Stone Container Corporation
Containerboard and Paper Division

P.O. Box 26998
Jacksonville, Florida 32226-6998
904-751-6400

RECEIVED

JUL 06 1998

BUREAU OF
AIR REGULATION

July 2, 1998

Mr. A. A. Linero, P.E.
Division of Air Resources Management
Florida Department of Environmental Protection
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Re: **Stone Container Corporation, Jacksonville Mill**
Proposed Package Boilers Steam Rate Increase

0310067-004-AC
PSD-FL-252

Dear Mr. Linero;

Please find enclosed with this letter a request to raise the permitted steam rates for the three package boilers located at our Jacksonville mill. Due to the potential increase in actual emissions, the project will be subject to prevention of significant deterioration (PSD) new source review. Four (4) copies of the air construction permit application are attached. Attached also is the permit review fee of $7,500.

Please call if you need any additional information in order to issue a permit for this request.

Sincerely,

STONE CONTAINER CORPORATION
Jacksonville Mill

John L. West,
General Manager

cc: S. Arif, BAR
NED
Duval Co
EPA
NPS
C. Holladay, BAR

/maa

Stone Container Corporation

invoice date/account	invoice reference	invoice amount	discount	net amount
6/18/98	061898 F 4503	7500.00	.00	7500.00
				$7500.00*

detach before presenting check for payment

CHECK IS VOID IF COLORED BACKGROUND IS ABSENT

Stone Container Corporation
9469 Eastport Road • Jacksonville, Florida 32218

NationsBank
Atlanta, Georgia

128239

64-1278
611

date
7/03/98

***7500 dollars and *****00 cents

amount
$7,500.00

PAY
to the order of

FL. DEPART. OF ENVIR. PROTECT.
TWIN TOWERS OFFICE BLDG
2600 BLAIR STONE ROAD
TALLAHASSE FL 323992400

Stone Container Corporation

David P. Ledbetter

⑈128239⑈ ⑆061112788⑆ 010 118 2328⑈

PSD APPLICATION
FOR
BOILER STEAM RATE INCREASE
STONE CONTAINER CORP.
JACKSONVILLE, FLORIDA

Prepared For:

Stone Container Corp.
9469 East Port Road
Jacksonville, Florida 32229

Prepared By:

Golder Associates Inc.
6241 NW 23rd Street, Suite 500
Gainesville, Florida 32653-1500

June 1998
9837525Y\F1

Department of
Environmental Protection

DIVISION OF AIR RESOURCES MANAGEMENT

APPLICATION FOR AIR PERMIT - LONG FORM

See Instructions for Form No. 62-210.900(1)

I. APPLICATION INFORMATION

This section of the Application for Air Permit form identifies the facility and provides general information on the scope and purpose of this application. This section also includes information on the owner or authorized representative of the facility (or the responsible official in the case of a Title V source) and the necessary statements for the applicant and professional engineer, where required, to sign and date for formal submittal of the Application for Air Permit to the Department. If the application form is submitted to the Department using ELSA, this section of the Application for Air Permit must also be submitted in hard-copy.

Identification of Facility Addressed in This Application

Enter the name of the corporation, business, governmental entity, or individual that has ownership or control of the facility; the facility site name, if any; and the facility's physical location. If known, also enter the facility identification number.

1. Facility Owner/Company Name: **Stone Container Corporation**	
2. Site Name: **Stone Container Corp - Jacksonville Mill**	
3. Facility Identification Number: **0310067** [ ] Unknown	
4. Facility Location Information: Street Address or Other Locator: **9469 East Port Road** City: **Jacksonville** County: **Duval** Zip Code: **32229**	
5. Relocatable Facility? [ ] Yes [x] No	6. Existing Permitted Facility? [x] Yes [ ] No

Application Processing Information (DEP Use)

1. Date of Receipt of Application:	July 6, 1998
2. Permit Number:	0310067-004-AC
3. PSD Number (if applicable):	PSD-FL-252
4. Siting Number (if applicable):	

Owner/Authorized Representative or Responsible Official

1. Name and Title of Owner/Authorized Representative or Responsible Official: **John L. West, General Manager**
2. Owner/Authorized Representative or Responsible Official Mailing Address: Organization/Firm: **Stone Container Corporation** Street Address: **PO Box 26998** City: **Jacksonville** State: **FL** Zip Code: **32226-6998**
3. Owner/Authorized Representative or Responsible Official Telephone Numbers: Telephone: **(904) 751-6400** Fax: **(904) 751-5172**
4. Owner/Authorized Representative or Responsible Official Statement: *I, the undersigned, am the owner or authorized representative* of the non-Title V source addressed in this Application for Air Permit or the responsible official, as defined in Rule 62-210.200, F.A.C., of the Title V source addressed in this application, whichever is applicable. I hereby certify, based on information and belief formed after reasonable inquiry, that the statements made in this application are true, accurate and complete and that, to the best of my knowledge, any estimates of emissions reported in this application are based upon reasonable techniques for calculating emissions. The air pollutant emissions units and air pollution control equipment described in this application will be operated and maintained so as to comply with all applicable standards for control of air pollutant emissions found in the statutes of the State of Florida and rules of the Department of Environmental Protection and revisions thereof. I understand that a permit, if granted by the Department, cannot be transferred without authorization from the Department, and I will promptly notify the Department upon sale or legal transfer of any permitted emissions unit.* Signature Date 7/2/98

* Attach letter of authorization if not currently on file.

Scope of Application

This Application for Air Permit addresses the following emissions unit(s) at the facility. An Emissions Unit Information Section (a Section III of the form) must be included for each emissions unit listed.

Emissions Unit ID		Description of Emissions Unit	Permit Type
Unit #	Unit ID		
1R	022	Package Boiler No. 1	AC1A
2R	023	Package Boiler No. 2	AC1A
3R	026	Package Boiler No. 3	AC1A

See individual Emissions Unit (EU) sections for more detailed descriptions.
Multiple EU IDs indicated with an asterisk (*). Regulated EU indicated with an "R".

Purpose of Application and Category

Check one (except as otherwise indicated):

Category I: All Air Operation Permit Applications Subject to Processing Under Chapter 62-213, F.A.C.

This Application for Air Permit is submitted to obtain:

[ ] Initial air operation permit under Chapter 62-213, F.A.C., for an existing facility which is classified as a Title V source.

[ ] Initial air operation permit under Chapter 62-213, F.A.C., for a facility which, upon start up of one or more newly constructed or modified emissions units addressed in this application, would become classified as a Title V source.

Current construction permit number: ______________________________

[ ] Air operation permit renewal under Chapter 62-213, F.A.C., for a Title V source.

Operation permit to be renewed: ______________________________

[ ] Air operation permit revision for a Title V source to address one or more newly constructed or modified emissions units addressed in this application.

Current construction permit number: ______________________________

Operation permit to be renewed: ______________________________

[ ] Air operation permit revision or administrative correction for a Title V source to address one or more proposed new or modified emissions units and to be processed concurrently with the air construction permit application. Also check Category III.

Operation permit to be revised/corrected: ______________________________

____

[ ] Air operation permit revision for a Title V source for reasons other than construction or modification of an emissions unit. Give reason for the revision e.g., to comply with a new applicable requirement or to request approval of an "Early Reductions" proposal.

Operation permit to be revised: ______________________________

Reason for revision: ______________________________

____

Category II: All Air Construction Permit Applications Subject to Processing Under Rule 62-210.300(2)(b),F.A.C.

This Application for Air Permit is submitted to obtain:

[ ] Initial air operation permit under Rule 62-210.300(2)(b), F.A.C., for an existing facility seeking classification as a synthetic non-Title V source.

Current operation/construction permit number(s): ______

[ ] Renewal air operation permit under Rule 62-210.300(2)(b), F.A.C., for a synthetic non-Title V source.

Operation permit to be renewed: ______

[ ] Air operation permit revision for a synthetic non-Title V source. Give reason for revision; e.g.; to address one or more newly constructed or modified emissions units.

Operation permit to be revised: ______

Reason for revision: ______

Category III: All Air Construction Permit Applications for All Facilities and Emissions Units.

This Application for Air Permit is submitted to obtain:

[x] Air construction permit to construct or modify one or more emissions units within a facility (including any facility classified as a Title V source).

Current operation permit number(s), if any: ______
N/A

[ ] Air construction permit to make federally enforceable an assumed restriction on the potential emissions of one or more existing, permitted emissions units.

Current operation permit number(s): ______

[ ] Air construction permit for one or more existing, but unpermitted, emissions units.

Application Processing Fee

Check one:

[x] Attached - Amount: $ 7,500.00   [ ] Not Applicable.

Construction/Modification Information

1. Description of Proposed Project or Alterations: **Increase in maximum permitted steam rate for Package Boilers Nos. 1-3 from 125,000 lb/hr to 150,000 lb/hr steam.**
2. Projected or Actual Date of Commencement of Construction : **1 Jun 1998**
3. Projected Date of Completion of Construction : **1 Jun 1998**

Professional Engineer Certification

1. Professional Engineer Name: **David A. Buff** Registration Number: **19011**
2. Professional Engineer Mailing Address: Organization/Firm: **Golder Associates Inc.** Street Address: **6241 NW 23 rd Street, Suite 50** City: **Gainesville** State: **FL** Zip Code: **32653-1500**
3. Professional Engineer Telephone Numbers: Telephone: **(352) 336-5600** Fax: **(352) 336-6603**

4. Professional Engineer's Statement:

I, the undersigned, hereby certify, except as particularly noted herein, that:*

(1) To the best of my knowledge, there is reasonable assurance that the air pollutant emissions unit(s) and the air pollution control equipment described in this Application for Air Permit, when properly operated and maintained, will comply with all applicable standards for control of air pollutant emissions found in the Florida Statutes and rules of the Department of Environmental Protection; and

(2) To the best of my knowledge, any emission estimates reported or relied on in this application are true, accurate, and complete and are either based upon reasonable techniques available for calculating emissions or, for emission estimates of hazardous air pollutants not regulated for an emissions unit addressed in this application, based solely upon the materials, information and calculations submitted with this application.

If the purpose of this application is to obtain a Title V source air operation permit (check here [ ] if so), I further certify that each emissions unit described in this Application for Air Permit, when properly operated and maintained, will comply with the applicable requirements identified in this application to which the unit is subject, except those emissions units for which a compliance schedule is submitted with this application.

If the purpose of this application is to obtain an air construction permit for one or more proposed new or modified emissions units (check here [X] if so), I further certify that the engineering features of each such emissions unit described in this application have been designed or examined by me or individuals under my direct supervision and found to be in conformity with sound engineering principles applicable to the control of emissions of the air pollutants characterized in this application.

If the purpose of this application is to obtain an initial air operation permit or operation permit revision for one or more newly constructed or modified emissions units (check here [ ] if so), I further certify that, with the exception of any changes detailed as part of this application, each such emissions unit has been constructed or modified in substantial accordance with the information given in the corresponding application for air construction permit and with all provisions contained in such permit.

David a. Buff — 6/17/98

Signature (seal) — Date

* Attach any exception to certification statement.

Application Contact

1. Name and Title of Application Contact: **Joe Eskridge, Environmental Engineer**	
2. Application Contact Mailing Address: Organization/Firm: **Stone Container Corporation** Street Address: **PO Box 26998** City: **Jacksonville** State: **FL** Zip Code: **32226-6998**	
3. Application Contact Telephone Numbers: Telephone: **(904) 751-6400** Fax: **(904) 751-5822**	

Application Comment

II. FACILITY INFORMATION

A. GENERAL FACILITY INFORMATION

Facility Location and Type

1. Facility UTM Coordinates: Zone: 17 East (km): 442.4 North (km): 3365.4			
2. Facility Latitude/Longitude: Latitude (DD/MM/SS): 30 / 25 / 15 Longitude: (DD/MM/SS): 81 / 36 / 0			
3. Governmental Facility Code: 0	4. Facility Status Code: A	5. Facility Major Group SIC Code: 26	6. Facility SIC(s): 2621
7. Facility Comment (limit to 500 characters):			

Facility Contact

1. Name and Title of Facility Contact: Joe Eskridge, Environmental Engineer
2. Facility Contact Mailing Address: Organization/Firm: Stone Container Corporation Street Address: PO Box 26998 City: Jacksonville State: FL Zip Code: 32226-6998
3. Facility Contact Telephone Numbers: Telephone: (904) 751=6400 Fax: (904) 751-5822

Facility Regulatory Classifications

1. Small Business Stationary Source?		
[ ] Yes	[x] No	[ ] Unknown
2. Title V Source?		
[x] Yes	[ ] No	
3. Synthetic Non-Title V Source?		
[ ] Yes	[x] No	
4. Major Source of Pollutants Other than Hazardous Air Pollutants (HAPs)?		
[x] Yes	[ ] No	
5. Synthetic Minor Source of Pollutants Other than HAPs?		
[ ] Yes	[x] No	
6. Major Source of Hazardous Air Pollutants (HAPs)?		
[x] Yes	[ ] No	
7. Synthetic Minor Source of HAPs?		
[ ] Yes	[x] No	
8. One or More Emissions Units Subject to NSPS?		
[x] Yes	[ ] No	
9. One or More Emissions Units Subject to NESHAP?		
[x] Yes	[ ] No	
10. Title V Source by EPA Designation?		
[ ] Yes	[x] No	
11. Facility Regulatory Classifications Comment (limit to 200 characters): **Fac. is potentially subject to 40 CFR 61, Subpart M-NESHAP for Asbestos. Fac. is major source of HAPs due to potential methanol emissions. If methanol is delisted as a HAP, fac. will be minor source.**		

B. FACILITY REGULATIONS

<u>Rule Applicability Analysis</u> (Required for Category II applications and Category III applications involving non Title-V sources. See Instructions.)

List of Applicable Regulations (Required for Category I applications and Category III applications involving Title-V sources. See Instructions.)

Not Applicable

C. FACILITY POLLUTANTS

Facility Pollutant Information

1. Pollutant Emitted		2. Pollutant Classification
HAPs	Total Hazardous Air Pollutants	A
H115	Methanol	A
SO2	Sulfur Dioxide	SM
NOx	Nitrogen Oxides	A

D. FACILITY POLLUTANT DETAIL INFORMATION

Facility Pollutant Detail Information:

1. Pollutant Emitted:		
2. Requested Emissions Cap:	(lb/hr)	(tons/yr)
3. Basis for Emissions Cap Code:		
4. Facility Pollutant Comment (limit to 400 characters):		

Facility Pollutant Detail Information:

1. Pollutant Emitted:		
2. Requested Emissions Cap:	(lb/hr)	(tons/yr)
3. Basis for Emissions Cap Code:		
4. Facility Pollutant Comment (limit to 400 characters):		

E. FACILITY SUPPLEMENTAL INFORMATION

Supplemental Requirements for All Applications

1. Area Map Showing Facility Location:
   [x] Attached, Document ID: SCC-FE-1
   [ ] Not Applicable [ ] Waiver Requested

2. Facility Plot Plan:
   [x] Attached, Document ID: SCC-FE-2
   [ ] Not Applicable [ ] Waiver Requested

3. Process Flow Diagram(s):
   [x] Attached, Document ID(s): SCC-FE-3
   [ ] Not Applicable [ ] Waiver Requested

4. Precautions to Prevent Emissions of Unconfined Particulate Matter:
   [ ] Attached, Document ID: ____
   [x] Not Applicable [ ] Waiver Requested

5. Fugitive Emissions Identification:
   [ ] Attached, Document ID: ____
   [x] Not Applicable [ ] Waiver Requested

6. Supplemental Information for Construction Permit Application:
   [x] Attached, Document ID: Attachment A
   [ ] Not Applicable

Additional Supplemental Requirements for Category I Applications Only

7. List of Proposed Exempt Activities:
   [ ] Attached, Document ID: ____
   [ ] Not Applicable

8. List of Equipment/Activities Regulated under Title VI:
   [ ] Attached, Document ID: ____
   [ ] Equipment/Activities On site but Not Required to be Individually Listed
   [ ] Not Applicable

