher	Improved	80.1
24-hour SO ₂	Higher	Improved	66.6
Annual SO ₂	Lower	Improved	45.7
24-hour PM-10	Lower	Improved	47.8
Annual PM-10	Lower	Improved	55.6
1-hour CO	Insignificant	Insignificant	Not Applicable
8-hour CO	Insignificant	Insignificant	Not Applicable
Annual NO ₂	Lower	Improved	49.1
24-hour Pb	Lower	Improved	97.3
Annual Pb	Lower	Improved	97.3
8-hour Air Toxics	Lower	Improved	96.6
24-hour Air Toxics	Lower	Improved	96.6
Annual Air Toxics	Lower	Improved	97.0

TABLE ES-5a

**Cedar Bay as Modified Plus SK Package Boilers vs. SKC Recycling
Net Change in Permitted Annual Emissions Due to
Cedar Bay as Modified Plus SK Package Boilers**

Pollutants Category	Net Change
Health Criteria and PSD Increments	Increase 679 tons
Total Regulated	Increase 470 tons
Total Non Regulated Air Toxics	Increase 3 tons
Total Pollutants	Increase 473 tons

TABLE ES-5b

**Net Changes Due To Additional Sources Shutting Down^(a)
at SKC for Conversion to Recycling Operation**

Pollutants Category	Net Change	Combined Net Change
Health Criteria and PSD Increments	Decrease 4,668 tons	Decrease 3,989 tons
Total Regulated	Decrease 4,754 tons	Decrease 4,284 tons
^(a) Recovery Boilers, Lime Kilns, Smelt Dissolving Tanks		

TABLE ES-6

**Cedar Bay as Modified Plus SK Package Boilers at Permitted Capacity
vs.
SKC Recycling at Permitted Capacity
Air Quality Changes Due to Cedar Bay Plus SK Package Boilers**

Pollutant	Change to Maximum Concentration	Net Regional Air Quality Effect	Percent of Locations with Air Quality Benefit
3-hour SO ₂	Lower	Improved	97.8
24-hour SO ₂	Lower	Improved	98.2
Annual SO ₂	Lower	Improved	99.6
24-hour PM-10	Lower	Improved	99.7
Annual PM-10	Lower	Improved	99.7
1-hour CO	Lower	Improved	99.7
8-hour CO	Lower	Improved	99.6
Annual NO ₂	Lower	Improved	99.7
24-hour Pb	Lower	Improved	94.9
Annual Pb	Lower	Improved	77.4
8-hour Air Toxics	Lower	Improved	99.6
24-hour Air Toxics	Lower	Improved	99.6
Annual Air Toxics	Lower	Improved	99.6

TABLE ES-7

**Cedar Bay as Certified Compliance with Ambient
Air Quality Standards (AAQ), PSD Increments,
Draft Air Toxics No Threat Levels (NTLs)**

Pollutant	Standard	Predicted Compliance Status
SO ₂	AAQS PSD Class II PSD Class I	Does Not Cause or Contribute to a Violation Does Not Cause or Contribute to a Violation Compliance
PM-10	AAQS	Insignificant Impacts
TSP	PSD Class II PSD Class I	Insignificant Impacts Compliance
CO	AAQS	Insignificant Impacts
NO ₂	AAQS PSD Class II PSD Class I	Insignificant Impacts Insignificant Impacts Compliance
Pb	AAQS	Compliance
Air Toxics	NTL's	Compliance with 51 NTLs for 20 Compounds

as proposed to be modified, alone complies with all 51 NTLs for 20 different compounds. Some compounds have NTLs for more than one averaging period.

As conclusively demonstrated by the foregoing summary and further documented herein, the Cedar Bay facility as proposed to be modified, as modified plus the SK package boilers to be proposed, on balance, in terms of air quality, result in lower environmental impacts than either the SKC recycling operating or the Cedar Bay facility as originally certified.

PREFACE

The Air Quality Technical Analysis prepared by ENSR Consulting and Engineering is separated into four sections. The first two sections show that, on balance, the net air quality impacts of the Cedar Bay cogeneration facility as proposed to be modified and the addition of the three as-yet-to-be-proposed package boilers scheduled for the Seminole Kraft facility necessary to provide 640,000 pounds of steam per hour are less than the net air quality impacts of the Seminole Kraft recycling operation without the Cedar Bay cogeneration facility and that the net air quality benefits of the Cedar Bay as proposed to be modified along with the three as-yet-to-be-proposed package boilers at full capacity will be less than Cedar Bay as permitted. The third section demonstrates that the Cedar Bay cogeneration facility as proposed to be modified will comply with certain nonprocedural agency standards. The fourth section presents a review of air emission control technologies.

In Section 1, "Net Emissions Changes," the total annual tons of pollutants emitted are compared. This comparison is based on terms similar to those used in the presentation before the Siting Board regarding issuance of the Board's Order Instituting Modification Proceedings.

In Section 2, "Net Air Quality Impacts," dispersion modeling of the air quality impacts at multiple receptor points is compared to demonstrate the net air quality impact improvement associated with the Cedar Bay project.

In Section 3, "Cedar Bay Compliance with Prevention of Significant Deterioration (PSD) Increments, Ambient Air Quality Standards (AAQS), and Comparison to Draft Air Toxics No Threat Levels (NTLs)," information is presented to demonstrate that the combustion sources and aggregate materials handling equipment at the Cedar Bay cogeneration facility as proposed to be modified will comply with PSD increments and AAQS, both of which are nonprocedural agency standards. For informational purposes, air quality impacts due to the air toxic emissions of the Cedar Bay cogeneration facility are compared to Florida's draft air toxics NTLs.

In Section 4, "Air Emissions Control Technology," a review of the air emissions control technologies and emission rates proposed for the combustion sources and aggregate materials handling equipment at the Cedar Bay facility is presented. This section contains technical and economic analyses of the controls for air emission sources for the project. For the circulating fluidized bed boilers, these controls include: boiler design and selective non-catalytic reduction for control of nitrogen oxides, fabric filtration for control of particulate matter and trace metals,

boiler design and operation for control of carbon monoxide and volatile organic compounds, and limestone injection for control of sulfur dioxide and acid gases.

1.0 COMPARISON NO. 1: NET EMISSIONS CHANGES

1.1 Introduction

The objective of the information to be presented for Comparison No. 1 is to provide data useful for assessing

- 1) whether, on balance, the pollutant emissions of the Cedar Bay Power Plant, as proposed to be modified, and the addition of the three new yet-to-be-proposed boilers scheduled for the Seminole Kraft Corporation (SKC) site necessary to provide the 640,000 lb of steam per hour for SKC's use, will be less than the emissions of the future SKC recycling operation without the power plant,
- 2) whether, on balance, the pollutant emissions of the Cedar Bay Power Plant, as proposed to be modified, and the addition of the three new yet-to-be-proposed boilers scheduled for the SKC site at their permitted capacity, will be less than the emissions of the Cedar Bay power plant as certified, and
- 3) whether, on balance, the permitted pollutant emissions of the Cedar Bay Power Plant, as proposed to be modified, and the addition of the three new yet-to-be-proposed boilers scheduled for the SKC site at their permitted capacity, will be less than the emissions of the future SKC recycling operation at permitted capacity without the power plant.

The "Cedar Bay Power Plant as certified" refers to 3 coal-fired circulating fluidized bed (CFB) boilers capable of generating 225 MW of electricity and supplying SKC with a total steam generating capacity of 640,000 lb/hr, two limestone dryers fired by No. 2 distillate fuel oil and associated coal and other aggregate (limestone, ash) handling equipment, as described in the Final Order and Power Plant Site Certification PA 88-24 dated February 11, 1991 and the March 28, 1991 Final Determination by the FDER, Permit No. PSD-FL-137.

The "Cedar Bay Power Plant as proposed to be modified" refers to the CFB boilers generating 250 MW of electricity and supplying SKC with 380,000 lb/hr of steam, two limestone dryers fired by No. 2 distillate fuel oil and associated coal and other aggregate (limestone, ash) handling equipment, as described in the Amended Petition for Modification of Certification filed with the Division of Administrative Hearings on July 22, 1992, plus further improvements proposed by The Cedar Bay Cogeneration Project. These include proposed reductions in CFB emissions of SO₂, TSP, PM-10, Lead, Beryllium, Sulfuric Acid Mist and Fluorides.

The "future SKC recycling operation without the power plant" refers to the two bark and three oil-fired power boilers presently at the SKC site as they would be operated should the Cedar Bay power plant not be. As currently permitted, the three power boilers would fire Grade No. 6 residual fuel oil with a maximum sulfur content of 1.0%. Power Boiler No. 1 has a steam generating capacity of 135,000 lb/hr while Power Boilers Nos. 2 and 3 each have a steam capacity of 180,000 lb/hr. In the future hypothetical case, without the Cedar Bay power plant, ENSR understands that the exhausts of the three power boilers would be combined and exhausted through a newly constructed 125 foot stack to lessen susceptibility to aerodynamic downwash effects caused by nearby structures. The bark, or "carbonaceous", fuel boilers each have a steam generation capacity of 125,000 lb/hr. They would fire mostly bark, but are also permitted to mix fuel oil when the bark is wetter than desirable, as well as fire recycle rejects, including plastic components (i.e. bale bindings: strappings and wrappings).

The addition of "the three new yet-to-be-proposed boilers scheduled the SKC site necessary to provide the 640,000 lb/hr of steam for SKC's use" refers to three package boilers to be proposed by SKC capable of producing a total of 375,000 lb/hr of steam. For purposes of the technical analyses for Comparison No. 1 it is assumed that the 640,000 lb/hr steam requirement is met by the Cedar Bay Power plant supplying 380,000 lb/hr and the SK package boilers supplying 260,000 lb/hr.

The addition of "the three new yet-to-be-proposed boilers scheduled the SKC site at their permitted capacity" refers to these same boilers producing a total of 375,000 lb/hr of steam.

The proposed SK package boilers are capable of accommodating either fuel oil or natural gas. Not yet permitted, the current SK plan calls for No. 2 distillate fuel oil with a maximum sulfur content of 0.5%, and an annual average of 0.3%.

In applying Comparison No. 1, the differences in total annual pollutant emissions are compared amongst 5 cases. These are:

Case 1: the future operation of the 3 power boilers and 2 bark boilers for the SKC recycling operation at a total annualized steam production rate of 640,000 lb/hr, (which corresponds to an annual capacity factor of 85.9 percent),

Case 1a: the operation of the 3 power boilers and 2 bark boilers for the SKC recycling operation at a total annualized steam production rate of 745,000 lb/hr (their permitted capacity),

Case 2: the operation of the Cedar Bay power plant as certified, (at a 93 percent annual capacity factor),

Case 3: the operation of the Cedar Bay power plant, as proposed to be modified, generating electricity and supplying a total annualized steam production rate of 380,000 lb/hr to SKC, (at an 85.5 percent annual capacity factor), plus the addition of the 3 new package boilers at the SKC recycling operation under two fuel scenarios, fuel oil or natural gas, at a total annualized steam production rate of 260,000 lb/hr, (which corresponds to an annual capacity factor of 69.3 percent) and

Case 4: the operation of the Cedar Bay power plant, as proposed to be modified, (permitted at an annual capacity factor of 93 percent), plus the addition of the 3 new package boilers at the SKC recycling operation under two fuel scenarios, fuel oil or natural gas (at an annual capacity factor of 100%).

To respond to the siting board order, three assessments are presented:

Assessment A: Case No. 4
vs.
Case No. 2

Assessment B: Case No. 3. (This is the comparison required directly by the
vs. June 16, 1992 Order of the Siting Board)
Case No. 1

Assessment C: Case No. 4
vs.
Case No. 1a

1.2 Source Data and Assumptions

The annual emissions for Case 1 are listed in Tables 1-1 and 1-2. Data is listed individually for each power boiler and bark boiler. The individual steam rates represent SK's intended manner of operating these units to produce 640,000 total lb/hr of steam in 1994 without. Two fuel scenarios are possible for the bark boilers, each producing different emissions levels. Scenario 1 represents allowable for particulate (PM-10) emissions. Scenario 2 represents allowable SO₂ emissions. For the other pollutants, emission rates are taken from the fuel scenario producing the higher allowable emissions.

The annual emissions for Case 1a are listed in Tables 1-3 and 1-4. The individual steam rates represent the permitted rated steam capacity of each unit, which represents a total rated steam

TABLE 1-1

Case 1: Maximum Regulated Pollutant Emissions for Seminole Kraft Emission Sources
Power and Bark Boilers at 640,000 lb/hr Total Annualized Steam Rate

Annualized Steam Rate (klb/hr)	Power Boiler #1		Power Boiler #2		Power Boiler #3		Bark Boiler #1		Bark Boiler #2		Total
	100 (1)/135(2)		145 (1)/180(2)		145 (1)/180(2)		125 (1)/72.5(2)		125 (1)/72.5(2)		640
Pollutant	(lb/hr)	(ton/yr)	(lb/hr)	(ton/yr)	(lb/hr)	(ton/yr)	(lb/hr)	(ton/yr)	(lb/hr)	(ton/yr)	Total ton/yr
SO2 (2)	203.5	891.3	270.6	1185.2	270.6	1185.2	34.3	150.2	34.3	150.2	3,562.3
NOx (2)	82.6	361.8	109.9	481.4	109.9	481.4	41.8	183.1	41.8	183.1	1,690.8
CO (1)	4.6	20.1	6.6	28.9	6.6	28.9	241.3	1056.9	241.3	1056.9	2,191.2
TSP (1)	13.7	60.0	19.8	86.7	19.8	86.7	38.6	169.1	38.6	169.1	571.6
PM-10 (1)	9.7	42.5	14.1	61.8	14.1	61.8	33.6	147.2	33.6	147.2	459.9
VOC (1)	0.7	3.1	1.0	4.4	1.0	4.4	32.9	144.1	32.9	144.1	300.1
Lead (1)	0.00384	1.68e-02	0.00554	0.024	0.00554	0.024	0.01737	0.076	0.01737	0.076	0.22
Mercury (1)	0.00044	1.93e-03	0.00063	0.0028	0.00063	0.0028	0.00058	0.0025	0.00058	0.0025	0.013
Beryllium (2)	0.00078	3.42e-03	0.00103	0.0045	0.00103	0.0045	0.00001	4.4e-05	0.00001	4.4e-05	0.013
Fluorides (2)	0.0218	9.55e-02	0.029	0.127	0.029	0.127	0.0066	0.029	0.0066	0.029	0.41
H2SO4 mist (2)	4.44	19.4	5.9	25.8	5.9	25.8	1.34	5.87	1.34	5.87	82.9

Notes:

Source: KBN Engineering and Applied Sciences, Inc. Memorandum to A.Hallquist (ENSR) from D.Buff (KBN) 10/22/92

Ton/yr values assume 8,760 hours/yr operation at 85.9% capacity.

(1) Fuel Scenario 1 for Bark Boilers, bark only (worst case PM emissions)

(2) Fuel Scenario 2 for Bark Boilers, 50% fuel oil/50% bark on a heat input basis (worst case SO₂ emissions)

1-4

TABLE 1-2

**Case 1: Maximum Non-Regulated Pollutant Emissions from Seminole Kraft Emission Sources
Power and Bark Boilers at 640,000 lb/hr Total Annualized Steam Rate**

Annualized Steam Rate (klb/hr)	Power Boiler #1		Power Boiler #2		Power Boiler #3		Bark Boiler #1		Bark Boiler #2		Total
	100 (1)/135(2)		145 (1)/180(2)		145 (1)/180(2)		125 (1)/72.5(2)		125 (1)/72.5(2)		640
Pollutant	(lb/hr)	(ton/yr)	(lb/hr)	(ton/yr)	(lb/hr)	(ton/yr)	(lb/hr)	(ton/yr)	(lb/hr)	(ton/yr)	Total ton/yr
Antimony (2)	0.00266	0.012	0.00354	0.016	0.00354	0.016	0.00081	0.0035	0.00081	0.0035	0.050
Arsenic (2)	0.00352	0.015	0.00467	0.020	0.00467	0.020	0.00011	0.0005	0.00011	0.0005	0.057
Barium (1)	0.00197	0.009	0.00285	0.012	0.00285	0.012	0.01974	0.086	0.01974	0.086	0.21
Cadmium (2)	0.0029	0.013	0.00386	0.017	0.00386	0.017	0.0006	0.0026	0.0006	0.0026	0.052
HCl (1)	0	0	0	0	0	0	4.39	19.2	4.39	19.2	38.5
Indium (1)	0.0021	0.0092	0.003	0.013	0.003	0.013	0.155	0.68	0.155	0.68	1.39
Chromium VI (1)	0.00288	0.013	0.00416	0.018	0.00416	0.018	0.00351	0.015	0.00351	0.015	0.080
Copper (2)	0.0514	0.23	0.0684	0.30	0.0684	0.30	0.0034	0.015	0.0034	0.015	0.85
Formaldehyde (1)	0.055	0.24	0.08	0.35	0.08	0.35	0.122	0.53	0.122	0.53	2.02
Manganese (1)	0.0036	0.016	0.0051	0.022	0.0051	0.022	0.011	0.048	0.011	0.048	0.16
Molybdenum (1)	0.0021	0.0092	0.003	0.013	0.003	0.013	0.3092	1.35	0.3092	1.35	2.74
Nickel (2)	0.2331	1.02	0.31	1.358	0.31	1.358	0.0068	0.030	0.0068	0.030	3.80
Phosphorous (1)	0.035	0.15	0.05	0.219	0.05	0.219	0.066	0.29	0.066	0.29	1.17
POM (1)	0.0013	0.0057	0.0018	0.0079	0.0018	0.0079	0.0483	0.21	0.0483	0.21	0.44
Selenium (2)	0.00044	0.0019	0.00059	0.0026	0.00059	0.0026	0.00013	0.0006	0.00013	0.0006	0.008
Tin (1)	0.00033	0.0014	0.00048	0.0021	0.00048	0.0021	0.19585	0.86	0.19585	0.86	1.72
Vanadium (2)	0.558	2.44	0.741	3.25	0.741	3.25	0.038	0.17	0.038	0.17	9.27
Radionuclides	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA

Notes:

Source: KBN Engineering and Applied Sciences, Inc. Memorandum to A.Hallquist (ENSR) from D.Buff (KBN) 10/22/92

Ton/yr values assume 8,760 hours/yr operation

NA - not applicable

(1) Fuel Scenario 1 for Bark Boilers, bark only (worst case PM emissions)

(2) Fuel Scenario 2 for Bark Boilers, 50% fuel oil/50% bark on a heat input basis (worst case SO₂ emissions)

TABLE 1-3

Case 1a: Maximum Regulated Pollutant Emissions for Seminole Kraft Emission Sources
Power and Bark Boilers at 745,000 lb/hr Total Annualized Steam Rate

	Power Boiler #1		Power Boiler #2		Power Boiler #3		Bark Boiler #1		Bark Boiler #2		
Annualized Steam Rate (klb/hr)	135		180		180		125		125		Total 745
Pollutant	(lb/hr)	(ton/yr)	(lb/hr)	(ton/yr)	(lb/hr)	(ton/yr)	(lb/hr)	(ton/yr)	(lb/hr)	(ton/yr)	Total ton/yr
SO ₂ (2)	203.5	891.3	270.6	1185.2	270.6	1185.2	59.1	258.9	59.1	258.9	3779.6
NO _x (2)	82.6	361.8	109.9	481.4	109.9	481.4	72.1	315.8	72.1	315.8	1955.7
CO (1)	6.2	27.2	8.2	35.9	8.2	35.9	241.3	1056.9	241.3	1056.9	2212.2
TSP (1)	18.5	81.0	24.6	107.7	24.6	107.7	38.6	169.1	38.6	169.1	634.7
PM-10 (1)	13.1	57.4	17.5	76.7	17.5	76.7	33.6	147.2	33.6	147.2	504.7
VOC (1)	0.9	3.9	1.3	5.7	1.3	5.7	32.9	144.1	32.9	144.1	303.3
Lead (1)	0.00518	2.27-02	0.00689	3.02-02	0.00689	3.02-02	0.01737	7.61-02	0.01737	7.61-02	0.24
Mercury (1)	0.00059	2.58-03	0.00079	3.46-03	0.00079	3.46-03	0.00058	2.54-03	0.00058	2.54-03	0.015
Beryllium (2)	0.00078	3.42-03	0.00103	4.51-03	0.00103	4.51-03	0.00002	8.76-05	0.00002	8.76-05	0.013
Fluorides (2)	0.0218	9.55-02	0.0290	1.27-01	0.0290	1.27-01	0.0114	4.99-02	0.0114	4.99-02	0.45
H ₂ SO ₄ mist (2)	4.44	19.4	5.90	25.8	5.90	25.8	2.32	10.2	2.32	10.2	91.5

Source: KBN Engineering and Applied Sciences, Inc., Fax from D. Buff, KBN to Al Hallquist, ENSR, 11/6/92

Ton/yr values assume 8760 hrs/yr operation.

(1) Fuel Scenario 1 for Bark Boilers, bark only (worst case PM emissions)

(2) Fuel Scenario 2 for Bark Boilers, 50% fuel oil/50% bark on a heat input basis (worst case SO₂ emissions)

TABLE 1-4

Case 1a: Maximum Non-Regulated Pollutant Emissions for Seminole Kraft Emission Sources
Power and Bark Boilers at 745,000 lb/hr Total Annualized Steam Rate

Annualized Steam Rate (klb/hr)	Power Boiler #1		Power Boiler #2		Power Boiler #3		Bark Boiler #1		Bark Boiler #2		Total 745
	135		180		180		125		125		
Pollutant	(lb/hr)	(ton/yr)	(lb/hr)	(ton/yr)	(lb/hr)	(ton/yr)	(lb/hr)	(ton/yr)	(lb/hr)	(ton/yr)	Total ton/yr
Antimony (2)	0.00266	0.012	0.00354	0.016	0.00354	0.016	0.00139	0.006	0.00139	0.006	0.055
Arsenic (2)	0.00352	0.015	0.00467	0.020	0.00467	0.020	0.00018	0.0008	0.00018	0.0008	0.058
Barium (1)	0.00266	0.012	0.00354	0.016	0.00354	0.016	0.01974	0.086	0.01974	0.086	0.22
Cadmium (2)	0.00290	0.013	0.00386	0.017	0.00386	0.017	0.00104	0.0046	0.00104	0.0046	0.056
HCl (1)	0.0	0.0	0.0	0.0	0.0	0.0	4.39	19.2	4.39	19.2	38.46
Indium (1)	0.0028	0.012	0.0037	0.016	0.0037	0.016	0.155	0.68	0.155	0.68	1.40
Chromium VI (1)	0.00389	0.017	0.00517	0.023	0.00517	0.023	0.00351	0.015	0.00351	0.015	0.093
Copper (2)	0.051	0.23	0.068	0.30	0.068	0.30	0.0059	0.026	0.0059	0.026	0.88
Formaldehyde (1)	0.075	0.33	0.100	0.44	0.100	0.44	0.122	0.53	0.122	0.53	2.27
Manganese (1)	0.0048	0.021	0.0064	0.028	0.0064	0.028	0.011	0.048	0.011	0.048	0.18
Molybdenum (1)	0.0028	0.012	0.0037	0.016	0.0037	0.016	0.3092	1.35	0.3092	1.35	2.75
Nickel (2)	0.233	1.02	0.310	1.358	0.310	1.358	0.0118	0.052	0.0118	0.052	3.84
Phosphorous (1)	0.047	0.21	0.062	0.27	0.062	0.27	0.066	0.29	0.066	0.29	1.33
POM (1)	0.0017	0.0074	0.0023	0.010	0.0023	0.010	0.0483	0.21	0.0483	0.21	0.45
Selenium (2)	0.00044	0.0019	0.00059	0.0026	0.00059	0.0026	0.00023	0.001	0.00023	0.001	0.009
Tin (1)	0.00044	0.0019	0.00059	0.0026	0.00059	0.0026	0.19585	0.86	0.19585	0.86	1.72
Vanadium (2)	0.558	2.44	0.741	3.25	0.741	3.25	0.065	0.28	0.065	0.28	9.51
Radionuclides	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA

Source: KBN Engineering and Applied Sciences, Inc., Fax from D. Buff, KBN to Al Hallquist, ENSR, 11/6/92
Ton per year values assume 8760 hrs/yr operation.

(1) Fuel Scenario 1 for Bark Boilers, bark only (worst case PM emissions)

(2) Fuel Scenario 2 for Bark Boilers, 50% fuel oil/50% bark on a heat input basis (worst case SO₂ emissions)

1-7

capacity of 745,000 lb/hr. As in Case 1, the composite of two fuel scenarios is presented, with the higher allowable emissions of the two scenarios listed.

The annual emissions for Case 2, Cedar Bay as certified, are listed in Tables 1-5 and 1-6. Tables 1-7 through 1-10 list the annual emissions for Case 3 Cedar Bay as proposed to be modified, with the SK package boilers on natural gas and fuel oil, at 260,000 lb/hr annualized steam rate. Tables 1-11 through 1-14 list the annual emissions for Case 4, Cedar Bay as proposed to be modified with the SK package boilers on natural gas and fuel oil, all at permitted capacity. The emissions listed for the Cedar Bay CFB boilers represent the exclusive firing of coal. Emissions from the firing of distillate oil during start-up, or the low percentage of short-fiber rejects from SK, will be lower.

1.3 Findings

The results of Assessment A, Case 4 with SK package boilers on fuel oil, vs Case 2 are presented in Table 1-15. The results of Assessment A, Case 4 with the SK package boilers on natural gas, vs Case 2 are presented in Table 1-16. The total aggregate emissions shown count both TSP and PM-10 as individual pollutants, even though PM-10 are a portion of TSP. In the context of ambient standards, which are established for PM-10, and PSD increments, which are established for TSP, the air quality impacts analyses treat the two pollutants exclusively. In order to be consistent with this treatment, they are also treated individually for aggregation purposes. These tables show that for Assessment A, while annual emissions of a few pollutants in Case 4 are greater than for Case 2, most others decrease to the extent that, on balance, the aggregate annual emissions of Case 4 are lower. The results of Assessment B, Case 3 vs. Case 1, are presented in Tables 1-17 and 1-18. These tables show that, for Assessment B, while annual emissions of some pollutants in Case 3, are greater than for Case 1, others decrease to the extent that, on balance, the aggregate annual emissions of Case 3 are lower.

The results of Assessment C, Case 4 vs. Case 1a, are presented in Tables 1-19 and 1-20. These tables show that, for Assessment C, while annual emissions of some pollutants in Case 4 are greater than for Case 1a, others decrease. The aggregate annual emissions are higher for Case 4 with the SK package boilers on oil and lower with the SK package boilers on gas. This comparison does not, however, account for additional substantial decreases resulting from the shut down of recovery boilers, lime kilns and smelt dissolving tanks at SKC as a result of the conversion to a recycling operation. Table 1-21 lists these changes. These are preliminary estimates provided by KBN Engineering and Applied Sciences in documentation being prepared in support of the PSD permit application for the SK package boilers. It is shown in Table 1-21 that decreases resulting from the additional SK shutdowns more than offset the increases shown in Table 1-19. Such a comparison is a more realistic assessment of the emissions at the

TABLE 1-5

Case 2: Maximum Regulated Pollutant Emissions for Cedar Bay as Certified (a)

Pollutant	CFB		Limestone Dryers (b)		Total (tons/yr)
	(lb/MMBtu)	(tons/yr)(e)	(lb/hr)	(tons/yr)	
SO2	0.31 (c)	4,026.9	5.00	43.8	4,070.7
NOx	0.29 (d)	3,767.1	2.40	21.0	3,788.1
CO	0.19	2,468.1	0.60	5.3	2,473.4
TSP	0.02	259.8	0.25	2.2	262.0
PM-10	0.02	259.8	0.25	2.2	262.0
VOC	0.015	194.9	0.05	0.44	195.3
Lead	0.007	90.9	1.45e-03(f)	1.27e-02	90.9
Beryllium	0.00011	1.4	4.26e-05(f)	3.73e-04	1.4
Mercury	0.00026	3.4	5.11e-05(f)	4.48e-04	3.4
Fluorides	0.086	1,117.1	NA (f)	NA	1,117.1
H2SO4 mist	0.024	308.0	0.11(f)	0.96	308.9

Notes:

(a) Source: Final Order and Certification PA-88-24 (2/11/91) and Final Determination, AES/Cedar Bay Cogeneration Project, Duval County, FL Permit No. PSD-FL-137 (3/28/91).

(b) lb/hr values represent emissions limits for each of two limestone dryers
Annual emissions are for both dryers, based on permitted 8760 hrs/yr operation

(c) 12 month running average

(d) 30 day running average

(e) Based on total heat input rate of 3189 MMBtu/hr at 93% annualized capacity factor

(f) These data supplied by Bechtel, Correspondence from A. Nawas to G. Weidenger (U.S. Generating Company), 10/23/92

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TABLE 1-6

Case 2: Maximum Non-Regulated Pollutant Emissions for Cedar Bay as Certified (a)

Pollutant	CFB		Limestone Dryers (c)		Total (tons/yr)
	(lb/MMBtu)	(tons/yr)(b)	(lb/hr)	(tons/yr)	
Antimony	1.32e-05	0.2	NA	NA	0.2
Arsenic	2.94e-03	38.2	7.16e-05	6.27e-04	38.2
Barium	9.36e-04	12.2	4.60e-05	4.03e-04	12.2
Cadmium	5.54e-05	0.7	1.79e-04	1.57e-03	7.01e-01
HCl	1.81e-03	23.5	NA	NA	23.5
Indium	2.11e-07	2.74e-03	NA	NA	2.74e-03
Chromium VI	1.66e-04	2.2	8.09e-04	7.09e-03	2.2
Copper	1.21e-04	1.6	4.77e-03	4.18e-02	1.6
Formaldehyde	1.30e-04	1.7	6.90e-03	6.05e-02	1.7
Manganese	2.80e-04	3.6	2.39e-04	2.09e-03	3.6
Molybdenum	1.56e-04	2.0	8.32e-04	7.28e-03	2.0
Nickel	1.24e-04	1.6	2.90e-03	2.54e-02	1.6
Phosphorous	5.09e-04	6.6	1.81e-03	1.58e-02	6.6
POM	1.86e-05	0.24	3.83e-04	3.36e-03	0.24
Selenium	2.18e-05	0.28	1.93e-04	1.69e-03	0.28
Tin	6.13e-05	0.80	5.62e-03	4.93e-02	0.85
Vanadium	3.86e-04	5.0	3.11e-02	2.72e-01	5.3
Radionuclides (d)	8.66e-10	0.022	NA	NA	0.022

Notes:

NA - Not applicable

(a) Emissions estimated based on emission factors developed by Bechtel Power (Letter from A. Nawaz, Bechtel to G. Weidinger, U.S. Generating Company, 10/23/92)

(b) Based on total heat input rate of 3189 MMBtu/hr at 93% annualized capacity factor

(c) lb/hr values represent emissions limits for each of two limestone dryers

Annual emissions are for both dryers, based on permitted 8760 hrs/yr operation

(d) Emission units expressed as curies

TABLE 1-7

Case 3: Maximum Regulated Pollutant Emissions for Cedar Bay as Modified (a)
and SK Package Boilers Firing Natural Gas at 260,000 lb/hr Steam

Pollutant	CFB		Limestone Dryers (e)		SK Package Boilers (f)		Total (tons/yr)
	(lb/MMBtu)	(tons/yr)(d)	(lb/hr)	(tons/yr)	(lb/hr)	(tons/yr)	
SO ₂	0.20 (b)	2388.5	5.00	14.6	0.1	1.31	2404.4
NO _x	0.17 (c)	2030.2	2.40	7.0	24.3	319.3	2356.5
CO	0.175 (c)	2090.0	0.60	1.8	43.4	570.0	2661.8
TSP	0.018	214.9	0.25	0.73	0.6	7.9	223.5
PM-10	0.018	214.9	0.25	0.73	0.6	7.9	223.5
VOC	0.015	179.2	0.05	0.15	0.17	2.2	181.5
Lead	6.38e-05	0.76	1.45e-03	4.23e-03	NA	NA	0.76
Beryllium	1.25e-05	0.15	4.26e-05	1.24e-04	NA	NA	0.15
Mercury	3.04e-05	0.36	5.11e-05	1.49e-04	1.7e-06	2.2e-05	0.36
Fluorides	8.54e-04	10.2	NA	NA	NA	NA	10.2
H ₂ SO ₄ mist	0.016	191.0	0.11	0.32	NA	NA	191.3

Notes:

(a) Source: Final Order and Certification PA-88-24 (2/11/91) and Amended Petition for Modification of Certification (July 22, 1992 Before the State of Florida, Division of Administrative Hearings, In Re: AES Cedar Bay Cogeneration Project, Power Plant Site Certification Application PA-88-24) plus proposed improvements by US Generating Company.