9. Alternative Methods of Operation:
   [ ] Attached, Document ID: ____
   [ ] Not Applicable

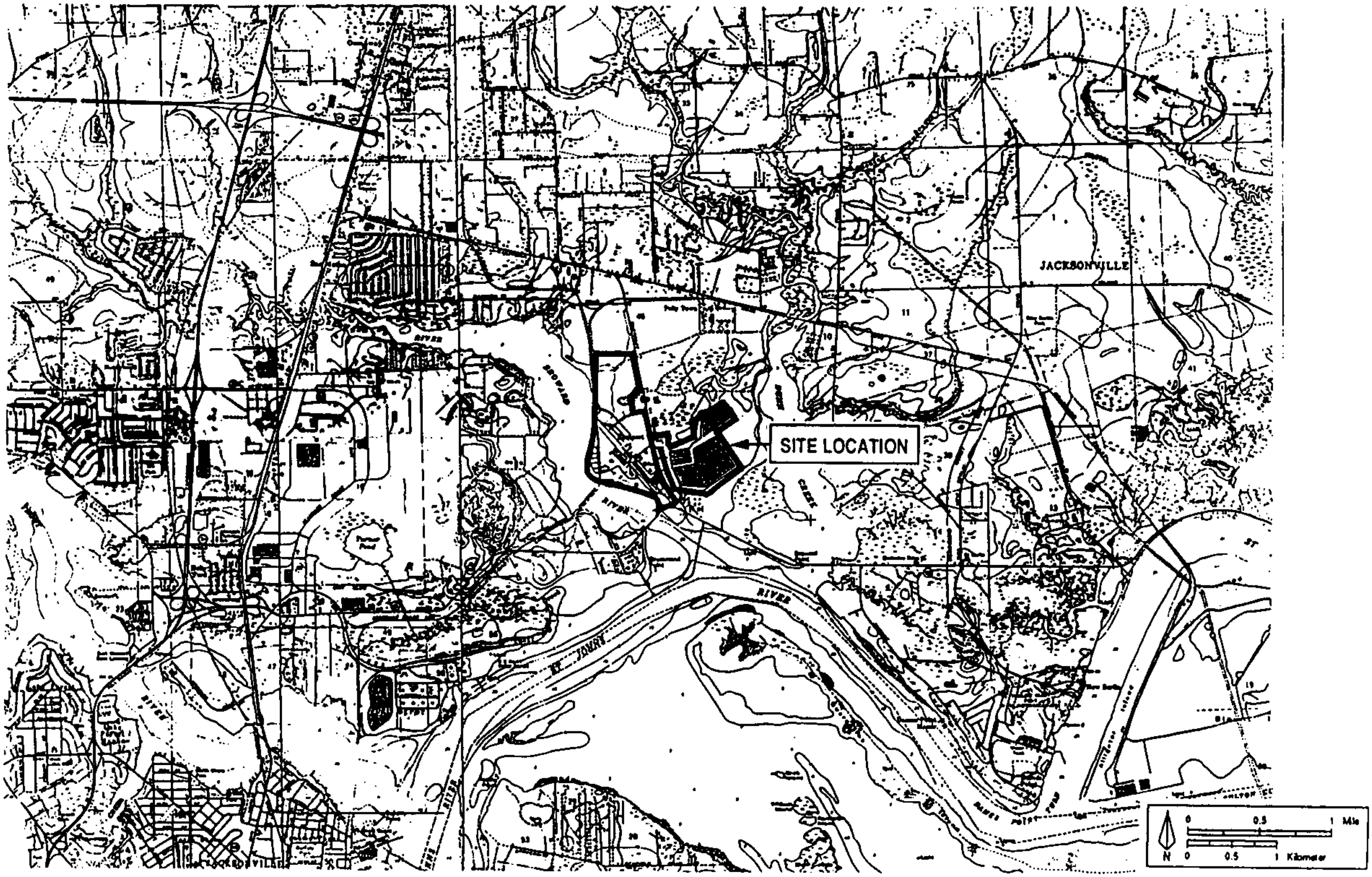
10. Alternative Modes of Operation (Emissions Trading):
    [ ] Attached, Document ID: ____
    [ ] Not Applicable

11. Identification of Additional Applicable Requirements: [ ] Attached, Document ID: ____________ [ ] Not Applicable
12. Compliance Assurance Monitoring Plan: [ ] Attached, Document ID: ____________ [ ] Not Applicable
13. Risk Management Plan Verification: [ ] Plan Submitted to Implementing Agency - Verification Attached Document ID: ____________ [ ] Plan to be Submitted to Implementing Agency by Required Date [ ] Not Applicable
14. Compliance Report and Plan [ ] Attached, Document ID: ____________ [ ] Not Applicable
15. Compliance Statement (Hard-copy Required) [ ] Attached, Document ID: ____________ [ ] Not Applicable

ATTACHMENT SCC-FE-1

AREA MAP

03-24-98



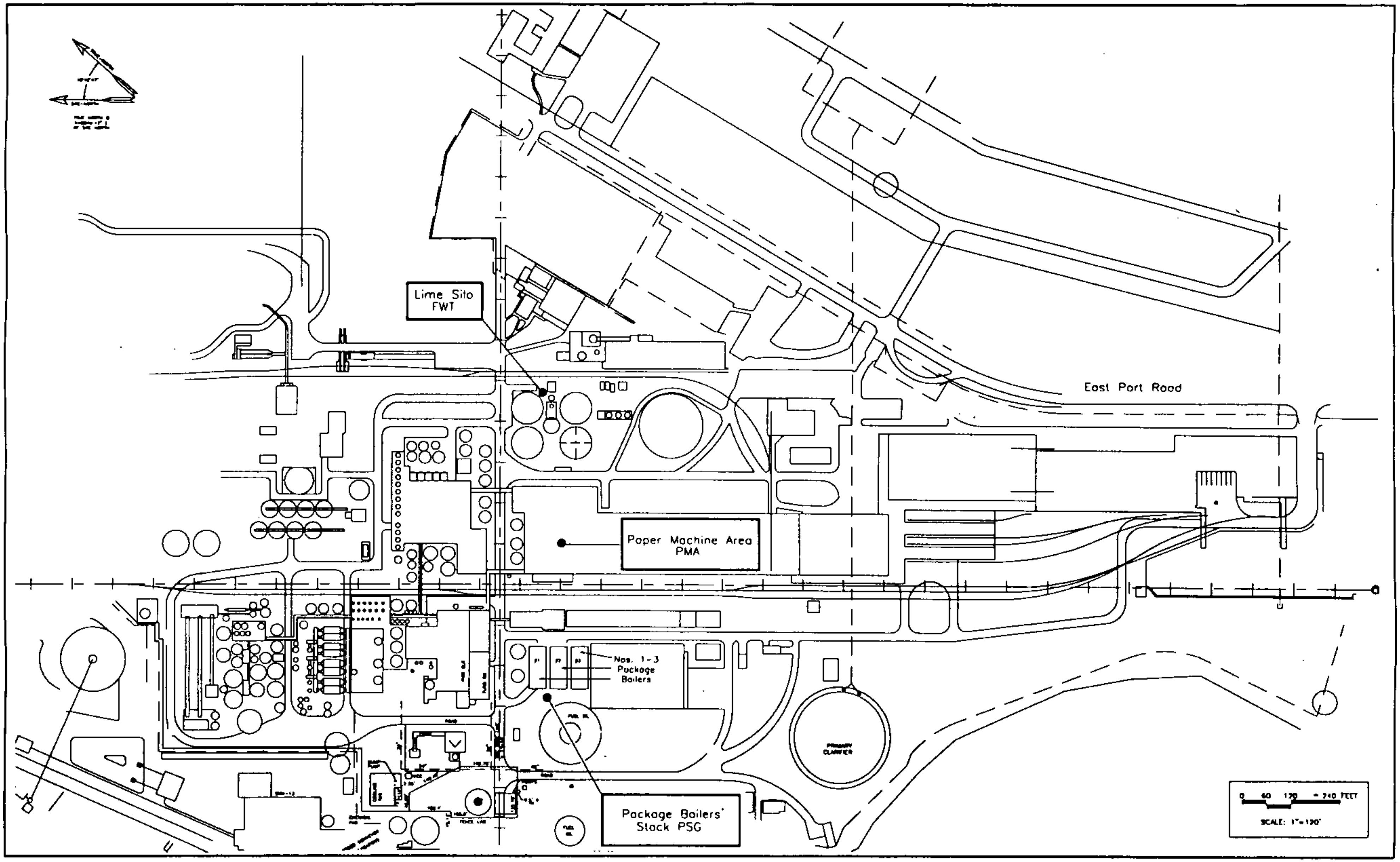
Attachment SCC-FE-1
Site Location of Stone Container Corporation, Jacksonville

Golder Associates

ATTACHMENT SCC-FE-2

FACILITY PLOT PLAN

03-24-98

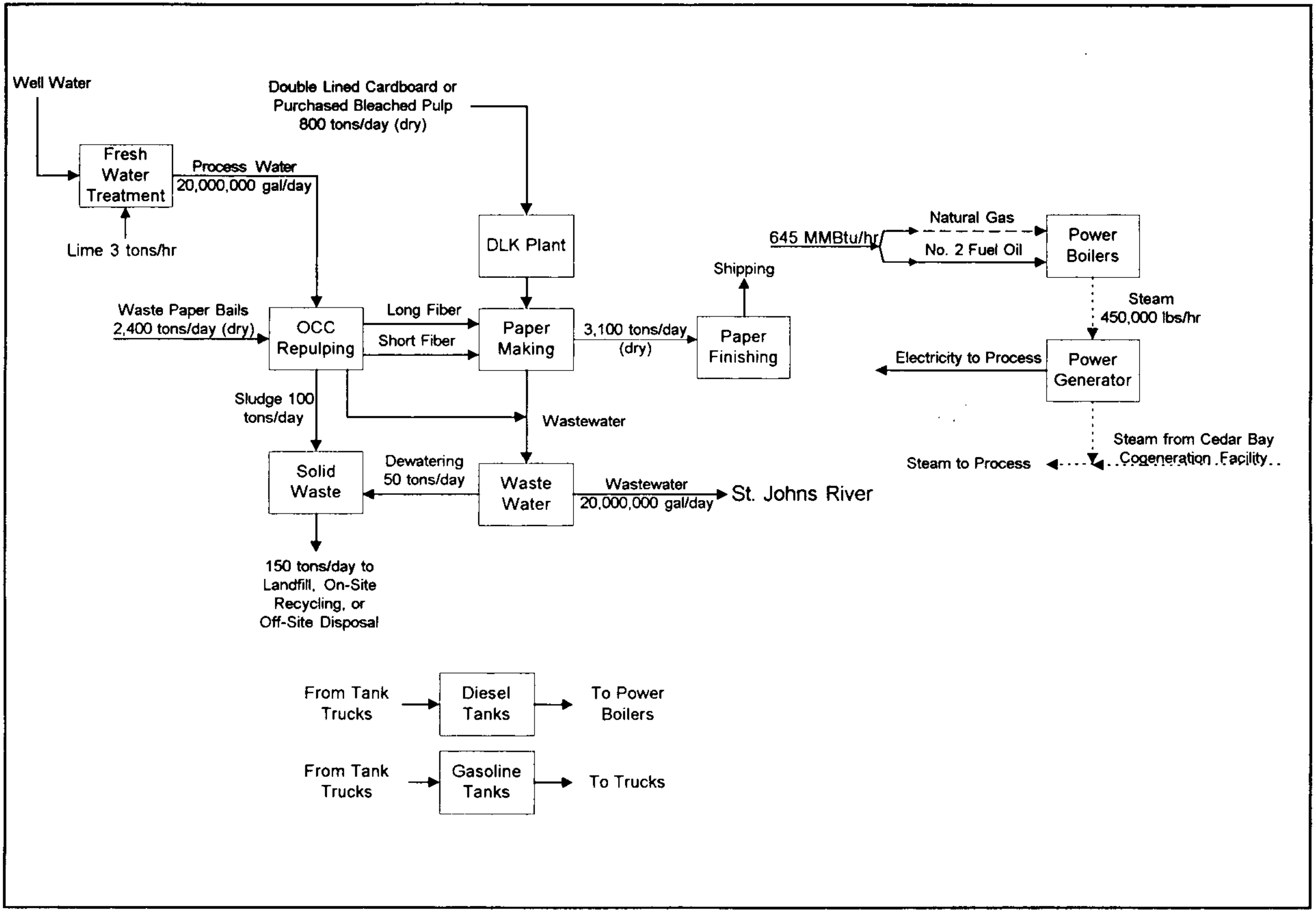


Attachment SCC-FE-2
Plot Plan of Stone Container Corporation Facility

Golder Associates

ATTACHMENT SCC-FE-3

PROCESS FLOW DIAGRAM



Process Flow Legend	Stone Container Corporation Jacksonville, FL	*Emission Unit:* FACILITY	Engineering and Applied Sciences, Inc.
Steam Flow		*Process Area:* FACILITY	
Gas Flow		*Filename:* SCCFIG.VSD	
Solid / Liquid Flow	Figure SCC-FD-3	*Latest Revision Date:* 4/15/98 09:50 AM	

III. EMISSIONS UNIT INFORMATION

A separate Emissions Unit Information Section (including subsections A through L as required) must be completed for each emissions unit addressed in this Application for Air Permit. If submitting the application form in hard copy, indicate, in the space provided at the top of each page, the number of this Emissions Unit Information Section and the total number of Emissions Unit Information Sections submitted as part of this application. Some of the subsections comprising the Emissions Unit Information Section of the form are intended for regulated emissions units only. Others are intended for both regulated and unregulated emissions units. Each subsection is appropriately marked.

A. TYPE OF EMISSIONS UNIT
(Regulated and Unregulated Emissions Units)

Type of Emissions Unit Addressed in This Section

1. Regulated or Unregulated Emissions Unit? Check one:

[x] The emissions unit addressed in this Emissions Unit Information Section is a regulated emissions unit.

[ ] The emissions unit addressed in this Emissions Unit Information Section is an unregulated emissions unit.

2. Single Process, Group of Processes, or Fugitive Only? Check one:

[x] This Emissions Unit Information Section addresses, as a single emissions unit, a single process or production unit, or activity, which produces one or more air pollutants and which has at least one definable emission point (stack or vent).

[ ] This Emissions Unit Information Section addresses, as a single emissions unit, a group of process or production units and activities which has at least one definable emission point (stack or vent) but may also produce fugitive emissions.

[ ] This Emissions Unit Information Section addresses, as a single emissions unit, one or more process or production units and activities which produce fugitive emissions only.

B. GENERAL EMISSIONS UNIT INFORMATION
(Regulated and Unregulated Emissions Units)

Emissions Unit Description and Status

1. Description of Emissions Unit Addressed in This Section (limit to 60 characters): Package Boiler No. 1		
2. Emissions Unit Identification Number: [ ] No Corresponding ID [ ] Unknown 022		
3. Emissions Unit Status Code: A	4. Acid Rain Unit? [ ] Yes [x] No	5. Emissions Unit Major Group SIC Code: 26
6. Emissions Unit Comment (limit to 500 characters): This boiler vents with two other boiler units to one common stack.		

Emissions Unit Control Equipment Information

A.

1. Description (limit to 200 characters):

   Low NOx Burners Burner Design

2. Control Device or Method Code: **24**

B.

1. Description (limit to 200 characters):

2. Control Device or Method Code:

C.

1. Description (limit to 200 characters):

2. Control Device or Method Code:

C. EMISSIONS UNIT DETAIL INFORMATION
(Regulated Emissions Units Only)

Emissions Unit Details

1. Initial Startup Date: 3 Mar 1994	
2. Long-term Reserve Shutdown Date:	
3. Package Unit: Manufacturer: ABB-Combustion Engineering	Model Number: 93104-20
4. Generator Nameplate Rating:	MW
5. Incinerator Information: Dwell Temperature: Dwell Time: Incinerator Afterburner Temperature:	 °F seconds °F

Emissions Unit Operating Capacity

1. Maximum Heat Input Rate:	215	mmBtu/hr
2. Maximum Incineration Rate:	lbs/hr	tons/day
3. Maximum Process or Throughput Rate:		
4. Maximum Production Rate:	150,000	lb/hr steam
5. Operating Capacity Comment (limit to 200 characters): 200 MMBtu/hr maximum when firing No. 2 fuel oil. 215 MMBtu/hr maximum when firing natural gas.		

Emissions Unit Operating Schedule

1. Requested Maximum Operating Schedule:			
24	hours/day	7	days/week
52	weeks/yr	8,760	hours/yr

D. EMISSIONS UNIT REGULATIONS
(Regulated Emissions Units Only)

Rule Applicability Analysis (Required for Category II Applications and Category III applications involving non Title-V sources. See Instructions.)

List of Applicable Regulations (Required for Category I applications and Category III applications involving Title-V sources. See Instructions.)

40 CFR 60 Appendix A
40 CFR 60.42b(a)
40 CFR 60.42b(g)
40 CFR 60.42b(j)
40 CFR 60.43b(g)
40 CFR 60.44b(a)
40 CFR 60.44b(b)
40 CFR 60.44b(h)
40 CFR 60.44b(i)
40 CFR 60.45b(a)
40 CFR 60.45b(j)
40 CFR 60.46b(a)
40 CFR 60.46b(c)
40 CFR 60.46b(d)
40 CFR 60.46b(e)(1)
40 CFR 60.46b(e)(4)
40 CFR 60.47b(f)
40 CFR 60.48b(a)
40 CFR 60.48b(b)
40 CFR 60.48b(c)
40 CFR 60.48b(d)
40 CFR 60.48b(e)
40 CFR 60.48b(f)
40 CFR 60.48b(g)
40 CFR 60.49b(a)
40 CFR 60.49b(b)
40 CFR 60.49b(d)
40 CFR 60.49b(f)
40 CFR 60.49b(g)
40 CFR 60.49b(h)
40 CFR 60.49b(i)
40 CFR 60.49b(j)
40 CFR 60.49b(o)
40 CFR 60.49b(r)
62-296.406(2)
62-296.406(3)
62-296.800(2)(a)3.

E. EMISSION POINT (STACK/VENT) INFORMATION
(Regulated Emissions Units Only)

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram: PSG
2. Emission Point Type Code: [ ] 1 [x] 2 [ ] 3 [ ] 4
3. Descriptions of Emissions Points Comprising this Emissions Unit for VE Tracking (limit to 100 characters per point):
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common: 23,26
5. Discharge Type Code: [ ] D [ ] F [ ] H [ ] P [ ] R [x] V [ ] W
6. Stack Height: 200 feet
7. Exit Diameter: 8 feet
8. Exit Temperature: 330 °F

9. Actual Volumetric Flow Rate:	**68,300** acfm
10. Percent Water Vapor:	%
11. Maximum Dry Standard Flow Rate:	dscfm
12. Nonstack Emission Point Height:	feet
13. Emission Point UTM Coordinates: Zone: East (km):	North (km):
14. Emission Point Comment (limit to 200 characters): **All three boilers exhaust into common stack. Stack parameters above are total for all three boilers burning natural gas. Parameters for No. 2 fuel oil are: 345 deg. F; 67,149 acfm.**	

F. SEGMENT (PROCESS/FUEL) INFORMATION
(Regulated and Unregulated Emissions Units)

Segment Description and Rate: Segment 1 of 2

1. Segment Description (Process/Fuel Type and Associated Operating Method/Mode) (limit to 500 characters): **External Combustion Boilers - Industrial; natural Gas: over 100 MMBtu**	
2. Source Classification Code (SCC): **1-02-006-01**	
3. SCC Units: **Million Cubic Feet Burned**	
4. Maximum Hourly Rate: **0.215**	5. Maximum Annual Rate: **1,883**
6. Estimated Annual Activity Factor:	
7. Maximum Percent Sulfur:	8. Maximum Percent Ash:
9. Million Btu per SCC Unit: **1,000**	
10. Segment Comment (limit to 200 characters): **Maximum Percent Sulfur = 0.001**	

Segment Description and Rate: Segment 2 of 2

1. Segment Description (Process/Fuel Type and Associated Operating Method/Mode) (limit to 500 characters): **External Combustion Boilers - Industrial; Distillate oil: over 100 MMBtu**	
2. Source Classification Code (SCC): **1-02-005-01**	
3. SCC Units: **Thousand Gallons Burned**	
4. Maximum Hourly Rate: **1.449**	5. Maximum Annual Rate: **10,750**
6. Estimated Annual Activity Factor:	
7. Maximum Percent Sulfur: **0.05**	8. Maximum Percent Ash: **0.1**
9. Million Btu per SCC Unit: **138**	
10. Segment Comment (limit to 200 characters): **Maximum combined yearly rate for Boiler No. 1, No. 2 and No. 3 is 10,750,000 gal/year.**	

G. EMISSIONS UNIT POLLUTANTS
(Regulated and Unregulated Emissions Units)

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
SO2			EL
NOx	024		EL
PM			NS
PM10			NS
CO			NS

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Pollutant Detail Information:

1. Pollutant Emitted: SO2

2. Total Percent Efficiency of Control: %

3. Potential Emissions: 10.43 lb/hour 38.7 tons/year

4. Synthetically Limited? [x] Yes [ ] No

5. Range of Estimated Fugitive/Other Emissions:

   [ ] 1 [ ] 2 [ ] 3 ________ to ________ tons/yr

6. Emission Factor: 0.05 %S

   Reference: AP-42 and %S

7. Emissions Method Code:

   [x] 0 [ ] 1 [ ] 2 [ ] 3 [ ] 4 [ ] 5

8. Calculation of Emissions (limit to 600 characters):

   1,449 gal/hr x 7.2 lb/gal x 0.0005 lb S/lb fuel x 2 lb SO2/lb S = 10.43 lbs/hr

9. Pollutant Potential/Estimated Emissions Comment (limit to 200 characters):

   Annual SO2 emissions from #2 fuel oil firing for all 3 boilers shall not exceed 25 TPY, except during periods of natural gas unavailability, emissions shall not exceed 40 TPY with proper notification.

Emissions Unit Information Section 1 **of** 3

Allowable Emissions (Pollutant identified on front page)

A.

1. Basis for Allowable Emissions Code: **OTHER**
2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **0.05 % Sulfur**
4. Equivalent Allowable Emissions: **10.43** lb/hour **38.7** tons/year
5. Method of Compliance (limit to 60 characters): **Fuel Oil analysis**
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters): **See Attachment SCC-EU1-HA6. Maximum annual emissions under normal operations, when natural gas is available is 25 TPY. Emissions under natural gas curtailment cannot exceed 40 TPY.**

B.

1. Basis for Allowable Emissions Code:
2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units:
4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance (limit to 60 characters):
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters):

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Pollutant Detail Information:

1. Pollutant Emitted: **NOx**
2. Total Percent Efficiency of Control: %
3. Potential Emissions: **34.94** lb/hour **153.1** tons/year
4. Synthetically Limited? [ ] Yes [x] No
5. Range of Estimated Fugitive/Other Emissions: [ ] 1 [ ] 2 [ ] 3 ________ to ________ tons/yr
6. Emission Factor: **0.2 lb/MMBtu** Reference: **Proposed Limit**
7. Emissions Method Code: [x] 0 [ ] 1 [ ] 2 [ ] 3 [ ] 4 [ ] 5
8. Calculation of Emissions (limit to 600 characters): **NOx emissions capped at current permit limit. Equivalent to 0.1625 lb/MMBtu at max heat input.**
9. Pollutant Potential/Estimated Emissions Comment (limit to 200 characters): **The maximum allowable NOx emissions shall not exceed 0.2 lb/MMBtu, 34.94 lbs/hr and 153.1 TPY per boiler. Total NOx emissions from all three boilers limited to 310 TPY.**

Emissions Unit Information Section 1 **of** 3

Allowable Emissions (Pollutant identified on front page)

A.

1. Basis for Allowable Emissions Code: **OTHER**
2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **0.2 lb/MMBtu**
4. Equivalent Allowable Emissions: **34.94** lb/hour **153.1** tons/year
5. Method of Compliance (limit to 60 characters): **CEM for NOx**
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters): **Self-imposed limit by permittee. Based on natural gas firing.**

B.

1. Basis for Allowable Emissions Code:
2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units:
4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance (limit to 60 characters):
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters):

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Pollutant Detail Information:

1. Pollutant Emitted: **PM**

2. Total Percent Efficiency of Control: %

3. Potential Emissions: **2.9** lb/hour **11.5** tons/year

4. Synthetically Limited? [x] Yes [ ] No

5. Range of Estimated Fugitive/Other Emissions:

   [ ] 1 [ ] 2 [ ] 3 ________ to ________ tons/yr

6. Emission Factor: **2 lbs/1000 gal**

   Reference: **AP-42**

7. Emissions Method Code:

   [ ] 0 [ ] 1 [ ] 2 [x] 3 [ ] 4 [ ] 5

8. Calculation of Emissions (limit to 600 characters):

   Fuel Oil: 1,449.3 gal/hr x 2 lbs/1000 gal = 2.90 lb/hr

9. Pollutant Potential/Estimated Emissions Comment (limit to 200 characters):

   See Attachment A for additional calculations

Allowable Emissions (Pollutant identified on front page)

A.

1. Basis for Allowable Emissions Code:
2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units:
4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance (limit to 60 characters):
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters):

B.

1. Basis for Allowable Emissions Code:
2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units:
4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance (limit to 60 characters):
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters):

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Pollutant Detail Information:

1. Pollutant Emitted: **PM10**

2. Total Percent Efficiency of Control: %

3. Potential Emissions: **1.45** lb/hour **6.1** tons/year

4. Synthetically Limited? [x] Yes [ ] No

5. Range of Estimated Fugitive/Other Emissions:

   [ ] 1 [ ] 2 [ ] 3 ________ to ________ tons/yr

6. Emission Factor: **50 % of PM**

   Reference: **AP-42**

7. Emissions Method Code:

   [ ] 0 [ ] 1 [ ] 2 [x] 3 [ ] 4 [ ] 5

8. Calculation of Emissions (limit to 600 characters):

   Fuel Oil: 2.90 lb/hr x 0.5 = 1.45 lb/hr

9. Pollutant Potential/Estimated Emissions Comment (limit to 200 characters):

   See Attachment A for additional calculations

Emissions Unit Information Section 1 of 3

Allowable Emissions (Pollutant identified on front page)

A.

1. Basis for Allowable Emissions Code:
2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units:
4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance (limit to 60 characters):
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters):

B.

1. Basis for Allowable Emissions Code:
2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units:
4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance (limit to 60 characters):
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters):

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Pollutant Detail Information:

1. Pollutant Emitted: **CO**

2. Total Percent Efficiency of Control: %

3. Potential Emissions: **8.96** lb/hour **19** tons/year

4. Synthetically Limited? [ ] Yes [x] No

5. Range of Estimated Fugitive/Other Emissions:

   [ ] 1 [ ] 2 [ ] 3 __________ to __________ tons/yr

6. Emission Factor: **50 ppmvd**

   Reference: **Test Data**

7. Emissions Method Code:

   [ ] 0 [x] 1 [ ] 2 [ ] 3 [ ] 4 [ ] 5

8. Calculation of Emissions (limit to 600 characters):

   Natural Gas: 41,084 dscfm x 50 ppmvd x 60 min/hr x 2,116.8 lb/sq.ft. x (28/1545) lb-deg. R/ft-lb x 1/528 deg. R = 8.96 lb/hr

9. Pollutant Potential/Estimated Emissions Comment (limit to 200 characters):

   Annual emissions based on 25 ppmvd. See Attachment A.

Emissions Unit Information Section 1 of 3

Allowable Emissions (Pollutant identified on front page)

A.

1. Basis for Allowable Emissions Code:
2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units:
4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance (limit to 60 characters):
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters):

B.

1. Basis for Allowable Emissions Code:
2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units:
4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance (limit to 60 characters):
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters):

I. VISIBLE EMISSIONS INFORMATION
(Regulated Emissions Units Only)

Visible Emissions Limitations: Visible Emissions Limitation 1 of 2

1.	Visible Emissions Subtype: VE05
2.	Basis for Allowable Opacity: [x] Rule [ ] Other
3.	Requested Allowable Opacity Normal Conditions: 5 % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour
4.	Method of Compliance: EPA Method 9
5.	Visible Emissions Comment (limit to 200 characters): Natural gas firing; based on BACT

Visible Emissions Limitations: Visible Emissions Limitation 2 of 2

1.	Visible Emissions Subtype: VE10
2.	Basis for Allowable Opacity: [x] Rule [ ] Other
3.	Requested Allowable Opacity Normal Conditions: 10 % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour
4.	Method of Compliance: EPA Method 9
5.	Visible Emissions Comment (limit to 200 characters): No. 2 fuel oil firing; based on BACT.

J. CONTINUOUS MONITOR INFORMATION
(Regulated Emissions Units Only)

Continuous Monitoring System Continuous Monitor 1 of 1

1. Parameter Code: EM	2. Pollutant(s): NOx
3. CMS Requirement: [X] Rule [ ] Other	
4. Monitor Information: Monitor Manufacturer: Servomex Model Number: 1491 Serial Number: 103	
5. Installation Date: 01 Feb 1994	
6. Performance Specification Test Date: 21 Jun 1994	
7. Continuous Monitor Comment (limit to 200 characters): CEMS for nitrogen oxides shall be operated and maintained in accordance with requirements of 40 CFR 60.48b.	

Continuous Monitoring System Continuous Monitor _____ of _____

1. Parameter Code:	2. Pollutant(s):
3. CMS Requirement: [ ] Rule [ ] Other	
4. Monitor Information: Monitor Manufacturer: Model Number: Serial Number:	
5. Installation Date:	
6. Performance Specification Test Date:	
7. Continuous Monitor Comment (limit to 200 characters):	

K. PREVENTION OF SIGNIFICANT DETERIORATION (PSD) INCREMENT TRACKING INFORMATION
(Regulated and Unregulated Emissions Units)

PSD Increment Consumption Determination

1. Increment Consuming for Particulate Matter or Sulfur Dioxide?

If the emissions unit addressed in this section emits particulate matter or sulfur dioxide, answer the following series of questions to make a preliminary determination as to whether or not the emissions unit consumes PSD increment for particulate matter or sulfur dioxide. Check the first statement, if any, that applies and skip remaining statements.

[x] The emissions unit is undergoing PSD review as part of this application, or has undergone PSD review previously, for particulate matter or sulfur dioxide. If so, emissions unit consumes increment.

[ ] The facility addressed in this application is classified as an EPA major source pursuant to paragraph (c) of the definition of "major source of air pollution" in Chapter 62-213, F.A.C., and the emissions unit addressed in this section commenced (or will commence) construction after January 6, 1975. If so, baseline emissions are zero, and the emissions unit consumes increment.

[ ] The facility addressed in this application is classified as an EPA major source and the emissions unit began initial operation after January 6, 1975, but before December 27, 1977. If so, baseline emissions are zero, and the emissions unit consumes increment.

[ ] For any facility, the emissions unit began (or will begin) initial operation after December 27, 1977. If so, baseline emissions are zero, and emissions unit consumes increment.

[ ] None of the above apply. If so, the baseline emissions of the emissions unit are nonzero. In such case, additional analysis, beyond the scope of this application, is needed to determine whether changes in emissions have occurred (or will occur) after the baseline date that may consume or expand increment.

2. Increment Consuming for Nitrogen Dioxide?

If the emissions unit addressed in this section emits nitrogen oxides, answer the following series of questions to make a preliminary determination as to whether or not the emissions unit consumes PSD increment for nitrogen dioxide. Check first statement, if any, that applies and skip remaining statements.

[x] The emissions unit addressed in this section is undergoing PSD review as part of this application, or has undergone PSD review previously, for nitrogen dioxide. If so, emissions unit consumes increment.

[ ] The facility addressed in this application is classified as an EPA major source pursuant to paragraph (c) of the definition of "major source of air pollution" in Chapter 62-213, F.A.C., and the emissions unit addressed in this section commenced (or will commence) construction after February 8, 1988. If so, baseline emissions are zero, and the source consumes increment.

[ ] The facility addressed in this application is classified as an EPA major source and the emissions unit began initial operation after February 8, 1988, but before March 28, 1988. If so, baseline emissions are zero, and the source consumes increment.

[ ] For any facility, the emissions unit began (or will begin) initial operation after March 28, 1988. If so, baseline emissions are zero, and the emissions unit consumes increment.

[ ] None of the above apply. If so, baseline emissions of the emissions unit are nonzero. In such case, additional analysis, beyond the scope of this application, is needed to determine whether changes in emissions have occurred (or will occur) after the baseline date that may consume or expand increment.