(b) 12 month running average

(c) 30 day running average

(d) Based on total heat input rate of 3189 MMBtu/hr at 85.5% annualized capacity factor

(e) Lb/hr values represent emission limits for each of two limestone dryers

Annual emissions are for both dryers and are based on maximum operation of 8 hours/day each, 365 days/yr

(f) Firing natural gas - lb/hr values for each of three boilers - emissions data from KBN Engineering (10/22/92)

TABLE 1-8

**Case 3: Maximum Non-Regulated Pollutant Emissions for Cedar Bay as Modified (a)
and SK Package Boilers Firing Natural Gas at 260,000 lb/hr Steam**

Pollutant	CFB		Limestone Dryers (c)		SK Package Boilers (d)		Total (tons/yr)
	(lb/MMBtu)	(tons/yr)(b)	(lb/hr)	(tons/yr)	(lb/hr)	(tons/yr)	
Antimony	1.32e-05	0.2	NA	NA	NA	NA	0.2
Arsenic	1.56e-04	1.9	7.16e-05	2.09e-04	NA	NA	1.9
Barium	9.36e-04	11.2	4.60e-05	1.34e-04	NA	NA	11.2
Cadmium	5.54e-05	0.7	1.79e-04	5.22e-04	NA	NA	0.7
HCl	1.81e-03	21.6	NA	NA	NA	NA	21.6
Indium	2.11e-07	2.52e-03	NA	NA	NA	NA	2.52e-03
Chromium VI	5.65e-05	0.7	2.09e-04	6.10e-04	NA	NA	0.7
Copper	1.21e-04	1.4	4.77e-03	1.39e-02	NA	NA	1.5
Formaldehyde	1.30e-04	1.6	6.90e-03	2.02e-02	NA	NA	1.6
Manganese	2.80e-04	3.3	2.39e-04	6.97e-04	NA	NA	3.3
Molybdenum	1.56e-04	1.9	8.32e-04	2.43e-03	NA	NA	1.9
Nickel	1.24e-04	1.5	2.90e-03	8.46e-03	NA	NA	1.5
Phosphorous	5.09e-04	6.1	1.81e-03	5.27e-03	NA	NA	6.1
POM	1.86e-05	0.22	3.83e-04	1.12e-03	NA	NA	0.22
Selenium	2.18e-05	0.26	1.93e-04	5.62e-04	NA	NA	0.26
Tin	6.13e-05	0.73	5.62e-03	1.64e-02	NA	NA	0.75
Vanadium	3.86e-04	4.6	2.17e-02	6.39e-02	NA	NA	4.7
Radionuclides (e)	8.66e-10	0.020	NA	NA	NA	NA	0.020

Notes:

NA - Not applicable

(a) Source: emission factors developed by Bechtel Power (10/23/92)

(b) Based on total heat input rate of 3189 MMBtu/hr at 85.5% annualized capacity factor

(c) Lb/hr values represent emission limits for each of two limestone dryers

Annual emissions are for both dryers and are based on maximum operation of 8 hours/day each, 365 days/yr

(d) Firing natural gas - lb/hr values for each of three boilers - emissions data from KBN Engineering (10/22/92)

(e) Emission units expressed as curies

TABLE 1-9

Case 3: Maximum Regulated Pollutant Emissions for Cedar Bay as Modified (a)
and SK Package Boilers Firing Distillate Oil at 260,000 lb/hr Steam

Pollutant	CFB		Limestone Dryers (e)		SK Package Boilers (f)		Total (tons/yr)
	(lb/MMBtu)	(tons/yr)(d)	(lb/hr)	(tons/yr)	(lb/hr)	(tons/yr)	
SO2	0.20 (b)	2388.5	5.0	14.6	34.2	449.0	2852.1
NOx	0.17 (c)	2030.2	2.4	7.0	22.8	299.6	2336.8
CO	0.175 (c)	2090.0	0.6	1.8	41.9	550.6	2642.4
TSP	0.018	214.9	0.25	0.73	1.6	21.5	237.1
PM-10	0.018	214.9	0.25	0.73	0.8	10.8	226.4
VOC	0.015	179.2	0.05	0.15	0.16	2.1	181.4
Lead	6.38e-05	0.76	1.45e-03	4.23e-03	1.0e-03	1.3e-02	0.78
Beryllium	1.25e-05	0.15	4.26e-05	1.24e-04	2.8e-04	3.7e-03	0.16
Mercury	3.04e-05	0.36	5.11e-05	1.49e-04	3.9e-04	5.1e-03	0.36
Fluorides	8.54e-04	10.2	NA	NA	3.6e-03	4.8e-02	10.2
H2SO4 mist	0.016	191.1	0.11	0.32	1.7	22.3	213.7

Notes:

- (a) Source: Final Order and Certification PA-88-24 (2/11/91) and Amended Petition for Modification of Certification (July 22, 1992 Before the State of Florida, Division of Administrative Hearings, In Re: AES Cedar Bay Cogeneration Project, Power Plant Site Certification Application PA-88-24) plus proposed improvements by US Generating Company.
- (b) 12 month running average
- (c) 30 day running average
- (d) Based on total heat input rate of 3189 MMBtu/hr at 85.5% annualized capacity factor
- (e) Lb/hr values represent emission limits for each of two limestone dryers
Annual emissions are for both dryers and are based on maximum operation of 8 hours/day each, 365 days/yr
- (f) Firing distillate oil - lb/hr values for each of three boilers - emissions data from KBN Engineering (10/22/92)

TABLE 1-10

Case 3: Maximum Non-regulated Pollutant Emissions for Cedar Bay as Modified (a)
and SK Package Boilers Firing Distillate Oil at 260,000 lb/hr Steam

Pollutant	CFB		Limestone Dryers (c)		SK Package Boilers (d)		Total (tons/yr)
	(lb/MMBtu)	(tons/yr)(b)	(lb/hr)	(tons/yr)	(lb/hr)	(tons/yr)	
Antimony	1.32e-05	0.2	NA	NA	NA	NA	0.2
Arsenic	1.56e-04	1.9	7.16e-05	2.09e-04	5.0e-04	6.3e-03	1.9
Barium	9.36e-04	11.2	4.60e-05	1.34e-04	3.0e-04	4.0e-03	11.2
Cadmium	5.54e-05	0.7	1.79e-04	5.22e-04	1.2e-03	1.6e-02	0.7
HCl	1.81e-03	21.6	NA	NA	7.3e-02	0.95	22.6
Indium	2.11e-07	2.52e-03	NA	NA	NA	NA	2.52e-03
Chromium VI	5.65e-05	0.7	2.09e-04	6.10e-04	5.4e-03	0.07	0.8
Copper	1.21e-04	1.4	4.77e-03	1.39e-02	3.2e-02	0.42	1.9
Formaldehyde	1.30e-04	1.6	6.90e-03	2.02e-02	NA	NA	1.6
Manganese	2.80e-04	3.3	2.39e-04	6.97e-04	1.1e-03	1.5e-02	3.4
Molybdenum	1.56e-04	1.9	8.32e-04	2.43e-03	5.6e-03	0.07	1.9
Nickel	1.24e-04	1.5	2.90e-03	8.46e-03	1.9e-02	2.5e-01	1.8
Phosphorous	5.09e-04	6.1	1.81e-03	5.27e-03	1.2e-02	0.16	6.3
POM	1.86e-05	0.22	3.83e-04	1.12e-03	NA	NA	0.22
Selenium	2.18e-05	0.26	1.93e-04	5.62e-04	1.3e-03	1.7e-02	0.28
Tin	6.13e-05	0.73	5.62e-03	1.64e-02	3.8e-02	0.49	1.24
Vanadium	3.86e-04	4.6	2.17e-02	6.39e-02	NA	NA	4.7
Radionuclides (e)	8.66e-10	0.020	NA	NA	NA	NA	0.020

Notes:

NA - Not applicable

(a) Source: emission factors developed by Bechtel Power (10/23/92)

(b) Based on total heat input rate of 3189 MMBtu/hr at 85.5% annualized capacity factor

(c) Lb/hr values represent emission limits for each of two limestone dryers

Annual emissions are for both dryers and are based on maximum operation of 8 hours/day each, 365 days/yr

(d) Firing distillate oil - lb/hr values for each of three boilers - emissions data from KBN Engineering (10/22/92)

(e) Emission units expressed as curies

TABLE 1-11

Case 4: Maximum Regulated Pollutant Emissions for Cedar Bay as Modified (a)
and SK Package Boilers Firing Natural Gas at 375,000 lb/hr Steam

Pollutant	CFB		Limestone Dryers (e)		SK Package Boilers (f)		Total (tons/yr)
	(lb/MMBtu)	(tons/yr)(d)	(lb/hr)	(tons/yr)	(lb/hr)	(tons/yr)	
SO ₂	0.20 (b)	2,598.0	5.0	14.6	0.1	1.31	2,613.9
NO _x	0.17 (c)	2,208.3	2.4	7.0	34.9	459.1	2,674.4
CO	0.175 (c)	2,273.3	0.6	1.8	61.2	804.6	3,079.7
TSP	0.018	233.8	0.25	0.73	0.9	11.8	246.4
PM-10	0.018	233.8	0.25	0.73	0.9	11.8	246.4
VOC	0.015	194.9	0.05	0.15	0.24	3.2	198.2
Lead	6.38e-05	0.83	1.45e-03	4.23e-03	NA	NA	0.83
Beryllium	1.25e-05	0.16	4.26e-05	1.24e-04	NA	NA	0.16
Mercury	3.04e-05	0.39	5.11e-05	1.49e-04	2.4e-06	3.2e-05	0.39
Fluorides	8.54e-04	11.1	NA	NA	NA	NA	11.1
H ₂ SO ₄ mist	0.016	207.8	0.11	0.32	NA	NA	208.1

Notes:

(a) Source: Final Order and Certification PA-88-24 (2/11/91) and Amended Petition for Modification of Certification (July 22, 1992 Before the State of Florida, Division of Administrative Hearings, In Re: AES Cedar Bay Cogeneration Project, Power Plant Site Certification Application PA-88-24) plus proposed improvements by US Generating Company.

(b) 12 month running average

(c) 30 day running average

(d) Based on total heat input rate of 3189 MMBtu/hr at 93% annualized capacity factor

(e) Lb/hr values represent emission limits for each of two limestone dryers

Annual emissions are for both dryers and are based on maximum operation of 8 hours/day each, 365 days/yr

(f) Firing natural gas - lb/hr values for each of three boilers - emissions data from KBN Engineering (10/22/92)

TABLE 1-12

Case 4: Maximum Non-Regulated Pollutant Emissions for Cedar Bay as Modified (a)
and SK Package Boilers Firing Natural Gas at 375,000 lb/hr Steam

Pollutant	CFB		Limestone Dryers (c)		SK Package Boilers (d)		Total (tons/yr)
	(lb/MMBtu)	(tons/yr)(b)	(lb/hr)	(tons/yr)	(lb/hr)	(tons/yr)	
Antimony	1.32e-05	0.2	NA	NA	NA	NA	0.2
Arsenic	1.56e-04	2.0	7.16e-05	2.09e-04	NA	NA	2.0
Barium	9.36e-04	12.2	4.60e-05	1.34e-04	NA	NA	12.2
Cadmium	5.54e-05	0.7	1.79e-04	5.22e-04	NA	NA	0.72
HCl	1.81e-03	23.5	NA	NA	NA	NA	23.5
Indium	2.11e-07	2.74e-03	NA	NA	NA	NA	2.74e-03
Chromium VI	5.65e-05	0.7	2.09e-04	6.10e-04	NA	NA	0.7
Copper	1.21e-04	1.6	4.77e-03	1.39e-02	NA	NA	1.6
Formaldehyde	1.30e-04	1.7	6.90e-03	2.02e-02	NA	NA	1.7
Manganese	2.80e-04	3.6	2.39e-04	6.97e-04	NA	NA	3.6
Molybdenum	1.56e-04	2.0	8.32e-04	2.43e-03	NA	NA	2.0
Nickel	1.24e-04	1.6	2.90e-03	8.46e-03	NA	NA	1.6
Phosphorous	5.09e-04	6.6	1.81e-03	5.27e-03	NA	NA	6.6
POM	1.86e-05	0.24	3.83e-04	1.12e-03	NA	NA	0.24
Selenium	2.18e-05	0.28	1.93e-04	5.62e-04	NA	NA	0.28
Tin	6.13e-05	0.80	5.62e-03	1.64e-02	NA	NA	0.81
Vanadium	3.86e-04	5.0	2.17e-02	6.39e-02	NA	NA	5.1
Radionuclides (e)	8.66e-10	0.022	NA	NA	NA	NA	0.022

Notes:

NA - Not applicable

(a) Source: emission factors developed by Bechtel Power (10/23/92)

(b) Based on total heat input rate of 3189 MMBtu/hr at 93% annualized capacity factor

(c) Lb/hr values represent emission limits for each of two limestone dryers

Annual emissions are for both dryers and are based on maximum operation of 8 hours/day each, 365 days/yr

(d) Firing natural gas - lb/hr values for each of three boilers - emissions data from KBN Engineering (10/22/92)

(e) Emission units expressed as curies

TABLE 1-13

Case 4: Maximum Regulated Pollutant Emissions for Cedar Bay as Modified (a)
and SK Package Boilers Firing Distillate Oil at 375,000 lb/hr Steam

Pollutant	CFB		Limestone Dryers (e)		SK Package Boilers (f)		Total (tons/yr)
	(lb/MMBtu)	(tons/yr)(d)	(lb/hr)	(tons/yr)	(lb/hr)	(tons/yr)	
SO2 (b)	0.20	2,598.0	5.0	14.6	49.4	648.5	3,261.1
NOx (c)	0.17	2,208.3	2.4	7.0	32.9	432.3	2,647.6
CO (c)	0.175	2,273.3	0.6	1.8	61.0	801.5	3,076.6
TSP	0.018	233.8	0.25	0.73	2.4	31.3	265.8
PM-10	0.018	233.8	0.25	0.73	1.2	15.7	250.2
VOC	0.015	194.9	0.05	0.15	0.24	3.2	198.2
Lead	6.38e-05	0.83	1.45e-03	4.23e-03	1.5e-03	1.9e-02	0.85
Beryllium	1.25e-05	0.16	4.26e-05	1.24e-04	4.1e-04	5.4e-03	0.17
Mercury	3.04e-05	0.39	5.11e-05	1.49e-04	5.6e-04	7.3e-03	0.39
Fluorides	8.54e-04	11.1	NA	NA	5.3e-03	6.9e-02	11.2
H2SO4 mist	0.016	207.8	0.11	0.32	2.5	32.4	240.5

Notes:

(a) Source: Final Order and Certification PA-88-24 (2/11/91) and Amended Petition for Modification of Certification (July 22, 1992 Before the State of Florida, Division of Administrative Hearings, In Re: AES Cedar Bay Cogeneration Project, Power Plant Site Certification Application PA-88-24) plus proposed improvements by US Generating Company.

(b) 12 month running average

(c) 30 day running average

(d) Based on total heat input rate of 3189 MMBtu/hr at 93% annualized capacity factor

(e) Lb/hr values represent emission limits for each of two limestone dryers

Annual emissions are for both dryers and are based on maximum operation of 8 hours/day each, 365 days/yr

(f) Firing distillate oil - lb/hr values for each of three boilers - emissions data from KBN Engineering (10/22/92)

TABLE 1-14

Case 4: Maximum Non-Regulated Pollutant Emissions for Cedar Bay as Modified (a)
and SK Package Boilers Firing Distillate Oil at 375,000 lb/hr Steam

Pollutant	CFB		Limestone Dryers (c)		SK Package Boilers (d)		Total (tons/yr)
	(lb/MMBtu)	(tons/yr)(b)	(lb/hr)	(tons/yr)	(lb/hr)	(tons/yr)	
Antimony	1.32e-05	0.2	NA	NA	NA	NA	0.2
Arsenic	1.56e-04	2.0	7.16e-05	2.09e-04	7.0e-04	9.1e-03	2.0
Barium	9.36e-04	12.2	4.60e-05	1.34e-04	4.0e-04	6.0e-03	12.2
Cadmium	5.54e-05	0.7	1.79e-04	5.22e-04	1.7e-03	2.3e-02	0.74
HCl	1.81e-03	23.5	NA	NA	1.0e-01	1.4	24.9
Indium	2.11e-07	2.74e-03	NA	NA	NA	NA	2.74e-03
Chromium VI	5.65e-05	0.7	2.09e-04	6.10e-04	7.8e-03	0.10	0.8
Copper	1.21e-04	1.6	4.77e-03	1.39e-02	4.6e-02	0.61	2.2
Formaldehyde	1.30e-04	1.7	6.90e-03	2.02e-02	NA	NA	1.7
Manganese	2.80e-04	3.6	2.39e-04	6.97e-04	1.6e-03	2.1e-02	3.7
Molybdenum	1.56e-04	2.0	8.32e-04	2.43e-03	8.0e-03	0.11	2.1
Nickel	1.24e-04	1.6	2.90e-03	8.46e-03	2.8e-02	0.37	1.97
Phosphorous	5.09e-04	6.6	1.81e-03	5.27e-03	1.7e-02	0.23	6.8
POM	1.86e-05	0.24	3.83e-04	1.12e-03	NA	NA	0.24
Selenium	2.18e-05	0.28	1.93e-04	5.62e-04	1.9e-03	2.4e-02	0.31
Tin	6.13e-05	0.80	5.62e-03	1.64e-02	5.4e-02	0.71	1.53
Vanadium	3.86e-04	5.0	2.17e-02	6.39e-02	NA	NA	5.1
Radionuclides (e)	8.66e-10	0.022	NA	NA	NA	NA	0.022

Notes:

NA - Not applicable

(a) Source: emission factors developed by Bechtel Power (10/23/92)

(b) Based on total heat input rate of 3189 MMBtu/hr at 93% annualized capacity factor

(c) Lb/hr values represent emission limits for each of two limestone dryers

Annual emissions are for both dryers and are based on maximum operation of 8 hours/day each, 365 days/yr

(d) Firing distillate oil - lb/hr values for each of three boilers - emissions data from KBN Engineering (10/22/92)

(e) Emission units expressed as curies

TABLE 1-15

**Emissions Comparison (tons/yr) Assessment A
Case 4: Cedar Bay as Modified with SK
Package Boilers at 375 k lb/hr Steam Firing Distillate Oil vs.
Case 2: Cedar Bay as Certified**

Pollutant	Case 2	Case 4	Change
SO2	4,070.7	3,261.1	-809.6
NOx	3,788.1	2,647.6	-1140.5
CO	2,473.4	3,076.6	603.2
TSP	262.0	265.8	3.8
PM-10	262.0	250.2	-11.8
VOC	195.3	198.2	2.9
Lead	90.9	0.85	-90.1
Beryllium	1.4	0.17	-1.2
Mercury	3.4	0.39	-3.0
Fluorides	1,117.1	11.2	-1106.0
H2SO4 mist	308.9	240.5	-68.4
Antimony	1.71e-01	1.71e-01	0
Arsenic	3.82e+01	2.0	-36.2
Barium	1.22e+01	1.22e+01	0
Cadmium	7.01e-01	7.43e-01	4.20e-02
HCl	2.35e+01	2.49e+01	1.38
Indium	2.74e-03	2.74e-03	0
Chromium VI	2.16	0.8	-1.36
Copper	1.61	2.19	0.58
Formaldehyde	1.75	1.77	0.02
Manganese	3.64	3.66	0.02
Molybdenum	2.03	2.13	0.10
Nickel	1.64	1.97	0.33
Phosphorous	6.63	6.85	0.22
POM	2.45e-01	2.43e-01	-2.24e-03
Selenium	2.85e-01	3.09e-01	2.38e-02
Tin	8.46e-01	1.53	6.81e-01
Vanadium	5.29	5.10	-1.82e-01
Radionuclides (curies)	0.022	0.022	0
Subtotal Non-Regulated Trace Pollutants	100.9	66.6	-34.3
Total Aggregate Emissions	12,671.5	10,019.2	-2,654.9

TABLE 1-16

Emissions Comparison (Tons/yr), Assessment A
Case 4: Cedar Bay as Modified with SK
Package Boilers at 375 k lb/hr Steam Firing Natural Gas vs.
Case 2: Cedar Bay as Certified

Pollutant	Case 2	Case 4	Change
SO2	4,070.7	2,613.9	-1456.8
NOx	3,788.1	2,674.4	-1113.7
CO	2,473.4	3,079.7	606.3
TSP	262.0	246.4	-15.6
PM-10	262.0	246.4	-15.6
VOC	195.3	198.2	2.9
Lead	90.9	0.83	-90.1
Beryllium	1.4	0.16	-1.3
Mercury	3.4	0.39	-3.0
Fluorides	1,117.1	11.1	-1106.1
H2SO4 mist	308.9	208.1	-100.8
Antimony	1.71e-01	1.71e-01	0
Arsenic	3.82e+01	2.0	-36.2
Barium	1.22e+01	1.22e+01	0
Cadmium	7.01e-01	7.20e-01	1.9e-02
HCl	2.35e+01	2.35e+01	0
Indium	2.74e-03	2.74e-03	0
Chromium VI	2.16	0.7	-1.46
Copper	1.61	1.59	-0.02
Formaldehyde	1.75	1.71	-0.04
Manganese	3.64	3.64	0
Molybdenum	2.03	2.02	-0.01
Nickel	1.64	1.62	-0.02
Phosphorous	6.63	6.62	-0.01
POM	2.45e-01	2.43e-01	-2.0e-03
Selenium	2.85e-01	2.84e-01	-1.0e-03
Tin	8.46e-01	8.13e-01	-3.3e-02
Vanadium	5.29	5.10	-1.9e-01
Radionuclides (curies)	0.022	0.022	0
Subtotal Non-Regulated Trace Pollutants	100.9	62.9	-38.0
Total Aggregate Emissions	12,671.5	9342.5	-3331.6

TABLE 1-17

**Pollutants Emissions Comparison (Tons/yr), Assessment B
Case 3: Cedar Bay as Modified Supplying 380 k lb/hr Steam to SK with SK Package Boilers
at 260 k lb/hr Steam vs. Case 1: the Future Operation of the 3 Power Boilers
and 2 Bark Boilers at 640 k lb/hr Steam for the SK Recycling Operation**

Pollutant	Case 1 SK Power & Bark Boilers	Case 3 Cedar Bay & SK Package Boilers			Net Change	
		Cedar Bay	SK Boilers Firing Oil	SK Boilers Firing Gas	SK Boilers Firing Oil	SK Boilers Firing Gas
SO2	3,562.3	2403.1	449.0	1.31	-710.2	-1157.9
NOx	1,690.8	2037.2	299.6	319.3	646.0	665.7
CO	2,191.2	2091.8	550.6	570.0	451.2	470.6
TSP	571.6	215.6	21.5	7.88	-334.5	-348.2
PM-10	459.9	215.6	10.8	7.88	-233.5	-236.4
VOC	300.1	179.4	2.10	2.23	-118.6	-118.5
Lead	0.22	0.76	0.013	NA	0.55	0.54
Mercury	0.013	0.36	0.005	2.2e-05	0.35	0.35
Beryllium	0.013	0.15	0.004	NA	0.14	0.14
Fluorides	0.41	10.2	0.048	NA	9.8	9.8
H2SO4 mist	82.9	191.3	22.3	NA	130.7	108.4
Subtotal Non-Regulated Trace Pollutants ^(a)	62.5	58.0	2.5	NA	-2.0	-4.5
Total Aggregate Emissions	8922.0	7403.5	1358.5	908.6	-160.0	-609.9

^(a)See Table 1-18

TABLE 1-18

**Non-Regulated Pollutant Emissions Comparison (Tons/yr), Assessment B
Case 3: Cedar Bay as Modified Supplying 380 k lb/hr Steam to SK with SK Package Boilers
at 260 k lb/hr Steam vs. Case 1: the Future Operation of the 3 Power Boilers
and 2 Bark Boilers at 640 k lb/hr Steam for the SK Recycling Operation**

Pollutant	Case 1 SK Power & Bark Boilers	Case 3 Cedar Bay & SK Package Boilers			Net Change	
		Cedar Bay	SK Boilers Firing Oil	SK Boilers Firing Gas	SK Boilers Firing Oil	SK Boilers Firing Gas
Antimony	0.050	0.2	NA	NA	0.15	0.15
Arsenic	0.057	1.9	0.007	NA	1.8	1.8
Barium	0.21	11.2	0.004	NA	11.0	11.0
Cadmium	0.052	0.66	0.016	NA	0.63	0.61
HCl	38.5	21.6	0.954	NA	-15.9	-16.9
Indium	1.39	0.003	NA	NA	-1.39	-1.39
Chromium VI	0.080	0.67	0.071	NA	0.66	0.59
Copper	0.85	1.46	0.419	NA	1.03	0.61
Formaldehyde	2.02	1.57	NA	NA	-0.45	-0.45
Manganese	0.16	3.34	0.015	NA	3.20	3.18
Molybdenum	2.74	1.87	0.074	NA	-0.80	-0.87
Nickel	3.80	1.49	0.255	NA	-2.06	-2.31
Phosphorous	1.17	6.08	0.159	NA	5.07	4.91
POM	0.44	0.22	NA	NA	-0.22	-0.22
Selenium	0.008	0.26	0.017	NA	0.27	0.25
Tin	1.72	0.76	0.494	NA	-0.47	-0.96
Vanadium	9.27	4.66	NA	NA	-4.61	-4.61
Radionuclides	NA	0.020	NA	NA	0.020	0.020

TABLE 1-19

Pollutants Emissions Comparison (Tons/yr)
Case 4: Cedar Bay as Modified Supplying 380k lb/hr Steam to SK with SK Package Boiler
at 375k lb/hr Steam vs. Case 1a: The Future Operation of the 3 Power Boilers
and 2 Bark Boilers at 745k lb/hr Steam for the SK Recycling Operation

Pollutant	Case 1a SK Power & Bark Boilers	Case 4 Cedar Bay and SK Package Boilers			Net Change	
		Cedar Bay	SK Boilers Firing Oil	SK Boilers Firing Gas	SK Boilers Firing Oil	SK Boilers Firing Gas
SO ₂	3779.6	2612.6	648.5	1.31	-518.5	-1165.7
NO _x	1955.7	2215.3	432.3	459.1	691.9	718.7
CO	2212.2	2275.1	801.5	804.6	864.4	867.5
TSP	634.7	234.5	31.3	11.8	-368.9	-388.4
PM-10	504.7	234.5	15.7	11.8	-254.5	-258.4
VOC	303.3	195.1	3.2	3.2	-105.0	-105.0
Lead	0.24	0.83	1.9E-02	NA	0.61	0.59
Mercury	0.015	0.39	7.3E-03	3.2E-05	0.38	0.38
Beryllium	0.013	0.16	5.4E-03	NA	0.15	0.147
Fluorides	0.45	11.1	6.9E-02	NA	10.7	10.7
H ₂ SO ₄ Mist	91.5	208.1	32.4	NA	149.0	116.6
Subtotal Non-Regulated Trace Pollutants ^(a)	63.3	62.9	3.6	NA	3.2	-0.4
Total Aggregate Emissions	9545.7	8050.6	1968.6	1291.8	473.50	-203.3

^(a)See Table 1-20

1-23

TABLE 1-20

Non-Regulated Pollutants Emissions Comparison (Tons/yr)
Case 4: Cedar Bay as Modified Supplying 380k lb/hr Steam to SK with SK Package Boiler at 375k lb/hr Steam vs. Case 1a: The Future Operation of the 3 Power Boilers and 2 Bark Boilers at 745k lb/hr Steam for the SK Recycling Operation

Pollutant	Case 1a: SK Power & Bark Boilers	Case 4 Cedar Bay and SK Package Boilers			Net Charge	
		Cedar Bay	SK Boilers Firing Oil	SK Boilers Firing Gas	SK Boilers Firing Oil	SK Boilers Firing Gas
Antimony	0.055	0.2	NA	NA	0.145	0.145
Arsenic	0.058	2.0	9.1-03	NA	1.95	1.94
Barium	0.22	12.2	6.0-03	NA	12.0	12.0
Cadmium	0.056	0.7	2.3-02	NA	0.67	0.64
HCl	38.5	23.5	1.4	NA	-13.6	-15.0
Indium	1.40	0.003	NA	NA	-1.4	-1.4
Chromium VI	0.093	0.7	0.10	NA	0.71	0.61
Copper	0.88	1.61	0.61	NA	1.34	0.73
Formaldehyde	2.27	1.72	NA	NA	-0.55	-0.55
Manganese	0.18	3.6	2.1-02	NA	3.44	3.42
Molybdenum	2.75	2.0	0.11	NA	-0.64	-0.75
Nickel	3.84	1.6	0.37	NA	-1.87	-2.24
Phosphorous	1.33	6.6	0.23	NA	5.5	5.27
POM	0.45	0.24	NA	NA	-0.21	-0.21
Selenium	0.009	0.28	2.4-02	NA	0.30	0.271
Tin	1.72	0.82	0.71	NA	-0.19	-0.9
Vanadium	9.51	5.1	NA	NA	-4.41	-4.41
Radionuclides	NA	0.022	NA	NA	0.022	0.022

TABLE 1-21

**Estimated Emissions Decreases Due To Additional Sources^(a)
Shutting Down at SKC from Conversion to Recycling Operation**

Pollutant	Emissions Change (tons/yr)
SO ₂	-31.2
NO _x	-500.6
CO	-2,816.4
TSP	-521.8
PM-10	-413.7
VOC	-384.7
Lead	0
Mercury	-0.0045
Beryllium	0
Fluoride	0
H ₂ SO ₄	-43.9
Total Aggregate	4,712.3
^(a) Recovery Boilers, Lime Kilns, Smelt Dissolving Tanks	

SKC/Cedar Bay site before conception of Cedar Bay and after the operation of Cedar Bay. In addition, as will be shown in Section 2 of the report, even though emissions of some pollutants increase for Case 4 vs. Case 1a, there will be a net benefit to air quality from Case 4 even ignoring the additional reductions in Table 1-21.

2.0 COMPARISON NO. 2: NET AIR QUALITY IMPACTS

2.1 Introduction

The objective of the information to be presented for Comparison No. 2 is to provide data useful for assessing

- 1) whether, on balance, the air quality impacts of the Cedar Bay Power Plant, as proposed to be modified, and the addition of the three new yet-to-be-proposed package boilers scheduled for the SKC site necessary to provide the 640,000 lb. of steam per hour for SKC's use, will be less than the air quality impacts of the SKC recycling operation without the power plant,
- 2) whether, on balance, the air quality impacts of the Cedar Bay Power Plant, as proposed to be modified, and the addition of the three new yet-to-be-proposed package boilers scheduled for the SKC site at their permitted capacity, will be less than the air quality impacts of the power plant as certified, and.
- 3) Whether, on balance, the air quality impacts of the Cedar Bay Power Plant, as proposed to be modified, and the addition of the three new yet-to-be-proposed package boilers scheduled for the SKC site at their permitted capacity, will be less than the air quality impacts of the SKC recycling operation at permitted capacity without the power plant.