3.	Increment Consuming/Expanding Code:			
	PM	[x] C	[ ] E	[ ] Unknown
	SO_2	[x] C	[ ] E	[ ] Unknown
	NO_2	[x] C	[ ] E	[ ] Unknown
4.	Baseline Emissions:			
	PM	lb/hour		tons/year
	SO_2	lb/hour		tons/year
	NO_2			tons/year
5.	PSD Comment (limit to 200 characters):			

L. EMISSIONS UNIT SUPPLEMENTAL INFORMATION
(Regulated Emissions Units Only)

Supplemental Requirements for All Applications

1.	Process Flow Diagram		
	[x] Attached, Document ID: SCC-EU1-L1		
	[ ] Not Applicable	[ ] Waiver Requested	
2.	Fuel Analysis or Specification		
	[x] Attached, Document ID: SCC-EU1-L2		
	[ ] Not Applicable	[ ] Waiver Requested	
3.	Detailed Description of Control Equipment		
	[ ] Attached, Document ID: ____		
	[x] Not Applicable	[ ] Waiver Requested	
4.	Description of Stack Sampling Facilities		
	[ ] Attached, Document ID: ____		
	[x] Not Applicable	[ ] Waiver Requested	
5.	Compliance Test Report		
	[ ] Attached, Document ID: ____	[x] Not Applicable	
	[ ] Previously Submitted, Date: ____		
6.	Procedures for Startup and Shutdown		
	[ ] Attached, Document ID: ____	[x] Not Applicable	
7.	Operation and Maintenance Plan		
	[ ] Attached, Document ID: ____	[x] Not Applicable	
8.	Supplemental Information for Construction Permit Application		
	[x] Attached, Document ID: Attachment A	[ ] Not Applicable	
9.	Other Information Required by Rule or Statute		
	[ ] Attached, Document ID: ____	[x] Not Applicable	

Additional Supplemental Requirements for Category I Applications Only

10. Alternative Methods of Operation

    [ ] Attached, Document ID: ____________ [ ] Not Applicable

11. Alternative Modes of Operation (Emissions Trading)

    [ ] Attached, Document ID: ____________ [ ] Not Applicable

12. Identification of Additional Applicable Requirements

    [ ] Attached, Document ID: ____________ [ ] Not Applicable

13. Compliance Assurance Monitoring Plan

    [ ] Attached, Document ID: ____________ [ ] Not Applicable

14. Acid Rain Permit Application (Hard Copy Required)

    [ ] Acid Rain Part - Phase II (Form No. 62-210.900(1)(a))
    Attached, Document ID: ____________

    [ ] Repowering Extension Plan (Form No. 62-210.900(1)(a)1.)
    Attached, Document ID: ____________

    [ ] New Unit Exemption (Form No. 62-210.900(1)(a)2.)
    Attached, Document ID: ____________

    [ ] Retired Unit Exemption (Form No. 62-210.900(1)(a)3.)
    Attached, Document ID: ____________

    [ ] Not Applicable

ATTACHMENT SCC-EU1-HA6

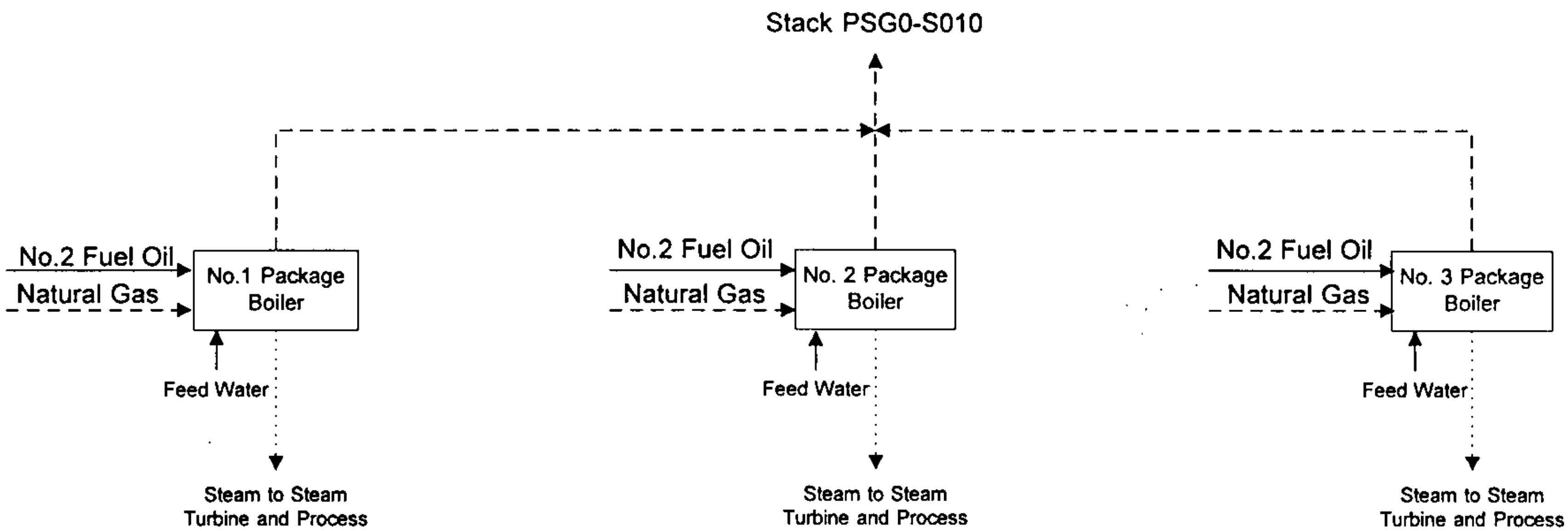
POLLUTANT ALLOWABLE EMISSIONS COMMENT

ATTACHMENT SCC-EU1-HA6
POLLUTANT ALLOWABLE EMISSIONS COMMENT

Boiler has SO_2 emission limit of 0.05% S fuel oil based on F.A.C. Rule 62-296.406, BACT, and 40 CFR Part 60, Subpart Db New Source Performance Standards. The BACT requires natural gas to be the primary fuel and the No. 2 fuel oil to be a maximum of 0.05 percent sulfur by weight. When using back up No. 2 fuel oil, emissions are limited to 25 TPY. If, due to factors beyond SCC, the limit is exceeded based on the unavailability of natural gas, then SCC shall provide a notice to the Department that will include a statement or reasons for the request to continue to burn No. 2 fuel oil. The emissions limit shall be less than 40 tons per year when burning No. 2 fuel oil. The notification of use of No. 2 fuel oil that causes emissions in excess of 25 TPY shall be published in a newspaper of general circulation in Jacksonville, Florida.

ATTACHMENT SCC-EU1-L1

PROCESS FLOW DIAGRAM



Process Flow Legend	Stone Container Corporation Jacksonville, FL	Emission Unit: PACKAGE BOILERS 1, 2, 3
Steam Flow		Process Area: PACKAGE BOILERS 1, 2, 3
Gas Flow		Filename: SCCFIG.VSD Project: 9837525Y/F1
Solid / Liquid Flow	Figure SCC-EU1-L1	Latest Revision Date: 3/26/98 02:35 PM

Golder Associates

ATTACHMENT SCC-EU1-L2

FUEL ANALYSIS OR SPECIFICATION

ATTACHMENT SCC-EU1-2

Package Boilers
Fuel Analysis

Fuel	Density (lb/gal)	Moisture (%)	Weight % Sulfur	Weight % Nitrogen	Weight % Ash	Heat Capacity
No. 2 Fuel Oil	7.2	—	0.05	—	0.1	138,000 BTU/gal
Natural Gas	—	—	.001	—	—	1000 BTU/ft^3

III. EMISSIONS UNIT INFORMATION

A separate Emissions Unit Information Section (including subsections A through L as required) must be completed for each emissions unit addressed in this Application for Air Permit. If submitting the application form in hard copy, indicate, in the space provided at the top of each page, the number of this Emissions Unit Information Section and the total number of Emissions Unit Information Sections submitted as part of this application. Some of the subsections comprising the Emissions Unit Information Section of the form are intended for regulated emissions units only. Others are intended for both regulated and unregulated emissions units. Each subsection is appropriately marked.

A. TYPE OF EMISSIONS UNIT
(Regulated and Unregulated Emissions Units)

<u>Type of Emissions Unit Addressed in This Section</u>

1. Regulated or Unregulated Emissions Unit? Check one:

[x] The emissions unit addressed in this Emissions Unit Information Section is a regulated emissions unit.

[ ] The emissions unit addressed in this Emissions Unit Information Section is an unregulated emissions unit.

2. Single Process, Group of Processes, or Fugitive Only? Check one:

[x] This Emissions Unit Information Section addresses, as a single emissions unit, a single process or production unit, or activity, which produces one or more air pollutants and which has at least one definable emission point (stack or vent).

[ ] This Emissions Unit Information Section addresses, as a single emissions unit, a group of process or production units and activities which has at least one definable emission point (stack or vent) but may also produce fugitive emissions.

[ ] This Emissions Unit Information Section addresses, as a single emissions unit, one or more process or production units and activities which produce fugitive emissions only.

B. GENERAL EMISSIONS UNIT INFORMATION
(Regulated and Unregulated Emissions Units)

Emissions Unit Description and Status

1. Description of Emissions Unit Addressed in This Section (limit to 60 characters): **Package Boiler No. 2**		
2. Emissions Unit Identification Number: [ ] No Corresponding ID [ ] Unknown **023**		
3. Emissions Unit Status Code: **A**	4. Acid Rain Unit? [ ] Yes [x] No	5. Emissions Unit Major Group SIC Code: **26**
6. Emissions Unit Comment (limit to 500 characters): **This boiler vents with two other boiler units to one common stack.**		

Emissions Unit Control Equipment Information

A.

1. Description (limit to 200 characters): **Low NOx Burners Burner Design**
2. Control Device or Method Code: **24**

B.

1. Description (limit to 200 characters):
2. Control Device or Method Code:

C.

1. Description (limit to 200 characters):
2. Control Device or Method Code:

C. EMISSIONS UNIT DETAIL INFORMATION
(Regulated Emissions Units Only)

Emissions Unit Details

1. Initial Startup Date: 3 Mar 1994		
2. Long-term Reserve Shutdown Date:		
3. Package Unit: Manufacturer: ABB-Combustion Engineering	Model Number: 93104-20	
4. Generator Nameplate Rating:	MW	
5. Incinerator Information: Dwell Temperature:	°F	
Dwell Time:	seconds	
Incinerator Afterburner Temperature:	°F	

Emissions Unit Operating Capacity

1. Maximum Heat Input Rate:	215	mmBtu/hr
2. Maximum Incineration Rate:	lbs/hr	tons/day
3. Maximum Process or Throughput Rate:		
4. Maximum Production Rate:	150,000	lb/hr steam
5. Operating Capacity Comment (limit to 200 characters): 200 MMBtu/hr maximum when firing No. 2 fuel oil. 215 MMBtu/hr maximum when firing natural gas.		

Emissions Unit Operating Schedule

1. Requested Maximum Operating Schedule:			
24	hours/day	7	days/week
52	weeks/yr	8,760	hours/yr

D. EMISSIONS UNIT REGULATIONS
(Regulated Emissions Units Only)

<u>Rule Applicability Analysis</u> (Required for Category II Applications and Category III applications involving non Title-V sources. See Instructions.)

List of Applicable Regulations (Required for Category I applications and Category III applications involving Title-V sources. See Instructions.)

40 CFR 60 Appendix A
40 CFR 60.42b(a)
40 CFR 60.42b(g)
40 CFR 60.42b(j)
40 CFR 60.43b(g)
40 CFR 60.44b(a)
40 CFR 60.44b(b)
40 CFR 60.44b(h)
40 CFR 60.44b(i)
40 CFR 60.45b(a)
40 CFR 60.45b(j)
40 CFR 60.46b(a)
40 CFR 60.46b(c)
40 CFR 60.46b(d)
40 CFR 60.46b(e)(1)
40 CFR 60.46b(e)(4)
40 CFR 60.47b(f)
40 CFR 60.48b(a)
40 CFR 60.48b(b)
40 CFR 60.48b(c)
40 CFR 60.48b(d)
40 CFR 60.48b(e)
40 CFR 60.48b(f)
40 CFR 60.48b(g)
40 CFR 60.49b(a)
40 CFR 60.49b(b)
40 CFR 60.49b(d)
40 CFR 60.49b(f)
40 CFR 60.49b(g)
40 CFR 60.49b(h)
40 CFR 60.49b(i)
40 CFR 60.49b(j)
40 CFR 60.49b(o)
40 CFR 60.49b(r)
62-296.406(2)
62-296.406(3)
62-296.800(2)(a)3.

E. EMISSION POINT (STACK/VENT) INFORMATION
(Regulated Emissions Units Only)

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram: PSG
2. Emission Point Type Code: [ ] 1 [x] 2 [ ] 3 [ ] 4
3. Descriptions of Emissions Points Comprising this Emissions Unit for VE Tracking (limit to 100 characters per point):
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common: 22,26
5. Discharge Type Code: [ ] D [ ] F [ ] H [ ] P [ ] R [x] V [ ] W
6. Stack Height: 200 feet
7. Exit Diameter: 8 feet
8. Exit Temperature: 330 °F

9. Actual Volumetric Flow Rate:	**68,300** acfm
10. Percent Water Vapor:	%
11. Maximum Dry Standard Flow Rate:	dscfm
12. Nonstack Emission Point Height:	feet
13. Emission Point UTM Coordinates: Zone: East (km): North (km):	
14. Emission Point Comment (limit to 200 characters): **All three boilers exhaust into common stack. Stack parameters above are for all three boilers firing natural gas. Parameters for No. 2 fuel oil are: 345 deg. F; 67,149 acfm.**	

F. SEGMENT (PROCESS/FUEL) INFORMATION
(Regulated and Unregulated Emissions Units)

Segment Description and Rate: Segment 1 of 2

1. Segment Description (Process/Fuel Type and Associated Operating Method/Mode) (limit to 500 characters): **External Combustion Boilers - Industrial; natural Gas: over 100 MMBtu**	
2. Source Classification Code (SCC): **1-02-006-01**	
3. SCC Units: **Million Cubic Feet Burned**	
4. Maximum Hourly Rate: **0.215**	5. Maximum Annual Rate: **1,883**
6. Estimated Annual Activity Factor:	
7. Maximum Percent Sulfur:	8. Maximum Percent Ash:
9. Million Btu per SCC Unit: **1,000**	
10. Segment Comment (limit to 200 characters): **Maximum Percent Sulfur = 0.001**	

Segment Description and Rate: Segment 2 of 2

1. Segment Description (Process/Fuel Type and Associated Operating Method/Mode) (limit to 500 characters): **External Combustion Boilers - Industrial; Distillate oil: over 100 MMBtu**	
2. Source Classification Code (SCC): **1-02-005-01**	
3. SCC Units: **Thousand Gallons Burned**	
4. Maximum Hourly Rate: **1.449**	5. Maximum Annual Rate: **10,750**
6. Estimated Annual Activity Factor:	
7. Maximum Percent Sulfur: **0.05**	8. Maximum Percent Ash: **0.1**
9. Million Btu per SCC Unit: **138**	
10. Segment Comment (limit to 200 characters): **Maximum combined yearly rate for Boiler No. 1, No. 2 and No. 3 is 10,750,000 gal/year.**	

G. EMISSIONS UNIT POLLUTANTS
(Regulated and Unregulated Emissions Units)

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
SO2			EL
NOx	024		EL
PM			NS
PM10			NS
CO			NS

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Pollutant Detail Information:

1. Pollutant Emitted: **SO2**

2. Total Percent Efficiency of Control: %

3. Potential Emissions: **10.43** lb/hour **38.7** tons/year

4. Synthetically Limited? [x] Yes [ ] No

5. Range of Estimated Fugitive/Other Emissions:

   [ ] 1 [ ] 2 [ ] 3 ________ to ________ tons/yr

6. Emission Factor: **0.05 %S**

   Reference: **AP-42 and %S**

7. Emissions Method Code:

   [x] 0 [ ] 1 [ ] 2 [ ] 3 [ ] 4 [ ] 5

8. Calculation of Emissions (limit to 600 characters):

   1,449 gal/hr x 7.2 lb/gal x 0.0005 lb S/lb fuel x 2 lb SO2/lb S = 10.43 lbs/hr

9. Pollutant Potential/Estimated Emissions Comment (limit to 200 characters):

   Annual SO2 emissions from #2 fuel oil firing for all 3 boilers shall not exceed 25 TPY, except during periods of natural gas unavailability, emissions shall not exceed 40 TPY with proper notification.

Emissions Unit Information Section 2 of 3

Allowable Emissions (Pollutant identified on front page)

A.

1. Basis for Allowable Emissions Code: **OTHER**
2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **0.05 % Sulfur**
4. Equivalent Allowable Emissions: **10.43** lb/hour **38.7** tons/year
5. Method of Compliance (limit to 60 characters): **Fuel Oil analysis**
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters): **See Attachment SCC-EU1-HA6. Maximum annual emissions under normal operations, when natural gas is available is 25 TPY. Emissions under natural gas curtailment cannot exceed 40 TPY.**

B.

1. Basis for Allowable Emissions Code:
2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units:
4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance (limit to 60 characters):
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters):

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Pollutant Detail Information:

1. Pollutant Emitted: NOx

2. Total Percent Efficiency of Control: %

3. Potential Emissions: 34.94 lb/hour 153.1 tons/year

4. Synthetically Limited? [ ] Yes [x] No

5. Range of Estimated Fugitive/Other Emissions:

   [ ] 1 [ ] 2 [ ] 3 ________ to ________ tons/yr

6. Emission Factor: 0.2 lb/MMBtu

   Reference: Proposed Limit

7. Emissions Method Code:

   [x] 0 [ ] 1 [ ] 2 [ ] 3 [ ] 4 [ ] 5

8. Calculation of Emissions (limit to 600 characters):

   NOx emissions capped at current permit limit. Equivalent to 0.1625 lb/MMBtu at max heat input.

9. Pollutant Potential/Estimated Emissions Comment (limit to 200 characters):

   The maximum allowable NOx emissions shall not exceed 0.2 lb/MMBtu, 34.94 lbs/hr and 153.1 TPY per boiler. Total NOx emissions from all three boilers limited to 310 TPY.

Emissions Unit Information Section 2 of 3

Allowable Emissions (Pollutant identified on front page)

A.

1. Basis for Allowable Emissions Code: **OTHER**	
2. Future Effective Date of Allowable Emissions:	
3. Requested Allowable Emissions and Units: **0.2 lb/MMBtu**	
4. Equivalent Allowable Emissions: **34.94** lb/hour	**153.1** tons/year
5. Method of Compliance (limit to 60 characters): **CEM for NOx**	
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters): **Self-imposed limit by permittee. Based on natural gas firing.**	

B.

1. Basis for Allowable Emissions Code:	
2. Future Effective Date of Allowable Emissions:	
3. Requested Allowable Emissions and Units:	
4. Equivalent Allowable Emissions: lb/hour	tons/year
5. Method of Compliance (limit to 60 characters):	
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters):	

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Pollutant Detail Information:

1. Pollutant Emitted: **PM**

2. Total Percent Efficiency of Control: %

3. Potential Emissions: **2.9** lb/hour **11.5** tons/year

4. Synthetically Limited? [x] Yes [ ] No

5. Range of Estimated Fugitive/Other Emissions:

   [ ] 1 [ ] 2 [ ] 3 ________ to ________ tons/yr

6. Emission Factor: **2 lb/1000 gal**

   Reference: **AP-42**

7. Emissions Method Code:

   [ ] 0 [ ] 1 [ ] 2 [x] 3 [ ] 4 [ ] 5

8. Calculation of Emissions (limit to 600 characters):

   Fuel Oil: 1,449.3 gal/hr x 2 lbs/1000 gal = 2.90 lb/hr

9. Pollutant Potential/Estimated Emissions Comment (limit to 200 characters):

   See Attachment A for additional calculations

Emissions Unit Information Section 2 of 3

Allowable Emissions (Pollutant identified on front page)

A.

1. Basis for Allowable Emissions Code:
2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units:
4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance (limit to 60 characters):
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters):

B.

1. Basis for Allowable Emissions Code:
2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units:
4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance (limit to 60 characters):
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters):

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Pollutant Detail Information:

1. Pollutant Emitted: **PM10**
2. Total Percent Efficiency of Control: %
3. Potential Emissions: **1.45** lb/hour **6.1** tons/year
4. Synthetically Limited? [x] Yes [ ] No
5. Range of Estimated Fugitive/Other Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/yr
6. Emission Factor: **50 % of PM** Reference: **AP-42**
7. Emissions Method Code: [ ] 0 [ ] 1 [ ] 2 [x] 3 [ ] 4 [ ] 5
8. Calculation of Emissions (limit to 600 characters): **Fuel Oil: 2.90 lb/hr x 0.5 = 1.45 lb/hr**
9. Pollutant Potential/Estimated Emissions Comment (limit to 200 characters): **See Attachment A for additional calculations**

Emissions Unit Information Section 2 **of** 3

Allowable Emissions (Pollutant identified on front page)

A.

1. Basis for Allowable Emissions Code:
2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units:
4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance (limit to 60 characters):
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters):

B.

1. Basis for Allowable Emissions Code:
2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units:
4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance (limit to 60 characters):
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters):

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Pollutant Detail Information:

1. Pollutant Emitted: **CO**
2. Total Percent Efficiency of Control: %
3. Potential Emissions: **8.96** lb/hour **19** tons/year
4. Synthetically Limited? [ ] Yes [X] No
5. Range of Estimated Fugitive/Other Emissions: [ ] 1 [ ] 2 [ ] 3 ________ to ________ tons/yr
6. Emission Factor: **50 ppmvd** Reference: **Test Data**
7. Emissions Method Code: [ ] 0 [X] 1 [ ] 2 [ ] 3 [ ] 4 [ ] 5
8. Calculation of Emissions (limit to 600 characters): **Natural Gas: 41,084 dscfm x 50 ppmvd x 60 min/hr x 2,116.8 lb/sq.ft. x (28/1545) lb-deg. R/ft-lb x 1/528 deg. R = 8.96 lb/hr**
9. Pollutant Potential/Estimated Emissions Comment (limit to 200 characters): **Annual emissions based on 25 ppmvd. See Attachment A.**

Emissions Unit Information Section 2 **of** 3

Allowable Emissions (Pollutant identified on front page)

A.

1. Basis for Allowable Emissions Code:
2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units:
4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance (limit to 60 characters):
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters):

B.

1. Basis for Allowable Emissions Code:
2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units:
4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance (limit to 60 characters):
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters):

I. VISIBLE EMISSIONS INFORMATION
(Regulated Emissions Units Only)

Visible Emissions Limitations: Visible Emissions Limitation 1 of 2

1.	Visible Emissions Subtype: **VE05**
2.	Basis for Allowable Opacity: [x] Rule [ ] Other
3.	Requested Allowable Opacity Normal Conditions: **5** % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour
4.	Method of Compliance: **EPA Method 9**
5.	Visible Emissions Comment (limit to 200 characters): **Natural gas firing; based on BACT**

Visible Emissions Limitations: Visible Emissions Limitation 2 of 2

1.	Visible Emissions Subtype: **VE10**
2.	Basis for Allowable Opacity: [x] Rule [ ] Other
3.	Requested Allowable Opacity Normal Conditions: **10** % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour
4.	Method of Compliance: **EPA Metod 9**
5.	Visible Emissions Comment (limit to 200 characters): **No. 2 fuel oil firing; based on BACT.**

J. CONTINUOUS MONITOR INFORMATION
(Regulated Emissions Units Only)

Continuous Monitoring System Continuous Monitor 1 of 1

1. Parameter Code: EM	2. Pollutant(s): NOx
3. CMS Requirement: [X] Rule [ ] Other	
4. Monitor Information: Monitor Manufacturer: Servomex Model Number: 1491 Serial Number: 103	
5. Installation Date: 01 Feb 1994	
6. Performance Specification Test Date: 21 Jun 1994	
7. Continuous Monitor Comment (limit to 200 characters): CEMS for nitrogen oxides shall be operated and maintained in accordance with requirements of 40 CFR 60.48b.	

Continuous Monitoring System Continuous Monitor ____ of ____

1. Parameter Code:	2. Pollutant(s):
3. CMS Requirement: [ ] Rule [ ] Other	
4. Monitor Information: Monitor Manufacturer: Model Number: Serial Number:	
5. Installation Date:	
6. Performance Specification Test Date:	
7. Continuous Monitor Comment (limit to 200 characters):	

K. PREVENTION OF SIGNIFICANT DETERIORATION (PSD) INCREMENT TRACKING INFORMATION
(Regulated and Unregulated Emissions Units)

PSD Increment Consumption Determination

1. Increment Consuming for Particulate Matter or Sulfur Dioxide?

   If the emissions unit addressed in this section emits particulate matter or sulfur dioxide, answer the following series of questions to make a preliminary determination as to whether or not the emissions unit consumes PSD increment for particulate matter or sulfur dioxide. Check the first statement, if any, that applies and skip remaining statements.

   [x] The emissions unit is undergoing PSD review as part of this application, or has undergone PSD review previously, for particulate matter or sulfur dioxide. If so, emissions unit consumes increment.

   [ ] The facility addressed in this application is classified as an EPA major source pursuant to paragraph (c) of the definition of "major source of air pollution" in Chapter 62-213, F.A.C., and the emissions unit addressed in this section commenced (or will commence) construction after January 6, 1975. If so, baseline emissions are zero, and the emissions unit consumes increment.

   [ ] The facility addressed in this application is classified as an EPA major source and the emissions unit began initial operation after January 6, 1975, but before December 27, 1977. If so, baseline emissions are zero, and the emissions unit consumes increment.

   [ ] For any facility, the emissions unit began (or will begin) initial operation after December 27, 1977. If so, baseline emissions are zero, and emissions unit consumes increment.

   [ ] None of the above apply. If so, the baseline emissions of the emissions unit are nonzero. In such case, additional analysis, beyond the scope of this application, is needed to determine whether changes in emissions have occurred (or will occur) after the baseline date that may consume or expand increment.

2. Increment Consuming for Nitrogen Dioxide?

If the emissions unit addressed in this section emits nitrogen oxides, answer the following series of questions to make a preliminary determination as to whether or not the emissions unit consumes PSD increment for nitrogen dioxide. Check first statement, if any, that applies and skip remaining statements.

[x] The emissions unit addressed in this section is undergoing PSD review as part of this application, or has undergone PSD review previously, for nitrogen dioxide. If so, emissions unit consumes increment.

[ ] The facility addressed in this application is classified as an EPA major source pursuant to paragraph (c) of the definition of "major source of air pollution" in Chapter 62-213, F.A.C., and the emissions unit addressed in this section commenced (or will commence) construction after February 8, 1988. If so, baseline emissions are zero, and the source consumes increment.

[ ] The facility addressed in this application is classified as an EPA major source and the emissions unit began initial operation after February 8, 1988, but before March 28, 1988. If so, baseline emissions are zero, and the source consumes increment.

[ ] For any facility, the emissions unit began (or will begin) initial operation after March 28, 1988. If so, baseline emissions are zero, and the emissions unit consumes increment.

[ ] None of the above apply. If so, baseline emissions of the emissions unit are nonzero. In such case, additional analysis, beyond the scope of this application, is needed to determine whether changes in emissions have occurred (or will occur) after the baseline date that may consume or expand increment.

3.	Increment Consuming/Expanding Code:			
	PM	[x] C	[ ] E	[ ] Unknown
	SO_2	[x] C	[ ] E	[ ] Unknown
	NO_2	[x] C	[ ] E	[ ] Unknown
4.	Baseline Emissions:			
	PM	lb/hour		tons/year
	SO_2	lb/hour		tons/year
	NO_2			tons/year
5.	PSD Comment (limit to 200 characters):			

L. EMISSIONS UNIT SUPPLEMENTAL INFORMATION
(Regulated Emissions Units Only)

Supplemental Requirements for All Applications

1.	Process Flow Diagram [x] Attached, Document ID: SCC-EU1-L1 [ ] Not Applicable	[ ] Waiver Requested
2.	Fuel Analysis or Specification [x] Attached, Document ID: SCC-EU1-L2 [ ] Not Applicable	[ ] Waiver Requested
3.	Detailed Description of Control Equipment [ ] Attached, Document ID: ______ [x] Not Applicable	[ ] Waiver Requested
4.	Description of Stack Sampling Facilities [ ] Attached, Document ID: ______ [x] Not Applicable	[ ] Waiver Requested
5.	Compliance Test Report [ ] Attached, Document ID: ______ [ ] Previously Submitted, Date: ______	[x] Not Applicable
6.	Procedures for Startup and Shutdown [ ] Attached, Document ID: ______	[x] Not Applicable
7.	Operation and Maintenance Plan [ ] Attached, Document ID: ______	[x] Not Applicable
8.	Supplemental Information for Construction Permit Application [x] Attached, Document ID: Attachment A	[ ] Not Applicable
9.	Other Information Required by Rule or Statute [ ] Attached, Document ID: ______	[x] Not Applicable

Additional Supplemental Requirements for Category I Applications Only

10.	Alternative Methods of Operation [ ] Attached, Document ID: ____________ [ ] Not Applicable
11.	Alternative Modes of Operation (Emissions Trading) [ ] Attached, Document ID: ____________ [ ] Not Applicable
12.	Identification of Additional Applicable Requirements [ ] Attached, Document ID: ____________ [ ] Not Applicable
13.	Compliance Assurance Monitoring Plan [ ] Attached, Document ID: ____________ [ ] Not Applicable
14.	Acid Rain Permit Application (Hard Copy Required) [ ] Acid Rain Part - Phase II (Form No. 62-210.900(1)(a)) Attached, Document ID: ____________ [ ] Repowering Extension Plan (Form No. 62-210.900(1)(a)1.) Attached, Document ID: ____________ [ ] New Unit Exemption (Form No. 62-210.900(1)(a)2.) Attached, Document ID: ____________ [ ] Retired Unit Exemption (Form No. 62-210.900(1)(a)3.) Attached, Document ID: ____________ [ ] Not Applicable

III. EMISSIONS UNIT INFORMATION

A separate Emissions Unit Information Section (including subsections A through L as required) must be completed for each emissions unit addressed in this Application for Air Permit. If submitting the application form in hard copy, indicate, in the space provided at the top of each page, the number of this Emissions Unit Information Section and the total number of Emissions Unit Information Sections submitted as part of this application. Some of the subsections comprising the Emissions Unit Information Section of the form are intended for regulated emissions units only. Others are intended for both regulated and unregulated emissions units. Each subsection is appropriately marked.

A. TYPE OF EMISSIONS UNIT
(Regulated and Unregulated Emissions Units)

Type of Emissions Unit Addressed in This Section

1. Regulated or Unregulated Emissions Unit? Check one:

[x] The emissions unit addressed in this Emissions Unit Information Section is a regulated emissions unit.

[ ] The emissions unit addressed in this Emissions Unit Information Section is an unregulated emissions unit.

2. Single Process, Group of Processes, or Fugitive Only? Check one:

[x] This Emissions Unit Information Section addresses, as a single emissions unit, a single process or production unit, or activity, which produces one or more air pollutants and which has at least one definable emission point (stack or vent).

[ ] This Emissions Unit Information Section addresses, as a single emissions unit, a group of process or production units and activities which has at least one definable emission point (stack or vent) but may also produce fugitive emissions.

[ ] This Emissions Unit Information Section addresses, as a single emissions unit, one or more process or production units and activities which produce fugitive emissions only.

B. GENERAL EMISSIONS UNIT INFORMATION
(Regulated and Unregulated Emissions Units)

Emissions Unit Description and Status

1. Description of Emissions Unit Addressed in This Section (limit to 60 characters):
   Package Boiler No. 3

2. Emissions Unit Identification Number: [ ] No Corresponding ID [ ] Unknown
   026

3. Emissions Unit Status Code: **A**	4. Acid Rain Unit? [ ] Yes [x] No	5. Emissions Unit Major Group SIC Code: **26**

6. Emissions Unit Comment (limit to 500 characters):
   This boiler vents with two other boiler units to one common stack.

Emissions Unit Control Equipment Information

A.

1. Description (limit to 200 characters): **Low NOx Burners Burner Design**
2. Control Device or Method Code: **24**

B.

1. Description (limit to 200 characters):
2. Control Device or Method Code:

C.

1. Description (limit to 200 characters):
2. Control Device or Method Code:

C. EMISSIONS UNIT DETAIL INFORMATION
(Regulated Emissions Units Only)

Emissions Unit Details

1. Initial Startup Date: 3 Mar 1994		
2. Long-term Reserve Shutdown Date:		
3. Package Unit: Manufacturer: ABB-Combustion Engineering	Model Number: 93104-20	
4. Generator Nameplate Rating:	MW	
5. Incinerator Information:		
Dwell Temperature:		°F
Dwell Time:		seconds
Incinerator Afterburner Temperature:		°F

Emissions Unit Operating Capacity

1. Maximum Heat Input Rate:	215	mmBtu/hr
2. Maximum Incineration Rate:	lbs/hr	tons/day
3. Maximum Process or Throughput Rate:		
4. Maximum Production Rate: 150,000	lb/hr steam	
5. Operating Capacity Comment (limit to 200 characters): 200 MMBtu/hr maximum when firing No. 2 fuel oil. 215 MMBtu/hr maximum when firing natural gas.		

Emissions Unit Operating Schedule

1. Requested Maximum Operating Schedule:			
24	hours/day	7	days/week
52	weeks/yr	8,760	hours/yr

D. EMISSIONS UNIT REGULATIONS
(Regulated Emissions Units Only)

<u>Rule Applicability Analysis</u> (Required for Category II Applications and Category III applications involving non Title-V sources. See Instructions.)