In applying Comparison No. 2, the differences in air quality impacts based on atmospheric dispersion modeling are compared amongst 5 cases. These are:

- Case 1: the future operation of the 3 power boilers and 2 bark boilers for the SKC recycling operation at a total annualized steam production rate of 640,000 lb/hr, (which corresponds to an annual capacity factor of 85.9 percent),
- Case 1a: the operation of the 3 power boilers and 2 bark boilers for the SKC recycling operation at a total annualized steam production rate of 745,000 lb/hr (their permitted capacity)
- Case 2: the operation of the Cedar Bay power plant as certified, (at a 93 percent annual capacity factor),

Case 3: the operation of the Cedar Bay power plant, as proposed to be modified, generating electricity and supplying a total annualized steam production rate of 380,000 lb/hr to SK, at the permitted annual capacity factor of 93 percent for conservatism plus the addition of the 3 new package boilers at the SKC recycling operation under two fuel scenarios, fuel oil or natural gas, at a total annualized steam production rate of 260,000 lb/hr, (which corresponds to an annual capacity factor of 69.3 percent), and

Case 4: the operation of the Cedar Bay power plant, as modified, (permitted at an annual capacity factor of 93 percent) generating 250 MW of electricity and supplying a total annualized steam production rate of 380,000 lb/hr to SK, based on a 93 percent capacity factor (used for initial comparison purposes), plus the addition of the 3 new package boilers at the SKC recycling operation under two fuel scenarios, fuel oil or natural gas, at a total annualized steam production rate of 375,000 lb/hr (100 percent capacity).

Three assessments are presented:

Assessment A: Case No. 4
vs.
Case No. 2

Assessment B: Case No. 3 (This is the comparison required directly by the
vs. June 16, 1992 Order of the Siting Board.)
Case No. 1

Assessment C: Case No. 4
vs.
Case No. 1a

2.2 Methodology

The methodology to be employed in this demonstration is the application of air quality dispersion modeling in accordance with EPA and FDER requirements for federal new source review. Air quality impacts are modeled for five individual criteria air pollutants (SO₂, PM-10, NO₂, CO and Pb), and total unregulated air toxics taken from the list included in the Draft Florida Air Toxics Permitting Strategy.

The model selected for this application is the EPA's Industrial Source Complex Short Term (ISCST2) model (Version 92062). This is the recommended model according to EPA's

"Guidelines on Air Quality Models (EPA 1986, 1987)", for application to the SK-Mill and Cedar Bay cogeneration facility. It is applicable to elevated point sources, volume, area and line sources of non-photochemical pollutants located in areas of flat or gently rolling terrain, either urban or rural in dispersion environment. It is also capable of simulating the effects of aerodynamic building downwash on the dispersion of source plumes, where applicable. The model requires as input hourly observed meteorological conditions of surface wind speed, wind direction, temperature, atmospheric stability and boundary layer mixing depth. In accordance with EPA guidelines, this data is obtained from the nearest representative national weather service stations, preferably for a five-year historical period so as to represent a comprehensive profile of future expected conditions from year to year. For this application the meteorological data is taken from surface observations at Jacksonville International Airport and upper air observations at Ware County Airport in Waycross, Georgia, the nearest representative upper air station. Data for the years 1983 through 1987 are employed. These years are preferred by the FDER for use in tracking the PSD increments consumed or expanded by major source changes.

The ISCST model requires the specification of several application options, most of which have EPA recommended default values, but some of which must be specified by the user. Table 2-1 lists the options selected for this application. The building downwash option is used where appropriate to simulate the aerodynamic effects of nearby structures on the dispersion of emissions from stacks that could be subject to downwash. These include all combustion source stacks at Cedar Bay and SKC except for the CFB boilers' stack, which is designed in accordance with EPA Good Engineering Practice (GEP) guidelines to avoid downwash effects. The rural dispersion option is chosen based on the land-use within a 3 km radius of the facilities according to a classification scheme recommended in the EPA Guideline. This is consistent with modeling performed for the SCA. All terrain in the model application is considered to be flat, that is having the same ground-level elevation as the Cedar Bay CFB stack. This is also consistent with the SCA. All of the source input data used in the modeling is described in detail in Section 2.4.

2.3 Analysis Results to be Presented

For Comparison No. 2, the net air quality effects of Case No. 4 versus Case No. 2 (Assessment A), Case No. 3 versus Case No. 1 (Assessment B) and Case No. 4 versus Case No. 1a (Assessment C) are determined. First, the maximum predicted pollutant concentration over all receptors, for each criteria pollutant and total air toxics for applicable averaging periods, are compared between the cases.

Second, the maximum predicted concentration for each criteria pollutant and total air toxics for applicable averaging periods are identified at each receptor. For Assessment A, these maximum receptor-specific impacts of Case No. 2 are subtracted from the maximum receptor specific

TABLE 2-1

ISCST2 Modeling Options

Option Description	Value
Dispersion Parameters	Rural
*Wind Profile Exponents	0.07, 0.07, 0.10, 0.15, 0.35, 0.55
*Vertical Potential Temperature Gradient	0.02, 0.035
*Stack-Tip Downwash	Used
*Buoyancy Induced Dispersion	Used
Anemometer Height (actual)	6.1 m
*Decay Coefficient	0.0
Building Downwash	Used as applicable for Cedar Bay and SK sources
*Gradual Plume Rise	Not used (except for building wake effect modeling)
* Default values recommended by EPA.	

impacts of Case No. 4. For any receptor, a positive difference indicates a pollutant increase, a negative difference indicates a pollutant decrease. The sum of the increases are subtracted from the sum of the absolute values of the decreases. This value is then divided by the total number of receptor points (1,008) in the receptor grid. If this value is a positive number, then a net air quality improvement is demonstrated. This approach is consistent with the definition of net air quality improvement in Rule 17-2.510(7)(a)1, Florida Administrative Code.

For Assessment B, the same analysis is performed with the impacts of Case No. 1 subtracted from the impacts of Case No. 3. For Assessment C, the same analysis is performed with the impacts of Case No. 1a subtracted from the impacts of Case No. 4.

For the criteria pollutants, maximum ground-level concentrations, predicted by atmospheric dispersion modeling for averaging periods consistent with the Florida ambient air quality standards for each pollutant, are compared for Assessment A, B and C. For total air toxics, maximum ground-level concentrations, predicted for averaging periods consistent with the Florida Draft Permitting Strategy are compared. Table 2-2 lists the pollutants and the applicable concentration averaging periods.

Ground-level concentrations are predicted at more than 1,000 locations input as model receptors. A circular (polar) grid of receptors is represented by the intersection of 36 radials at 10° intervals and 28 concentric circles (rings) centered on the Cedar Bay CFB stack location. The ring distances along the radials are specified at the following intervals:

<u>Range (km)</u>	<u>Interval (km)</u>
0.1 to 1.0	0.1
1.0 to 2.0	0.25
2.0 to 5.0	0.5
5.0 to 10.0	1.0
10.0 to 25.0	5.0

The radius of 25 kilometers extends well beyond the distances where maximum impacts are expected and beyond the distances where significant concentration gradient would be predicted. This receptor grid is entirely consistent with the modeling performed for the SCA, and includes receptors located within the property boundaries of the two facilities.

TABLE 2-2

Concentration Averaging Periods Employed In Modeling

Pollutant	Averaging Period				
	1-Hr	3-Hr	8-Hr	24-Hr	Annual
SO ₂		X		X	X
TSP				X	X
PM-10				X	X
NO ₂					X
CO	X		X		
Pb ^(a)				X	X
Total Air Toxics			X	X	X

^(a) AAQS is 3-month averaging period, 24-hour and annual periods used for lead to bracket 3-month average.

2.4 SK and Cedar Bay Pollutant Source Input Data Employed in the Modeling

The ISCST2 model requires specification of hourly average pollutant emission rates and exhaust parameters, and pertinent building dimensions, where applied, for each individual source (e.g., stack) being modeled. To address the subject issue these parameters are developed for the following source configurations:

1. Cedar Bay as currently certified; including only the CFB's, at a 93 percent capacity factor, and the limestone dryers,
2. Cedar Bay as modified including the same sources as above,
3. SK Power Boilers and Bark Boilers in the future recycling mode, at 640,000 lb/steam per hour total, and at the permitted capacity of 745,000 lb/steam per hour total,
4. Future SK Package Boilers firing fuel-oil at 260,000 lb/steam per hour total and 375,000 lb/steam per hour total,
5. Future SK Package Boilers firing natural gas at 260,000 lb/steam per hour total and 375,000 lb/hr.

Tables 2-3 through 2-8 list the pertinent exhaust parameters for these configurations. Physical exhaust parameters for the SK Bark Boilers are taken from the KBN memorandum cited in Section 1. Parameters for the new stack with combined power boiler exhausts were provided by KBN (fax from D. Buff, KBN to J. Yuhas, ENSR, 10/28/92). Physical exhaust parameters for Cedar Bay as certified are taken from the SCA. Physical exhaust parameters for Cedar Bay as modified were provided by Bechtel.

As discussed in Section 2.2., the ISCST2 model requires building dimensions for simulating downwash effects. The plot plan provided in Figure 2-1 identifies pertinent stack and building locations for both Cedar Bay and the SK-Mill. The building dimensions provided in the figure and the location of the individual stacks relative to these buildings were evaluated to develop dimensions for input to the model for those buildings causing downwash. These buildings were identified as the Cedar Bay Boiler Building and the SK-Mill buildings housing the power boilers, bark boilers and recovery boilers. Based on the geometry presented in Figure 2-1, wind direction specific building parameters, including building heights and widths (normalized to the specified wind directions) were developed as input to the ISCST2 model.

Hourly emission rates used in the modeling are derived from those presented in Section 1. Annual average emission rates assumed a 93% capacity factor for the CFB boilers in the "as modified" case, to be conservative. For the SK package boilers the hourly SO₂ emission rate used to model 3 and 24-hour concentrations is based on the maximum hourly emission rate of 0.5 lb/MMBtu, while the annual rate is based on a proposed 0.3 lb/MMBtu annual average used

TABLE 2-3

**Stack Exhaust Parameters for SKC Power Boilers and Bark Boilers
In Future Recycling Mode^(a) at 640,000 lb/hr Total Steam Generation
Fuel Scenario 1 (Worst-Case PM-10)**

	PB1	PB2	PB3	BB1	BB2
Steam Flow (lb/hr)	100,000	145,000	145,000	125,000	125,000
Heat Input (MMBtu/hr)	137	198	198	193	193
Fuel Type	Oil	Oil	Oil	Bark	Bark
UTM East (km)	441.871			441.849	441.856
UTM North (km)	3365.587			3365.613	3365.606
Stack height (m)	38.1			41.5	41.5
Stack diameter (m)	3.20			2.46	2.46
Temperature (deg. K)	443			332	332
Velocity (m/s)	13.78			13.08	13.08
^(a) Power boilers exhausted through new common stack Source: Fax from D. Buff, KBN to J. Yuhas, ENSR, 10/28/92					

TABLE 2-4**Stack Parameters for SKC Power Boilers and Bark Boilers
In Future Recycling Mode^(a) at 640,000 lb/hr Total Steam Generation
Fuel Scenario 2 (Worst-Case SO₂)**

	PB1	PB2	PB3	BB1	BB2
Steam Flow (lb/hr)	135,000	180,000	180,000	72,500	72,500
Heat Input (MMBtu/hr)	185	246	246	112	112
Fuel Type	Oil	Oil	Oil	Bark/Oil	Bark/Oil
UTM East (km)	441.871			441.849	441.856
UTM North (km)	3365.587			3365.613	3365.606
Stack height (m)	38.1			41.5	41.5
Stack diameter (m)	3.20			2.46	2.46
Temperature (deg. K)	443			332	332
Velocity (m/s)	17.48			7.59	7.59
(a) Power Boilers exhausted through new common stack Source: Fax from D. Buff, KBN to J. Yuhas, ENSR, 10/28/92					

TABLE 2-5

**Stack Exhaust Parameters for SKC Power Boilers and Bark Boilers
in Future Recycling Mode^(a) at 745,000 lb/hr Total Steam Generation
for Both Fuel Scenario 1 (Worst-Case PM₁₀) and
Fuel Scenario 2 (Worst-Case SO₂)**

	PB1	PB2	PB3	BB1	BB2
Steam Flow (lb/hr)	135,000	180,000	180,000	125,000	125,000
Heat Input (MMBtu/hr)	185	246	246	193	193
Fuel Type	Oil	Oil	Oil	Bark ^(b) Bark/Oil ^(c)	Bark ^(b) Bark/Oil ^(c)
UTM East (km)	441.871			441.849	441.856
UTM North (km)	3365.587			3365.613	3365.606
Stack Height (m)	38.1			41.5	41.5
Stack Diameter (m)	3.2			2.46	2.46
Temperature (K)	443			332	332
Velocity (m/s)	17.48			13.08	13.08
^(a) Power boilers exhausted through new common stack ^(b) Fuel scenario 1 (worst-case PM ₁₀) ^(c) Fuel scenario 2 (worst-case SO ₂) Source: KBN Engineering and Applied Sciences, Inc. Fax from D. Buff, KBN to Al Hallquist, ENSR, 11/6/92					

TABLE 2-6

**Cedar Bay
Physical Stack Exhaust Parameters**

Parameter	Cedar Bay As Certified		Cedar Bay As Modified (a)	
	CFBs	Limestone Dryers	CFBs	Limestone dryers
UTM East (km)	441.61	441.664	441.61	441.664
UTM North (km)	3365.54	3365.68	3365.54	3365.68
Stack Height (m)	129.54	9.14	122.68	19.21
Stack Diameter (m)	4.27	1.04	4.04	1.27
Stack Exit Velocity (m/s)	33.22	21.34	32.45	18.26
Stack Exit Temperature (K)	403.0	355	403.0	355
(a) Source: Correspondence from A. Nawaz, Bechtel to G. Harkness, ENSR, 11/6/92				

TABLE 2-7

**Design Parameters for New SK Package Boilers -
Maximum Steam Capacity (375,000 lb/hr)**

Parameter	Units	No. 2 Fuel Oil (per boilers)	Natural Gas (per boiler)
Steam Flow	lb/hr	125,000	125,000
Heat Input	MMBtu/hr	164.5	174.7
Exhaust Gas: Temperature	°K	447	439
Common Stack ^(a) Diameter	m	2.43	2.43
Velocity	m/sec	16.18	16.23
Height	m	60.96	60.96
UTM East	km	441.919	
UTM North	km	3365.538	

^(a)All three boilers will exhaust into a common stack. Velocity shown is total all three boilers.
Source: KBN 10/22/92

TABLE 2-8

**Design Parameters for New SK Package Boilers -
260,000 lb/hr Total Steam Generation**

Parameter	Units	No. 2 Fuel Oil (per boiler)	Natural Gas (per boiler)
Steam Flow	lb/hr	86,663	86,663
Heat Input	MMBtu/hr	113.93	121.46
Exhaust Gas: Temperature	°K	435	431
Common Stack ^(a) Diameter	m	2.43	2.43
Velocity	m/sec	10.90	11.10
Height	m	60.96	60.96

^(a)All three boilers will exhaust into a common stack. Velocity shown is total all three boilers.
Source: KBN 10/22/92

2-14

Height	Stack Key
402.5'	CB1 -CFB
63'	CB2 - Limestone Dryers
63'	CB3 - . . .
200'	SK1 - Package Boiler
106'	SK2 - Power Boiler
	SK3 - . . .
	SK4 - . . .
136'	SK5 - Bark Boiler
	SK6 - . . .

Scale
50 feet

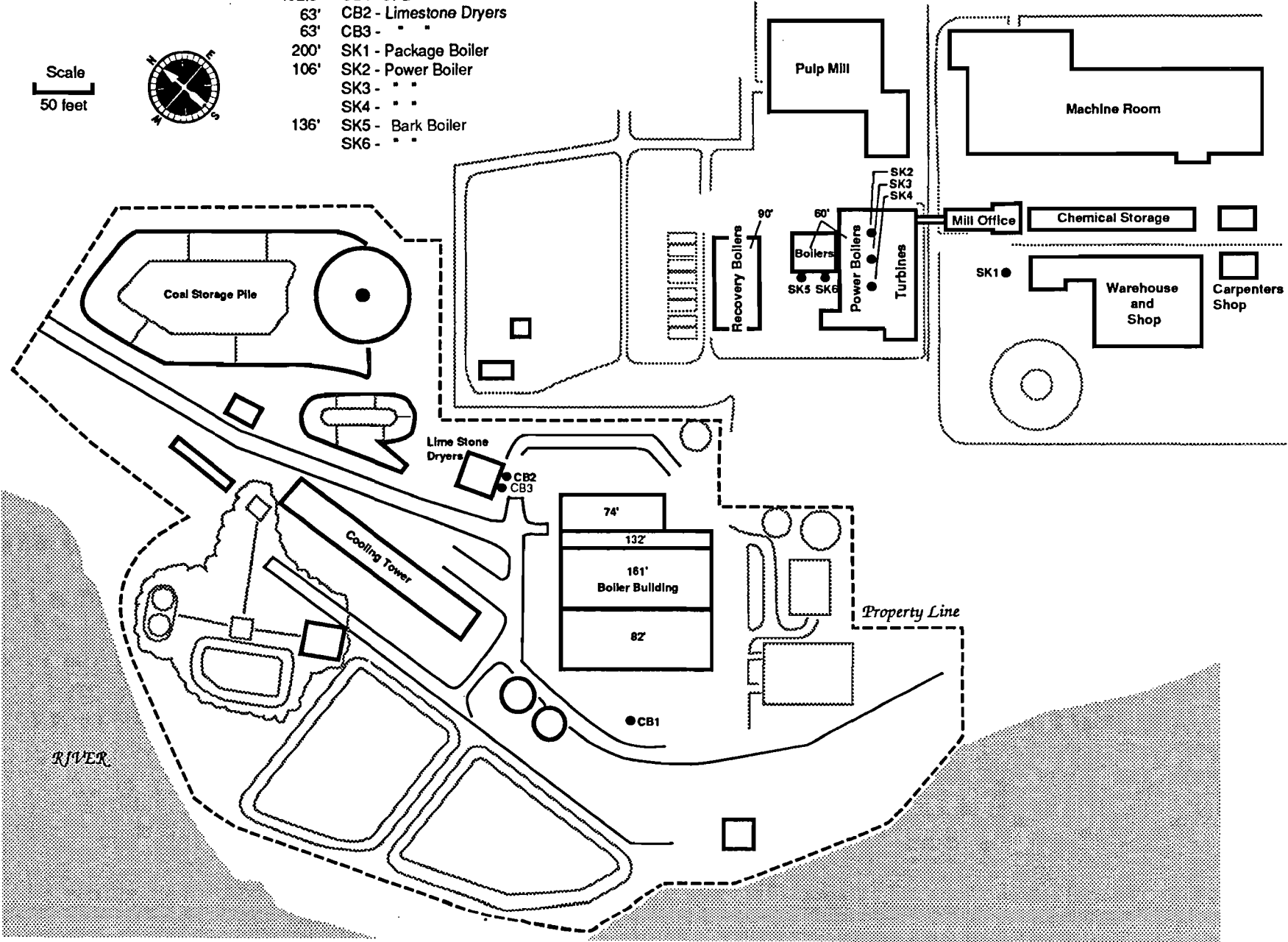


FIGURE 2-1
STACK AND BUILDING CONFIGURATION

in calculating annual emissions. For the limestone dryers in the Cedar Bay as modified case, emission rates for averaging periods of 8-hours or less use the maximum hourly emissions and for 24-hours or more use the annual average rate. This is due to the fact that they will only operate 8 hours per day, the maximum hourly emissions being three times the 24-hour average or annual average rate. For the CFB as certified case, short-term SO₂ emissions are based on the 0.6 lb/MMBtu limit, while the annual emissions are based on the 0.31 lb/MMBtu limit. For the CFB as modified case, short-term SO₂ emissions are based on 0.24 lb/MMBtu and annual emissions are based on 0.20 lb/MMBtu.

2.5 Findings

The findings for Assessment B, Case 3 vs Case 1, are displayed in Tables 2-9 and 2-10 for the SK package boilers in Case 3 on fuel oil and natural gas, respectively. For each pollutant and averaging period and for each meteorological year modeled, four numbers are provided. The first is the maximum modeled concentration over all receptors for Case 1, the existing SK power and bark boilers producing 640,000 lb/hr of steam for the recycling operation. The next number is the maximum modeled concentration over all receptors for Case 3, the Cedar Bay facility as modified plus the proposed SK package boilers providing a combined 640,000 lb/hr of steam for the recycling operation. The third number demonstrates the "net air quality effect" of Case 3 replacing Case 1; that is, the sum of the increases in maximum modeled pollutant concentrations at each receptor subtracted from the sum of the absolute values of the decreases in maximum modeled pollutant concentrations at each receptor, divided by the total number of receptors. If this value is positive, a net benefit is demonstrated. If this value is negative a net degradation is demonstrated. The fourth number is the total number of receptors at which the modeled maximum concentration for Case 3 is lower than the modeled maximum concentration for Case 1.

Referring to Table 2-9, the maximum predicted concentrations for Case 3, with the SK Package Boilers on oil, are much lower than the corresponding Case 1 concentrations for each pollutant and averaging period. In addition, the net air quality effect of Case 3 is positive for each pollutant and averaging period, indicating an average net benefit to air quality over the entire model receptor grid. For the vast majority of receptors, out of a total of 1008, the maximum predicted impacts of Case 3 show an improvement over Case 1 for the individual criteria pollutants and total air toxics.

Table 2-10 presents the results of the same comparison with the SK package boilers firing natural gas. The Case 3 results for the package boiler on fuel oil (Table 2-9) showed a net improvement in air quality for all pollutants. Since emissions for Case 3 are lower for all pollutants, except CO and NO_x than with the SK package boilers firing oil, it stands to reason that there is no need to model pollutants other than CO and NO_x for this comparison. Since CO and NO_x emissions

TABLE 2-9

Findings for Comparison No. 2, Assessment B, Net Air Quality Effect of
 Case 3: Cedar Bay as Modified Supplying 380 k lb/hr Steam to SK
 with SK Package Boilers at 260 k lb/hr Steam Firing Fuel Oil
 vs. Case 1: The Future Operation of the 3 Power Boilers and 2 Bark Boilers
 at 640 k lb/hr Steam for the SKC Recycling Operation

Pollutant	Averaging Period	Meteorological Year	Maximum Predicted Impacts ($\mu\text{g}/\text{m}^3$)		Case 3 Net Air Quality Effect ($\mu\text{g}/\text{m}^3$)	Case 3 Number of Receptors Improved ^(b)
			Case 1	Case 3		
SO ₂	3 Hr	1983	667.30	421.76	81.09	991
		1984	631.97	259.34	67.95	1002
		1985	483.92	275.87	66.97	999
		1986	442.87	264.61	60.42	984
		1987	502.10	280.84	66.45	991
	24 Hr	1983	274.63	108.36	26.14	995
		1984	189.32	61.31	20.76	1004
		1985	246.96	70.01	19.14	999
		1986	175.19	68.99	20.49	990
		1987	163.15	93.54	20.91	991
	Annual	1983	5.81	3.99	1.41	1004
		1984	4.91	3.14	1.30	1003
		1985	5.81	3.88	1.34	1004
		1986	4.95	2.95	1.23	1004
		1987	9.02	3.47	1.43	1004

TABLE 2-9 (Cont'd)

**Findings for Comparison No. 2, Assessment B, Net Air Quality Effect of
Case 3: Cedar Bay as Modified Supplying 380 k lb/hr Steam to SK
with SK Package Boilers at 260 k lb/hr Steam Firing Fuel Oil
vs. Case 1: The Future Operation of the 3 Power Boilers and 2 Bark Boilers
at 640 k lb/hr Steam for the SKC Recycling Operation**

Pollutant	Averaging Period	Meteorological Year	Maximum Predicted Impacts ($\mu\text{g}/\text{m}^3$)		Case 3 Net Air Quality Effect ($\mu\text{g}/\text{m}^3$)	Case 3 Number of Receptors Improved ^(a)
			Case 1	Case 3		
PM10	24 Hr	1983	41.29	1.52	7.89	1004
		1984	35.35	1.26	7.59	1004
		1985	49.45	1.23	7.17	1004
		1986	42.44	1.04	7.18	1004
		1987	39.21	1.32	7.47	1004
PM10	Annual	1983	2.27	0.10	0.58	1004
		1984	2.28	0.10	0.57	1004
		1985	2.28	0.10	0.58	1004
		1986	2.28	0.10	0.55	1004
		1987	3.09	0.10	0.54	1004
CO	1 Hr	1983	986.81	330.24	205.75	1004
		1984	947.32	336.40	207.05	1004
		1985	927.57	331.98	206.68	1004
		1986	913.88	334.01	209.0	1004
		1987	1036.09	331.82	212.23	1004
	8 Hr	1983	412.55	151.28	81.52	1004
		1984	368.58	95.31	83.54	1004
		1985	432.25	135.57	78.97	1004
		1986	367.64	136.10	75.90	1004
		1987	382.87	103.21	78.97	1004

TABLE 2-9 (Cont'd)

Findings for Comparison No. 2, Assessment B, Net Air Quality Effect of
 Case 3: Cedar Bay as Modified Supplying 380 k lb/hr Steam to SK
 with SK Package Boilers at 260 k lb/hr Steam Firing Fuel Oil
 vs. Case 1: The Future Operation of the 3 Power Boilers and 2 Bark Boilers
 at 640 k lb/hr Steam for the SKC Recycling Operation

Pollutant	Averaging Period	Meteorological Year	Maximum Predicted Impacts ($\mu\text{g}/\text{m}^3$)		Case 3 Net Air Quality Effect ($\mu\text{g}/\text{m}^3$)	Case 3 Number of Receptors Improved ^(a)
			Case 1	Case 3		
NO ₂	Annual	1983	4.82	2.64	1.15	1004
		1984	5.00	2.07	1.10	1004
		1985	4.97	2.57	1.13	1004
		1986	4.27	1.94	1.06	1004
		1987	7.18	2.27	1.17	1004
Pb	24 Hr	1983	2.0e-02	5.0e-03	3.22e-03	965
		1984	1.8e-02	7.0e-03	3.0e-03	961
		1985	2.4e-02	5.0e-03	2.9e-03	976
		1986	2.1e-02	6.0e-03	2.8e-03	961
		1987	1.9e-02	6.0e-03	3.0e-03	955
	Annual	1983	1.1e-03	5.0e-04	2.3e-04	797
		1984	1.2e-03	7.0e-04	2.1e-04	753
		1985	1.1e-03	5.0e-04	2.5e-04	829
		1986	1.1e-03	6.0e-04	2.1e-04	793
		1987	1.5e-03	6.0e-04	2.4e-04	783

TABLE 2-9 (Cont'd)

**Findings for Comparison No. 2, Assessment B, Net Air Quality Effect of
Case 3: Cedar Bay as Modified Supplying 380 k lb/hr Steam to SK
with SK Package Boilers at 260 k lb/hr Steam Firing Fuel Oil
vs. Case 1: The Future Operation of the 3 Power Boilers and 2 Bark Boilers
at 640 k lb/hr Steam for the SKC Recycling Operation**

Pollutant	Averaging Period	Meteorological Year	Maximum Predicted Impacts ($\mu\text{g}/\text{m}^3$)		Case 3 Net Air Quality Effect ($\mu\text{g}/\text{m}^3$)	Case 3 Number of Receptors Improved ^(a)
			Case 1	Case 3		
Total Air Toxics	8 Hr	1983	9.5	0.70	1.93	1004
		1984	8.4	0.53	1.87	1004
		1985	9.7	0.64	1.85	1004
		1986	9.0	0.63	1.79	1004
		1987	9.8	0.62	1.85	1004
	24 Hr	1983	5.7	0.37	1.09	1004
		1984	5.1	0.28	1.06	1004
		1985	6.6	0.28	1.00	1004
		1986	6.1	0.24	1.00	1004
		1987	5.4	0.32	1.04	1004
	Annual	1983	0.34	0.02	0.08	1003
		1984	0.35	0.03	0.08	1003
		1985	0.34	0.02	0.08	1003
		1986	0.32	0.02	0.08	1003
		1987	0.46	0.02	0.09	1003

^(a)Out of a total of 1008

TABLE 2-10

**Findings for Comparison No. 2, Assessment B, Net Air Quality Effect of
Case 3: Cedar Bay as Modified Supplying 380 k lb/hr Steam to SK
with SK Package Boilers at 260 k lb/hr Steam Firing Natural Gas
vs. Case 1: The Future Operation of the 3 Power Boilers and 2 Bark Boilers
at 640 k lb/hr Steam for the SKC Recycling Operation**

Pollutant	Averaging Period	Meteorological Year	Maximum Predicted Impacts ($\mu\text{g}/\text{m}^3$)		Case 3 Net Air Quality Effect ($\mu\text{g}/\text{m}^3$)	Case 3 Number of Receptors Improved(a)
			Case 1	Case 3		
CO	1 Hr	1983	986.81	339.81	205.13	1004
		1984	947.32	343.18	206.46	1004
		1985	927.57	340.70	206.08	1004
		1986	913.88	342.88	208.40	1004
		1987	1036.09	339.64	211.64	1004
	8 Hr	1983	412.55	154.82	81.30	1004
		1984	368.58	97.06	79.60	1004
		1985	432.25	139.31	78.75	1004
		1986	367.64	139.56	75.69	1004
		1987	382.77	106.09	78.75	1004
NO ₂	Annual	1983	4.82	2.81	1.14	1004
		1984	5.00	2.21	1.09	1004
		1985	4.97	2.73	1.12	1004
		1986	4.27	2.07	1.05	1004
		1987	7.18	2.42	1.16	1004

^(a)Out of a total of 1008

increase, however, for Case 3 with the package boilers firing natural gas, results are presented in Table 2-10 for CO and NO₂ only for Case 3 with natural gas. Referring to Table 2-10, Case 3 with natural gas still represents a large improvement over Case 1 maximum impacts, producing a positive net air quality benefit and lower maximum impacts over virtually all receptors.

The above results demonstrate that the Cedar Bay facility as modified, meets the first criteria of Comparison No. 2. That is, on balance the air quality impacts of the Cedar Bay Power Plant, as modified, and the addition of any boilers on the SKC site necessary to provide the 640,000 lb. of steam per hour for SKC's use will be less than the air quality impacts of the future SKC recycling operation without the power plant.

The findings for Assessment A, Case 4 vs Case 2, are displayed in Tables 2-11 and 2-12, for the SK package boilers in Case 4 on fuel oil and natural gas, respectively. These findings are presented in the same format as those for Assessment B.

Referring to Table 2-11, with the exception of the pollutants SO₂ and CO, the maximum predicted impacts of Case 4, Cedar Bay as modified plus the SK package boilers, are lower than those of Case 2, Cedar Bay as certified. For SO₂, due to downwash of the package boiler emissions, the maximum predicted impacts for Case 4 are higher for some averaging periods for some of the meteorological years modeled. However, the average net SO₂ air quality effect of Case 4 is positive for all averaging periods and meteorological years, demonstrating a net SO₂ improvement with Case 4 over Case 2. This is due to the fact that maximum SO₂ impacts are lower for Case 4 at the majority of receptors. For all other pollutants except CO, the average net air quality effect of Case 4 is also positive, and the number of receptors where lower maximum impacts are predicted for Case 4 are in the majority.

For the pollutant CO, due to higher total emissions, the maximum impacts are higher for Case 4 and the calculated average net air quality effects are negative, with a minority of receptors showing improvement. However, it is very important to note that the maximum CO impacts for both cases are much less than the Florida and EPA Significant Impact Levels (SILs) for 1-hour CO (2000 µg/m³) and 8-hour CO (500 µg/m³). The SILs are used to determine if a source has a significant impact and/or contributes to a violation of an ambient air quality standard or PSD increment. The SILs for CO are 5 percent of the AAQS. In this case, a comparison as to a benefit in air quality is not meaningful, since impacts are insignificant in both cases.