List of Applicable Regulations (Required for Category I applications and Category III applications involving Title-V sources. See Instructions.)

40 CFR 60 Appendix A
40 CFR 60.42b(a)
40 CFR 60.42b(g)
40 CFR 60.42b(j)
40 CFR 60.43b(g)
40 CFR 60.44b(a)
40 CFR 60.44b(b)
40 CFR 60.44b(h)
40 CFR 60.44b(i)
40 CFR 60.45b(a)
40 CFR 60.45b(j)
40 CFR 60.46b(a)
40 CFR 60.46b(c)
40 CFR 60.46b(d)
40 CFR 60.46b(e)(1)
40 CFR 60.46b(e)(4)
40 CFR 60.47b(f)
40 CFR 60.48b(a)
40 CFR 60.48b(b)
40 CFR 60.48b(c)
40 CFR 60.48b(d)
40 CFR 60.48b(e)
40 CFR 60.48b(f)
40 CFR 60.48b(g)
40 CFR 60.49b(a)
40 CFR 60.49b(b)
40 CFR 60.49b(d)
40 CFR 60.49b(f)
40 CFR 60.49b(g)
40 CFR 60.49b(h)
40 CFR 60.49b(i)
40 CFR 60.49b(j)
40 CFR 60.49b(o)
40 CFR 60.49b(r)
62-296.406(2)
62-296.406(3)
62-296.800(2)(a)3.

E. EMISSION POINT (STACK/VENT) INFORMATION
(Regulated Emissions Units Only)

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram: PSG	
2. Emission Point Type Code: [ ] 1 [x] 2 [ ] 3 [ ] 4	
3. Descriptions of Emissions Points Comprising this Emissions Unit for VE Tracking (limit to 100 characters per point):	
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common: 22,23	
5. Discharge Type Code: [ ] D [ ] F [ ] H [ ] P [ ] R [x] V [ ] W	
6. Stack Height:	200 feet
7. Exit Diameter:	8 feet
8. Exit Temperature:	330 °F

9. Actual Volumetric Flow Rate:	**68,300** acfm
10. Percent Water Vapor:	%
11. Maximum Dry Standard Flow Rate:	dscfm
12. Nonstack Emission Point Height:	feet
13. Emission Point UTM Coordinates: Zone: East (km): North (km):	
14. Emission Point Comment (limit to 200 characters): **All three boilers exhaust into common stack. Stack parameters above are total for all three boilers burning natural gas. Parameters for No. 2 fuel oil are: 345 deg. F; 67,149 acfm.**	

F. SEGMENT (PROCESS/FUEL) INFORMATION
(Regulated and Unregulated Emissions Units)

Segment Description and Rate: Segment 1 of 2

1. Segment Description (Process/Fuel Type and Associated Operating Method/Mode) (limit to 500 characters): **External Combustion Boilers - Industrial; natural Gas: over 100 MMBtu**	
2. Source Classification Code (SCC): **1-02-006-01**	
3. SCC Units: **Million Cubic Feet Burned**	
4. Maximum Hourly Rate: **0.215**	5. Maximum Annual Rate: **1,883**
6. Estimated Annual Activity Factor:	
7. Maximum Percent Sulfur:	8. Maximum Percent Ash:
9. Million Btu per SCC Unit: **1,000**	
10. Segment Comment (limit to 200 characters):	

Segment Description and Rate: Segment 2 of 2

1. Segment Description (Process/Fuel Type and Associated Operating Method/Mode) (limit to 500 characters): **External Combustion Boilers - Industrial; Distillate oil: over 100 MMBtu**	
2. Source Classification Code (SCC): **1-02-005-01**	
3. SCC Units: **Thousand Gallons Burned**	
4. Maximum Hourly Rate: **1.449**	5. Maximum Annual Rate: **10,750**
6. Estimated Annual Activity Factor:	
7. Maximum Percent Sulfur: **0.05**	8. Maximum Percent Ash: **0.1**
9. Million Btu per SCC Unit: **138**	
10. Segment Comment (limit to 200 characters): **Maximum combined yearly rate for Boiler No. 1, No. 2 and No. 3 is 10,750,000 gal/year.**	

G. EMISSIONS UNIT POLLUTANTS
(Regulated and Unregulated Emissions Units)

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
SO2			EL
NOx	024		EL
PM			NS
PM10			NS
CO			NS

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Pollutant Detail Information:

1. Pollutant Emitted: SO2

2. Total Percent Efficiency of Control: %

3. Potential Emissions: 10.43 lb/hour 38.7 tons/year

4. Synthetically Limited? [x] Yes [ ] No

5. Range of Estimated Fugitive/Other Emissions:

   [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/yr

6. Emission Factor: 0.05 %S

   Reference: AP-42 and %S

7. Emissions Method Code:

   [x] 0 [ ] 1 [ ] 2 [ ] 3 [ ] 4 [ ] 5

8. Calculation of Emissions (limit to 600 characters):

   1,449 gal/hr x 7.2 lb/gal x 0.0005 lb S/lb fuel x 2 lb SO2/lb S = 10.43 lbs/hr

9. Pollutant Potential/Estimated Emissions Comment (limit to 200 characters):

   Annual SO2 emissions from #2 fuel oil firing for all 3 boilers shall not exceed 25 TPY, except during periods of natural gas unavailability, emissions shall not exceed 40 TPY with proper notification.

Emissions Unit Information Section 3 **of** 3

Allowable Emissions (Pollutant identified on front page)

A.

1. Basis for Allowable Emissions Code: **OTHER**
2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **0.05 % Sulfur**
4. Equivalent Allowable Emissions: **10.43** lb/hour **38.7** tons/year
5. Method of Compliance (limit to 60 characters): **Fuel Oil analysis**
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters): **See Attachment SCC-EU1-HA6. Maximum annual emissions under normal operations, when natural gas is available is 25 TPY. Emissions under natural gas curtailment cannot exceed 40 TPY.**

B.

1. Basis for Allowable Emissions Code:
2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units:
4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance (limit to 60 characters):
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters):

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Pollutant Detail Information:

1. Pollutant Emitted: NOx

2. Total Percent Efficiency of Control: %

3. Potential Emissions: 34.94 lb/hour 153.1 tons/year

4. Synthetically Limited? [ ] Yes [x] No

5. Range of Estimated Fugitive/Other Emissions:

   [ ] 1 [ ] 2 [ ] 3 ________ to ________ tons/yr

6. Emission Factor: 0.2 lb/MMBtu

   Reference: Proposed Limit

7. Emissions Method Code:

   [x] 0 [ ] 1 [ ] 2 [ ] 3 [ ] 4 [ ] 5

8. Calculation of Emissions (limit to 600 characters):

   NOx emissions capped at current permit limit. Equivalent to 0.1625 lb/MMBtu at max heat input.

9. Pollutant Potential/Estimated Emissions Comment (limit to 200 characters):

   The maximum allowable NOx emissions shall not exceed 0.2 lb/MMBtu, 34.94 lbs/hr and 153.1 TPY per boiler. Total NOx emissions from all three boilers limited to 310 TPY.

Allowable Emissions (Pollutant identified on front page)

A.

1. Basis for Allowable Emissions Code: **OTHER**	
2. Future Effective Date of Allowable Emissions:	
3. Requested Allowable Emissions and Units: **0.2 lb/MMBtu**	
4. Equivalent Allowable Emissions: **34.94** lb/hour	**153.1** tons/year
5. Method of Compliance (limit to 60 characters): **CEM for NOx**	
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters): **Self-imposed limit by permittee. Based on natural gas firing.**	

B.

1. Basis for Allowable Emissions Code:	
2. Future Effective Date of Allowable Emissions:	
3. Requested Allowable Emissions and Units:	
4. Equivalent Allowable Emissions: lb/hour	tons/year
5. Method of Compliance (limit to 60 characters):	
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters):	

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Pollutant Detail Information:

1. Pollutant Emitted: **PM**
2. Total Percent Efficiency of Control: %
3. Potential Emissions: **2.9** lb/hour **11.5** tons/year
4. Synthetically Limited? [x] Yes [ ] No
5. Range of Estimated Fugitive/Other Emissions: [ ] 1 [ ] 2 [ ] 3 ________ to ________ tons/yr
6. Emission Factor: **2 lbs/1000 gal** Reference: **AP-42**
7. Emissions Method Code: [ ] 0 [ ] 1 [ ] 2 [x] 3 [ ] 4 [ ] 5
8. Calculation of Emissions (limit to 600 characters): **Fuel Oil: 1,449.3 gal/hr x 2 lbs/1000 gal = 2.90 lb/hr**
9. Pollutant Potential/Estimated Emissions Comment (limit to 200 characters): **See Attachment A for additional calculations**

Allowable Emissions (Pollutant identified on front page)

A.

1. Basis for Allowable Emissions Code:
2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units:
4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance (limit to 60 characters):
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters):

B.

1. Basis for Allowable Emissions Code:
2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units:
4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance (limit to 60 characters):
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters):

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Pollutant Detail Information:

1. Pollutant Emitted: PM10			
2. Total Percent Efficiency of Control:	%		
3. Potential Emissions:	1.45 lb/hour	6.1 tons/year	
4. Synthetically Limited?	[x] Yes	[ ] No	
5. Range of Estimated Fugitive/Other Emissions: [ ] 1 [ ] 2 [ ] 3	______ to ______ tons/yr		
6. Emission Factor: 50 % of PM Reference: AP-42			
7. Emissions Method Code: [ ] 0 [ ] 1 [ ] 2 [x] 3 [ ] 4 [ ] 5			
8. Calculation of Emissions (limit to 600 characters): **Fuel Oil: 2.90 lb/hr x 0.5 = 1.45 lb/hr**			
9. Pollutant Potential/Estimated Emissions Comment (limit to 200 characters): **See Attachment A for additional calculations**			

Emissions Unit Information Section 3 **of** 3

Allowable Emissions (Pollutant identified on front page)

A.

1. Basis for Allowable Emissions Code:
2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units:
4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance (limit to 60 characters):
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters):

B.

1. Basis for Allowable Emissions Code:
2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units:
4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance (limit to 60 characters):
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters):

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Pollutant Detail Information:

1. Pollutant Emitted: CO

2. Total Percent Efficiency of Control: %

3. Potential Emissions: 8.96 lb/hour 19 tons/year

4. Synthetically Limited? [ ] Yes [X] No

5. Range of Estimated Fugitive/Other Emissions:

   [ ] 1 [ ] 2 [ ] 3 ________ to ________ tons/yr

6. Emission Factor: 50 ppmvd

   Reference: Test Data

7. Emissions Method Code:

   [ ] 0 [x] 1 [ ] 2 [ ] 3 [ ] 4 [ ] 5

8. Calculation of Emissions (limit to 600 characters):

   Natural Gas: 41,084 dscfm x 50 ppmvd x 60 min/hr x 2,116.8 lb/sq.ft. x (28/1545) lb-deg. R/ft-lb x 1/528 deg. R = 8.96 lb/hr

9. Pollutant Potential/Estimated Emissions Comment (limit to 200 characters):

   Annual emissions based on 25 ppmvd. See Attachment A.

Emissions Unit Information Section 3 **of** 3

Allowable Emissions (Pollutant identified on front page)

A.

1. Basis for Allowable Emissions Code:
2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units:
4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance (limit to 60 characters):
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters):

B.

1. Basis for Allowable Emissions Code:
2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units:
4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance (limit to 60 characters):
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters):

I. VISIBLE EMISSIONS INFORMATION
(Regulated Emissions Units Only)

Visible Emissions Limitations: Visible Emissions Limitation 1 of 2

1.	Visible Emissions Subtype: **VE05**
2.	Basis for Allowable Opacity: [x] Rule [ ] Other
3.	Requested Allowable Opacity Normal Conditions: **5** % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour
4.	Method of Compliance: **EPA Method 9**
5.	Visible Emissions Comment (limit to 200 characters): **Natural gas firing; based on BACT**

Visible Emissions Limitations: Visible Emissions Limitation 2 of 2

1.	Visible Emissions Subtype: **VE10**
2.	Basis for Allowable Opacity: [x] Rule [ ] Other
3.	Requested Allowable Opacity Normal Conditions: **10** % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour
4.	Method of Compliance: **EPA Metod 9**
5.	Visible Emissions Comment (limit to 200 characters): **No. 2 fuel oil firing; based on BACT.**

J. CONTINUOUS MONITOR INFORMATION
(Regulated Emissions Units Only)

Continuous Monitoring System Continuous Monitor 1 of 1

1. Parameter Code: EM	2. Pollutant(s): NOx
3. CMS Requirement: [X] Rule [ ] Other	
4. Monitor Information: Monitor Manufacturer: Servomex Model Number: 1491 Serial Number: 103	
5. Installation Date: 01 Feb 1994	
6. Performance Specification Test Date: 21 Jun 1994	
7. Continuous Monitor Comment (limit to 200 characters): **CEMS for nitrogen oxides shall be operated and maintained in accordance with requirements of 40 CFR 60.48b.**	

Continuous Monitoring System Continuous Monitor _____ of _____

1. Parameter Code:	2. Pollutant(s):
3. CMS Requirement: [ ] Rule [ ] Other	
4. Monitor Information: Monitor Manufacturer: Model Number: Serial Number:	
5. Installation Date:	
6. Performance Specification Test Date:	
7. Continuous Monitor Comment (limit to 200 characters):	

K. PREVENTION OF SIGNIFICANT DETERIORATION (PSD) INCREMENT TRACKING INFORMATION
(Regulated and Unregulated Emissions Units)

PSD Increment Consumption Determination

1. Increment Consuming for Particulate Matter or Sulfur Dioxide?

If the emissions unit addressed in this section emits particulate matter or sulfur dioxide, answer the following series of questions to make a preliminary determination as to whether or not the emissions unit consumes PSD increment for particulate matter or sulfur dioxide. Check the first statement, if any, that applies and skip remaining statements.

[x] The emissions unit is undergoing PSD review as part of this application, or has undergone PSD review previously, for particulate matter or sulfur dioxide. If so, emissions unit consumes increment.

[ ] The facility addressed in this application is classified as an EPA major source pursuant to paragraph (c) of the definition of "major source of air pollution" in Chapter 62-213, F.A.C., and the emissions unit addressed in this section commenced (or will commence) construction after January 6, 1975. If so, baseline emissions are zero, and the emissions unit consumes increment.

[ ] The facility addressed in this application is classified as an EPA major source and the emissions unit began initial operation after January 6, 1975, but before December 27, 1977. If so, baseline emissions are zero, and the emissions unit consumes increment.

[ ] For any facility, the emissions unit began (or will begin) initial operation after December 27, 1977. If so, baseline emissions are zero, and emissions unit consumes increment.

[ ] None of the above apply. If so, the baseline emissions of the emissions unit are nonzero. In such case, additional analysis, beyond the scope of this application, is needed to determine whether changes in emissions have occurred (or will occur) after the baseline date that may consume or expand increment.

2. Increment Consuming for Nitrogen Dioxide?

If the emissions unit addressed in this section emits nitrogen oxides, answer the following series of questions to make a preliminary determination as to whether or not the emissions unit consumes PSD increment for nitrogen dioxide. Check first statement, if any, that applies and skip remaining statements.

[x] The emissions unit addressed in this section is undergoing PSD review as part of this application, or has undergone PSD review previously, for nitrogen dioxide. If so, emissions unit consumes increment.

[ ] The facility addressed in this application is classified as an EPA major source pursuant to paragraph (c) of the definition of "major source of air pollution" in Chapter 62-213, F.A.C., and the emissions unit addressed in this section commenced (or will commence) construction after February 8, 1988. If so, baseline emissions are zero, and the source consumes increment.

[ ] The facility addressed in this application is classified as an EPA major source and the emissions unit began initial operation after February 8, 1988, but before March 28, 1988. If so, baseline emissions are zero, and the source consumes increment.

[ ] For any facility, the emissions unit began (or will begin) initial operation after March 28, 1988. If so, baseline emissions are zero, and the emissions unit consumes increment.

[ ] None of the above apply. If so, baseline emissions of the emissions unit are nonzero. In such case, additional analysis, beyond the scope of this application, is needed to determine whether changes in emissions have occurred (or will occur) after the baseline date that may consume or expand increment.

3.	Increment Consuming/Expanding Code:			
	PM	[x] C	[ ] E	[ ] Unknown
	SO_2	[x] C	[ ] E	[ ] Unknown
	NO_2	[x] C	[ ] E	[ ] Unknown
4.	Baseline Emissions:			
	PM	lb/hour		tons/year
	SO_2	lb/hour		tons/year
	NO_2			tons/year
5.	PSD Comment (limit to 200 characters):			

L. EMISSIONS UNIT SUPPLEMENTAL INFORMATION
(Regulated Emissions Units Only)

Supplemental Requirements for All Applications

1.	Process Flow Diagram		
	[x] Attached, Document ID: SCC-EU1-L1		
	[ ] Not Applicable	[ ] Waiver Requested	
2.	Fuel Analysis or Specification		
	[x] Attached, Document ID: SCC-EU1-L2		
	[ ] Not Applicable	[ ] Waiver Requested	
3.	Detailed Description of Control Equipment		
	[ ] Attached, Document ID: ______		
	[x] Not Applicable	[ ] Waiver Requested	
4.	Description of Stack Sampling Facilities		
	[ ] Attached, Document ID: ______		
	[x] Not Applicable	[ ] Waiver Requested	
5.	Compliance Test Report		
	[ ] Attached, Document ID: ______	[x] Not Applicable	
	[ ] Previously Submitted, Date: ______		
6.	Procedures for Startup and Shutdown		
	[ ] Attached, Document ID: ______	[x] Not Applicable	
7.	Operation and Maintenance Plan		
	[ ] Attached, Document ID: ______	[x] Not Applicable	
8.	Supplemental Information for Construction Permit Application		
	[x] Attached, Document ID: Attachment A	[ ] Not Applicable	
9.	Other Information Required by Rule or Statute		
	[ ] Attached, Document ID: ______	[x] Not Applicable	

Additional Supplemental Requirements for Category I Applications Only

10. Alternative Methods of Operation

    [ ] Attached, Document ID: ____________ [ ] Not Applicable

11. Alternative Modes of Operation (Emissions Trading)

    [ ] Attached, Document ID: ____________ [ ] Not Applicable

12. Identification of Additional Applicable Requirements

    [ ] Attached, Document ID: ____________ [ ] Not Applicable

13. Compliance Assurance Monitoring Plan

    [ ] Attached, Document ID: ____________ [ ] Not Applicable

14. Acid Rain Permit Application (Hard Copy Required)

    [ ] Acid Rain Part - Phase II (Form No. 62-210.900(1)(a))
    Attached, Document ID: ____________

    [ ] Repowering Extension Plan (Form No. 62-210.900(1)(a)1.)
    Attached, Document ID: ____________

    [ ] New Unit Exemption (Form No. 62-210.900(1)(a)2.)
    Attached, Document ID: ____________

    [ ] Retired Unit Exemption (Form No. 62-210.900(1)(a)3.)
    Attached, Document ID: ____________

    [ ] Not Applicable

ATTACHMENT A
PSD REPORT

ATTACHMENT A
PSD REPORT

1.0 INTRODUCTION

Stone Container Corporation (SCC) currently operates a 100-percent recycled fiber paper mill facility located in Jacksonville, Florida. The facility has been operating as a 100-percent recycled fiber facility since 1992. Formerly, the facility had two bark boilers and three power boilers to provide steam to the paper making process. These five boilers were shutdown in March, 1994, when the U.S. Generating Company Cedar Bay facility began commercial operation.

The Cedar Bay cogeneration facility, licensed under the Florida Power Plant Site Certification Act (FPPSCA), is located adjacent to the existing SCC facility. This coal-fired power plant provides part of the steam required for the recycle fiber facility. The recycle fiber facility requires additional steam beyond that provided by the Cedar Bay facility. As a result, three new package boilers were installed by SCC to provide this necessary steam. These package boilers are fueled with natural gas and very low sulfur fuel oil. A federal and state PSD construction permit for the three package boilers was issued in July, 1993 (AC16-222359; PSD-FL-198). These permits were amended in 1995 to allow increased steam production, i.e., 125,000 lb/hr steam for each of the three package boilers (see Appendix A).

SCC is currently requesting an increase in the maximum steam production rate for each boiler from 125,000 lb/hr to 150,000 lb/hr steam. More flexibility in steam production is desired by SCC in the case of a shutdown or curtailment by Cedar Bay. Although at present SCC anticipates that this increased level of steam production will be needed infrequently, such as during a scheduled outage by Cedar Bay, SCC would like to plan for the future independently of Cedar Bay.

Although the increase in the maximum steam rates of the three boilers will result not result in an increase in allowable emissions for the boilers, an increase in actual air emissions will occur. The requested revisions for the package boilers will constitute a major modification at a major stationary facility under current federal and Florida PSD regulations. This report addresses the requirements of the PSD review procedures, pursuant to rules and regulations implementing the Clean Air Act (CAA) Amendments of 1977.

This application contains six additional sections. A complete description of the project, including air emission rates, is presented in Section 2.0. The air quality requirements for the project and new source review applicability are discussed in Section 3.0. A preconstruction ambient air quality data analysis is presented in Section 4.0. The control technology review and best available control technology (BACT) analysis is presented in Section 5.0. The required air quality impact analysis is presented in Section 6.0, and an additional impact analysis (i.e., to soils, vegetation and visibility) is described in Section 7.0.

2.0 PROJECT DESCRIPTION

2.1 GENERAL

SCC currently operates a 100 percent recycled fiber paper mill located in Jacksonville, Florida (see Attachment SCC-FE-1). Three package boilers are operated to support the paper mill operations. The boilers are fired with natural gas or very low sulfur No. 2 fuel oil with a maximum sulfur content of 0.05 percent. The current maximum steam production for each boiler is 125,000 lb/hr steam. The current maximum heat input to each boiler is 174.7 MMBtu/hr when firing natural gas, and 164.5 MMBtu/hr when firing fuel oil.

The Cedar Bay cogeneration facility currently supplies SCC with steam. However, the SCC recycle fiber facility at times requires additional steam beyond that provided by the Cedar Bay facility. SCC would like to plan for future operation and maximum flexibility by permitting the boilers to operate up to 150,000 lb/hr steam each. Although SCC anticipates that operation at this level with all three boilers will be very infrequent, SCC will no longer be constrained by Cedar Bay operation.

SCC is proposing to increase the maximum steam rate and heat input rate to the boilers, while maintaining the current permitted emission levels. The boilers currently have permitted allowable emissions rates for nitrogen oxides (NO_x) and sulfur dioxide (SO2). Each of the three package boilers will be rated at 150,000 lb/hr steam at 650 psig and 750°F. Maximum heat input to each boiler will be 215 MMBtu/hr when firing natural gas, and 200 MMBtu/hr when firing No. 2 fuel oil. Design parameters for each package boiler at the increased steam production rate are presented in Table 2-1.

Firing of No. 2 fuel oil will be limited to 10,750,000 gallons per year for all three boilers combined. This limit will insure SO_2 emissions do not exceed 40 tons per year.

2.2 EMISSIONS OF REGULATED POLLUTANTS

The package boilers are subject to the federal New Source Performance Standards (NSPS) for industrial boilers since the maximum heat input to each boiler is greater than 100 MMBtu/hr. The NSPS are contained in the Code of Federal Regulations (CFR), Title 40, Part 60, Subpart Db, and are summarized in Table 2-2. The NSPS limit emissions of NO_x to 0.2 lb/MMBtu for both natural gas firing and distillate fuel oil firing in high heat release rate boilers. The NSPS defines a high heat release rate boiler as a boiler heat release rate of greater than 70,000 Btu/hr-ft^3.

SO_2 emissions are limited under the NSPS to 0.50 lb/MMBtu(equivalent to 0.5 percent sulfur fuel) for sources which do not use an add-on SO_2 control device, such as a flue gas desulfurization system. The No. 2 fuel oil burned in the package boilers contains 0.05 percent sulfur (0.05 lb/MMBtu) or less, which will meet the NSPS requirements. There is no PM limit under NSPS for natural gas or distillate fuel oil firing.

The maximum estimated hourly emissions of regulated pollutants from each of the package boilers are presented in Table 2-3. Emissions for both No. 2 fuel oil and natural gas are shown. Also shown is the equivalent emission rate in terms of lb/MMBtu heat input.

For No. 2 fuel oil firing, total suspended particulate matter [PM(TSP)] emissions and emissions of particulate matter with an aerodynamic particle size diameter of 10 micrometers (μm) or less (PM10) are based on EPA Publication AP-42 factors for uncontrolled oil-fired boilers. The AP-42 data show that 50 percent of the PM(TSP) emissions are of PM10 size (refer to Appendix B).

The fuel oil burned in the package boilers will be a No. 2 fuel oil with a maximum sulfur content of 0.05 percent, equivalent to 0.052 lb/MMBtu, to meet the NSPS. Natural gas contains only trace quantities of sulfur.

SCC is retaining the current hourly and annual NOx emission rate for each boiler of 39.94 lb/hr and 153.1 TPY. Thus, at the maximum heat input rate, equivalent emissions will be limited to 0.1747 lb/MMBtu for oil firing, and to 0.1625 lb/MMBtu for natural gas firing. At lower loads, the boilers will continue to meet a limit of 0.2 lb/MMBtu, which is equivalent to federal NSPS for new boilers of greater than 100 MMBtu/hr heat input capacity with a high heat release rate and firing distillate oil or natural gas. The design heat release rate of the boilers will be 119,474 Btu/hr-ft^3 for No. 2 fuel oil and 128,435 Btu/hr-ft^3 for natural gas, which classifies the boilers as high heat release rate boilers.

Emissions of VOC from the boilers are based on AP-42 factors for distillate-oil-fired and natural gas-fired boilers (see Appendix B). Maximum hourly carbon monoxide (CO) emissions for both

No. 2 distillate oil firing and natural gas firing are based upon a maximum CO concentration of 50 ppm in the exhaust gases, based upon source testing of the boilers. The equivalent hourly CO emission rate is 0.0432 lb/MMBtu for oil firing, and 0.0417 lb/MMBtu for gas firing. Maximum annual CO emissions are based upon one-half of the hourly rate, or 25 ppmvd, also based on source test data.

Emissions of other PSD regulated pollutants are based on published emission factors, as indicated in the footnotes to Table 2-3. As shown in the table, fuel oil burning in the package boilers results in the maximum emissions for all pollutants on a lb/MMBtu basis.

Maximum estimated annual emissions for all three package boilers combined are presented in Table 2-4. The maximum annual emissions for certain pollutants are limited based on total annual fuel oil firing equivalent to 1.4835×10^{12} Btu/yr (equivalent to 10,750,000 gal/yr). This limitation ensures that the maximum annual SO_2 emission due to all three boilers does not exceed 40 tons per year (TPY). There is no restriction on annual natural gas firing in the boilers.

Presented in Table 2-5 are the maximum annual emissions on a per boiler basis. The maximum emissions for each boiler take into consideration the total fuel oil burning limitation of 10,750,000 gal/yr for all three boilers.

2.3 STACK PARAMETERS

Stack parameters for the package boilers are presented in Table 2-1. All three boilers are served by a single common stack 200 feet (ft) tall with an 8.0 ft diameter. The exhaust gases from each are ducted to this common stack. The location of the common stack in relation to the structures at SCC is shown in Attachment SCC-FE-2.

Table 2-1. Design Parameters for New Package Boilers

Parameter	Units	No. 2 Fuel Oil (per boiler)	Natural Gas (per boiler)
Steam Flow	lb/hr	150,000	150,000
Steam Pressure	psi	650	650
Steam Temperature	deg. F	709	750
Heat Input	MMBtu/hr	200	215
Furnace Volume	ft^3	1,674	1,674
Heat Release Rate	Btu/hr-ft^3	119,474	128,435
Fuel Heating Value	Btu/gal	138,000	--
	Btu/lb	19,167 (a)	--
	Btu/scf	--	1,000
Fuel Flow	lb/hr	10,435	--
	gal/hr	1,449.3	--
	scf/hr	--	215,000
Exhaust Gas:			
Temperature	deg. F	345	330
Moisture	%	10	10
Flow Rate	lb/hr	192,000	199,000
	acfm	67,149	68,300
	dscfm	39,638	41,084
Common Stack (b)			
Diameter	ft	8	8
Velocity	ft/s	66.79	67.94
Height	ft	200	200

(a) Density of No. 2 fuel oil is approximately 7.2 lb/gal.
(b) All three boilers will exhaust into a common stack.
Velocity shown is total all three boilers.

Table 2-2. NSPS for Natural Gas/Oil-Fired Steam-Generating Units With Heat Input Between 100 x 10^6 and 250 x 10^6 Btu/hr

Pollutant	Fuel	Annual Capacity Factor (%)	Standard
SO_2	Fuel oil	31-100 on oil	0.80 lb/10^6 Btu; 90% reduction[a]
	Fuel oil	0-30 on oil	0.50 lb/10^6 Btu
	Natural gas	0-100 on gas	No SO_2 limit
PM	Fuel oil	0-100	a. 0.10 lb/10^6 Btu if a conventional or emerging SO_2 control technology is used b. no PM limit if an SO_2 control technology is not used
	Natural gas	0-100	No PM limit
Opacity	Fuel oil or natural gas	0-100	20% opacity, except 27% for one 6-minute period per hour
NO_x	Distillate oil or natural gas	11-100 on oil or gas	Distillate oil or natural gas a. Low heat release rate--0.10 lb/10^6 Btu b. High heat release rate--0.20 lb/10^6 Btu
	Distillate oil	0-10 on oil	No NO_x standard

Note: lb/10^6 Btu = pounds per million British thermal units.
NO_x = nitrogen oxides.
SO_2 = sulfur dioxide.

[a] Percentage reduction requirement does not apply if burning very-low-sulfur oil (<0.50 lb/10^6 Btu).

Source: 40 CFR 60, Subpart Db.

Table 2-3. Maximum Hourly Emissions from Modified Package Boilers (per boiler), Stone Container Corporation, Jacksonville Mill

Regulated Pollutant	No. 2 Fuel Oil: Emission Factor (a)	Ref.	Hourly Activity Factor (a)	Hourly Emissions (lbs/hr)	Equivalent (lb/MMBtu)	Natural Gas: Emission Factor (b)	Ref.	Hourly Activity Factor (b)	Hourly Emissions (lbs/hr)	Equivalent (lb/MMBtu)
Criteria and Precursor Pollutants										
Particulate Matter (PM)	2 lbs/1000 gal	1	1,449.3 gal/hr	2.90	0.0145	5 lb/MMscf	1	0.215 MMscf/hr	1.08	0.0050
Particulate Matter (PM10)	50% of PM	1	1,449.3 gal/hr	1.45	0.0072	5 lb/MMscf	1	0.215 MMscf/hr	1.08	0.0050
Sulfur dioxide	7.2 lbs/1000 gal	2	1,449.3 gal/hr	10.43	0.052	0.6 lb/MMscf	1	0.215 MMscf/hr	0.13	0.0006
Nitrogen oxides	0.2 lbs/MMBtu	3	200 MMBtu/hr	34.94	0.2	0.2 lbs/MMBtu	3	215 MMBtu/hr	34.94	0.2
Carbon monoxide	50 ppmvd	4	39,638 dscfm	8.64	0.0432	50 ppmvd	4	41,084 dscfm	8.96	0.0417
VOC	0.2 lbs/1000 gal	1	1,449.3 gal/hr	0.29	0.0014	1.4 lbs/MMscf	1	0.215 MMscf/hr	0.30	0.0014
Lead - Total	8.9E-06 lbs/MMBtu	1	200 MMBtu/hr	0.0018	8.90E-06	2.71E-04 lbs/MMscf	1	0.215 MMscf/hr	5.8E-05	2.7E-07
Designated Pollutants										
Sulfuric Acid Mist	0.12 lbs/1000 gal	5	1,449.3 gal/hr	0.18	8.88E-04	--		--	--	--
Fluorides - Total	3.2E-05 lbs/MMBtu	6	200 MMBtu/hr	0.0064	3.20E-05	--		--	--	--
Hazardous Air Pollutants										
Beryllium	2.5E-06 lbs/MMBtu	1	200 MMBtu/hr	5.0E-04	2.50E-06	--		--	--	--
Mercury	3.0E-06 lbs/MMBtu	1	200 MMBtu/hr	0.00060	3.00E-06	1.5E-10 lbs/MMBtu	7	215 MMBtu/hr	3.2E-08	1.50E-10

Footnotes:
(a) Based on firing only No. 2 fuel oil (0.05% Sulfur) at 200 MMBtu/hr; No. 2 oil @ 138,000 Btu/gal and 7.2 lb/gal.
(b) Based on firing only natural gas at 215 MMBtu/hr; 1,000 Btu/scf.