Table 2-12 displays the findings for Assessment A for the SK package boilers firing natural gas. The Case 4 results for the package boilers on fuel oil showed net improvements on balance for all pollutants. It can be concluded that these improvements would be greater for pollutants whose emissions decrease when firing natural gas. Thus, results are shown for CO and NO₂ only, since

TABLE 2-11

**Findings for Comparison No. 2, Assessment A, Net Air Quality Effect of Case 4:
Cedar Bay as Modified with
SK Package Boilers at 375 k lb/hr Steam Firing Fuel Oil vs.
Case 2: Cedar Bay as Certified**

Pollutant	Averaging Period	Meteorological Year	Maximum Predicted Impacts ($\mu\text{g}/\text{m}^3$)		Case 4 Net Air Quality Effect ($\mu\text{g}/\text{m}^3$)	Case 4 Number of Receptors Improved
			Case 2	Case 4		
SO ₂	3 hr	1983	165.60	443.25	5.70	831
		1984	173.48	232.21	6.95	829
		1985	236.12	299.74	9.75	841
		1986	210.39	260.78	7.03	807
		1987	173.15	267.99	6.11	845
	24 hr	1983	60.99	112.54	3.12	742
		1984	89.88	68.87	4.23	766
		1985	70.75	83.26	3.71	809
		1986	81.04	65.48	3.59	768
		1987	72.54	86.38	109	671
	Annual	1983	9.33	3.75	0.46	467
		1984	9.92	2.84	0.50	477
		1985	9.82	3.72	0.49	483
		1986	12.39	2.64	0.51	497
		1987	10.11	3.44	0.47	460
PM-10	24 hr	1983	3.05	1.64	0.20	491
		1984	4.49	1.26	0.23	505
		1985	3.54	1.23	0.21	508
		1986	4.05	1.04	0.20	508
		1987	3.63	1.26	0.21	481
	Annual	1983	0.47	0.09	0.03	560
		1984	0.50	0.10	0.03	568
		1985	0.49	0.10	0.03	575
		1986	0.62	0.10	0.03	602

TABLE 2-11 (Cont'd)

Findings for Comparison No. 2, Assessment A, Net Air Quality Effect of Case 4:
 Cedar Bay as Modified with
 SK Package Boilers at 375 k lb/hr Steam Firing Fuel Oil vs.
 Case 2: Cedar Bay as Certified

Pollutant	Averaging Period	Meteorological Year	Maximum Predicted Impacts ($\mu\text{g}/\text{m}^3$)		Case 4 Net Air Quality Effect ($\mu\text{g}/\text{m}^3$)	Case 4 Number of Receptors Improved
			Case 2	Case 4		
PM-10	Annual	1987	0.51	0.10	0.03	559
CO	1 hr	1983	47.38	367.49	-15.86	87
		1984	57.94	356.48	-15.41	91
		1985	60.60	366.49	-15.43	90
		1986	69.07	365.90	-15.40	95
		1987	52.69	369.81	-15.23	96
		1983	14.17	147.28	-5.37	117
		1984	16.84	96.36	-5.27	115
		1985	16.86	131.26	-5.42	113
		1986	16.39	132.33	-5.28	114
		1987	15.58	111.25	-5.24	115
NO ₂	Annual	1983	4.44	2.48	0.20	494
		1984	4.72	1.87	0.22	546
		1985	4.68	2.46	0.21	504
		1986	5.90	1.73	0.23	541
		1987	4.82	2.25	0.20	530
Pb	24 hr	1983	0.13	4.8E-03	0.05	980
		1984	0.14	0.01	0.05	980
		1985	0.17	0.01	0.05	980
		1986	0.14	0.01	0.05	980
		1987	0.15	0.01	0.05	980
		Annual	1983	0.01	5.0E-03	0.002
	1984	0.14	7.0E-03	0.003	980	
1985	0.17	6.0E-03	0.002	980		

TABLE 2-11 (Cont'd)

**Findings for Comparison No. 2, Assessment A, Net Air Quality Effect of Case 4:
Cedar Bay as Modified with
SK Package Boilers at 375 k lb/hr Steam Firing Fuel Oil vs.
Case 2: Cedar Bay as Certified**

Pollutant	Averaging Period	Meteorological Year	Maximum Predicted Impacts ($\mu\text{g}/\text{m}^3$)		Case 4 Net Air Quality Effect ($\mu\text{g}/\text{m}^3$)	Case 4 Number of Receptors Improved	
			Case 2	Case 4			
Pb	Annual	1986	0.01	6.0E-03	0.002	980	
		1987	0.01	6.0E-03	0.002	980	
Total Air Toxics	8 hr	1983	4.20	1.24	1.39	973	
		1984	4.90	1.46	1.49	975	
		1985	6.46	1.26	1.59	975	
		1986	4.83	1.23	1.41	974	
		1987	4.60	1.15	1.40	975	
		24 hr	1983	1.78	0.36	0.60	975
			1984	1.94	0.28	0.66	976
	1985		2.25	0.28	0.68	976	
	Annual	1986	1.86	0.23	0.60	976	
		1987	2.07	0.28	0.61	976	
		1983	0.10	0.02	0.032	977	
		1984	0.11	0.03	0.035	978	
		1985	0.11	0.02	0.034	978	
		1986	0.14	0.02	0.034	980	
1987		0.11	0.02	0.030	979		

^(a)Out of a total of 1008

TABLE 2-12

Findings for Comparison No. 2, Assessment A, Net Air Quality Effect of Case 4:
 Cedar Bay as Modified with
 SK Package Boilers at 375 k lb/hr Steam Firing Natural Gas vs.
 Case 2: Cedar Bay as Certified

Pollutant	Averaging Period	Meteorological Year	Maximum Predicted Impacts ($\mu\text{g}/\text{m}^3$)		Case 4 Net Air Quality Effect ($\mu\text{g}/\text{m}^3$)	Case 4 Number of Receptors Improved ^(a)
			Case 2	Case 4		
CO	1 hr	1983	47.38	368.53	-16.14	85
		1984	57.94	356.94	-15.69	88
		1985	60.60	367.49	-15.71	90
		1986	69.07	366.98	-15.72	93
		1987	52.69	370.96	-15.51	94
	8 hr	1983	14.17	147.61	-5.49	114
		1984	16.84	96.57	-5.39	115
		1985	16.86	132.39	-5.53	111
		1986	16.39	133.79	-5.41	113
		1987	15.58	111.25	-5.36	112
NO ₂	Annual	1983	4.44	2.62	0.19	447
		1984	4.72	1.98	0.21	476
		1985	4.68	2.60	0.20	453
		1986	5.90	1.84	0.22	489
		1987	4.82	2.40	0.19	459

^(a)Out of total of 1008

these are the only pollutants that increase in Case 4, due to the package boilers firing natural gas. For CO, the same conclusions can be drawn as in the oil-firing case. Impacts, although higher for Case 4, are insignificant, thus rendering a comparison meaningless. For Case 4, NO₂ maximum impacts are again lower than Case 2, and a positive average net air quality benefit is demonstrated.

The above results demonstrate that the Cedar Bay facility, as modified, meets the second criteria of Comparison No. 2. That is, on balance, the air quality impacts of the Cedar Bay Power Plant, as modified, and the addition of any boilers on the SKC site at their permitted capacity will be less than the air quality impacts of the power plant as certified.

The findings for Assessment C, Case 4 vs. Case 1a, are displayed in Tables 2-13 and 2-14, for the SK package boilers in Case 4 on fuel oil and natural gas, respectively. Referring to Table 2-13, the maximum predicted concentrations for Case 4, with the SK package boilers on oil, are much lower than the corresponding Case 1a concentrations for each pollutant and averaging period. In addition, the net air quality effect of Case 4 is positive for each pollutant and averaging period, indicating an average net benefit to air quality over the entire model receptor grid. For the vast majority of receptors, out of a total of 1008, the maximum predicted impacts of Case 4 show an improvement over Case 1a for the individual criteria pollutants and total air toxics.

Table 2-14 presents the results of the same comparison with the SK package boilers firing natural gas. Since only CO and NO_x emissions increase from the package boilers firing natural gas, while emissions of all other pollutants decrease, results are presented in Table 2-14 for CO and NO₂ only. These results show that Case 4 with natural gas still represents a large improvement over Case 1a maximum impacts, a positive net air quality benefit and lower maximum impacts over the vast majority of receptors.

The above results demonstrate the Cedar Bay facility, as modified, meets the third criteria of Comparison No. 2. That is, on balance, the air quality impacts of the Cedar Bay Power Plant, as modified, and the addition of the boilers on the SKC site at their permitted capacity will be less than the air quality impacts of the SKC recycling operation with power and bark boilers at their maximum permitted capacity.

TABLE 2-13

**Findings for Comparison No. 2, Assessment C, Net Air Quality Effect of Case 4:
Cedar Bay as Modified with SK Package Boilers at 375k lb/hr Steam
Firing Fuel Oil vs. Case 1a: The Future Operation of the 3 Power
Boilers and 2 Bark Boilers at 745k lb/hr Steam for the SKC Recycling Operation**

Pollutant	Averaging Period	Meteorological Year	Maximum Predicted Impacts ($\mu\text{g}/\text{m}^3$)		Case 4 Net Air Quality Effect ($\mu\text{g}/\text{m}^3$)	Case 4 Number of Receptors Improved ^(a)
			Case 1a	Case 4		
SO ₂	3 hr	1983	678.13	443.25	85.58	989
		1984	637.91	232.21	72.84	1001
		1985	500.85	299.74	71.27	997
		1986	461.10	260.78	64.91	985
		1987	527.11	267.99	70.75	990
	24 hr	1983	281.34	112.54	27.60	997
		1984	190.00	68.87	22.28	1004
		1985	259.58	83.26	20.49	997
		1986	184.73	65.48	21.98	993
		1987	171.91	86.38	22.33	989
	Annual	1983	6.01	3.75	1.50	1004
		1984	4.95	2.84	1.39	1003
		1985	6.11	3.72	1.42	1004
		1986	5.04	2.64	1.31	1003
		1987	9.33	3.44	1.52	1004
CO	1 hr	1983	980.12	367.49	202.98	1004
		1984	943.78	356.48	204.42	1004
		1985	922.11	366.49	204.11	1004
		1986	910.40	365.90	206.37	1004
		1987	1036.23	369.81	209.57	1004
	8 hr	1983	410.77	147.28	80.63	1003
		1984	367.68	96.36	78.97	1003

TABLE 2-13 (Cont'd)

Findings for Comparison No. 2, Assessment C, Net Air Quality Effect of Case 4:
 Cedar Bay as Modified with SK Package Boilers at 375k lb/hr Steam
 Firing Fuel Oil vs. Case 1a: The Future Operation of the 3 Power
 Boilers and 2 Bark Boilers at 745k lb/hr Steam for the SKC Recycling Operation

Pollutant	Averaging Period	Meteorological Year	Maximum Predicted Impacts ($\mu\text{g}/\text{m}^3$)		Case 4 Net Air Quality Effect ($\mu\text{g}/\text{m}^3$)	Case 4 Number of Receptors Improved ^(a)
			Case 1a	Case 4		
CO	8 hr	1985	431.98	131.26	78.02	1004
		1986	365.36	132.33	75.32	1004
		1987	380.01	111.25	78.11	1004
NO _x	Annual	1983	5.23	2.48	1.26	1004
		1984	5.05	1.87	1.21	1004
		1985	5.33	2.46	1.24	1004
		1986	4.51	1.73	1.15	1004
		1987	7.56	2.25	1.29	1004
PM-10	24 hr	1983	39.80	1.64	7.57	1004
		1984	32.56	1.26	7.30	1004
		1985	46.21	1.23	6.91	1004
		1986	39.24	1.04	6.92	1004
		1987	36.26	1.26	7.17	1004
	Annual	1983	2.14	0.09	0.57	1004
		1984	2.20	0.11	0.55	1004
		1985	2.16	0.10	0.57	1004
		1986	1.99	0.10	0.53	1004
		1987	2.94	0.10	0.58	1004
Lead	24 hr	1983	0.019	0.005	0.0031	968
		1984	0.016	0.01	0.0028	958
		1985	0.022	0.01	0.0027	979
		1986	0.020	0.01	0.0027	970
		1987	0.018	0.01	0.0029	956

TABLE 2-13 (Cont'd)

Findings for Comparison No. 2, Assessment C, Net Air Quality Effect of Case 4: Cedar Bay as Modified with SK Package Boilers at 375k lb/hr Steam Firing Fuel Oil vs. Case 1a: The Future Operation of the 3 Power Boilers and 2 Bark Boilers at 745k lb/hr Steam for the SKC Recycling Operation

Pollutant	Averaging Period	Meteorological Year	Maximum Predicted Impacts ($\mu\text{g}/\text{m}^3$)		Case 4 Net Air Quality Effect ($\mu\text{g}/\text{m}^3$)	Case 4 Number of Receptors Improved ^(a)
			Case 1a	Case 4		
Lead	Annual	1983	0.0011	0.005	0.0023	808
		1984	0.0011	0.007	0.00021	779
		1985	0.0011	0.006	0.00022	798
		1986	0.0010	0.006	0.00021	811
		1987	0.0015	0.006	0.00023	800
Total Air Toxics	8 hr	1983	9.24	1.24	1.89	1004
		1984	8.26	1.46	1.83	1004
		1985	9.62	1.26	1.81	1004
		1986	8.66	1.23	1.75	1004
		1987	9.32	1.15	1.81	1004
	24 hr	1983	5.58	0.36	1.07	1004
		1984	4.86	0.28	1.04	1004
		1985	6.31	0.28	0.98	1004
		1986	5.83	0.23	0.98	1004
		1987	5.14	0.28	1.02	1004
	Annual	1983	0.33	0.02	0.08	1004
		1984	0.34	0.03	0.08	1004
		1985	0.33	0.02	0.08	1004
		1986	0.31	0.02	0.08	1004
		1987	0.44	0.02	0.08	1004

^(a)Out of a total of 1008.

TABLE 2-14

Findings for Comparison No. 2, Assessment C, Net Air Quality Effect of Case 4: Cedar Bay as Modified with SK Package Boilers at 375k lb/hr Steam Firing Natural Gas vs. Case 1a: The Future Operation of the 3 Power Boilers and 2 Bark Boilers at 745k lb/hr Steam for the SKC Recycling Operation

Pollutant	Averaging Period	Meteorological Year	Maximum Predicted Impacts ($\mu\text{g}/\text{m}^3$)		Case 4 Net. Air Quality Effect ($\mu\text{g}/\text{m}^3$)	Case 4 Number of Receptors Improved ^(a)
			Case 1a	Case 4		
CO	1 hr	1983	980.12	368.53	202.70	1004
		1984	943.78	356.94	204.14	1004
		1985	922.11	367.49	203.84	1004
		1986	910.40	366.98	206.05	1004
		1987	1036.23	370.96	209.29	1004
	8 hr	1983	410.77	147.61	80.51	1003
		1984	367.68	96.57	78.85	1003
		1985	431.98	132.39	77.91	1004
		1986	365.36	133.79	75.20	1004
		1987	380.01	111.25	77.99	1004
NO _x	Annual	1983	5.23	2.62	1.25	1004
		1984	5.05	1.98	1.20	1004
		1985	5.33	2.60	1.23	1004
		1986	4.51	1.84	1.14	1004
		1987	7.56	2.40	1.28	1004

^(a)Out of a total of 1008.

3.0 COMPARISON NO. 3: CEDAR BAY COMPLIANCE WITH AMBIENT AIR QUALITY STANDARDS (AAQS), PREVENTION OF SIGNIFICANT DETERIORATION (PSD) INCREMENTS, AND COMPARISON TO DRAFT AIR TOXICS NO THREAT LEVELS (NTLS)

3.1 Introduction

The objective of the information presented in this section is to provide data useful for assessing whether the Cedar Bay cogeneration facility by itself, as modified, would either cause or contribute to a violation of an ambient air quality standard (AAQS) or cause or contribute to a violation of the allowable PSD increments, in either the region surrounding the facility (a PSD Class II area) or the two distant PSD Class I areas. The two PSD Class I areas are the Okefenokee and Wolf Island Wilderness Areas in Georgia. In addition, information is presented to provide data useful for assessing whether the Cedar Bay facility would produce air toxics concentrations above the Draft Florida No Threat Levels. For annual average estimates of impacts the Cedar Bay CFB boilers are assumed to operate at a capacity of 93%.

The national and Florida AAQS are listed in Table 3-1. The PSD increments are listed in Table 3-2. Also listed are the "significant impact levels" (SIL) established by EPA for these pollutants. The Draft NTL's for air toxics being modeled are listed in Table 3-3. These were selected from the entire list of NTL's for those toxic air pollutants emitted from the Cedar Bay sources.

The modeling for AAQS purposes considers the impacts of other major existing and permitting sources in Duval County as well as background concentrations of the AAQS pollutants.

For PSD increment consumption calculations, SO₂, NO_x and TSP sources in Duval County existing as of the respective minor source baseline dates which have had permitted changes or increased or decreased emissions since applicable baseline dates are considered, plus increment consuming sources permitted since baseline dates, along with the Cedar Bay facility. This includes increment expansions resulting from the shutdown of the 3 power boilers and 2 bark boilers at the SK facility.

TABLE 3-1

**National and Florida Ambient Air Quality Standards ($\mu\text{g}/\text{m}^3$)
For Pollutants Being Modeled**

Pollutant	Averaging Period	NAAQS Standards		Florida State Standards	EPA Significant Impact Level ^(a)
		Primary	Secondary		
SO ₂	Annual	80	--	60	1
	24-hour	365	--	260	5
	3-hour	--	1,300	1,300	25
NO ₂	Annual	100	100	100	1
PM ₁₀	Annual	50	50	50	1
	24-hour	150	150	150	5
CO	8-hour	10,000	--	10,000	500
	1-hour	40,000	--	40,000	2,000
Lead (Pb)	Calendar Quarter	1.5	1.5	1.5	

^(a)40 CFR 51.165(b)(2)

TABLE 3-2

Federal and Florida PSD Increments

Pollutant	Averaging Period	PSD Area Classification		PSD Class II Significant Impact Levels
		Class I	Class II	
SO ₂	3-hour	25	512	25
	24-hour	5	91	5
	Annual	2	20	1
TSP	24-hour	10	37	5
	Annual	5	19	1
NO ₂	Annual	2.5	25	1

TABLE 3-3

No Threat Levels (NTLs) For Air Toxics Being Modeled^(a)

Pollutant	No Threat Levels ($\mu\text{g}/\text{m}^3$)		
	8 hr	24 hr	Annual
antimony compounds	5	1.2	3.0E-01
arsenic	2	0.48	2.3E-04
barium	5	1.2	5.0E+01
beryllium	0.02	0.0048	4.2E-04
cadmium	0.5	0.12	5.6E-04
chromium VI compounds	0.5	0.12	8.3E-05
copper	10	2.4	
fluorides (as F)	25	6	
formaldehyde	12	2.88	7.7E-02
hydrogen chloride (hydrochloric acid)	75	18	7.0E+00
indium compounds (as In)	1	0.24	
lead	0.5	0.12	9.0E-02
manganese (as Mn)	50	12	4.0E-01
mercury (as Hg) alkyl compounds	0.1	0.024	
molybdenum, soluble compounds, (as Mo)	50	12	
nickel, soluble compounds, (as Ni)	1	0.24	
phosphorus	1	0.24	
selenium	2	0.48	
sulfuric acid (H_2SO_4)	10	2.4	
tin	1	0.24	
vanadium, as(V_2O_5)	0.5	0.12	2.0E+01

(a) There are no NTLs listed for POM or radionuclides.

The following are the applicable baseline dates:

PSD Pollutant	Minor Source Baseline Date	Major Source Baseline Date
SO ₂	December 27, 1977	January 6, 1975
TSP	December 27, 1977	January 6, 1975
NO ₂	March 28, 1988	February 8, 1988

3.2 Methodology

The modeling methodology employed is identical to that employed in addressing Comparison No. 2: Net Air Quality Impacts, the model being applied, the pollutants being modeled and the meteorological data. However, since the maximum impacts of Cedar Bay facility, by itself, occur in the near field and the facility has predicted air quality impacts below the significant impact levels beyond 4.5 km for the criteria pollutants, the receptor grid for Comparison No. 3 extended to 5 km only. The only exception is that receptors are added at the two PSD Class I areas for the PSD analysis.

3.2.1 AAQS Analysis

Modeling of the AAQS pollutants is first performed for the Cedar Bay facility alone. No offsetting sources are considered. Pollutants for which the maximum modeled concentrations are less than the SILs for the applicable averaging periods are eliminated from further consideration. The concept here is that if these impacts are not significant, then they can neither cause nor contribute to a violation, as promulgated by EPA at 40 CFR 51.165(b)(2). For pollutants for which the Cedar Bay facility is modeled to have a significant impact, multi-source modeling is performed with the existing and permitted source inventories.

Background concentrations of those pollutants are then added to modeled impacts to determine total pollutant concentrations for comparison to the AAQS.

3.2.2 PSD Analysis

PSD pollutants for which maximum modeled concentrations in the PSD Class II area around the facility, due to the Cedar Bay facility alone, are less than the SILs are eliminated from further consideration. The concept here is that if these impacts are not significant, then the facility will neither cause nor contribute to a violation of a PSD Class II increment (U.S. EPA Memorandum,

G. Emison, OAQPS to T. Maslany, AMD, 7/5/88). For PSD pollutants for which the facility is modeled to have a significant impact, multi-source modeling is performed with the PSD source inventories for the compliance evaluations. Multi-source PSD increment modeling is also performed for receptors in the PSD Class I areas.

3.2.3 NTL Comparison

The modeled maximum ground-level concentration of each draft air toxic pollutant for averaging periods consistent with the draft NTLs is identified. These concentrations are then compared to the draft NTLs. This analysis is performed for the Cedar Bay facility alone, since the NTLs are intended as source-specific screening levels.

3.3 Source Data and Assumptions

The emissions and exhaust parameters used in the PSD, AAQS and NTL modeling for the Cedar Bay facility as modified are the same as those used in the net air quality impacts modeling. The PSD emissions and exhaust parameters for the SK Power and Bark Boilers to be shut down, representative of the respective baseline years are given in Tables 3-4 through 3-8. These were supplied by KBN Engineering and Applied Sciences as the proposed baseline data to be submitted for review and approval by the FDER as part of SKC's air permit application for the proposed SK Package Boilers. The inventories of Duval County sources used in the PSD and NAAQS modeling are presented in Tables 3-9 through 3-11. The SO₂ source data was provided to ENSR by KBN Engineering and Applied Sciences on 10-8-92. According to KBN, this is a proposed current update of major source inventories to be submitted for review and approval by the FDER as part of SKC's air permit application for the proposed SK Package Boilers. The TSP/PM-10 and NO_x source data were developed by ENSR from FDER's Air Program Information System Facility Emission Reports for 1975-1991 and the Master Detail Reports for major sources. The facility emission reports were surveyed to identify major (potential to emit 100 TPY or greater) sources and source changes between the respective baseline years and 1991. The master detail reports for those sources were examined to extract source data for modeling. Allowable emissions, as listed in the FDER inventories, were employed. The tables note where a source is either a PSD increment consuming (CON) or increment expanding (EXP) source. These sources were the only sources employed in the PSD modeling. All other sources are assumed to be unaltered baseline sources and were included along with increment consuming sources in the modeling for AAQS.

TABLE 3-4

**SO₂ and TSP PSD Baseline Stack and Operating
Data for the Seminole Kraft^a Facility in Jacksonville, Florida**

Unit Description	Stack Height (m)	Stack Diameter (m)	Velocity (m/s)	Temperature (deg K)	Basis
Bark Boiler No. 1	41.45	2.46	13.01	332	Current stack data
Bark Boiler No. 2	41.45	2.46	13.01	332	Current stack data
Power Boiler No. 1	32.31	1.83	15.82	450	Current stack data and an average of 1974/1975 stack test data
Power Boiler No. 2	32.31	2.13	18.35	487	Current stack data and 1975 stack test data
Power Boiler No. 3	32.31	2.13	17.22	462	Current stack data and 1975 stack test data
<p>Source: KBN Engineering and Applied Sciences, Inc. Memorandum from David Buff (KBN) to Al Hallquist (ENSR), October 23, 1992. ^aFormerly St. Regis Paper Company KBN Source: Fuel data for St. Regis Paper, 1974. Stack test data from 1974, 1975 and 1977. Current stack and operating data.</p>					

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TABLE 3-5

PSD Baseline SO₂ Emission Data
for the Seminole Kraft^a Facility in Jacksonville, Florida

Unit Description	Fuel Usage	Fuel Type	% Sulfur in Fuel Oil	Hours of Operation	SO ₂ Emissions			
					Annual (tons/yr)	Short Term (lb/hr) ^b	Annual (g/s)	Short Term (g/s)
Bark Boiler No. 1	1,394,774 121,520	Fuel Oil (gal) Bark (tons)	2.27	8,712	272.8	458.7 ^c	7.85	57.80
Bark Boiler No. 2	1,696,627 112,480	Fuel Oil (gal) Bark (tons)	2.27	8,064	324.8	458.7 ^c	9.34	57.80
Power Boiler No. 1	7,935,037	Fuel Oil (gal)	2.27	8,472	1,414.0	333.8	40.68	42.06
Power Boiler No. 2	11,610,539	Fuel Oil (gal)	2.27	8,472	2,069.0	488.4	59.52	61.54
Power Boiler No. 3	11,569,935	Fuel Oil (gal)	2.27	8,496	2,062.0	485.4	59.32	61.16

Source: KBN Engineering and Applied Sciences, Inc. memorandum from David Buff (KBN) to Al Hallquist (ENSR), October 23, 1992
^aFormerly St. Regis Paper Company
^bBased on total annual hours of operation and annual emissions, unless otherwise indicated.
^cMaximum short-term emissions for Bark Boilers 1 and 2 are based on 100-percent fuel oil usage at 1,287 gallons/hour.
 KBN Source: 1976/1977 Annual Operating Report submitted to FDER.

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TABLE 3-6

PSD Baseline PM Emission Data
for the Seminole Kraft^a Facility in Jacksonville, Florida

Unit Description	Basis	Hours of Operation	PM Emissions			
			Annual (TPY)	Short Term (lb/hr) ^b	Annual (g/s)	Short Term (g/s)
Bark Boiler No. 1	1977 PM stack test and operating hours	8,712	58.8	13.50	1.69	1.70
Bark Boiler No. 2	1977 PM stack test and operating hours	8,064	44.4	11.01	1.28	1.39
Power Boiler No. 1	7,935,637 gal fuel oil; 25.7 lb/1000 gal based on AP-42	8,472	102.0	24.08	2.93	3.03
Power Boiler No. 2	11,610,539 gal fuel oil; 25.7 lb/1000 gal based on AP-42	8,472	149.2	35.22	4.29	4.44
Power Boiler No. 3	11,569,935 gal fuel oil; 25.7 lb/1000 gal based on AP-42	8,496	148.7	35.00	4.28	4.41

Source: KBM Engineering and Applied Sciences, Inc. Memorandum from David Buff (KBN) to Al Hallquist (ENSR), October 23, 1992
^aFormerly St. Regis Paper Company
^bBased on total annual hours of operation and annual emissions.

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TABLE 3-7

**NO_x PSD Baseline Stack and Operating
Data for the Seminole Kraft^a Facility in Jacksonville, Florida**

Unit Description	Stack Height (m)	Stack Diameter (m)	Velocity (m/s)	Temperature (K)	Basis
Bark Boiler No. 1	41.45	2.46	13.01	332	1991 stack test data
Bark Boiler No. 2	41.45	2.46	13.01	332	1991 stack test data
Power Boiler No. 1	32.31	1.83	14.02	455	1991 stack test data
Power Boiler No. 2	32.31	2.13	14.51	439	1991 stack test data
Power Boiler No. 3	32.31	2.13	14.51	439	1991 stack test data

Source: KBN Engineering and Applied Sciences, Inc. Memorandum from David Buff (KBN) to Al Hallquist (ENSR), October 23, 1992.
^aFormerly St. Regis Paper Company

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TABLE 3-8

**PSD Baseline NO_x Emission Data for the
Seminole Kraft^a Facility in Jacksonville, Florida**

Unit Description	Basis	1989-1990 Hours of Operation	Annual Baseline NO _x Emissions	
			tons/yr	g/s
Bark Boiler No. 1	74.1 lb/hr, 1991 stack test	8,169	302.7	8.71
Bark Boiler No. 2	45.9 lb/hr, 1991 stack test	7,877	180.8	5.20
Power Boiler No. 1	8,129,846 gal/yr, 67 lb/1000 gal	8,255	272.3	7.83
Power Boiler No. 2	8,581,041 gal/yr, 67 lb/1000 gal	8,472	287.5	8.27
Power Boiler No. 3	8,723,551 gal/yr, 67 lb/1000 gal	8,489	292.2	8.41

Source: KBN Engineering and Applied Sciences, Inc. Memorandum from David Buff (KBN) to Al Hallquist (ENSR), October 23, 1992.
^aFormerly St. Regis Paper Company
 KBN Source: 1989/1990 Annual Operating Reports submitted to FDER and stack tests.

Table 3-9

SO₂ Source Data Used in the Modeling Analysis

APIS Number/Facility	Source Description	APIS Source Number	Stack Data (m)		Operating Data		SO ₂ Emissions		SO ₂ PSD Source (EXP/CON)	UTM (km)	
			Height	Diameter	Temperature (K)	Velocity (m/sec)	(g/s)	(TPY)		East	North
31DVL160202 Celotex	Gypsum Crushing System	01	7.6	0.49	321.9	18.90	0.26	9	-	446.4	3362.6
	Calcining Kettle #1 - #3	07, 11, 12	22.9	0.91	727.4	4.88	0.83	30	-		
	Wallboard Drying Kilns	08, 13, 14	15.2	0.94	435.8	7.32	20.16	701	-		
31DVL160213 U.S. Naval Station - Mayport	Boiler #1 - #3, Bldg. 1241	01, 02, 03	12.2	0.91	544.1	14.33	16.33	544	-	460.4	3362.8
	Boiler #1 - #2, Bldg 250	04, 08	14.0	1.22	560.8	7.92	10.53	351	-		
	Carbonaceous Fuel Boiler, Hot Water Boiler	07	18.3	1.52	533.0	7.01	0.62	19	-		
31DVL160005 Anchor Hocking Glass	Glass Melt Furnace #1	01	17.4	0.91	511.3	19.51	2.05	68	-	431.5	3357.5
	Glass Melt Furnace #2	02	17.4	0.82	522.4	14.02	2.41	84	-		
	Glass Melt Furnace #3	03	33.2	1.71	429.7	11.58	10.40	361	-		
	Glass Melt Furnace #4	04	35.7	1.58	510.8	11.89	3.75	131	-		
31DVL160006 Anheuser Busch	Boiler #1 - #4	01 - 04	30.5	1.07	483.0	17.37	72.58	2120	-	437.9	3366.8
	Grain Dryer #1, 2	05	21.3	1.68	322.0	9.00	19.78	269	CON		
	Anerobic & Bio Gas Flare	31,32	6.1	2.20	1000.0	15.00	5.66	54	CON		
31DVL160039 SCM Glidco Organics	Boiler #3 (Retired)	03	12.2	1.10	658.0	10.06	8.49	295	EXP	435.6	3360.7
	Boiler #4	04	12.2	1.10	405.2	14.02	19.91	692	-		
	Boiler #5	05	15.2	1.10	535.8	12.80	20.92	728	-		
	Boiler #6	06	15.2	1.22	513.6	10.36	24.44	850	-		
	Boiler #7	11	13.7	1.22	449.7	5.49	4.01	139	CON		
31DVL160042 Duval Asphalt Products	Asphalt Batch Plant	01,02	11.6	0.98	376.3	31.09	36.54	1270	-	428.7	3361.4
31DVL160001 JEA - SJRPP	Units #1 & #2	01, 04	194.2	10.13	328.0	18.29	1175.96	40904	CON	446.9	3366.3

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Table 3-9 (Cont'd)

SO₂ Source Data Used in the Modeling Analysis

APIS Number/Facility	Source Description	APIS Source Number	Stack Data (m)		Operating Data		SO ₂ Emissions		SO ₂ PSD Source (EXP/CON)	UTM (km)	
			Height	Diameter	Temperature (K)	Velocity (m/sec)	(g/s)	(TPY)		East	North
31DVL160045 JEA - Northside	Steam Generator #1	01	73.2	5.03	400.8	23.16	690.35	23998	-	446.9	3365.0
	Steam Generator #2	02	88.4	5.12	394.1	13.11	586.78	20398	-		
	Steam Generator #3	03	103.6	7.01	438.6	19.20	1255.59	43647	-		
	Combustion Turbines #3 - #6	06 - 09	10.1	6.55	779.7	18.29	231.60	8050	-		
	Auxiliary Boiler A	14	73.2	5.03	671.9	1.22	28.60	20	CON		
	Auxiliary Boiler B	13	76.2	5.03	588.6	0.30	8.47	294	CON		
31DVL160046 JEA - Southside	Steam Generator #1 & #2	01, 02	40.8	2.44	433.0	11.58	105.34	3,664	-	437.6	3353.8
	Steam Generator #3	03	40.8	3.05	406.9	10.36	79.76	2,773	-		
	Steam Generator #4	04	43.9	3.35	421.9	11.89	110.25	3,833	-		
	Steam Generator #5	05	44.2	3.05	416.9	13.72	207.90	7,227	-		
	Auxiliary Boiler	10	6.7	0.49	493.6	17.68	1.31	46	-		
31DVL160047 JEA - Kennedy	Combustion Turbine #3 - #6	03 - 06	13.7	2.80	651.9	8.84	191.14	6,646	-	440.0	3359.1
	Steam Generator #8	07	45.7	3.20	394.1	7.92	74.98	2,607	EXP		
	Steam Generator #9	08	45.7	3.20	398.0	7.92	74.98	2,607	-		
	Steam Generator #10	09	41.5	2.74	410.8	15.54	198.95	6,918	-		
	Auxiliary Boiler	13	10.1	0.49	493.6	17.68	1.22	42	CON		
31JAX450003 Container Corporation of Amer	Power Boiler #7	15	103.6	4.42	489.0	13.52	154.40	5,367	CON	455.1	3386.7
	Power Boiler #5	06	78.3	3.35	454.0	15.35	190.40	6,619	CON		
	Recovery Boiler #4	07	75.9	3.76	513.0	16.55	35.10	1,220	CON		
	Recovery Boiler #5	11	87.8	2.74	496.0	14.36	31.20	1,084	CON		
	Lime Kiln #4	21	31.1	1.45	436.0	21.07	3.38	117	CON		

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Table 3-9 (Cont'd)

SO₂ Source Data Used in the Modeling Analysis

APIS Number/Facility	Source Description	APIS Source Number	Stack Data (m)		Operating Data		SO ₂ Emissions		SO ₂ PSD Source (EXP/CON)	UTM (km)	
			Height	Diameter	Temperature (K)	Velocity (m/sec)	(g/s)	(TPY)		East	North
31JAX450003 Container Corporation of Amer. (cont'd)	Smelt Dissolving Tank #4	14	75.9	1.22	340.0	16.77	0.70	25	CON		
	Smelt Dissolving Tank #5	14	87.8	1.45	436.0	21.07	0.70	25	CON		
	Power Boiler #3 & #4	05	69.2	2.44	483.0	16.86	144.70	5,030	EXP		
	Power Boiler #5	06	69.2	3.35	480.0	16.25	170.0	5,910	EXP		
	Recovery Boiler #4	07	75.9	3.51	493.0	18.78	35.10	1,220	EXP		
	Recovery Boiler #3	??	40.8	2.74	390.0	13.26	10.50	365	EXP		
	Lime Kiln #2	??	13.4	1.07	361.0	12.25	1.30	45	EXP		
	Lime Kiln #3	??	13.4	1.37	360.0	17.59	1.30	45	EXP		
	Smelt Dissolving Tank #3	??	69.5	1.83	350.0	5.21	0.60	21	EXP		
	Smelt Dissolving Tank #4	??	33.2	0.61	360.0	5.82	0.20	7	EXP		
31DVL160003 Jefferson Smurfit	Power Boiler #10	11	61.0	3.05	341.5	9.70	36.48	1,265	CON	439.9	3359.3
	Recovery Boiler #9	05	53.3	3.20	409.8	22.86	5.52	834	CON		
	Smelt Dissolving Tank #9	04	53.3	1.65	362.0	4.32	0.48	17			
	Lime Kiln #1, 2	06	15.8	1.45	347.0	6.7	0.68	34	EXP		
	Lime Kiln #3	23	60.7	1.37	340.4	12.22	1.31	37	CON		
	Power Boilers	??	76.2	3.75	455.4	8.04	36.48	1,268	EXP		
	Recovery Boiler #9	05	53.3	3.20	389.8	11.56	16.81	834	EXP		
31DVL160069 Georgia Pacific	Boiler	01	11.6	0.61	477.4	9.14	2.58	90	-	440.1	3368.3
	Boiler	02	4.9	0.61	505.2	6.40	3.36	117	-		
31DVL160072 U.S. Gypsum	Wallboard Kiln #2	33	13.7	1.07	421.9	28.96	12.60	416	-	438.9	3361.2
	Calcining Kettles #1 - #7	36	28.3	1.07	505.2	0.91	18.38	607	-		
	Dowtherm Heater	41	20.7	0.91	733.0	6.40	1.22	40	-		

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Table 3-9 (Cont'd)

SO₂ Source Data Used in the Modeling Analysis

APIS Number/Facility	Source Description	APIS Source Number	Stack Data (m)		Operating Data		SO ₂ Emissions		SO ₂ PSD Source (EXP/CON)	UTM (km)	
			Height	Diameter	Temperature (K)	Velocity (m/sec)	(g/s)	(TPY)		East	North
31DVL160072 U.S. Gypsum (cont'd)	Rotary Kiln	48	26.8	0.49	339.1	59.13	4.08	137	-		
31DVL160148 Occidental Chemical	Bulk Ship Loading Conveyor, Phosphate Railcar Unloading	01	3.7	0.91	298.0	52.12	4.38	76	-	439.3	3359.8
	Hot Water Boiler #1 & #2	03, 04	6.1	0.30	355.2	11.89	4.23	148	-		
	Steam Boilers	05	18.3	0.91	427.4	10.06	3.86	134	-		
31DVL160146 J. W. Swisher	Boilers #1 - #3	01	18.3	1.22	505.2	0.61	4.26	148	-	437.9	3357.9
	Boiler #4 - 6	02	9.1	0.30	477.4	7.01	4.21	36	-		
31DVL160010 Baptist Medical Center	Turbines, Reciprocative Engine	03	15.2	1.07	435.8	24.69	13.89	128	-	435.4	3352.0
31DVL160004 Maxwell House	Boiler #1	03	45.7	0.98	606.9	0.61	3.96	138	-	439.7	3350.0
	Boiler #2	04	45.7	0.43	396.9	67.97	7.52	261	-		
	Boiler #2 (Retired)	13	15.2	0.91	402.4	20.73	2.44	85	EXP		
31DVL160155 Gulf Life Insurance	Boilers #1 & #2	01	18.3	0.91	421.9	2.74	7.82	91	-	436.2	3354.1
	Duel Fuel Engine	02	18.3	0.30	852.4	56.08	0.97	12	-		
31DVL160043 Duval Asphalt Products	Asphalt Batch Plant	01	11.6	0.98	376.3	31.09	11.06	384	-	443.2	3344.0
31DVL450004 ITT Rayonier	Power Boilers #1 - #3	01 - 03	55.0	3.05	329.0	9.75	173.88	5,532	CON	454.7	3392.2
	Recovery Boiler	06	76.2	2.29	324.7	17.37	40.6	1,352	-		
	Power Boilers #1 - #3	01 - 03	37.2	3.05	329.0	9.75	173.88	1,383	EXP		
31DVL160071 Union Camp	Waste Product Incinerator	01	16.2	1.07	699.7	9.45	9.69	337	-	427.6	3357.3
	Boilers, Myrcene Units	14	20.1	1.22	585.8	11.58	8.03	237	-		
31DVL160198 E S Metals		02	25.6	0.91	324.7	15.24	18.77	651	EXP	431.8	3358.3
		03	24.4	1.22	355.2	3.96	5.38	187	EXP		

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Table 3-9 (Cont'd)

SO₂ Source Data Used in the Modeling Analysis

APIS Number/Facility	Source Description	APIS Source Number	Stack Data (m)		Operating Data		SO ₂ Emissions		SO ₂ PSD Source (EXP/CON)	UTM (km)	
			Height	Diameter	Temperature (K)	Velocity (m/sec)	(g/s)	(TPY)		East	North
GA Gilman Paper Company**	Power Boiler No. 3		83.8	4.30	450.0	2.82	87.29	3034	CON	448.2	3401.3
	Coal Fired Boiler		45.7	3.05	326.0	7.76	88.75	3085	CON		
	Recovery Boiler No. 2, 3		54.9	2.13	425.0	16.76	15.2	264	CON		
	Recovery Boiler No. 4		76.2	2.59	411.0	12.19	15.80	549	CON		
	Lime Kiln		30.5	1.52	350.0	11.64	2.13	74	CON		
	Power Boilers No. 1 - 3		83.8	4.30	449.7	7.30	281.00	9768	EXP		
	Power Boiler No. 4		36.6	1.80	699.7	20.00	59.90	2082	EXP		
	Recovery Boiler No. 2		47.2	2.30	425.8	13.10	7.60	264	EXP		
	Recovery Boiler No. 3		53.3	1.60	394.1	25.20	7.60	264	EXP		
	Recovery Boiler No. 4		76.2	2.60	427.4	22.10	15.80	549	EXP		

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TABLE 3-10

TSP/PM-10 Source Data Used In the Modeling Analysis

APIS Number/Facility	Source Description	APIS Source Number	Stack Data (m)		Operating Data		PM Emissions		PM PSD Source (EXP/CON)	UTM (km)	
			Height	Diameter	Temperature (K)	Velocity (m/sec)	(g/s)	(TPY)		East	North
31DVL160202 Celotex	Gypsum Crushing System	01	7.6	0.49	321.9	18.90	0.63	21	-	446.4	3362.6
	Calcining Kettle #1 - #3	07, 11, 12	22.9	0.91	727.4	4.88	0.42	14	-		
	Wallboard Drying Kilns	08, 13, 14	15.2	0.94	435.8	7.32	0.32	11	-		
	Calcining Kettle	03	27.4	1.00	344.2	24.69	4.96	172			
	Material Equipment Storage	04	11.3	0.21	294.2	132.0	0.63	22			
	Wallboard End Trim System	05	18.3	0.49	294.2	26.8	0.63	21			
31DVL160005 Anchor Hocking Glass	Glass Melt Furnace #1	01	17.4	0.91	511.3	19.51	1.28	45	-	431.5	3357.5
	Glass Melt Furnace #2	02	17.4	0.82	522.4	14.02	1.32	46	-		
	Glass Melt Furnace #3	03	33.2	1.71	429.7	11.58	2.04	71	-		
	Glass Melt Furnace #4	04	35.7	1.58	510.8	11.89	1.83	64	-		
31DVL160039 SCM Glidco Organics	Boiler #3 (Retired)	03	12.2	1.10	658.0	10.06	0.31	18	EXP	435.6	3360.7
	Boiler #4	04	12.2	1.10	405.2	14.02	1.22	42	-		
	Boiler #5	05	15.2	1.10	535.8	12.80	1.27	44	-		
	Boiler #6	06	15.2	1.22	513.6	10.36	1.50	52	-		
	Boiler #7	11	13.7	1.22	449.7	5.49	0.78	10	CON		
	Dryer	07	12.5	1.22	310.9	2.74	0.12	1			
	Sodium Acetate Dryer #1	08	12.2	1.22	314.2	6.70	0.12	11			
	Sodium Acetate Dryer #2	09	12.5	1.22	310.9	2.44	0.12	11			
31DVL160001 JEA - SJRPP	Units #1 & #2	01, 04	194.2	10.13	328.0	18.29	46.44	1615	CON	446.9	3366.3
31DVL160045 JEA - Northside	Steam Generator #1	01	73.2	5.03	400.8	23.16	34.86	1061	-	446.9	3365.0
	Steam Generator #2	02	88.4	5.12	394.1	13.11	29.64	901	-		
	Steam Generator #3	03	103.6	7.01	438.6	19.20	190.24	827	-		
	Combustion Turbines #3 - #6	06 - 09	10.1	6.55	779.7	18.29	9.02	572	-		

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TABLE 3-10 (Cont'd)

TSP/PM-10 Source Data Used in the Modeling Analysis (cont'd)

APIS Number/Facility	Source Description	APIS Source Number	Stack Data (m)		Operating Data		PM Emissions		PM PSD Source (EXP/CON)	UTM (km)	
			Height	Diameter	Temperature (K)	Velocity (m/sec)	(g/s)	(TPY)		East	North
	Auxiliary Boiler A	14	73.2	5.03	671.9	1.22	1.46	1	CON		
	Auxiliary Boiler B	13	76.2	5.03	588.6	0.30	0.44	15	CON		
31DVL160046 JEA - Southside	Steam Generator #1 & #2	01, 02	40.8	2.44	433.0	11.58	9.58	414	-	437.6	3353.8
	Steam Generator #3	03	40.8	3.05	406.9	10.36	7.26	315	-		
	Steam Generator #4	04	43.9	3.35	421.9	11.89	10.03	305	-		
	Steam Generator #5	05	44.2	3.05	416.9	13.72	18.90	821	-		
	Auxiliary Boiler	10	6.7	0.49	493.6	17.68	0.04	1	-		
31DVL160047 JEA - Kennedy	Combustion Turbine #4	04	13.7	2.80	651.9	8.84	9.37	326*	-	440.0	3359.1
	Steam Generator #8	07	45.7	3.20	394.1	7.92	6.82	296	EXP		
	Steam Generator #9	08	45.7	3.20	398.0	7.92	6.82	296	-		
	Steam Generator #10	09	41.5	2.74	410.8	15.54	16.82	731	-		
	Auxiliary Boiler	13	10.1	0.49	493.6	17.68	0.04	1	CON		
31DVL160003 Jefferson Smurfit	Power Boiler #10	11	61.0	3.05	341.5	9.70	5.56	152	CON	439.9	3359.3
	Recovery Boiler #9	05	53.3	3.20	409.8	22.86	15.12	526			
	Smelt Dissolving Tank #9	04	53.3	1.65	362.0	4.32	4.59	160			
	Lime Kiln #1	06	15.8	1.52	334.7	2.93	2.65	92	EXP		
	Lime Kiln #2	07	15.8	1.37	341.3	6.58	2.65	93	EXP		
	Lime Kiln #3	23	60.7	1.37	340.4	12.22	2.65	92	CON		
	Coal Bark Boiler #1	12	53.3	1.65	366.5	3.96	4.59	160			
	Coal Bark Boiler #2	13	61.0	3.05	334.8	10.67	5.56	152			
	Coal Handling Silo #1, #2	21, 22, 20	32.9	0.30	298.11	7.01	0.14	4			
Line Storage Silo	24	27.4	0.52	338.7	2.13	0.02	0.66				
31DVL160072 U.S. Gypsum	Wallboard Kiln #2	33	13.7	1.07	421.9	28.96	0.77	25	-	438.9	3361.2

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TABLE 3-10 (Cont'd)

TSP/PM-10 Source Data Used in the Modeling Analysis (cont'd)

APIS Number/Facility	Source Description	APIS Source Number	Stack Data (m)		Operating Data		PM Emissions		PM PSD Source (EXP/CON)	UTM (km)	
			Height	Diameter	Temperature (K)	Velocity (m/sec)	(g/s)	(TPY)		East	North
	Calcining Kettles #1 - #7	36	28.3	1.07	505.2	0.91	1.47	46	-		
	Dowtherm Heater	41	20.7	0.91	733.0	6.40	0.23	8	-		
	Rotary Kiln	48	26.8	0.49	339.1	59.13	0.20	6	-		
	Combustion Turbine #1 - #2	68,69	36.6	1.01	346.9	24.99	0.15	6	-		
	Steam Boiler	86					3.2	14			
	Ambient Vents #1	5, 36, 40, 73, 78	3.0	1.06	298.1	11.89	0.34	10			
	Ambient Vents #2	34, 35, 42, 70, 71, 72	6.1	0.70	294.2	8.84	1.40	29			
	Ambient Vents #3	37, 44, 54, 62, 63, 64, 65, 66	0.9	0.61	316.5	8.23	1.17	39			
	Stucco Bin No. 3 & No. 4	6, 7	18.3	0.46	344.2	8.53	0.08	6			
	Stucco & Feed Bin	8, 9	21.9	0.30	344.2	19.20	0.07	4			
	Kettles	39, 46, 47, 55	22.9	1.22	363.7	3.05	1.18	40			
	Storage Bins	43, 58	26.5	0.61	310.4	7.92	0.37	12			
	Tube Mill Discharge	45	20.7	0.24	298.7	72.20	0.03**	1.0			
	#5 Raymond Mill	60	26.8	0.15	331.5	49.68	0.05	2			
	Additive Feed System	61	28.9	0.46	344.22	4.27	0.05	2			
Calcium Carbonate Storage	67	10.1	0.15	305.40	15.24	7.56 x 10 ⁻³	0.2				
31DVL160004 Maxwell House	Agglom. Process	1, 10, 30, 31	14.6	1.0	374.8	15.55	1.14	40		439.7	3350.0
	Scrap Paper Cyclone	26, 27, 28, 29	21.3	0.03	298	0.61	0.22	8			
	Thermal Afterburner	60, 61	27.4	0.49	793	18.98	0.14	5			
	Powder Airveyor	21, 22, 18, 20, 52	27.4	0.61	298.1	0.91	0.13	4			
	Continuous Roaster	5, D4, 12, 16	27.4	0.61	311.5	19.81	0.58	20			
	Boiler #2	4	45.7	0.43	397.0	67.97	0.72	25			

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TABLE 3-10 (Cont'd)

TSP/PM-10 Source Data Used in the Modeling Analysis (cont'd)

APIS Number/Facility	Source Description	APIS Source Number	Stack Data (m)		Operating Data		PM Emissions		PM PSD Source (EXP/CON)	UTM (km)	
			Height	Diameter	Temperature (K)	Velocity (m/sec)	(g/s)	(TPY)		East	North
	Green Coffee Silo	F0, F1, F2, F3, F4, F5, 53, 55, 56, 57, 58, 59, 23, 24, 25, 54	27.4	0.31	306.5	14.33	0.40	14			
	Cooling Carts	32, 33, 34, 35, 36, 37, 38, 39, 40, 41, 42, 43, 44, 45, 46, 47, 48, 49, 50, 51	30.5	0.18	310.9	18.29	1.84	64			
	Thermal Roaster #1	7	45.7	0.79	844.2	9.75	0.75	26			
	Roaster Afterburner	D3	27.4	2.29	811.5	3.66	0.31	11			
	Soluble Coffee Spray Dryer	6, 8, 9	47.2	1.07	383.7	18.59	2.20	76			
	Dryer	D5, D6, D7, D8, E0, E1, D2, 14, 15, 17	23.2	1.49	327.6	7.93	0.64	22			
	Boiler #1	D1, 98, 2, 3	45.7	0.98	607.0	0.61	0.42	14			
	Probat Afterburners	E2, E3, E4, E5, 77, 78, 79, 80, 81, 82, 83, 84, 85, 86	27.4	1.0	737.6	7.93	1.24	43			
	Thermal Stoner Cyclone	64, 65, 62, 63, 66, 87, 89, 90, 88, Z9, E6, E7, E8, E9, 97, B1, B2, B3, B4-B9, C1-C9, 67-76, 91-96, D9, F6, A1, A2, A3, A4, A5, A7, A8, A9	27.4	0.61	308.1	7.93	4.46	156			
<p>* Calculated based on allowable lb/hr of particulates permitted. ** Annual TPY allowable were given, calculated lb/hr.</p>											

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TABLE 3-11

NO_x Source Data Used in the Modeling Analysis

APIS Number/Facility	Source Description	APIS Source Number	Stack Data (m)		Operating Data		NO _x Emissions		NO _x PSD Source (EXP/CON)	UTM (km)	
			Height	Diameter	Temperature (K)	Velocity (m/sec)	(g/s)	(TPY)		East	North
31DVL160213 U.S. Naval Station - Mayport	Boiler #1 - #3, Bldg. 1241	01, 02, 03	12.2	0.91	544.1	14.33	9.67	336	-	460.4	3362.8
	Boiler #1 - #2, Bldg.250	04, 08	14.0	1.22	560.8	7.92	5.58	194	-		
	Hot Water Boiler B-1	11	15.5	0.24	477.4	7.32	9.69 × 10 ⁻³	.337			
31DVL160005 Anchor Hocking Glass	Glass Melt Furnace #2	02	17.4	0.82	522.4	14.02	5.00	174	-		
	Glass Melt Furnace #3	03	33.2	1.71	429.7	11.58	8.91	310	-		
	Glass Melt Furnace #4	04	35.7	1.58	510.8	11.89	6.84	238	-		
31DVL160006 Anheuser Busch	Boiler #1 - #4	01 - 04	30.5	1.07	483.0	17.37	9.78	340	-	437.9	3366.8
	Grain Dryer #1	05	21.3	1.68	322.0	9.60	1.29	45	-		
	Grain Dryer #2	06	21.3	2.07	327.6	9.00	2.31	80	-		
	Wastewater Boiler	30	12.19	0.52	477.6	5.49	0.14	5	-		
	Anerobic & Bio Gas Flare	31,32	6.1	2.20	1000.0	15.00	0.06	2	-		
31DVL160039 SCM Glidco Organics	Boiler #4	04	12.2	1.10	405.2	14.02	1.64	57 (P)	-		
	Boiler #7	11	13.7	1.22	449.7	5.49	0.92	32	-		
31DVL160045 JEA - Northside	Steam Generator #1	01	73.2	5.03	400.8	23.16	187.10	6504 (P)	-	446.9	3365.0
	Steam Generator #2	02	88.4	5.12	394.1	13.11	130.86	4549 (P)	-		
	Steam Generator #3	03	103.6	7.01	438.6	19.20	190.23	6613	-		
	Combustion Turbines #3 - #6	06 - 09	10.1	6.55	779.7	18.29	72.17	2509 (Δ)	-		
	Auxiliary Boiler A	14	73.2	5.03	671.9	1.22	8.26	287 (P)	-		
	Auxiliary Boiler B	13	76.2	5.03	588.6	0.30	0.58	20 (P)	-		
31DVL16001 JEA - SJRPP	Units #1 & #2	01, 04	194.2	10.13	328.0	18.29	487.69	16953			
31DVL160046 JEA - Southside	Auxiliary Boiler	10	6.7	0.49	493.6	17.68	0.09	3	-		
31DVL160047 JEA - Kennedy	Combustion Turbine #4 & #5	03 - 06	13.7	2.80	651.9	8.84	5.61	195 (Δ)	-	440.0	3359.1
	Steam Generator #9	08	45.7	3.20	398.0	7.92	115.56	4017 (Δ)	-		

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TABLE 3-11 (Cont'd)

NO_x Source Data Used in the Modeling Analysis

APIS Number/Facility	Source Description	APIS Source Number	Stack Data (m)		Operating Data		NO _x Emissions		NO _x PSD Source (EXP/CON)	UTM (km)	
			Height	Diameter	Temperature (K)	Velocity (m/sec)	(g/s)	(TPY)		East	North
	Auxiliary Boiler	13	10.1	0.49	493.6	17.68	0.34	12 (P)	-		
31DVL160003 Jefferson Smurfit	Power Boiler #10	11	61.0	3.05	341.5	9.70	38.89	1352	-	439.9	3359.3
	Recovery Boiler #9	05	53.3	3.20	409.8	22.86	4.32	150			
	Bark/Coal Boiler	13	60.96	3.05	334.8	10.67	38.89	1352			
31DVL160072 U.S. Gypsum	Wallboard Kiln #2	33	13.7	1.07	421.9	28.96	0.98	34 (P)	-	438.9	3361.2
	Calcining Kettles #1 - #7	36	28.3	1.07	505.2	0.91	0.53	154	-		
	Dowtherm Heater	41	20.7	0.91	733.0	6.40	0.29	10 (P)	-		
	Rotary Kiln	48	26.8	0.49	339.1	59.13	0.98	34	-		
	Wall Board Kiln #3	59	29.0	2.04	369.1	1.52	2.70	94	-		
	Combustion Turbine #1 - #2	68.69	36.6	1.01	346.9	24.99	3.05	106	-		
31DVL160215 Naval Air Station - Mayport	Bldg. #104 Boiler	01	13.72	1.40	505.35	11.58	4.11	143		434.02	3342.08
	Power Plant #2 Boilers	02	39.62	2.13	505.35	3.66	0.75	26 (P)			
	Power Plant #3 Boilers	05	13.72	1.37	505.35	8.23	0.35	12 (P)			
	Enoine Test Cells 7, 8, 9	07	3.66	3.81	310.91	6.10	0.17	6 (P)			
	Enoine Test Cells 11 & 12	10	7.62	4.82	505.35	17.07	5.23	182			

(P) Denotes potential emissions used when allowable were not available
 (Δ) Denotes calculated tons per year from lb/hr data.

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3.4 Background SO₂, PM₁₀, NO₂, and Lead Concentrations

For comparison of total ambient concentrations to the AAQS, background concentrations are estimated to account for sources which are not explicitly included in the atmospheric dispersion modeling analysis.

In order to estimate reasonable background SO₂ concentrations, a review of recent, available SO₂ monitoring data in Duval County was performed. Table 3-12 lists all of the continuous SO₂ monitors currently in operation in Duval County and their respective location relative to Cedar Bay. Annual average, 24-hour maximums, and 3-hour maximums for SO₂ for each monitor are shown in the table. The Ft. Caroline STP monitor ceased operation in March, 1990, so the station's 1990 averages are biased. All of the other five monitor's data recoveries exceeded 95 percent for that year. All stations except Kooker Park reported the lowest annual average SO₂ concentrations in 1990.

Highest short-term and annual average concentrations measured at these stations could have significant contributions from major SO₂ point sources. Use of the highest short-term and annual average SO₂ concentrations from any of these stations could over-estimate the actual background SO₂ concentrations, since all major sources of SO₂ (>100 tpy) are explicitly included in the dispersion modeling analysis, and their impacts could be double counted.

Therefore, it is reasonable to select the lowest of the second-highest short-term and annual average concentrations reported at any of the monitoring stations as the SO₂ background concentrations to be used in the compliance analysis. Referring to Table 3-12, these concentrations are 68 µg/m³, 3-hour; 28 µg/m³, 24-hour; and 5 µg/m³, annual average. These were all measured at the Minerva Street monitoring station.

Available data for PM₁₀ and NO₂ are shown in Table 3-13 and 3-14, respectively. The same reasoning applies to this data in terms of major source influences and potential double counting of source impacts being modeled. Therefore, the lowest of the second-highest short-term and annual average concentrations are selected for use in the compliance analyses.

Lead concentrations were also measured at two sites in Jacksonville, Kooker Park and Roselle & Copeland. All quarterly lead concentrations at these two sites for the three year period 1989-1991 were reported as 0.0 µg/m³. Therefore, lead background concentrations were not included in the impact evaluation.

Table 3-15 summarizes all of the background concentrations selected. These are added to the modeled impacts of major sources and the totals compared to the applicable AAQS.

TABLE 3-12

Summary of Continuous SO₂ Air Quality Data
in Duval County, 1989 - 1991

SAROAD Site No. (Distance Away)	Location	Monitoring Method	Period	No. of Obs.	Percent Data Recovery	SO ₂ Concentration (µg/m ³)		
						3-Hour ^(a)	24-Hour ^(a)	Annual Average
1960-081-HO2 (1.4 km)	Cedar Bay STP	Continuous	1989	8410	96.0	122	38	8
			1990	8517	97.2	140	42	7
			1991	8315	94.9	187	41	7
1960-094-HO2 (3.5 km)	9501 August Rd.	Continuous	1989	8186	93.4	211	58	8
			1990	8388	95.8	198	54	7
			1991	8060	92.0	169	55	7
1960-079-HO2 (5.6 km)	Ft. Caroline STP	Continuous	1989	8071	92.1	167	71	8
			1990b	1689	19.3	86	34	6
			1991					
1960-094-HO2 (7.3 km)	5060 Cedar Pt. Rd.	Continuous	1989	6776	77.4	225	70	10
			1990	8547	97.6	137	38	6
			1991	8181	93.4	206	45	5
1960-032-HO2 (7.9 km)	Kooker Park	Continuous	1989	7586	86.6	129	33	6
			1990	8401	95.9	107	35	8
			1991	8172	93.3	108	32	7
1960-080-HO2 (13.4 km)	1605 Minerva St.	Continuous	1989	7536	86.0	107	35	7
			1990	8439	96.3	68	28	5
			1991	8372	95.6	83	30	6

Note:

km = kilometers.

No. of Obs. = number of observations.

SO₂ = sulfur dioxide

µg/m³ = micrograms per cubic meter.

^aSecond-highest concentrations for calendar year are shown.

^bCeased operations 3/90

Source: Florida DER, 1989, 1990, 1991.

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TABLE 3-13

Summary of PM-10 Air Quality Data
in Duval County, 1989-1991

SAROAD Site	Location	Monitoring Method	Period	No. of Obs.	PM10 Concentration ($\mu\text{g}/\text{m}^3$)	
					24-Hr ^(a)	Annual
1960-004	1070 E. Adams St	64	1989	32	57	38
			1990	60	56	34
			1991	60	53	28
1960-053	Sewage Treatment Plant 2221 Buckmans	64	1989	3	32	32
			1990	61	61	32
			1991	60	50	31
1960-084	Roselle & Copeland	64	1989	59	58	35
			1990	61	60	32
			1991	60	59	32

^(a)Second-highest for calendar year.

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TABLE 3-14

Summary of NO₂ Air Quality Data

SAROAD Site No.	Location	Monitoring Method	Period	No. of Obs.	Percent Data Recovery	NO₂ Concentration (µg/m³) Annual
1960-032	Kooker Park	Continuous	1989	7815	89.2	29
			1990	8169	93.3	28
			1991	8055	91.9	25

TABLE 3-15

**Background Concentrations Used in the
AAQS Compliance Evaluation**

Site	Location	Pollutant	Period	Concentration ($\mu\text{g}/\text{m}^3$)
1960-080	1605 Minerva St.	SO ₂	3H 24H Annual	68 28 5
1960-032	Kooker Park	NO ₂	Annual	25
1960-053 1960-004	Sewage Treatment Plant 1070 E. Adams St.	PM ₁₀	24H Annual	32 28

3.5 Finding for the AAQS Compliance Evaluation

The results of the modeling for the Cedar Bay facility alone, as modified, are presented in Tables 3-16 through 3-20 for the pollutants CO, NO₂, TSP/PM-10, Pb and SO₂. Each table lists the maximum predicted impact of the Cedar Bay facility and the location of the model receptor at which the impact is predicted for each applicable AAQS averaging period and each year of meteorological data modeled. The significant impact (SIL) level is also listed for the applicable pollutant and averaging period. However, no SIL for Pb has yet been promulgated by EPA, thus none is available for comparison.

The results for CO, NO₂ and TSP/PM-10 are all well below the SILs. For this reason, these pollutants were eliminated from further consideration since they can neither cause nor contribute to an AAQS violation. The maximum predicted 24-hour concentrations of Pb shown in Table 3-20 are on the order of 0.3% of the 3-month AAQS. The 24-hour average impact is used as a very conservative measure of the expected 3-month average impact. Given this very low, yet conservative predicted impact and the fact that state monitoring has not detected measurable ambient Pb concentrations, it is concluded that Pb impacts are insignificant and therefore could neither cause nor contribute to a violation of the AAQS.

The modeling results for SO₂ are presented in Table 3-20. The Cedar Bay facility is predicted to have maximum impacts above the SILs. These maximum impacts are predicted to occur at short distances. Table 3-20 also lists the distance beyond which the Cedar Bay impacts are below the SILs. The maximum of these distances defines the facility's significant impact area (SIA) for SO₂ concentrations. The SIA extends 4.5 kilometers from the CFB boilers' stack.

Since significant SO₂ concentrations were predicted for the Cedar Bay facility, a multi-source modeling analysis was performed. All of the existing and permitted SO₂ sources in the inventory presented in Table 3-9 were modeled along with the Cedar Bay facility. The background SO₂ concentrations from Table 3-15 were added to the modeled concentrations to represent total ambient SO₂ concentrations for comparison to the AAQS. For the 3 and 24-hour averages, the highest predicted total concentration over the year was set aside. This is due to the fact that one exceedance of the short-term standards per year is allowed and thus it is inappropriate to compare the highest concentrations to the standards. The remaining concentrations were then scanned to identify the maximum predicted total ambient SO₂ concentrations to which the Cedar Bay facility contributes an impact above the SILs. If these total concentrations do not exceed the AAQS, then it can be concluded that the Cedar Bay facility will neither cause nor contribute to a violation. The results of this analysis are summarized in Table 3-21. For each averaging period and for each meteorological year modeled, the maximum predicted total ambient SO₂

TABLE 3-16

**Findings For The AAQS Compliance Evaluation
Maximum Predicted CO Impacts Due To
The Cedar Bay Facility As Modified**

Averaging Period	Meteorological Year	Concentration ($\mu\text{g}/\text{m}^3$)	Location ^(a)		SIL ($\mu\text{g}/\text{m}^3$)
			Distance (km)	Azimuth (deg)	
1-Hour	1983	54.9	1.25	70	2000
	1984	54.6	1.0	80	
	1985	65.6	1.0	70	
	1986	64.5	1.0	240	
	1987	55.0	1.25	50	
8-Hour	1983	9.1	3.0	70	500
	1984	11.1	1.0	260	
	1985	13.4	1.25	50	
	1986	11.2	2.5	80	
	1987	12.8	1.25	50	

^(a)Relative to the CFB Boilers Stack

TABLE 3-17

Findings For The AAQS Compliance Evaluation
 Maximum Predicted Annual Average NO₂ Impacts Due To
 The Cedar Bay Facility As Modified

Meteorological Year	Concentration (µg/m ³)	Location ^(a)	
		Distance (km)	Azimuth (deg)
1983	0.56	0.2	90
1984	0.56	0.2	90
1985	0.53	0.4	10
1986	0.54	0.4	30
1987	0.07	0.2	80
SIL = 1.0 µg/m ³			
^(a) Relative to the CFB Boilers Stack			

TABLE 3-18

**Findings For The AAQS Compliance Evaluation
Maximum Predicted TSP/PM-10 Impacts Due
To The Cedar Bay Facility As Modified**

Averaging Period	Meteorological Year	Concentration ($\mu\text{g}/\text{m}^3$)	Location ^(a)		SIL ($\mu\text{g}/\text{m}^3$)
			Distance (km)	Azimuth (deg)	
24-Hour	1983	0.90	0.096	200	5.0
	1984	1.32	0.315	20	
	1985	1.24	0.269	337	
	1986	1.21	0.3	30	
	1987	1.14	0.3	30	
Annual	1983	0.14	0.3	40	1.0
	1984	0.16	0.3	30	
	1985	0.15	0.3	30	
	1986	0.19	0.3	30	
	1987	0.16	0.2	70	

^(a)Relative to the CFB Boilers Stack

TABLE 3-19

**Findings For The AAQS Compliance Evaluation
Maximum 24-Hour Predicted Pb Impacts Due To
The Cedar Bay Facility As Modified**

Meteorological Year	Concentration ($\mu\text{g}/\text{m}^3$)	Location ^(b)	
		Distance (km)	Azimuth (deg)
1983	0.0048	0.2	80
1984	0.0045	0.2	90
1985	0.0032	0.4	10
1986	0.0031	0.2	100
1987	0.0044	0.2	80

^(a) AAQS = 1.5 3-month Average, Background is below detectable
^(b) Relative to the CFB Boilers Stack

TABLE 3-20

Findings For The AAQS Compliance Evaluation
 Maximum Predicted SO₂ Impacts Due To
 The Cedar Bay Facility As Modified

Averaging Period	Meteorological Year	Concentration (µg/m ³)	Location ^(a)		SIL (µg/m ³)	Significant Impact Distance ^(b) (km)
			Distance (km)	Azimuth (deg)		
3-Hour	1983	152.3	0.3	350	25.0	1.5
	1984	131.5	0.2	80		1.75
	1985	97.1	0.2	80		2.5
	1986	103.7	0.2	80		2.5
	1987	193.5	0.2	80		2.5
24-Hour	1983	16.6	0.2	80	5.0	3.5
	1984	19.4	2.5	20		4.0
	1985	19.7	0.4	10		4.5
	1986	20.6	0.3	260		4.5
	1987	15.0	0.2	60		4.5
Annual	1983	1.18	0.2	90	1.0	0.2
	1984	1.18	0.2	90		0.2
	1985	1.11	0.4	10		0.4
	1986	1.08	0.4	30		0.4
	1987	1.40	0.2	80		0.2

^(a)Relative to CFB Boiler Stack

^(b)Furthest Distance Beyond Which Impacts Are Less Than SILs

TABLE 3-21

Findings For The AAQS Compliance Evaluation
 Maximum Predicted Total Ambient SO₂ Concentrations
 To Which Cedar Bay Facility As Modified Contributes An
 Impact Above The SILs

Averaging Period	Meteorological Year	Concentration ^(a) (µg/m ³)	AAQS (µg/m ³)	Cedar Bay Contribution (µg/m ³)
3-Hour	1983	479.1	1300 ^(b)	40.1
	1984	478.3		40.6
	1985	500.5		36.0
	1986	393.0		34.2
	1987	472.6		26.2
24-Hour	1983	150.1	365 ^(c) /260 ^(d)	6.0
	1984	152.7		5.0
	1985	157.0		6.5
	1986	125.5		5.4
	1987	128.7		6.3
Annual	1983	36.4	80 ^(c) /60 ^(d)	1.05
	1984	36.3		1.18
	1985	38.0		1.11
	1986	34.7		1.04
	1987	33.3		1.05

^(a)Excluding Highest Impact At Any Receptor For 3 and 24-Hour Periods
^(b)Primary AAQS
^(c)Florida Secondary AAQS

concentration (excluding the highest 3 and 24-hour impacts) to which the Cedar Bay facility contributes a significant impact is presented. These are compared to the applicable AAQS. Also listed is Cedar Bay's contribution to the total concentration. None of the total concentrations exceed the AAQS. Thus, it can be concluded that the Cedar Bay facility, as modified, would neither cause nor contribute to a violation of the SO₂ AAQS.

Based on all of the foregoing results, it appears that the Cedar Bay cogeneration facility by itself, as modified, would neither cause nor contribute to a violation of an ambient air quality standard.

3.6 Findings for the PSD Increment Compliance Evaluations

The SILs are the same for AAQS and PSD Class II increments. The Cedar Bay facility was shown in the previous section not to have a significant impact for the pollutants TSP and NO₂. Thus, in addition to not causing or contributing to an AAQS violation, they would neither cause nor contribute to a violation of the PSD Class II increments. Since SO₂ impacts are above the SIL's, a PSD Class II increment compliance evaluation was performed. A PSD Class I increment compliance evaluation was performed for SO₂, TSP and NO₂.

3.6.1 SO₂ PSD Increment Compliance Evaluation

First, the maximum predicted Class II and Class I SO₂ increment consumed by the Cedar Bay facility itself was determined. These results are summarized in Table 3-22. For each averaging period and meteorological year, the maximum SO₂ impact of the Cedar Bay facility is presented for the Class II and Class I areas. The respective allowable increments are also listed. As shown in the table, the maximum SO₂ impacts of the Cedar Bay facility by itself exceed neither the Class II nor Class I allowable increments. Next, an analysis was performed to identify the maximum total Class II increment consumption by all PSD increment consuming and expanding sources to which Cedar Bay would contribute an impact above the Class II SILs. The results of this analysis are summarized in Table 3-23. For each averaging period and meteorological year the maximum predicted total Class II increment consumption (excluding the highest 3- and 24-hour impacts) to which Cedar Bay contributes an impact above the SILs is listed, along with the Cedar Bay contribution. As shown in this table, none of the total concentrations exceed the Class II PSD increments. Thus it can be concluded that the Cedar Bay facility, as modified, would neither cause nor contribute to a violation of the PSD Class II SO₂ increments.

For the Class I areas, the maximum total SO₂ increment consumption due to all increment consuming and expanding sources was identified for each averaging period and meteorological year. These results are summarized in Table 3-24. For the 3- and 24-hour averaging periods,

TABLE 3-22

**Findings For The PSD Increment Compliance Evaluation
Maximum Predicted PSD SO₂ Increment Consumed
By The Cedar Bay Facility As Modified**

Averaging Period	Meteorological Year	PSD Class II Area		PSD Class I Areas		
		Concentration (µg/m ³)	Allowable Increment	Concentration (µg/m ³)		Allowable Increment (µg/m ³)
				Okefenokee	Wolf Island	
3-Hour	1983	152.3	512	2.97	1.50	25
	1984	131.5		3.39	1.82	
	1985	97.1		3.11	2.97	
	1986	103.7		2.95	1.50	
	1987	193.5		4.10	1.55	
24-Hour	1983	16.6	91	0.98	0.300	5
	1984	19.4		0.85	0.463	
	1985	19.7		1.12	0.603	
	1986	20.6		1.12	0.250	
	1987	15.0		1.01	0.411	
Annual	1983	1.18	20	0.033	0.016	2
	1984	1.18		0.042	0.019	
	1985	1.11		0.041	0.024	
	1986	1.08		0.040	0.017	
	1987	1.40		0.039	0.016	

TABLE 3-23

**Findings For The PSD Increment Compliance Evaluation
Maximum Predicted Total PSD Class II SO₂ Increment Consumption
To Which Cedar Bay Facility As Modified Contributes An
Impact Above The SILs**

Averaging Period	Meteorological Year	Concentration^(a) µg/m³	Class II Increment	Cedar Bay Contribution (µg/m³)
3-Hour	1983	113.9	512	113.9
	1984	116.9		116.9
	1985	96.5		96.5
	1986	106.7		71.8
	1987	129.6		129.6
24-Hour	1983	24.6	91	6.1
	1984	23.7		15.5
	1985	28.5		5.1
	1986	69.2		5.1
	1987	24.3		14.8
Annual	1983	5.01	20	1.18
	1984	4.37		1.18
	1985	5.04		1.11
	1986	4.24		1.08
	1987	4.59		1.30

^(a)Excluding Highest Impact At Any Receptor for 3 and 24-hour Periods

TABLE 3-24

Findings For The PSD Increment Compliance Evaluation
 Total PSD Class I SO₂ Increment Consumption
 In The Okefenokee and Wolf Island Wilderness Areas

Averaging Period	Meteorological Year	Allowable Increment (µg/m ³)	Okefenokee Concentrations (µg/m ³)			Wolf Island Concentrations (µg/m ³)		
			Highest	Highest ^(a) Second-High	Cedar Bay Contribution To Highest Second-High	Highest	Highest ^(a) Second-High	Cedar Bay Contribution To Highest Second-High
3-Hour	1983	25	18.4	13.5	1.1	12.3	10.7	0.29
	1984		21.0	16.3	0.9	11.1	9.4	0.95
	1985		21.3	17.4	0.7	13.9	12.6	0.95
	1986		21.2	17.4	1.6	8.5	7.9	0.63
	1987		16.6	14.8	0.2	11.9	10.3	0.26
24-Hour	1983	5	4.2	3.5	0.3	2.1	1.8	0.04
	1984		4.1	3.3	0.3	1.8	1.8	0.06
	1985		4.2	3.8	0.3	2.5	2.1	0.17
	1986		4.6	3.6	0.3	1.8	1.5	0.13
	1987		4.3	2.9	0.4	3.2	2.3	0.06
Annual	1983	2	0.02	NA	0.03	-0.04	NA	0.02
	1984		0.04	NA	0.04	-0.09	NA	0.02
	1985		0.04	NA	0.04	-0.09	NA	0.02
	1986		0.03	NA	0.04	-0.04	NA	0.02
	1987		0.05	NA	0.04	-0.06	NA	0.02

^(a)For 3 and 24-hour periods the highest second-high is compared to standards since one exceedance per year is allowed.

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the highest and highest second-high concentrations are listed for each of the Class I areas. For the annual average period, the highest concentration is listed. Also listed are the contribution of the Cedar Bay facility to these impacts. As shown in the table, none of the concentrations exceed allowable increments. In fact, the results for the Wolf Island Wilderness Area indicate that the annual average SO₂ Class I increment is being expanded. The negative concentrations result from the impacts of increment expanding sources exceeding those of increment consuming sources. Based on these results, it can be concluded that the Cedar Bay facility, as modified, would neither cause nor contribute to a violation of the PSD Class I SO₂ increments.

3.6.2 Findings for the PSD Class I TSP Increment Compliance Evaluation

Table 3-25 summarizes the results of the modeling for TSP increment consumption in the Class I area. For each averaging period and meteorological year several predicted concentrations are presented for each Class I area. First, the maximum total increment consumption due to Cedar Bay plus the other TSP increment consuming and expanding sources from Table 3-10 is listed. For 3- and 24-hour periods both the highest and highest second-high concentrations are listed. The contribution of the Cedar Bay facility to those total concentrations is listed. Finally, the maximum Cedar Bay impact, by itself, in the Class I area is listed. As shown in the table, none of the total increment consumption concentrations exceed the allowable Class I increments. As a result, it can be concluded that the Cedar Bay facility, as modified, would neither cause nor contribute to a violation of the PSD Class I TSP increments.

3.6.3 Findings for the PSD Class I NO₂ Increment Compliance Evaluation

The results of the increment consumption analysis for NO₂ are summarized in Table 3-26. For each year modeled, the maximum total annual average increment consumption is listed along with the contribution of Cedar Bay to that concentration. The maximum annual average Cedar Bay impact in the Class I areas is also listed. As shown in the table, there is a net increment expansion resulting from the cumulative effect of the increment expansion sources and those consuming increment. In this case, the SK Power and Bark Boilers are the only increment expansion sources (by shutting down) and the Cedar Bay facility the only increment consuming source. The impacts of the Cedar Bay facility by itself are well below the allowable PSD Class I NO₂ increment. Based on these results, it is demonstrated that the Cedar Bay facility, as modified, would neither cause nor contribute to a violation of the PSD Class I NO₂ increment.

TABLE 3-25

Findings For The PSD Increment Compliance Evaluation
Total PSD Class I TSP Increment Consumption

Averaging Period	Meteorological Year	Allowable Increment (µg/m³)	Okefenokee Concentrations (µg/m³)				Wolf Island Concentrations (µg/m³)			
			Highest	Highest ^(a) Second-High	Cedar Bay Contribution To Highest Second-High	Maximum Cedar Bay Impact	Highest	Highest ^(a) Second-High	Cedar Bay Contribution To Highest Second-High	Maximum Cedar Bay Impact
24-Hour	1983	10	0.55	0.33	0.009	0.073	0.13	0.08	0.019	0.022
	1984		0.56	0.36	0.017	0.064	0.11	0.10	0.019	0.035
	1985		0.62	0.45	0.083	0.083	0.14	0.14	0.045	0.045
	1986		0.57	0.44	0.064	0.083	0.08	0.07	0.003	0.019
	1987		0.51	0.41	0.075	0.075	0.12	0.11	0.017	0.031
Annual	1983	5	0.010	NA	0.003	0.003	0.005	NA	0.001	0.001
	1984		0.011	NA	0.004	0.004	0.006	NA	0.001	0.002
	1985		0.012	NA	0.004	0.004	0.007	NA	0.002	0.002
	1986		0.014	NA	0.004	0.004	0.006	NA	0.002	0.002
	1987		0.011	NA	0.004	0.004	0.005	NA	0.001	0.001

^(a)For 3 and 24-hour periods the highest second-high is compared to standards since one exceedance per year is allowed.

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TABLE 3-26

Findings For The PSD Increment Compliance Evaluation
 Total PSD Class I Annual Average NO₂ Increment Consumption

Meteorological Year	Okefenokee Concentrations (µg/m ³)			Wolf Island Concentrations (µg/m ³)		
	Highest	Cedar Bay Contribution To Highest	Maximum Cedar Bay Impact	Highest	Cedar Bay Contribution To Highest	Maximum Cedar Bay Impact
1983	-0.006	0.024	0.024	-0.01	0.013	0.013
1984	-0.005	0.017	0.017	-0.02	0.016	0.016
1985	-0.009	0.018	0.018	-0.02	0.020	0.020
1986	-0.004	0.013	0.013	-0.01	0.014	0.014
1987	-0.004	0.022	0.022	-0.02	0.013	0.013
Allowable Increment = 2.5 µg/m ³						

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3.7 Findings for the Draft Air Toxics No Threat Levels (NTL) Evaluation

The air toxics emissions from the Cedar Bay facility, by itself, as modified, were modeled to determine the maximum impact of each pollutant for each averaging period for which a draft NTL has been proposed. The results are summarized in Table 3-27. For each pollutant and averaging period the maximum predicted concentration due to the Cedar Bay facility is presented and compared to the applicable proposed NTL. A thorough review of the results for each pollutant demonstrates that in each case the impacts are below the draft No Threat Levels.

The NTLs are developed with a conservative bias intentionally built in to represent levels that are not likely to endanger public health nor cause appreciable health risks. Thus, it can be concluded that emissions of air toxics from the Cedar Bay facility, as modified, would not endanger the public health nor pose unacceptable health risks.

TABLE 3-27

Maximum Cedar Bay Air Toxics Impacts ($\mu\text{g}/\text{m}^3$)

Pollutant	Averaging Period	Year	Cedar Bay	No Threat Levels
Antimony Compounds	8-hour	1983	0.63E-03	5
		1984	0.77E-03	5
		1985	0.93E-03	5
		1986	0.78E-03	5
		1987	0.89E-03	5
	24-hour	1983	0.27E-03	1.2
		1984	0.30E-03	1.2
		1985	0.33E-03	1.2
		1986	0.28E-03	1.2
		1987	0.31E-03	1.2
	Annual	1983	0.27E-03	3.0E-01
		1984	0.30E-03	3.0E-01
		1985	0.33E-03	3.0E-01
		1986	0.16E-04	3.0E-01
		1987	0.31E-03	3.0E-01

TABLE 3-27 (Cont'd)

Maximum Cedar Bay Air Toxics Impacts ($\mu\text{g}/\text{m}^3$)

Pollutant	Averaging Period	Year	Cedar Bay	No Threat Levels
Arsenic	8-hour	1983	0.008	2
		1984	0.009	2
		1985	0.011	2
		1986	0.009	2
		1987	0.011	2
	24-hour	1983	0.003	0.48
		1984	0.004	0.48
		1985	0.004	0.48
		1986	0.003	0.48
		1987	0.004	0.48
	Annual	1983	1.6E-04	2.3E-04
		1984	1.8E-04	2.3E-04
		1985	1.6E-04	2.3E-04
		1986	1.9E-04	2.3E-04
		1987	2.1E-04	2.3E-04

TABLE 3-27 (Cont'd)

Maximum Cedar Bay Air Toxics Impacts ($\mu\text{g}/\text{m}^3$)

Pollutant	Averaging Period	Year	Cedar Bay	No Threat Levels
Barium	8-hour	1983	0.04	5
		1984	0.05	5
		1985	0.07	5
		1986	0.06	5
		1987	0.06	5
	24-hour	1983	0.02	1.2
		1984	0.02	1.2
		1985	0.02	1.2
		1986	0.02	1.2
		1987	0.02	1.2
	Annual	1983	0.96E-03	5.0E+01
		1984	0.11E-02	5.0E+01
		1985	0.97E-03	5.0E+01
		1986	0.12E-02	5.0E+01
		1987	0.13E-02	5.0E+01

TABLE 3-27 (Cont'd)

Maximum Cedar Bay Air Toxics Impacts ($\mu\text{g}/\text{m}^3$)

Pollutant	Averaging Period	Year	Cedar Bay	No Threat Levels
Beryllium	8-hour	1983	0.94E-03	0.02
		1984	0.11E-02	0.02
		1985	0.96E-03	0.02
		1986	0.94E-03	0.02
		1987	0.87E-03	0.02
	24-hour	1983	0.26E-03	0.0048
		1984	0.28E-03	0.0048
		1985	0.32E-03	0.0048
		1986	0.27E-03	0.0048
		1987	0.30E-03	0.0048
	Annual	1983	0.15E-04	4.2E-04
		1984	0.19E-04	4.2E-04
		1985	0.17E-04	4.2E-04
		1986	0.18E-04	4.2E-04
		1987	0.17E-04	4.2E-04

TABLE 3-27 (Cont'd)

Maximum Cedar Bay Air Toxics Impacts ($\mu\text{g}/\text{m}^3$)

Pollutant	Averaging Period	Year	Cedar Bay	No Threat Levels
Cadmium	8-hour	1983	0.40E-02	0.5
		1984	0.47E-02	0.5
		1985	0.40E-02	0.5
		1986	0.39E-02	0.5
		1987	0.38E-02	0.5
	24-hour	1983	0.12E-02	0.12
		1984	0.13E-02	0.12
		1985	0.14E-02	0.12
		1986	0.12E-02	0.12
		1987	0.14E-02	0.12
	Annual	1983	0.62E-04	5.6E-04
		1984	0.81E-04	5.6E-04
		1985	0.72E-04	5.6E-04
		1986	0.75E-04	5.6E-04
		1987	0.77E-04	5.6E-04

TABLE 3-27 (Cont'd)

Maximum Cedar Bay Air Toxics Impacts ($\mu\text{g}/\text{m}^3$)

Pollutant	Averaging Period	Year	Cedar Bay	No Threat Levels
Chromium VI Compounds	8-hour	1983	0.005	0.5
		1984	0.004	0.5
		1985	0.004	0.5
		1986	0.003	0.5
		1987	0.004	0.5
	24-hour	1983	0.0012	0.12
		1984	0.0013	0.12
		1985	0.0015	0.12
		1986	0.0012	0.12
		1987	0.0014	0.12
	Annual	1983	6.0E-05	8.3E-05
		1984	6.8E-05	8.3E-05
		1985	6.0E-05	8.3E-05
		1986	7.1E-05	8.3E-05
		1987	7.7E-05	8.3E-05

TABLE 3-27 (Cont'd)

Maximum Cedar Bay Air Toxics Impacts ($\mu\text{g}/\text{m}^3$)

Pollutant	Averaging Period	Year	Cedar Bay	No Threat Levels
Copper	8-hour	1983	0.11	10
		1984	0.12	10
		1985	0.11	10
		1986	0.10	10
		1987	0.10	10
	24-hour	1983	0.02	2.4
		1984	0.02	2.4
		1985	0.02	2.4
		1986	0.02	2.4
		1987	0.02	2.4
Fluorides (as F)	8-hour	1983	0.04	25
		1984	0.05	25
		1985	0.06	25
		1986	0.05	25
		1987	0.06	25
	24-hour	1983	0.02	6
		1984	0.02	6
		1985	0.02	6
		1986	0.02	6
		1987	0.02	6

TABLE 3-27 (Cont'd)

Maximum Cedar Bay Air Toxics Impacts ($\mu\text{g}/\text{m}^3$)

Pollutant	Averaging Period	Year	Cedar Bay	No Threat Levels
Formaldehyde	8-hour	1983	0.15	12
		1984	0.18	12
		1985	0.16	12
		1986	0.15	12
		1987	0.14	12
	24-hour	1983	0.23	2.88
		1984	0.35	2.88
		1985	0.034	2.88
		1986	0.029	2.88
		1987	0.027	2.88
	Annual	1983	0.24E-02	7.7E-02
		1984	0.31E-02	7.7E-02
		1985	0.28E-02	7.7E-02
		1986	0.29E-02	7.7E-02
		1987	0.27E-02	7.7E-02

TABLE 3-27 (Cont'd)

Maximum Cedar Bay Air Toxics Impacts ($\mu\text{g}/\text{m}^3$)

Pollutant	Averaging Period	Year	Cedar Bay	No Threat Levels
Hydrogen Chloride	8-hour	1983	0.087	75
		1984	0.11	75
		1985	0.13	75
		1986	0.11	75
		1987	0.12	75
	24-hour	1983	0.037	18
		1984	0.041	18
		1985	0.046	18
		1986	0.039	18
		1987	0.043	18
	Annual	1983	0.19E-02	7.0E+00
		1984	0.21E-02	7.0E+00
		1985	0.19E-02	7.0E+00
		1986	0.23E-02	7.0E+00
		1987	0.24E-02	7.0E+00

TABLE 3-27 (Cont'd)

Maximum Cedar Bay Air Toxics Impacts ($\mu\text{g}/\text{m}^3$)

Pollutant	Averaging Period	Year	Cedar Bay	No Threat Levels
Indium Compounds	8-hour	1983	0.10E-04	1
		1984	0.12E-04	1
		1985	0.15E-04	1
		1986	0.12E-04	1
		1987	0.14E-04	1
	24-hour	1983	0.43E-05	0.24
		1984	0.48E-05	0.24
		1985	0.53E-05	0.24
		1986	0.45E-05	0.24
		1987	0.50E-05	0.24

TABLE 3-27 (Cont'd)

Maximum Cedar Bay Air Toxics Impacts ($\mu\text{g}/\text{m}^3$)

Pollutant	Averaging Period	Year	Cedar Bay	No Threat Levels
Lead Compounds	8-hour	1983	0.011	0.5
		1984	0.009	0.5
		1985	0.006	0.5
		1986	0.007	0.5
		1987	0.010	0.5
	24-hour	1983	0.0048	0.12
		1984	0.0045	0.12
		1985	0.0032	0.12
		1986	0.0031	0.12
	Annual	1983	3.4E-04	9.0E-02
		1984	3.4E-04	9.0E-02
		1985	3.2E-04	9.0E-02
		1986	3.1E-04	9.0E-02
		1987	4.1E-04	9.0E-02

TABLE 3-27 (Cont'd)

Maximum Cedar Bay Air Toxics Impacts ($\mu\text{g}/\text{m}^3$)

Pollutant	Averaging Period	Year	Cedar Bay	No Threat Levels
Manganese	8-hour	1983	0.01	50
		1984	0.02	50
		1985	0.02	50
		1986	0.02	50
		1987	0.02	50
	24-hour	1983	0.0057	12
		1984	0.0064	12
		1985	0.0071	12
		1986	0.0060	12
		1987	0.0067	12
	Annual	1983	0.29E-03	4.0E-01
		1984	0.33E-03	4.0E-01
		1985	0.29E-03	4.0E-01
		1986	0.35E-03	4.0E-01
		1987	0.38E-03	4.0E-01

TABLE 3-27 (Cont'd)

Maximum Cedar Bay Air Toxics Impacts ($\mu\text{g}/\text{m}^3$)

Pollutant	Averaging Period	Year	Cedar Bay	No Threat Levels
Mercury Alkyl Compounds	8-hour	1983	0.28E-02	0.1
		1984	0.35E-02	0.1
		1985	0.42E-02	0.1
		1986	0.35E-02	0.1
		1987	0.40E-02	0.1
	24-hour	1983	0.12E-02	0.024
		1984	0.13E-02	0.024
		1985	0.15E-02	0.024
		1986	0.13E-02	0.024
		1987	0.14E-02	0.024
Molybdenum	8-hour	1983	0.02	50
		1984	0.02	50
		1985	0.02	50
		1986	0.02	50
		1987	0.02	50
	24-hour	1983	0.32E-02	12
		1984	0.42E-02	12
		1985	0.41E-02	12
		1986	0.34E-02	12
		1987	0.38E-02	12

TABLE 3-27 (Cont'd)

Maximum Cedar Bay Air Toxics Impacts ($\mu\text{g}/\text{m}^3$)

Pollutant	Averaging Period	Year	Cedar Bay	No Threat Levels
Nickel	8-hour	1983	0.06	1
		1984	0.08	1
		1985	0.07	1
		1986	0.06	1
		1987	0.06	1
	24-hour	1983	0.01	0.24
		1984	0.01	0.24
		1985	0.01	0.24
		1986	0.01	0.24
		1987	0.01	0.24
Phosphorous	8-hour	1983	0.04	1
		1984	0.05	1
		1985	0.04	1
		1986	0.04	1
		1987	0.04	1
	24-hour	1983	0.01	0.24
		1984	0.01	0.24
		1985	0.01	0.24
		1986	0.01	0.24
		1987	0.01	0.24

TABLE 3-27 (Cont'd)

Maximum Cedar Bay Air Toxics Impacts ($\mu\text{g}/\text{m}^3$)

Pollutant	Averaging Period	Year	Cedar Bay	No Threat Levels
Selenium	8-hour	1983	0.43E-02	2
		1984	0.50E-02	2
		1985	0.43E-02	2
		1986	0.42E-02	2
		1987	0.40E-02	2
	24-hour	1983	0.64E-03	0.48
		1984	0.98E-03	0.48
		1985	0.95E-03	0.48
		1986	0.81E-03	0.48
		1987	0.76E-03	0.48
Sulfuric Acid Mist (H_2SO_4)	8-hour	1983	2.181	10
		1984	2.009	10
		1985	1.451	10
		1986	1.542	10
		1987	2.279	10
	24-hour	1983	0.365	2.4
		1984	0.366	2.4
		1985	0.419	2.4
		1986	0.346	2.4
		1987	0.392	2.4

TABLE 3-27 (Cont'd)

Maximum Cedar Bay Air Toxics Impacts ($\mu\text{g}/\text{m}^3$)

Pollutant	Averaging Period	Year	Cedar Bay	No Threat Levels
Tin	8-hour	1983	0.12	1
		1984	0.15	1
		1985	0.13	1
		1986	0.12	1
		1987	0.12	1
	24-hour	1983	0.02	0.24
		1984	0.03	0.24
		1985	0.03	0.24
		1986	0.02	0.24
		1987	0.02	0.24

TABLE 3-27 (Cont'd)

Maximum Cedar Bay Air Toxics Impacts ($\mu\text{g}/\text{m}^3$)

Pollutant	Averaging Period	Year	Cedar Bay	No Threat Levels
Vanadium	8-hour	1983	0.43	0.5
		1984	0.39	0.5
		1985	0.28	0.5
		1986	0.30	0.5
		1987	0.45	0.5
	24-hour	1983	0.07	0.12
		1984	0.07	0.12
		1985	0.05	0.12
		1986	0.05	0.12
		1987	0.07	0.12
	Annual	1983	0.01	2.0E+01
		1984	0.01	2.0E+01
		1985	0.01	2.0E+01
		1986	0.01	2.0E+01
		1987	0.01	2.0E+01

4.0 AIR EMISSIONS CONTROL TECHNOLOGY

4.1 Introduction

4.1.1 Project Description

The Cedar Bay Cogeneration Project in Jacksonville FL will be capable of generating 250 net megawatts (MW) of power and 380,000 lb/hr of steam @ 620 psig from a circulating fluidized bed (CFB) boiler-based generating plant. Electrical power will be supplied to the utility grid, and process steam will be supplied to the Seminole Kraft paper mill, located adjacent to the generating plant. Major combustion equipment for the plant consists of three CFB boilers and two distillate oil-fired limestone dryers.

The heat input of the three boilers at full load (combined) is estimated at 3,189 MMBtu/hr. The bulk of the fuel fired in the boilers will be low sulfur coal, however the Cedar Bay Cogeneration Project proposes a test to ascertain whether short-fiber rejects from the adjacent paper mill can be burned consistent with all requirements, and with the CFB's capability. The charging rate of this fuel will not exceed 300 tons/day. The Cedar Bay Cogeneration Project is proposing to burn the short-fiber rejects so long as it can satisfy its requirements and use of this fuel can be accomplished consistent with proper CFB operation.

Limestone used in the boilers for desulfurization and acid gas control will be ground and dried in the two limestone dryers prior to injection into the CFBs. Each limestone dryer will consist of a crusher, in which a stream of heated air both classifies (separates by size fraction) the ground limestone, and dries the material. Air will be heated using distillate oil-fired heaters with a fuel consumption estimated at 120 gallons/hr per dryer. The limestone dryers will be permitted to operate 8 hrs/day, equivalent to 2,920 hours per year. The dryers will be equipped with fabric filters which are integral to operation of the equipment.

Additional equipment will be included to receive, store, and handle coal and limestone, and to store, handle and pelletize ash generated by the boilers.

4.1.2 Purpose of Control Technology Review

Based on a control technology assessment in the Site Certification Application and a recommendation by Florida DER, an Air Permit was issued for the Cedar Bay facility in March, 1991 and the Conditions of Certification were issued by the Siting Board in February 1991. The

Air Permit contained emission limitations that were thought to satisfy all air quality requirements applicable to the Cedar Bay facility. Given concerns about other aspects of the project, AES subsequently offered (and the Siting Board preliminarily accepted) additional proposed reductions in certain emissions. The Cedar Bay Cogeneration Project has undertaken to achieve those additional reductions and to satisfy the Siting Board's conditions.

These lower emission rates and the inclusion of a new add-on technology (selective non-catalytic reduction) require some changes to the Conditions of Certification and original Air Permit (March 1991). To provide the state and EPA with accurate and updated information on the project for review of the proposed changes, The Cedar Bay Cogeneration Project is providing this technical review of the air emission controls and emission rates. Although not required, the review is presented in a "top-down" format for ease of review by DER, EPA and the public.

4.1.3 Emission Estimates and Proposed Controls

The facility will be an emission source of nitrogen oxides, sulfur dioxide (SO₂), particulate matter (PM), carbon monoxide (CO), volatile organic compounds (VOC), beryllium, mercury, lead, fluorides and sulfuric acid mist. Emission rates proposed for the Cedar Bay combustion sources are shown on Table 4-1. For the CFBs, the emission rates listed in the previously issued Air Permit and Conditions of Certification, as well as the proposed emission rates, are shown on this table.

For the CFB boilers, the proposed controlled emissions level for particulate matter is 0.018 lb/MMBtu (30-day rolling average), which will be achieved with fabric filters. The proposed levels for SO₂ are 0.2 lb/MMBtu (12 month rolling average) and 0.24 lb/MMBtu (3 hr average), which will be achieved with limestone injection in the CFB boilers firing low sulfur coal. For beryllium, mercury, lead, fluorides and sulfuric acid mist, the proposed emission levels are 1.25×10^{-5} , 3.04×10^{-5} , 6.38×10^{-5} , 8.5×10^{-4} , and 0.016 lb/MMBtu, respectively. Control of particulate matter through fabric filtration will simultaneously achieve control of beryllium, mercury, and lead, while control of SO₂ with limestone injection will also control emissions of sulfuric acid mist and fluorides (as HF). The proposed level for nitrogen oxides is 0.17 lb/MMBtu (30-day rolling average), which will be achieved by design of the boilers and selective non-catalytic reduction. For CO and VOC, the proposed emission levels are 0.175 lb/MMBtu and 0.015 lb/MMBtu, respectively. These emission levels will be achieved using advanced combustion controls.

Emissions of particulate matter from the limestone dryer will be controlled via fabric filtration, while NO_x, CO and VOC from this source will be minimized by combustion controls. Emissions of SO₂ and sulfuric acid mist from the limestone dryer will be controlled with firing low sulfur fuel and direct contact between the air heater exhaust and the limestone.

TABLE 4-1

**Cedar Bay Facility Combustion Sources
Emission Rates**

Pollutant	CFBs		Limestone Dryers (lb/hr)	
	As Certified (a) (lb/MMBtu)	As Proposed (b) (lb/MMBtu)	As Certified (a) (lb/hr (c))	As Proposed (b) (lb/hr (c))
SO ₂ (d)	0.31	0.20	5.0	5.0
SO ₂ (e)	0.60	0.24	5.0	5.0
NO _x (f)	0.29	0.17	2.4	2.4
CO	0.19	0.175	0.6	0.6
TSP	0.020	0.018	0.25	0.25
PM-10	0.020	0.018	0.25	0.25
VOC	0.015	0.015	0.05	0.05
Lead	7 x 10 ⁻³	6.38 x 10 ⁻⁵	N/A	1.45 x 10 ⁻³
Beryllium	1.1 x 10 ⁻⁴	1.25 x 10 ⁻⁵	N/A	4.26 x 10 ⁻⁵
Mercury	2.6 x 10 ⁻⁴	3.04 x 10 ⁻⁵	N/A	5.11 x 10 ⁻⁵
Fluorides	8.6 x 10 ⁻²	8.54 x 10 ⁻⁴	N/A	N/A
H ₂ SO ₄ mist	0.024	0.016	0.11	0.11

Notes:

(a) Emission limits as contained in Final Order and Certification PA-88-24 (2/11/91) and Final Determination, AES/Cedar Bay Cogeneration Project, Duval County, FL Permit No. PSD-FL-137 (3/28/91)

(b) Emission rates from Amended Petition of Certification (July 22, 1992 Before the State of Florida, Division of Administrative Hearings, In Re: AES/Cedar Bay Cogeneration Project, Power Plant Site Certification Application PA-88-24) plus proposed improvements by US Generating Company

(c) lb/hr values represent emissions for each of two limestone dryers

(d) annual average

(e) 3-hour average

(f) 30-day average

Materials handling emissions will be controlled using wet suppression, fabric filters and enclosures, as detailed in Section 4.2.2.

4.2 Controls For Particulate Matter, Beryllium, And Lead

4.2.1 Stack Emissions

4.2.1.1 Circulating Fluidized Bed Boilers

Introduction

For TSP and PM-10, the Site Certification Application recommended the use of fabric filtration to achieve emission rates of 0.020 lb/MMBtu for both pollutants. Emissions of lead (Pb) and beryllium (Be) were recommended to be controlled by fabric filtration to levels of 0.007 lb/MMBtu and 0.00011 lb/MMBtu, respectively. In response, Florida DER staff concurred with these recommendations, and FDER wrote these limits into the Air Permit for Cedar Bay. This emission rate for particulate matter is in conformance with the applicable New Source Performance Standard (NSPS) for Electric Utility Steam Generating Units, 40 CFR 60, Subpart Da (0.03 lb/MMBtu, 99% reduction).

To satisfy the Siting Board's concerns over Cedar Bay, as permitted, which did not address the adequacy of Cedar Bay's emission limitation for PM, and to further improve the environmental performance of Cedar Bay, the Cedar Bay Cogeneration Project proposes to achieve emission rates of 0.018 lb/MMBtu for both TSP and PM-10, of 1.25×10^{-5} lb Pb/MMBtu, and 6.38×10^{-5} lb Be/MMBtu, using fabric filtration.

The composition and amount of particulate matter emitted from coal-fired boilers are a function of firing configuration, boiler operation and coal properties (EPA 1985). Particulate matter (as total suspended particulates or TSP) will be emitted from the proposed CFB boilers as a result of entrainment of uncombustible inert matter (ash) and condensible substances. Since CFB boilers attain nearly complete combustion, very little unburned carbon will be present (EPA 1985). Due to the fine nature of the particles which escape collection in a fabric filter, it is conservatively assumed that all the particles emitted will be less than 10 microns in diameter or PM-10.

The quantity and characteristics of the regulated trace metal emissions (beryllium and lead) from the Cedar Bay CFB boilers depend on the fuel composition, the chemical and physical properties of the particular trace metal, and the performance of the emission controls. Operational features of the combustion process do not significantly affect metal emissions.

Due to the high temperature and turbulence in the CFB, metals are released in both particulate and vapor phases, often as metal oxides, chlorides and sulfates. Depending on the metal compound involved and its condensation temperature, a vaporized metal begins to condense mostly on the surfaces of the fine solid particles in the flue gas (since that fraction has the greatest surface area) at normal stack temperatures (Hasselriis, 1985). Condensation occurs as the flue gases cool in the boiler and flue gas treatment equipment. Since the condensation temperatures of two of these regulated trace metals (beryllium - 2,300°F, lead - 622°F) are above the operating temperature of the fabric filter (289-300°F), the probability of removing them in the particulate control device is high.

Technically Feasible Alternatives

Fabric filters and electrostatic precipitators (ESPs) represent technically feasible options for the control of PM and trace metals from CFB boilers. Wet control techniques (scrubbers) do not represent a demonstrated control technique for CFB boilers, nor do they offer more stringent levels of control than fabric filters.

Since fabric filters and ESPs are both capable of PM and trace metal control levels in excess of 99%, performance is compared on a lb PM/MMBtu basis. This allows for a straightforward comparison with the emissions levels listed in the Clearinghouse.

Of these two options, fabric filters are capable of achieving the most stringent levels of PM control. While ESPs may rival the performance of fabric filters, they are not judged to be consistently capable of a higher degree of control of TSP, PM-10, Be, and Pb.

When specifying the emission limitation for PM in the Cedar Bay Air Permit, DER deemed fabric filters the superior fine particulate emission control device since their performance is not as sensitive to particle size distribution as an ESP. According to Appendix C.2 of Supplement A of AP-42 (EPA 1985), fabric filters are more efficient than ESPs at controlling fine particulate (i.e. with diameters less than 6 microns). Consequently, fabric filters are also considered superior control devices for trace metals since these materials selectively condense onto smaller particles in the flue gas.

Because they are superior to ESPs for control of PM-10 and trace metals, fabric filters are considered to represent the best technology for control of TSP, PM-10, Be, and Pb from the Cedar Bay project.

Emission Levels

Based on information on control of particulate matter from the Cedar Bay boilers supplied by the equipment vendors, particulate matter control down to a level of 0.01 lb/MMBtu would be technologically feasible with fabric filters. This emission level, however, is only achievable through the use of specialty fabric filter bags (i.e. Gore-Tex laminated or Nomex), which as detailed further in the economic analysis which follows, are significantly more expensive than conventional (woven fiberglass) bags. Based on vendor information, the lowest level achievable with woven fiberglass bags is 0.018 lb/MMBtu (Bechtel 1992), which is consistent with recent permits for coal-fired plants in Florida and EPA Region IV.

As described previously, for a given boiler configuration, trace metal emission rates are determined primarily based on the concentrations of the materials in the fuel. The emission rates proposed for beryllium and lead (1.25×10^{-5} and 6.38×10^{-5} lb/MMBtu, respectively) are based on analyses of the coal to be fired in the Cedar Bay boilers and the performance of the fabric filters proposed for Cedar Bay. Considering that these metals will condense selectively on the fine particles in the flue gas, the fact that a fabric filter offers superior control of fine particles compared to the alternative ESP, and that a fabric filter will be used in this case, control of beryllium and lead at these levels can be concluded to be the lowest emission rates achievable for the proposed project.

Economic Comparison

This section compares the cost of the most stringent level of control of particulate matter (0.01 lb/MMBtu), achievable using specialty bags, to the level of control achievable using conventional bags (0.018 lb/MMBtu).

The three Cedar Bay boilers will have a combined total of 6,336 filter bags. The difference in cost per bag for Gore-Tex laminated bags compared to woven fiberglass bags is \$210 (Bechtel 1992); thus, the total increase in capital cost to the project to achieve the more stringent level of control is \$1,331,000. At a bag life of 2 years and an annual interest rate of 10%, the annualized cost to the project to achieve the more stringent level of control is greater than \$760,000. Considering that the difference in annual emissions of the two levels of control is 95.5 tons/yr, the incremental cost effectiveness of achieving 0.01 lb/MMBtu is greater than \$8,000/ton. This is not considered cost effective.

CFB Stack Particulate Matter Conclusion

The Cedar Bay CFB boilers will employ fabric filters for control of particulate matter, beryllium and lead. Compared to the alternative control device (ESP), the fabric filter offers a greater degree of control of fine particles and trace metals. This alternative is thus considered appropriate for control of particulate matter, beryllium, and lead. A more stringent emission level of particulate matter is technologically feasible by utilizing specialty bags in the fabric filter. This lower level, however, is not considered to be appropriate since it would result in adverse economic impacts to the project of greater than \$8,000/ton of additional PM controlled. Therefore, the emission level of 0.018 lb/MMBtu, which is comparable to the emission level of other recently permitted coal projects in Florida, is considered appropriate for control of TSP and PM-10 for the CFBs. Considering this level of PM control and based on an analysis of the coal to be fired, emission rates for Pb and Be of 1.25×10^{-5} and 6.38×10^{-5} lb/MMBtu, respectively, are considered appropriate as well.

4.2.1.2 Limestone Dryers

After FDER staff reported that the heavy metal emissions from the limestone dryers were negligible, the Air Permit issued for the project included an emission limit of 0.25 lb/hr per dryer for both TSP and PM-10. This emission limitation was not an issue in the Siting Board's Order on June 16, 1992.

The Cedar Bay Cogeneration Project is proposing to utilize fabric filters to achieve an emission rate of 0.25 lb/hr for TSP and PM-10 from each limestone dryer, with a total annual emission rate of 0.73 tons/yr. In comparison, annual emissions from the Cedar Bay CFB boilers will be less than 214.9 tons/yr. Thus, the limestone dryers' emissions of particulate matter are negligible.

Control of PM emissions from this equipment using fabric filters is considered to represent the most stringent alternative, and since the Cedar Bay limestone dryers will be equipped with fabric filters and the operation of these filters is integral to the operation of the dryers, this alternative is concluded to be appropriate for control of particulate matter.

4.2.1.3 Material Handling Emissions

Emissions of particulate matter will occur as a result of delivery, storage and handling of coal and limestone, and storage and handling ash. These emissions can be characterized as either windblown dust from outdoor storage piles, or dust released during unloading, processing, and conveying operations.

In recommending conditions of certification to the Cedar Bay project (March 1991), the DER noted that all practical measures would be employed to control fugitive dust emissions, including the use of enclosures, water sprays, compaction, covered conveyors, and fabric filters. The material handling systems and fugitive emission control systems, however, have undergone revisions since then, as described in the proposed modifications attached to the Siting Board's Order of June 16, 1992.

The Cedar Bay Cogeneration Project has performed an extensive review of the design of the material handling equipment and fugitive emission controls. The control systems now being proposed are described further in subsequent subsections.

Coal Delivery

Coal will be delivered to the facility by railcar; unloading will take place within a rail unloading building. Coal unloading is achieved via bottom dump hopper cars, which discharge into a subterranean surge bin. The perimeter of the surge bin is equipped with water sprays to control fugitive dust. Since the water sprays suppress additional dust that may be generated during unloading, within an enclosed unloading building, this alternative for control of fugitive dust emissions is considered appropriate.

Coal Storage

Coal will be stored at the facility in two outdoor piles. A receiving pile will be used to stage coal as it is reclaimed for transfer to storage piles or to the coal hopper. The inactive coal storage pile is compacted and sealed to prevent weathering and is maintained as an emergency reserve in case of fuel supply interruption.

Coal Handling

Coal will be transferred from the unloading building receiving hoppers to the coal receiving pile using enclosed belt conveyors. Coal in this area is expected to be wet from the water sprays of the coal unloading operation. Mobile equipment (front end loaders) will be used to stack coal from the receiving pile to the inactive storage pile when necessary and to pack the coal in the storage pile to eliminate voids. Mobile equipment will also be used to remove coal from the storage pile to the coal reclaim hopper. Coal will be transported by enclosed belt conveyors from the reclaim hopper to one of the redundant coal crushers, and from the coal crusher via enclosed conveyors to the coal silos.

The conveyors, coal crushers and the coal storage silos are ventilated with a suction fan and equipped with fabric filters. The fabric filters which serve the crushers and silos will control particulate emissions to 0.003 gr/dscf which is considered appropriate for dust control from these material handling operations.

Limestone Delivery

Limestone with a particle size distribution of 3/4"x0 will be delivered to the facility in bulk dump body trucks. Limestone in this size range contains very few of the fine particles which generate fugitive dust. The limestone is pushed with portable equipment to "dozer traps" where it is reclaimed for drying, sizing, and silo storage.

Limestone Storage

Bulk limestone (3/4"x0) will be stored in an inactive outdoor storage pile to protect against interruptions in limestone supply.

Limestone Handling

From the "dozer traps" limestone will be reclaimed by enclosed continuous conveyor to the limestone dryer pulverizers, and by pneumatic conveyor from the dryer/crushers to the limestone hoppers. The limestone dryer/crushers operate in a totally enclosed system which exhausts through a fabric filter. Pneumatic conveying air is exhausted from the silos through bin vent filters. The totally enclosed nature of the dryer/crusher system and pneumatic conveying lines, and the use of fabric filters on all emission vents is considered appropriate for the control of fugitive limestone dust.

Ash Handling

Fly ash will be discharged from the bottom of the baghouse filters and air heater hoppers, conveyed to the fly ash silo, and subsequently pneumatically conveyed to the pelletizing system.

Bed ash will be discharged from the bottom of each CFB boiler, transported via drag conveyor which will transport the bed ash to a bed ash hopper. From the hopper, the bed ash will be pneumatically conveyed to the bed ash silo, and then pneumatically conveyed to the pelletizing system.

The bed ash drag conveyor will be totally enclosed up to the bed ash hopper, and equipped with a fabric filter for venting. Each of the receivers for pneumatically conveyed material (fly ash silos,

bed ash hopper, bed ash silo, pelletizing operation receivers) will be equipped with fabric filters for venting and to separate transport air from entrained particulate matter.

The ash handling operations at Cedar Bay will be either pneumatically conveyed (and thus sealed), totally enclosed or equipped with fabric filters. These measures are considered appropriate for control of particulate matter from the ash handling process.

Pelletization

Ash pelletization will take place within a totally enclosed building to minimize emissions of fugitive particulate matter. In addition, particulate matter controls will be installed on the major pelletization equipment. Fabric filters will be installed on the bed and fly ash receivers, the vibratory screen, the ash recycle tank, the recycle hopper, and the pellet silo outlet conveyors. A venturi scrubber will be installed on the pelletizing hydrator, and impingement scrubbers will be installed to control emissions from the curing silo and pelletizing pan. Wet suppression will be used to control emissions from the recycle belt discharge. These measures are considered appropriate for the proposed project.

4.3 Nitrogen Oxides

4.3.1 Introduction

For Nitrogen Oxides (NO_x) from the CFB boilers, the Site Certification Application recommended boiler design and operation to achieve an emission rate of 0.36 lb/MMBtu. This proposed emission rate for NO_x was in conformance with the applicable NSPS (40 CFR 60, Subpart Da) of 0.6 lb/MMBtu. Florida DER staff responded to the recommendations by suggesting that a 0.29 lb/MMBtu be required. FDER concurred with this recommendation; EPA concurred in this judgement. To satisfy the Siting Board's concerns over Cedar Bay, as permitted, which did not address the adequacy of Cedar Bay's emission limitation for NO_x, AES proposed to lower the 0.29 lb/MMBtu emission rate to 0.17 lb/MMBtu, to go into effect 18 months after commencement of operation. The Siting Board's Order of June 16, 1992 reflects a preliminary acceptance of this new emission limitation in partial satisfaction of its concerns.

To further improve the environmental performance of the project, the Cedar Bay Cogeneration Project proposes to achieve an emission rate of 0.17 lb NO_x/MMBtu using selective non-catalytic reduction (SNCR) without the proposed 18 month delay.

NO_x is formed in combustion sources by either the thermal oxidation of nitrogen in the combustion air or the reduction and subsequent oxidation of fuel nitrogen. Virtually all NO_x emissions

originate as nitric oxide (NO) as both nitrogen and oxygen dissociate into atomic form at the high temperatures within the boiler and then recombine to form NO. A minor fraction of the NO is further oxidized in the flue gas system to form NO₂. The bulk of the NO_x formation in this facility will be through thermal oxidation of nitrogen from the combustion air, referred to as thermal NO_x.

The rate of formation of thermal NO_x is a function of the residence time, free oxygen, and peak flame temperature. Therefore, most control techniques for thermal NO_x are aimed at minimizing one or more of these variables. Other control methods, known as "add-on", "tail gas", or "back-end" techniques, remove NO_x from the exhaust gas stream.

4.3.2 Circulating Fluidized Bed Boilers

Various coal-fired boiler configurations exhibit unique design and operational characteristics which affect the technical feasibility of certain NO_x control alternatives. Of the available alternatives, CFB technology offers the lowest potential NO_x emissions of commercially available boiler designs due to inherently lower combustion temperatures and staged combustion. The design and operation of a CFB boiler has a significant impact on both the formation and subsequent emission of NO_x, as well as the potential application of add-on NO_x controls. Moreover, an assessment of NO_x control must take into account the adverse affect on CO emissions of some NO_x control measures.

4.3.2.1 Control Alternatives

Alternative NO_x controls for the proposed CFB boilers include combustion controls, selective non-catalytic reduction (SNCR) and selective catalytic reduction (SCR). It should be noted that although both SNCR and SCR have been applied to pulverized coal (PC) and stoker fired coal units in Japan and Europe, and have recently been concluded to represent BACT for a number of these types of generating units in the US, SCR has never been applied to a CFB boiler, for reasons discussed further in subsequent sections.

4.3.2.2 Selective Catalytic Reduction

SCR has been demonstrated to achieve high levels of NO_x reduction on certain combustion sources. In the United States, SCR has been applied to natural gas-fired combustion turbines and boilers, and has recently been concluded to be appropriate for domestic pulverized coal and stoker-fired coal boilers.

The SCR process involves postcombustion removal of NO_x from the flue gas with a catalytic reactor. Ammonia (NH₃) is injected into the flue gas stream upstream of the catalyst bed, and

NO_x and NH_3 combine at the catalyst surface, forming elemental nitrogen and water. The function of the catalyst is to lower the activation energy of the NO_x decomposition reaction; the catalyst allows NO_x reduction to proceed at a lower temperature than required for SNCR.

Technical Considerations

The optimum operating temperature for SCR systems has been shown to be in the range of 500-850°F. Below this temperature, the reduction reactions do not occur; above this range the catalyst promotes oxidation of ammonia, thereby actually increasing NO_x emissions. As discussed, the bed temperature in a CFB lies within the range of 1,600 - 1,700°F, which is higher than the operating range of SCR systems. Thus, the only temperature location suitable for catalyst bed location is within the boiler sections downstream of the hot cyclone.

None of the European or Japanese installations utilizing SCR, however, are CFB boilers, nor do any of these installations utilize baghouse filters (Nakabayashi, 1987; Cichanowicz, 1988). Thus the effect of SCR system operation on baghouse performance in general, and ammonium bisulfate formation in particular, is not well known. Therefore SCR technology from Japanese and European coal-fired sources, none of which are similar boiler technology or equipped with the type of particulate control which Cedar Bay will employ, may not be directly transferrable in this application.

Prior to the full-scale commercialization of the SCR process in both Japan and Europe, the process underwent a considerable degree of development and trials on small scale equipment. In Japan, the process was thoroughly studied in both laboratory and pilot-scale equipment for many years prior to commercialization (Kuroda 1989, Kobayashi 1987).

Kuroda noted that twenty pilot studies were conducted by Babcock-Hitachi in West Germany, Austria, Denmark and Sweden between 1984 and 1989 (Kuroda 1989); Schonbucher states that seventy pilot plants were operated within the same time frame (Schonbucher 1989). These studies were carried out prior to construction of the first commercial unit in order to determine important design and operating parameters such as optimum space velocity, effect of European fuel supplies on SCR system performance, variability of ammonia slip, process control alternatives and others. From a process development standpoint, these pilot studies were an important step in the transfer of Japanese SCR technology to European sources.

Plant energy use is a major consideration in CFB facilities where the fluidization and circulation of the bed in these boilers results in large fan power demands. Minimization of pressure drop through the boiler is thus a major design and operating consideration with a CFB. In addition, control of the air pressure in the combustor is critical to successful performance of the CFB. The

additional boiler pressure drop due to an SCR catalyst bed (typically 2-3 inches of water) adds to the boiler energy requirements and air pressure control complexity.

SCR has been installed on stoker boilers and PC boilers, but not on CFB boilers. SCR application on CFBs is thus not considered demonstrated or appropriate for the Cedar Bay project.

The alternative NO_x controls both require the injection of a reducing agent to promote the reduction reactions, thus both SNCR and SCR require equipment to store, vaporize, and deliver this material to the flue gas at appropriate concentration, location, and temperature. However, the catalyst required by the SCR system is expensive and results in this alternative being more costly than SNCR.

Since SCR has never been demonstrated on a CFB boiler, there is no reliable information to suggest that this alternative offers a greater degree of control of NO_x than SNCR. Even if SNCR and SCR were able to achieve comparable levels of control, the choice of SCR over SNCR would not be economically justifiable due to the higher cost associated with SCR. Thus in addition to being considered undemonstrated on CFB boilers, SCR is not considered economically justifiable when compared to SNCR.

4.3.2.3 Selective Non-Catalytic Reduction

SNCR has been applied to a number of different types of combustion sources, including petroleum heaters, utility and industrial boilers fired with natural gas and oil, as well as Japanese and European PC boilers.

The SNCR process is based on a gas phase homogeneous reaction, within a specified temperature range, between NO_x in the flue gas and either injected NH₃ or urea to produce gaseous nitrogen and water vapor. SNCR systems do not employ a catalyst; the NO_x reduction reactions are driven by the thermal decomposition of ammonia and the subsequent reduction of NO_x. Consequently the SNCR process operates at higher temperatures than the SCR process.

Two SNCR processes are commercially available. In the Thermal DeNO_x® process, developed and licensed by Exxon Research and Engineering, anhydrous or aqueous ammonia is the reduction reagent. In the NO_xOUT process, developed by EPRI and licensed by Nalco/Fuel Tech, the reduction reagent is urea.

Critical to the successful reduction of NO_x in these applications is the temperature of the flue gas at the point where the reagent is injected. For Thermal DeNO_x®, the necessary temperature

range is 1,700 - 1,900°F; for NO_xOUT the nominal temperature range is 1,600 - 2,100°F. Also critical to effective application of these processes are gas mixing, residence time at temperature, and ammonia slip.

Theoretically, one mole of ammonia or urea will react with one mole of NO_x, forming elemental nitrogen and water. In reality, not all the injected reagent will react due to imperfect mixing, uneven temperature distribution, and insufficient residence time. These physical limitations may be compensated for by injecting a large amount of excess of reagent and essentially achieving low NO_x emissions at the expense of emissions of unreacted reagent, referred to as "slip." These emissions represent an adverse environmental impact and can lead to formation of ammonium salts. Thus for a given boiler configuration, there is a limit on the degree of NO_x reduction which can be achieved with SNCR while maintaining acceptable levels of slip.

The CFB design is described as the ideal application for SNCR in the available open literature. CFB boilers are constant temperature, variable heat transfer devices. The bed temperature and downstream flue gas temperature can be set by the operator to within a few degrees. The typical temperature of CFB flue gas leaving the bed and entering the hot cyclone is at the ideal temperature for SNCR. Additionally, the reduction reagent is injected at the inlet to the hot cyclone, where all of the flue gas is swirled at 50-75 ft/second, and forced to change direction several times. This cyclonic action homogenizes the reagent flue gas NO_x concentration, thus maximizing mixing.

The CFB design offers lower NO_x formation potential than other commercial boiler types due to the lower combustion temperatures and staged air operation. However, there are site-specific technical features of the Cedar Bay CFB boilers which must be considered in determining the lowest emission level which SNCR is capable of meeting in this case.

For example, the Cedar Bay boilers are similar in physical size to the two boilers at the AES Barbers Point facility. However, due to operational differences, these two cases are not directly comparable in terms of NO_x emission rate. The Barbers Point boilers operate at 664,444 lb/hr of main steam flow and 598,269 lb/hr of reheat steam flow per boiler with a maximum process steam flow of 30,000 lb/hr @ 65 psig on an interruptible basis. The design heat input per boiler at Barbers Point to accomplish this output is 939.5 MMBtu/hr. In contrast, the Cedar Bay boilers will operate at 745,840 lb/hr of main steam flow and 542,517 lb/hr of reheat steam flow with a maximum process steam flow of 380,000 lb/hr @ 620 psig on an uninterruptible basis requiring heat input of 1,063 MMBtu/hr per boiler (Black & Veatch, 1992).

Even though Cedar Bay and Barbers Point will both employ SNCR for control of NO_x emissions, Cedar Bay, by nature of its higher heat input per boiler, will have a higher uncontrolled NO_x

emission rate than Barbers Point or any other similarly-sized boiler operating at its design condition. This higher uncontrolled rate in turn means that Cedar Bay would have to utilize more ammonia or urea in its SNCR system than other units to achieve the same emissions level. This increase in reagent would result in increased capital and operating costs (detailed further below) an increase in unreacted reagent (from 5 to 20 ppm, Black & Veatch, 1992), increased fouling of the air heater with ammonium salts, and contamination of the flyash with unreacted reagent, thereby causing problems with the ash pelletizing system.

Use of SNCR at Cedar Bay poses another challenge. Since the Cedar Bay boilers were not originally designed and constructed with the intent to employ SNCR, use of this alternative has required that the control equipment be retrofit. Retrofit equipment will include reagent receiving, storage, vaporization and handling equipment (tanks, pumps, piping, heaters), injection equipment to be located in the boilers (piping, injection nozzles) as well as control equipment to monitor and regulate system performance. The Cedar Bay Cogeneration Project is proposing to retrofit SNCR systems to the Cedar Bay boilers consistent with an emission rate of 0.17 lb/MMBtu. This rate is proposed since it is thought to be the lowest achievable at Cedar Bay's CFBs, with their high heat input rate, a retrofit application of SNCR a CO emission limitation of 0.175, and providing uninterrupted energy. Any lower level is not considered demonstrated or appropriate for Cedar Bay. Certainly, no other project has reported data demonstrating a lower NO_x emission rate over time under these conditions.

Pushing SNCR to the apparent bounds of technology will result in increased capital and operating costs to the project. However, the Cedar Bay Cogeneration Project does not consider the increased costs to achieve this rate unreasonable.

4.3.2.4 Economic Impact of Lower NO_x Levels

Should Cedar Bay be required to attempt to achieve lower NO_x levels, the Cedar Bay Cogeneration Project would have to experiment with SNCR beyond its demonstrated limits. This process would require, at a minimum, additional equipment beyond what is required to achieve 0.17 lb/MMBtu (larger pumps and piping, more injection nozzles), additional operating costs (more reagent, more power for pumping and vaporization), and likely require derating Cedar Bay's CFBs or raising their CO limitations.

The cost associated with this additional equipment were estimated and are shown on Tables 4-2 and 4-3. They are presented in the cost estimating format recommended by EPA in their latest guidance document on the subject (EPA 1990). The cost-effectiveness figures in these tables are based on the assumption that incurring these costs would reduce NO_x emissions to 0.11 lb/MMBtu and FDER wrote these limits into the air permit for Cedar Bay.

TABLE 4-2

Increased Capital Costs to Achieve 0.1 lb NO_x/MMBtu

(1) Purchased Equipment	
(a) Basic Equipment	444,000
(b) Auxiliaries	included
(c) Instrumentation and Controls	included
(d) Structural Support	44,000
(e) Freight & Taxes	39,000
(2) Direct Installation	158,000
Total Direct Costs (TDC)	\$685,000
(3) Indirect Installation	
(a) Engineering & Supervision	69,000
(b) Construction & Field Expense	69,000
(c) Construction Fee	34,000
(d) Contingencies	137,000
(e) Startup & Performance Test	7,000
Total Indirect Costs (TIC)	\$316,000
Total Capital Cost (TCC)	\$1,000,000
Annualized Capital Recovery (b)	\$162,000
Notes:	
Combined costs for three CFB boilers	
Cost information from U.S. Generating Company	
(a) Cost Factors: 1990 EPA OAQPS Control Cost Manual	
(a) amortized over 10 years straight line @ 10% interest rate	

TABLE 4-3

Increased Annualized Operating Costs to Achieve 0.1 lb NO_x/MMBtu

Direct Operating Costs	
Increased Operating Labor (OL)	\$0
Increase Maintenance (a)	90,000
Replacement Fabric Filter Bags (b)	150,000
Utilities - Electricity and Fuel (c)	30,000
Raw Materials - Ammonia (d)	70,000
Lost Power During Downtime (e)	2,009,000
Indirect Operating Costs	
Overhead @ 30% OL & 12% Maintenance	11,000
Taxes @ 1% TCC	10,000
Insurance @ 1% TCC	10,000
Administration @ 2% TCC	20,000
Annual Operating Costs	\$2,400,000
Annual Capital and Operating Costs	\$2,562,000
Annual Tons Removed (f)	717
Cost Effectiveness (\$/ton)	\$3,573
<p>Notes: Combined costs for three CFB boilers Source of operating cost information: U.G. Generating Company (a) Two additional air heater washes per year required due to ammonium salt contamination (b) Increased bag replacement due to ammonium salt contamination (c) Increase in auxiliary load of 140 kw (ammonia injection, vaporization and pumping) plus 0.06% negative effect on plant heat rate, resulting in increased fuel use (d) 190 lb/hr additional aqueous ammonia consumption (e) Decrease availability due to additional air heater cleaning, lost power and steam sales during downtime (f) Compared to 0.17 lb/MMBtu</p>	

Table 4-2 shows the increase in retrofit costs to the three CFB boilers (total) for the additional equipment to lower the NO_x emission rate from 0.17 to 0.1 lb/MMBtu. Total installed costs, including equipment costs, commercialization costs, and installation costs, are estimated at \$1,000,000. On an annualized basis, this increased costs translates to \$162,000/yr (based on 10 year equipment life and a average interest rate of 10%).

Table 4-3 shows the increase in operating costs for the three CFB boilers (combined) to achieve the lower emission rate. No additional operating labor would be required; additional power charges represent costs to pump and vaporize the additional reagent prior to injection, as well as increased fuel cost to overcome the decrease in plant heat rate. Additional ammonia costs are based on 190 lb/hr of additional ammonia at a cost of \$4.94/100 lb.

As described previously, achieving this lower level would result in increased levels of reagent slip, which will in turn create ammonium salts (ammonium sulfate and ammonium bisulfate) in the flue gas within the boilers. These salts will condense in the cooler portions of the boilers, resulting in increased fouling of the air heaters and blinding of the fabric filters, necessitating increased maintenance and decreased availability associated with cleaning and maintaining this equipment. Additional maintenance costs are estimated based on two additional outages per boiler per year to clean the air heater and replace fouled bags. These outages will result in decreased availability of 2% and lost power production, estimated at a value of \$1,000,000 per percent on a annual basis.

Considering indirect costs such as administration, overhead, and taxes, total annualized costs to reduce NO_x emissions from 0.17 to 0.1 lb/MMBtu are estimated at \$2,400,000/yr, with total annualized operating and capital costs at over \$2,500,000/yr.

This lower emission rate would result in a decrease in annual NO_x emissions of 717 tons/yr, based on a heat input of 3,189 MMBtu/hr and an annual capacity factor of 85%, which is considered a reasonable estimate of an actual operating schedule. This results in a cost effectiveness of this emission reduction of over \$3,570/ton controlled. The costs of derating Cedar Bay to augment the effort attempting to reduce NO_x emissions would dwarf this estimate of cost effectiveness. In addition, the adverse environmental impacts of increased CO emissions, unreacted reagent, increased fouling of the air heater, and contamination of the flyash and of the ash pelletizing system would have to be accounted for. Furthermore, it is unclear how much, if at all, this effort would actually reduce NO_x emissions since there are no data for the hypothetical cases of NO_x emission reduction that were considered in the cost effectiveness computation. Accordingly, SNCR associated with an emission rate below 0.17 in Cedar Bay's circumstances is considered uneconomical and inappropriate for the proposed project, as well as unproven technologically.

4.3.2.5 CFB NO_x Conclusion

As described, the NO_x emission rate for the CFB boilers in the previously issued Air Permit is 0.31 lb/MMBtu (30 day average) using combustion controls and boiler operation to minimize formation of NO_x, whereas the Cedar Bay Cogeneration Project is proposing a lower emission rate of 0.17 lb/MMBtu (30 day average) using SNCR. Selective non-catalytic reduction is preferred over SCR for fluidized bed boilers since it has been demonstrated, is operating on existing units, and has lower capital costs. SNCR has been utilized on CFB boilers at emissions levels as low as 0.11 lb/MMBtu, however attempting to achieve this level on Cedar Bay would require technological experimentation and adverse economic impacts.

Therefore, the emission rate of 0.17 lb/MMBtu is considered appropriate and the best achievable for Cedar Bay. This rate is in conformance with the most recently issued air permits for coal-fired plants in Florida and EPA Region IV, and the applicable NSPS.

4.3.3 Limestone Dryers

The Air Permit issued for the project lists an emission limit of 2.4 lb/hr per dryer for NO_x. This emission limitation was not an issue in the Siting Board's Order on June 16, 1992.

The Cedar Bay Cogeneration Project is proposing to utilize combustion controls to achieve an emission rate of 2.4 lb/hr for NO_x from each limestone dryer, with a total annual emission rate of 7.0 tons/yr. In comparison, annual NO_x emissions from the Cedar Bay CFB boilers will be less than 2,030.2 tons/yr. Thus, the limestone dryers' emissions of NO_x are negligible.

As described, the limestone dryers will incorporate a heated stream of air to classify and dry the ground limestone. Air will be heated by direct contact with exhaust from distillate oil-fired burners. The use of burners designed for minimal NO_x formation are considered to represent the top technology for control of NO_x from these sources. Add-on controls such as SNCR and SCR are not considered feasible due to the physical design of the dryers. The air heaters are physically too small to provide adequate residence time at temperature for SNCR to be feasible, and there are no locations in the equipment where an SCR catalyst could be situated which provide for the correct temperature. Consequently, there are no available alternatives which offer a greater degree of NO_x control than the burners proposed, and this alternative is thus concluded to be appropriate for control of NO_x from the limestone dryers.

4.4 Carbon Monoxide

4.4.1 Introduction

For CO, the Site Certification Application recommended the use of boiler design and combustion controls to achieve an emission rate of 0.19 lb/MMBtu. In response, Florida DER staff concurred with this recommendation and wrote this limit into the air permit for Cedar Bay. To satisfy the Siting Board's concerns over Cedar Bay, as permitted, which did not address the adequacy of Cedar Bay's emission limitation for CO, AES proposed, among other things, to lower the emission limitation for CO to 0.175 lb/MMBtu. The Siting Board's order of June 16, 1992 reflects a preliminary acceptance of this new emission limitation in partial satisfaction of its concerns.

The Cedar Bay Cogeneration Project proposes to meet this emission rate of 0.175 lb CO/MMBtu using boiler design and combustion controls; and based on vendor-supplied emissions guarantees, the Cedar Bay Cogeneration Project considers this limit to be the lowest achievable emission rate.

Emissions of CO result from the incomplete combustion of carbon and organic compounds. CO emissions are a function of oxygen availability (excess air), flame temperature, residence time at flame temperature, combustor design, and turbulence. Control of the emissions of CO may be effected two ways: (1) combustion modifications to minimize the formation of the pollutant, and (2) flue gas catalytic oxidation of any CO formed in the combustion process.

4.4.2 Circulating Fluidized Bed Boilers

Alternative controls for CO from combustion sources include combustion controls and catalytic oxidation. Combustion controls are the predominant control technology utilized for coal-fired sources.

Catalytic oxidation is the alternative used to obtain the most stringent control level for CO from gas turbine combustion units. This technology has never been applied to a coal-fired unit, however. In this alternative, a catalyst would be situated in the flue gas stream which would lower the activation energy of a series of reactions where reactant species (CO, VOC and O₂) are converted to carbon dioxide and water. The catalyst permits combination of the reactant species at lower gas temperatures than would be required for uncatalyzed oxidation.

The catalyst would have to be located at a point where the gas temperature is within an acceptable range. The effective temperature range for CO oxidation is between 600 and 1,150°F.

In a CFB, this means that the catalyst grid would need to be installed at a point upstream of the baghouse filter.

Catalyst non-selectivity is a problem for sulfur containing fuels such as coal and fuel oil. Catalysts promote oxidation of SO_2 to SO_3 as well as CO to CO_2 . The amount of SO_2 conversion is a function of temperature and catalyst design. Under optimum conditions, formation of SO_3 can be minimized to 20% of inlet SO_2 . Compared to the proposed emissions level, this level of conversion would result in an increase in H_2SO_4 emissions of approximately 800 tons per year, which aside from the increased ambient air impacts would result in unacceptable amounts of corrosion to the air preheater and ductwork.

ENSR contacted an oxidation catalyst system vendor to determine the technical feasibility of installing this system on a coal-fired boiler. Due to the high particulate loading of the flue gas, trace element concentration and SO_2 level, the vendor stated that they could not provide a catalyst system for coal-fired applications. This vendor also noted that oxidation catalysts are generally designed for a maximum particulate loading of 50 mg/Nm^3 (Englehard, 1990). The proposed Cedar Bay CFB boilers will have a particulate loading of the baghouse filters in excess of $2,000 \text{ mg/Nm}^3$. Consequently, oxidation systems are considered technically infeasible for this facility.

The next most stringent level of control of CO from CFB boilers has been achieved through the design and operation of the boiler in a manner so as to limit formation of this pollutant. Such controls are commonly referred to as combustion controls. In general, a combustion control system seeks to maintain the proper conditions to ensure complete combustion through one or more of the following operation design features: low excess air, staged combustion, overfire air, sufficient residence time, and good mixing.

In the case of the Cedar Bay CFBs, the boilers themselves incorporate design features which enhance uniform fuel/air distribution and mixing, along with oxygen monitoring and adjustment of the staged air combustion to suppress CO formation. In assessing the CO emission rates that Cedar Bay can achieve, one must optimize these factors in the context of efforts to reduce NO_x emissions since those efforts tend to increase CO emissions. In light of the NO_x emission reductions discussed above, the lowest emission level that the vendor of the boiler equipment for Cedar Bay will guarantee is $0.175 \text{ lb CO/MMBtu}$.

Since the measures to control CO are inherent to the operation of the boilers, there are no adverse economic impacts associated with this alternative. Therefore, there is no basis for selecting an emission control alternative that is less restrictive than the level that provides the

most stringent degree of control of CO; 0.175 lb/MMBtu is considered appropriate for the proposed project.

4.4.3 Limestone Dryers

The Air Permit issued for the project lists an emission limit of 0.6 lb/hr per dryer for this pollutant. This emission limitation was not an issue in the Siting Board's Order on June 16, 1992.

The Cedar Bay Cogeneration Project is proposing to utilize combustion controls to achieve an emission rate of 0.6 lb/hr for CO from each limestone dryer, with a total annual emission rate of 7.0 tons/yr. In comparison, annual CO emissions from the Cedar Bay CFB boilers will be less than 2,090 tons/yr. Thus, the limestone dryers' emissions of CO are negligible.

The most stringent available alternative for control of this pollutant from these sources is considered to be the use of burners which maximize complete combustion, which will result in minimization of formation of CO. Such burners, which will be utilized in the proposed facility, are thus concluded to be appropriate for control of CO.

4.5 Sulfur Dioxide And Acid Gases

4.5.1 Introduction

Emissions of sulfur oxides are generated in fossil fuel-fired sources from the release of sulfur present in the fuel. Approximately 98% of sulfur in solid fuels is emitted upon combustion as gaseous sulfur oxides. Uncontrolled emissions of SO₂ are thus affected by fuel sulfur content alone, and not by the firing mechanism, boiler size, or operation. Similarly, uncontrolled emissions of fluorides (as hydrogen fluoride) are only affected by the fluoride content of the fuel. Sulfuric acid mist, however, is formed from the reaction of sulfur trioxide (SO₃) with water vapor outside of the combustion section. Since the formation of SO₃ is a function of the generation of SO₂, uncontrolled emissions of sulfuric acid mist are also a function of the sulfur content of the fuel.

Sulfur dioxide, hydrogen fluoride and sulfuric acid mist, referred to collectively as acid gases, are all controlled by the same technology, as described in further detail below.

4.5.2 Circulating Fluidized Bed Boilers

The SO₂ emission rates for the CFB boilers recommended in the Site Certification Application were 0.6 lb/MMBtu (3-hour average) and 0.31 lb/MMBtu (annual average firing coal with a sulfur

content of from 1.7 - 3.3%). Recommended emission limits for the other acid gases, sulfuric acid mist and fluorides, were 0.024 and 0.086 lb/MMBtu, respectively. Cedar Bay proposed to utilize the operation of the CFB boilers, including limestone injection, to control sulfur dioxide and acid gas emissions. The emission limitation for SO₂ in the electric utility steam generating unit NSPS (40 CFR 60, Subpart Da) is 0.6 lb/MMBtu and 70% reduction, thus the proposed emission rates were in conformance with the NSPS. In response, Florida DER staff concurred with the applicant's analysis that neither add-on controls nor lower sulfur coal were economically feasible, and consequently included these emission limits in the Conditions of Certification. To satisfy the Siting Board's concerns over Cedar Bay, as permitted, which did not address the adequacy of Cedar Bay's emission limitation for acid gases, AES proposed to lower the SO₂ emission limit to 0.24 lb/MMBtu (12-hour average). The Siting Board's Order of June 16, 1992, reflects a preliminary acceptance of this new emission limitation in partial satisfaction of its concerns.

The Cedar Bay Cogeneration Project proposes to further lower the emission limitations for SO₂ to 0.2 lb/MMBtu (annual average) and 0.24 lb/MMBtu (3-hour average), for sulfuric acid mist to 0.016 lb/MMBtu, and for fluorides to 8.54×10^{-4} lb/MMBtu, and to meet these lower emission rates using lower sulfur coal, limestone injection and CFB boiler operation. These are considered the lowest achievable emission rates for these pollutants for these units firing the contracted coal.

Control of SO₂ and acid gases is inherent to CFB operation. Second generation fluidized bed combustors were developed specifically to utilize domestic coal in an environmentally acceptable manner. In a circulating fluidized bed, sulfur released from the fuel is removed in the combustion zone by reaction with lime. Thus, the control of acid gases is integral to CFB operation and does not rely on downstream flue gas desulfurization.

Crushed limestone is fed to a CFB combustor, becoming the solid medium in which coal combustion takes place. When limestone is heated to 1600°F, it releases CO₂ and forms lime (CaO) which subsequently reacts with acid gases released from the burning coal to form gypsum (CaSO₄). Theoretically, one mole of sulfur (or fluorine) combines with one mole of calcium; in theory 100% SO₂ removal could be achieved with a Ca/S ratio of 1:0. In practice, however, the desulfurization process yields less than ideal reactivity, and it has been found that only about 50% of the SO₂ is removed at this ratio. As the ratio is increased, greater desulfurization can be achieved, but with diminishing return.

The technical factors related to in-bed acid gas (SO₂, H₂SO₄, HF) control with limestone include calcium to sulfur (Ca/S) ratio, reactivity of limestone, particle size, fuel properties, mixing, and gas phase residence time. To a certain extent, these factors are related in that they are dependent on physical characteristics of the fuel and limestone used. For instance, a certain limestone may exhibit high reactivity, based on particle pore size and hardness, regardless of calcium content.

Limestone reactivity is thought to depend on the ability of acid gases to reach the center of a particle. Soft limestones tend to abrade, exposing fresh surfaces. Thus, it has been found that reactivity for a given limestone can only be determined as a result of actual combustion testing. Some fuel types have been found to contain impurities which may blind the limestone, lowering its reactivity. Further, the fuel sulfur content will impact desulfurization efficiency and Ca/S ratio. The removal of SO₂ and acid gases in a CFB requires contact between each molecule of acid gas and each unreacted particle of lime. Since the boiler has a limited gas residence time, lime and acid gas molecules thus have a limited time to chemically combine. When flue gas acid gases are in low concentrations, it is far more difficult for the acid gas molecules to find an active lime site in the time available, and a greater percentage escape the boiler without reacting. In this case with low sulfur coal and low SO₂ concentrations, the acid gas removal percentage may be lower than at high inlet SO₂ concentrations, even though the emissions on a mass/heat input basis will always be lower for lower sulfur fuels.

The proposed level of control was determined based on the minimum and maximum coal sulfur and fluorine contents expected from the coal supplier, and the corresponding maximum degree of acid gas capture. The emission levels (0.2 lb SO₂/MMBtu annual average, 0.24 lb SO₂/MMBtu 3-hr average, 8.54 x 10⁻⁴ lb HF/MMBtu, 0.016 lb H₂SO₄/MMBtu) are thus the lowest levels which can be achieved with this alternative on this facility.

4.5.3 Limestone Dryers

After FDER staff reported that the H₂SO₄ and fluorides emissions from the limestone dryers were negligible, the air permit still included an emission limit of 5.0 lb/hr per dryer for these pollutants. This emission limitation was not an issue in the Siting Board's Order on June 16, 1992.

The Cedar Bay Cogeneration Project is proposing to utilize low sulfur oil in conjunction with direct contact between limestone and air heater exhaust to achieve an emission rate of 5.0 lb/hr for SO₂ from each limestone dryer, and 0.11 lb/hr per dryer for sulfuric acid mist. Total annual emission rate from the limestone dryers will be less than 14.6 tons SO₂/yr and 0.96 tons H₂SO₄/yr. In comparison, annual SO₂ and H₂SO₄ emissions from the Cedar Bay CFB boilers will be less than 2,388.5 tons/yr and 207.8 tons/yr, respectively. Thus, the limestone dryers' emissions of H₂SO₄ and fluorides are negligible.

No emissions of hydrogen fluorides are expected from the limestone dryers. In the proposed systems, SO₂ and sulfuric acid mist emissions will be controlled by a combination of firing low sulfur fuel in the air heaters and direct contact of the air heater exhaust with limestone. As in the CFB boiler, direct contact of the exhaust with limestone is expected to result in reduced emissions, when compared to non-direct contact drying. These measures will limit SO₂ and

sulfuric acid mist emissions to a maximum of 5 lb/hr and 0.11 lb/hr per dryer, respectively, are considered to be the most stringent available control alternative, and are thus concluded to be appropriate for control of SO₂ and sulfuric acid mist emissions from the limestone dryers.

4.6 Mercury

4.6.1 Circulating Fluidized Bed Boilers

4.6.2 Introduction

Trace quantities of mercury are present in coal, and most of this mercury is expected to volatilize during combustion. Approximately two-thirds of the mercury content in the flue gas exits as solid mercuric chloride (HgCl₂); the other third is exhausted as elemental mercury vapor (Flakt, 1990). Mercury is expected to condense upon submicron particles contained in the flue gas and exit as either condensed aerosol or solid mercuric chloride and be controlled by the fabric filter. Some of the vapor is expected to be emitted.

For mercury, the site certification application recommended the use of fabric filtration for control of emissions, and an emission rate of 0.00026 lb/MMBtu. In response, DER staff concurred with this recommendation, and FDER wrote this limit into the Air Permit for Cedar Bay. To satisfy the Siting Board's concerns over Cedar Bay, as permitted, which did not address the adequacy of Cedar Bay's emission limitation for mercury, however, AES proposed to lower the mercury emission limit by about 88% and to test an innovative technology that might produce further reductions. The Siting Board's Order of June 16, 1992, reflects a preliminary acceptance of this new approach in partial satisfaction of its concerns.

The Cedar Bay Cogeneration Project has evaluated the anticipated control efficiency for mercury from the fabric filter and the levels of mercury in the contracted coal. Based on these evaluations, it is proposing to meet this lower emission limitation of 3.04×10^{-5} lb/MMBtu using fabric filtration. In addition, the Cedar Bay Cogeneration Project proposes testing activated carbon injection on one of the CFB boilers and install this control alternative permanently on all three CFB boilers if the test is successful, as described further below.

4.6.2.1 Control Alternatives

Programs to assess the relative advantages and disadvantages of alternative pollution control devices on mercury collection from coal combustion have only recently begun. However, test data is available from programs to determine the best system of trace metals control from municipal waste combustors (MWCs), in conjunction with the recently promulgated new source

performance standard for these sources; these data are currently more complete than any other data available in the published literature and as such are considered the best representation of mercury control from combustion sources in general. Even for this more complete data set, there are major uncertainties. As detailed further below, understanding mercury emissions from CFB's firing coal are further clouded by the differences in the concentration of mercury in the respective flue gases.

Potential control alternatives for mercury include:

- Sodium sulfide injection upstream of SO₂/PM control devices
- Activated carbon injection upstream of fabric filter
- Wet scrubbing techniques
- Spray dryer followed by a fabric filter
- Flue gas cooling

At this time, EPA is not clear on which control alternative best reduces mercury emissions from any combustion process (Porter, 1990) or which operating variables in the combustor influence alternative controls' performance. Recognizing this, the EPA stated in the preamble to the proposed NSPS for MWCs that a joint EPA/industry task force is being established to investigate mercury emissions and controls, and that the findings would be considered in development of the final standards (EPA 1989b).

As part of the effort of the joint task force, two meetings were held at Research Triangle Park in February 1990 to discuss both "precombustion" controls of mercury emissions and add-on control of mercury emissions. It is evident from the meetings' transcripts that there are not only numerous unknowns regarding mercury formation and control, but there are some valid side issues that must also be resolved before the subject can be understood and the MWC NSPS for Hg fairly promulgated.

Some of the key issues raised in the meetings were:

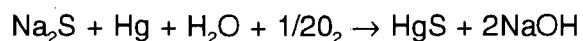
- the potential of NO_x controls by ammonia injection to reduce mercury control efficiencies of downstream (fabric filter) systems;

- the relationship between the amount of carbon in the flue gas and the amount of mercury control, and whether this is more influential on mercury emissions than NO_x controls;
- the conversion of mercuric chloride on the filter cake to mercury vapor over time;
- reliability of current test methods;
- the inconsistencies in test data between the U.S. and European facilities (which use different test methods)
- lack of data on mercury content of ash, effects of add-on mercury control to ash toxicity and possible outgassing;
- contradictory data and general variability of data;
- the overemphasis on mercury control from MWCs;
- establishing which mercury control systems are "demonstrated"; and
- how to handle all the work activities at the U.S. EPA prior to promulgation with limited resources.

The following provides more information on the controls discussed by the EPA/industry task force.

4.6.2.2 Sodium Sulfide Injection

For combustion units utilizing spray drying/absorption (SDA) for control of SO₂ emissions, sodium sulfide (Na₂S) can be sprayed into the gas stream as a 10 percent water solution, either upstream of or in the spray dryer. The mercury vapor is converted to solid mercuric sulfide according to the following reaction:



The resulting solids are collected in the baghouse or ESP as particulate. (Buschmann, 1990). Since the Cedar Bay CFB boilers do not employ SDA's, this alternative is not feasible in this case.

4.6.2.3 Activated Carbon Injection

Injecting activated carbon or a modified activated carbon material into the flue gas upstream of the fabric filter may achieve mercury emissions reductions. There are, however, currently no CFB units operating which employ activated carbon injection. Activated carbon injection systems are listed as being offered commercially by A/S Niro Atomizer of Denmark and Research Cottrell for use on MSW incinerators. There are no vendors offering such systems for use on CFB boilers.

On MSW plants, carbon injection may achieve sizeable mercury reductions, as shown by two sets of test data in the Niro patent. In three pilot-test runs, injection of 80 mg/Nm³ in flue gas at a location between the SDA and fabric filter resulted in overall mercury reductions of 89 percent (230°F run), 95 percent (230°F run), and 91 percent (284°F run). Mercury reductions with no carbon injection (fabric filter only) were still sizeable, however, at about 69 percent.

On full-size MWCs tests, 78 to 93 percent mercury reductions were achieved with carbon injection. However, data from these tests indicate mercury removals of 66 to 27 percent with the carbon injection system off, and utilizing only the fabric filter for mercury control. This implies that mercury control attributable to the carbon injection system was on the order of 75% of inlet mercury.

Comparisons between the potential effectiveness of this alternative on MSW plants vs CFB plants are necessarily inconclusive due to the difference in flue gas mercury concentrations. The air permit for Cedar Bay's CFBs limits mercury emissions to 3.04×10^{-5} lb/MMBtu which converts to approximately 15 ug/dscm, while MSW plants typically operate with mercury levels of 510 ug/dscm (EPA 1989d). Since programs to assess the effect of this difference have only recently begun, and considering the fact that this alternative has not been installed on a CFB boiler, carbon injection systems are consequently not considered to be demonstrated effective emission controls on CFB boilers.

4.6.2.4 Wet Scrubbing Techniques

There is a general opinion in the scientific community that because of the saturated operating conditions and cooler flue gas temperatures in wet scrubbing, better mercury condensation and collection should occur than in dry systems. The NJDEP tested the efficiency of mercury removal at the small scale resource recovery facility in Ft. Dix, New Jersey, which uses a baghouse upstream of a wet scrubber. Using EPA Test Method 101A, the removal efficiency ranged over three test runs between 16.6 percent and 74.9 percent (average 42.8 percent). Not only was the variability in test results similar to that observed in SDA/FF-equipped MWC facilities, less mercury

was removed with wet scrubbing compared to SDA/FF. These test data do not support use of wet scrubbers for control of mercury from coal-fired facilities.

4.6.2.5 Flue Gas Cooling

Flue gas cooling has been considered essential for Hg removal because Hg typically enters the control equipment as a vapor. Test data available for MWCs both support and refute this theory. Env. Canada and Flakt reported mercury reduction of 40 percent when flue gas was cooled to 289°F (Env. Canada, 1987). Environment Canada also reported (1986) data that are more inconclusive. Over two test runs for each temperature, mercury reductions were 90.9% (230°F), 97.3% (257°F) and, 93.7% (284°F). The lowest flue gas temperature achieved the lowest percent mercury control. Tests conducted in June 1989 at Ogden Martin's Indianapolis Resource Recovery Facility, which uses a spray dryer/fabric filter control system, indicate that measured emissions of mercury were well below the expected levels. Mercury removal efficiency was measured at spray dryer outlet temperatures of 265 and 295°F. The study concluded that lowering the spray dryer outlet temperature by 25°F has no significant impact on the mercury stack emission. Ogden Martin has also conducted tests at one of its facilities and has observed no "discernible" reductions at a temperature of 285°F versus 325°F. Therefore, operating at temperatures below 325°F does not appear to be warranted.

Because it is questionable whether flue gas cooling achieves considerable, if any, mercury control, flue gas cooling to temperatures such as 285 to 325°F is not considered appropriate for the proposed project.

4.6.2.6 CFB Mercury Conclusion

There are many questions yet to be answered mercury formation and control. However, a well-operated and maintained limestone injection/fabric filter control train (a control train providing high mercury removal efficiencies) is proposed for mercury control since no clear evidence exists that there is a more stringent control alternative available.

The Cedar Bay Cogeneration Project has agreed to conduct a test of the activated carbon injection system on one of the Cedar Bay CFB boilers. This test will be used to determine if this process is capable of controlling mercury emissions from these boilers. If the test shows reductions of controlled emissions (after the fabric filter) of an additional 50% or greater, the Cedar Bay Cogeneration Project has agreed to permanently install and operate the process on all three boilers.

4.6.3 Limestone Dryers

After FDER staff reported that the heavy metal emissions from the limestone dryers were negligible, the Air Permit did not include an emission limit for mercury from this source.

The mercury emissions from the limestone dryers will be negligible since the Cedar Bay Cogeneration Project will use fabric filtration to achieve an emission rate of 5.11×10^{-5} lb/hr for mercury from each limestone dryer, with a total annual emission rate of less than 1.49×10^4 tons mercury/yr.

Since the measures to control the mercury emissions are the only available alternative, they are proposed as appropriate control of mercury emissions from the limestone dryers.

4.7 Radionuclides

Coal-fired facilities release trace amounts of radioactive elements to the atmosphere from naturally occurring radionuclides present in the fuel. The radionuclides that are associated with emissions from coal combustion are potassium-40 (K^{40}), uranium-235 (U^{235}) and decay products, uranium-238 (U^{238}) and decay products, and thorium-232 (Th^{232}) and decay products.

K^{40} is present as a fixed proportion of naturally occurring potassium. The U^{235} decay series contributes only a small fraction of the radioactivity of the U^{238} and Th^{232} decay series; most of the radioactive emissions from a coal-fired plant come from the U^{238} and Th^{232} series. Control of radionuclides for coal-fired boilers is the same as control of particulate matter: fabric filter.

For the proposed Cedar Bay boilers, it is estimated that approximately 2.2×10^2 curies/year of Th^{232} and U^{238} (combined) will be emitted. Since radionuclides will be emitted as particulate matter, these emission estimates are based on the projected controlled PM emissions.

On December 15, 1989, EPA released the final rule for the National Emissions Standards for Hazardous Air Pollutants (NESHAPs) for radionuclides (54 FR 51654). In that ruling, EPA announced its decision not to further control radionuclides from coal-fired power plants since the risk that they pose is so small that it is below the assumed safe level.

Since the emissions of radionuclides from coal combustion are emitted as particulate matter, the particulate control device (fabric filter) will also control radionuclide emissions. Use of a fabric filter to control emissions of radionuclides incurs no additional economic impact, has no adverse energy or environmental impacts, and is technologically demonstrated. Fabric filtration thus can be concluded to be an appropriate control for radionuclide emissions from the Cedar Bay CFB boilers.

No data is available in the open literature which shows that there are radionuclide emissions from oil combustion, such as for the limestone dryers.

4.8 Volatile Organic Compounds

4.8.1 Introduction

As with emissions of CO, emissions of volatile organic compounds (VOCs) result from the incomplete combustion of carbon and organic compounds, and are a function of oxygen availability, temperature, residence time, and turbulence. VOCs are controlled in two ways: (1) controlling combustion parameters in order to maximize complete combustion, and (2) flue gas catalytic oxidation.

4.8.2 Circulating Fluidized Bed Boilers

For VOC, the Site Certification Application recommended the use of boiler design and combustion controls for minimization of VOC formation to a level 0.016 lb/MMBtu. In response, Florida DER staff concurred with this recommendation, however the Air Permit established the emission rate at 0.015 lb/MMBtu. To satisfy the Siting Board's concerns over Cedar Bay as permitted, which did not address the adequacy of Cedar Bay's emission limitation for VOCs, AES proposed to lower the emission limitations for other pollutants. The Siting Board Order of June 16, 1992 reflects a preliminary acceptance of this approach to retaining the VOC emission limitation.

The Cedar Bay Cogeneration Project proposes to achieve this emission rate using boiler design and combustion controls; based on information from the boiler vendor, the emission level of 0.015 lb/MMBtu is the lowest achievable emission rate which is technologically feasible for the Cedar Bay CFB boilers.

As described previously in the discussion for CO, catalytic oxidation is not technically feasible on coal-fired boilers. Thus, the only technically feasible control alternative is combustion control.

The boiler supplier for the Cedar Bay project has offered an emission guarantee of 0.015 lb VOC/MMBtu for this project. According to the vendor, this is the lowest the boilers can meet on a consistent basis. This emission rate is considered the lowest achievable for Cedar Bay since there is no technically feasible alternative which could be employed to allow Cedar Bay to meet a lower emission limit, in particular there are physical and operational limitations on Cedar Bay which preclude this project from achieving any lower emission rates.

Although the Cedar Bay CFB boilers will employ the same means to minimize formation of VOC as other CFB boilers, as described earlier in Section 4.3, the Cedar Bay CFB boilers will operate at different conditions than originally designed. Since the change in operating conditions will affect both combustion temperature and residence time, it is anticipated that emissions of VOC will be affected. However, there are no other boilers with which a direct comparison of emission limits can be made since there are no other boilers of the same size and type as Cedar Bay which are operating at the same rate. Consequently, there is no clear evidence, apart from vendor guarantees, which could be utilized to define a feasible emission rate for VOC.

Since the proposed boilers will employ the same alternative controls permitted for VOC, and the proposed level of emissions is the lowest level possible given the fuel being fired, the boiler size, and the operating conditions, 0.015 lb/MMBtu is considered the lowest VOC emission rate that Cedar Bay can achieve.

4.8.3 Limestone Dryers

Although FDER staff reported that the VOC emissions from the limestone dryers were negligible, the Air Permit still included an emission rate of 0.05 lb/hr VOC per dryer. This emission limit was not an issue in the Siting Board's Order of June 16, 1992.

The Cedar Bay Cogeneration Project is proposing to use combustion controls to achieve an emission rate of 0.05 lb/hr for VOC from each limestone dryer, with a total annual emission rate of less than 0.15 tons VOC/yr. For comparison, annual emissions of VOC from the CFB boilers are estimated at less than 179.2 tons/yr. Thus, the limestone dryers' emissions of VOCs are negligible.

The most stringent available alternative for control of this pollutant from these sources is considered to be the use of burners which maximize complete combustion, which will result in minimization of formation of VOC. Such burners, which will be utilized in the proposed facility, are thus concluded to be appropriate for control of VOC.

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