References:
1. Based on Compilation of Air Pollutant Emission Factors, AP-42, Tables 1.3-1, 1.3-2, 1.3-5, 1.3-9, 1.4-1, 1.4-2, 1.4-3 and 1.4-5.
2. 7.2 lb/gal x 0.0005 lbS/lb fuel x 2 lb SO2/lb fuel x 1000 gal= 7.2 lb/1000 gal
3. Proposed by permittee; current permit limits.
4. Based on test data from Stone Container package boilers which showed maximum hourly CO emissions of less than 50 ppmvd.
5. AP-42, Table 1.3-2. Factor is the SO3 emission factor of 2S lb/1000 gal, where S= fuel sulfur content, multiplied by the ratio of H2SO4 to SO3.
6. Emissions Assessment of Conventional Stationary Combustion Sources: Vol. V.: Industrial Combustion Sources-Uncontrolled Fuel Oil Combustion (EPA-600/7-81-003c), Table 18.
7. From "Study of Hazardous Air Pollutant Emissions From Electric Utility Steam Generating Units", Report to Congress. 1997.

Table 2-4. Maximum Annual Emissions From Modified Package Boilers (total all boilers), Stone Container Corporation

Regulated Pollutant	No. 2 Fuel Oil Emission Factor (a)	No. 2 Fuel Oil Annual Activity Factor (b)	No. 2 Fuel Oil Annual Emissions (TPY)	Natural Gas Emission Factor (a)	Natural Gas Annual Activity Factor (b)	Natural Gas Annual Emissions (TPY)	Total Annual Emissions (TPY)
<u>Criteria and Precursor Pollutants</u>							
Particulate Matter (PM)	0.0145 lb/MMBtu	1,483,500 MMBtu/yr	10.76	0.0050 lb/MMBtu	4,055,438 MMBtu/yr	10.14	20.89
Particulate Matter (PM10)	0.0072 lb/MMBtu	1,483,500 MMBtu/yr	5.34	0.0050 lb/MMBtu	4,055,438 MMBtu/yr	10.14	15.48
Sulfur dioxide	0.052 lb/MMBtu	1,483,500 MMBtu/yr	38.6	0.0006 lb/MMBtu	4,055,438 MMBtu/yr	1.22	39.79
Nitrogen oxides	0.2 lb/MMBtu	1,483,500 MMBtu/yr	(c)	0.2 lb/MMBtu	4,055,438 MMBtu/yr	(c)	310 (c)
Carbon monoxide	0.0216 lb/MMBtu	1,483,500 MMBtu/yr	16.02	0.0209 lb/MMBtu	4,055,438 MMBtu/yr	42.38	58.4
VOC	0.0014 lb/MMBtu	1,483,500 MMBtu/yr	1.04	0.0014 lb/MMBtu	4,055,438 MMBtu/yr	2.84	3.88
Lead - Total	8.90E-06 lb/MMBtu	1,483,500 MMBtu/yr	0.0066	2.71E-07 lb/MMBtu	4,055,438 MMBtu/yr	0.00055	0.0072
<u>Designated Pollutants</u>							
Sulfuric Acid Mist	8.88E-04 lbs/MMBtu	1,483,500 MMBtu/yr	0.66	--	--	--	0.66
Fluorides - Total	3.20E-05 lbs/MMBtu	1,483,500 MMBtu/yr	0.024	--	--	--	0.024
<u>Hazardous Air Pollutants</u>							
Beryllium	2.50E-06 lbs/MMBtu	1,483,500 MMBtu/yr	0.00185	--	--	--	0.00185
Mercury	3.00E-06 lbs/MMBtu	1,483,500 MMBtu/yr	0.0022	1.50E-10 lbs/MMBtu	4,055,438 MMBtu/yr	3.0E-07	0.0022

Footnotes:
(a) Obtained from Table 2-3, except for CO. For CO, annual emisions are based on 25 ppm, or one-half of maximum hourly emissions.
(b) Based on maximum amount of fuel oil firing in order not to exceed 40 TPY SO2 emissions cap, with remainder of fuel firing due to natural gas.
The maximum total heat input due to fuel oil firing is equivalent to 10,750,000 gal/yr fuel oil at 138,000 Btu/gal.
This is equivalent to one boiler operating at 100% capacity on fuel oil for 7,417 hr/yr.
(c) Total NOx emissions capped at 310 TPY for facility.

Table 2-5. Maximum Annual Emissions from Each Modified Package Boilers (per boiler), Stone Container Corporation, Jacksonville Mill

Regulated Pollutant	No. 2 Fuel Oil Emission Factor (a)	No. 2 Fuel Oil Annual Activity Factor (b)	No. 2 Fuel Oil Annual Emissions (TPY)	Natural Gas Emission Factor (a)	Natural Gas Annual Activity Factor (b)	Natural Gas Annual Emissions (TPY)	Total Annual Emissions (TPY)
Criteria and Precursor Pollutants							
Particulate Matter (PM)	0.0145 lb/MMBtu	1,483,500 MMBtu/yr	10.76	0.0050 lb/MMBtu	288,745 MMBtu/yr	0.72	11.48
Particulate Matter (PM10)	0.0072 lb/MMBtu	1,483,500 MMBtu/yr	5.34	0.0050 lb/MMBtu	288,745 MMBtu/yr	0.72	6.06
Sulfur dioxide	0.052 lb/MMBtu	1,483,500 MMBtu/yr	38.57	0.0006 lb/MMBtu	288,745 MMBtu/yr	0.09	38.66
Nitrogen oxides	0.2 lb/MMBtu	1,483,500 MMBtu/yr	(c)	0.2 lb/MMBtu	1,883,400 MMBtu/yr	(c)	153.1 (c)
Carbon monoxide	0.0216 lb/MMBtu	1,483,500 MMBtu/yr	16.02	0.0209 lb/MMBtu	288,745 MMBtu/yr	3.02	19.0
VOC	0.0014 lb/MMBtu	1,483,500 MMBtu/yr	1.04	0.0014 lb/MMBtu	288,745 MMBtu/yr	0.20	1.24
Lead - Total	8.90E-06 lb/MMBtu	1,483,500 MMBtu/yr	0.0066	2.7E-07 lb/MMBtu	288,745 MMBtu/yr	3.9E-05	0.0066
Designated Pollutants							
Sulfuric Acid Mist	8.88E-04 lbs/MMBtu	1,483,500 MMBtu/yr	0.66	--	--	--	0.66
Fluorides - Total	3.20E-05 lbs/MMBtu	1,483,500 MMBtu/yr	0.024	--	--	--	0.024
Hazardous Air Pollutants							
Beryllium	2.50E-06 lbs/MMBtu	1,483,500 MMBtu/yr	0.0019	--	--	--	0.0019
Mercury	3.00E-06 lbs/MMBtu	1,483,500 MMBtu/yr	0.0022	1.5E-10 lbs/MMBtu	288,745 MMBtu/yr	2.2E-08	0.0022

Footnotes:
(a) Obtained from Table 2-3, except for CO. For CO, annual emissions are based on 25 ppm, or one half of maximum hourly emissions.
(b) Based on maximum amount of fuel oil firing in order to not exceed 40 TPY SO2 emission cap, with remainder of fuel firing due to natural gas. The maximum total heat input due to fuel oil firing is equivalent to 10,750,000 gal/yr of fuel oil at 138,000 Btu/gal. This is equivalent to one boiler operating for 7,417 hr/yr on fuel oil.
(c) Total NOx emissions capped at 153.1 TPY for each boiler.

3.0 PSD SOURCE APPLICABILITY ANALYSIS

Federal PSD requirements are contained in Title 40, Code of Federal Regulations (CFR), Part 52.21, Prevention of Significant Deterioration of Air Quality. The State of Florida has adopted PSD regulations (Chapter 62-212.400, F.A.C.) that essentially are identical to the federal regulations. PSD regulations require that all new major stationary sources or major modifications to existing major sources of air pollutants regulated under CAA be reviewed and a construction permit issued. Florida's State Implementation Plan (SIP), which contains PSD regulations, has been approved by EPA and PSD approval authority in Florida has been granted to FDEP.

A "major facility" is defined under Florida PSD regulations as any one of 28 named source categories that has the potential to emit 100 tons per year (TPY) or more of any pollutant regulated under the CAA, or any other stationary facility that has the potential to emit 250 TPY or more of any pollutant regulated under CAA. A "source" is defined as an identifiable piece of process equipment or emissions unit. "Potential to emit" means the capability, at maximum design capacity, to emit a pollutant, considering the application of control equipment and any other federally enforceable limitations on the source's capacity. A "major modification" is defined under PSD regulations as a change at an existing major stationary facility that increases emissions by greater than significant amounts. PSD significant emission rates are shown in Table 3-1.

The SCC facility is located in Duval County, which has been designated by EPA and FDEP as an attainment area for SO_2 and NO_x. Duval County and surrounding counties are designated as PSD Class II areas for SO_2 and NO_x. The site is located about 61 km from a PSD Class I area (Okefenokee National Wilderness Area).

The SCC facility is an existing major stationary facility because potential emissions of certain regulated pollutants exceed 100 TPY (for example, potential NO_x emissions currently exceeds 100 TPY). SCC has previously been issued a PSD permit for the package boilers, and is now requesting a revision to the maximum steam production and heat input rates. Since SCC is requesting a change in the method of operation of the facility, the net increase in emissions must be determined by comparing the current actual emissions (i.e., PSD baseline emissions) to the proposed maximum emissions. PSD review is then required for the proposed modification for each pollutant for which the net increase in emissions exceeds specified PSD significant emission rates (i.e., a major modification).

Future maximum annual emissions for the new package boilers were presented previously in Table 2-4. The PSD baseline emissions for the package boilers are presented in Table 3-2. The PSD source applicability analysis, based on the current actual and the future annual emissions, is presented in Table 3-3. As shown in Table 3-3, the increase in emissions for all pollutants except NOx will not exceed the PSD significant emission rates. Therefore, the proposed modification is subject to PSD review for NOx.

Table 3-1. PSD Significant Emission Rates and *De Minimis* Monitoring Concentrations

Pollutant	Regulated Under	Significant Emission Rate (TPY)	*De Minimis* Monitoring Concentration ($\mu g/m^3$)
Sulfur Dioxide	NAAQS, NSPS	40	13, 24-hour
Particulate Matter (TSP)	NSPS	25	NA
Particulate Matter (PM10)	NAAQS	15	10, 24-hour
Nitrogen Oxides	NAAQS, NSPS	40	14, annual
Carbon Monoxide	NAAQS, NSPS	100	575, 8-hour
Volatile Organic Compounds (Ozone)	NAAQS, NSPS	40	100 TPY[a]
Lead	NAAQS	0.6	0.1, 3-month
Sulfuric Acid Mist	NSPS	7	NM
Total Fluorides	NSPS	3	0.25, 24-hour
Mercury	NESHAP	0.1	0.25, 24-hour
Total Reduced Sulfur	NSPS	10	10, 1-hour
Reduced Sulfur Compounds	NSPS	10	10, 1-hour
Hydrogen Sulfide	NSPS	10	0.2, 1-hour
MWC Organics (as dioxin/furan)	NSPS	3.5×10^{-6}	NA
MWC Metals (as PM)	NSPS	15	NA
MWC Acid Gases (as SO_2+HCl)	NSPS	40	NA
MSW Landfill Emissions (as NMVOC)	NSPS	50	NA

Note: Ambient monitoring requirements for any pollutant may be exempted if the impact of the increase in emissions is below *de minimis* monitoring concentrations.

MWC = Municipal waste combustor
MSW = Municipal solid waste
NA = Not Applicable
NAAQS = National Ambient Air Quality Standards
NESHAP = National Emission Standards for Hazardous Air Pollutants
NM = No ambient measurement method
NMVOC = Non-methane volatile organic compounds
NSPS = New Source Performance Standards
PM10 = particulate matter with aerodynamic diameter less than or equal to 10 micrometers
PSD = prevention of significant deterioration
TPY = tons per year
TSP = total suspended particulate matter
$\mu g/m^3$ = micrograms per cubic meter

[a] No *de minimis* concentration; an increase in VOC emissions of 100 TPY or more will require monitoring analysis for ozone.

Source: F.A.C., Rule 62-212.400, Tables 212.400-2 and 212.400-3.

Table 3-2. Estimated Baseline Annual Emissions for Existing Package Boilers (total all boilers), Stone Container Corporation

Regulated Pollutant	No. 2 Fuel Oil Emission Factor (a)	No. 2 Fuel Oil Annual Activity Factor (b)	No. 2 Fuel Oil Annual Emissions (TPY)	Natural Gas Emission Factor (a)	Natural Gas Annual Activity Factor (b)	Natural Gas Annual Emissions (TPY)	Total Annual Emissions (TPY)
Criteria and Precursor Pollutants							
Particulate Matter (PM)	0.0145 lb/MMBtu	0 MMBtu/yr	0.0	0.0050 lb/MMBtu	251,000 MMBtu/yr	0.63	0.63
Particulate Matter (PM10)	0.0072 lb/MMBtu	0 MMBtu/yr	0.0	0.0050 lb/MMBtu	251,000 MMBtu/yr	0.63	0.63
Sulfur dioxide	0.052 lb/MMBtu	0 MMBtu/yr	0.0	0.0006 lb/MMBtu	251,000 MMBtu/yr	0.08	0.08
Nitrogen oxides	0.05 lb/MMBtu	0 MMBtu/yr	0.0	0.05 lb/MMBtu	251,000 MMBtu/yr	6.28	6.28
Carbon monoxide	0.0216 lb/MMBtu	0 MMBtu/yr	0.0	0.0209 lb/MMBtu	251,000 MMBtu/yr	2.62	2.62
VOC	0.0014 lb/MMBtu	0 MMBtu/yr	0.0	0.0014 lb/MMBtu	251,000 MMBtu/yr	0.18	0.18
Lead - Total	8.90E-06 lb/MMBtu	0 MMBtu/yr	0.0	2.71E-07 lb/MMBtu	251,000 MMBtu/yr	3.40E-05	3.40E-05
Designated Pollutants							
Sulfuric Acid Mist	8.88E-04 lbs/MMBtu	0 MMBtu/yr	0.0	--	--	--	0.0
Fluorides - Total	3.20E-05 lbs/MMBtu	0 MMBtu/yr	0.0	--	--	--	0.0
Hazardous Air Pollutants							
Beryllium	2.50E-06 lbs/MMBtu	0 MMBtu/yr	0.0	--	--	--	0.0
Mercury	3.00E-06 lbs/MMBtu	0 MMBtu/yr	0.0	1.50E-10 lbs/MMBtu	251,000 MMBtu/yr	1.88E-08	1.88E-08

Footnotes:
(a) Obtained from Table 2-3, except for NOx, which is based on CEM data for 1997.
(b) Based on actual average fuel usage for 1996-1997. Fuel heating value assumed at 138,000 Btu/gal for oil and 1,000 BTU/scf for gas.

Table 3-3. PSD Source Applicability Analysis, SCC Package Boiler Modification

Regulated Pollutant	Current Actual Emissions (TPY)	Maximum Future Emissions (TPY)	Net Change (TPY)	Significant Emission Rate (TPY)	PSD Review Applies ?
Particulate (TSP)	0.63	20.9	20.3	25	No
Particulate (PM10)	0.63	15.5	14.9	15	No
Sulfur dioxide	0.08	39.8	39.7	40	No
Nitrogen oxides	6.28	310	303.7	40	Yes
Carbon monoxide	2.62	58.4	55.8	100	No
Volatile organic compds.	0.18	3.88	3.70	40	No
Lead	3.40E-05	0.0072	0.0072	0.6	No
Mercury	1.88E-08	0.0022	0.0022	0.1	No
Fluorides	0.0	0.024	0.024	3	No
Sulfuric acid mist	0.0	0.66	0.66	7	No

4.0 AMBIENT MONITORING ANALYSIS

4.1 MONITORING REQUIREMENTS

The CAA Amendments of 1977 require that the owner or operator of any proposed major new source or major modification conduct ambient air monitoring for applicable pollutants. As discussed in the source applicability section, Section 3.0, only NO_x requires an air quality analysis to meet PSD preconstruction monitoring requirements for the proposed SCC modification. Monitoring must be conducted for a period of up to 1 year prior to submission of a construction permit application. However, if the increase in impacts due to the proposed new source or modification is less than the PSD *de minimis* monitoring concentrations, the applicant may be exempted from the PSD preconstruction monitoring requirements. For NO_x, the *de minimis* level is 14 $\mu g/m^3$, annual average (measured by NO_2). As demonstrated in Section 6.0, the predicted maximum increase in annual average NO_x impacts due to the proposed modification at SCC is 1.2 $\mu g/m^3$. As a result, the proposed modification may be exempted from preconstruction NO_x monitoring.

4.2 BACKGROUND NO_2 CONCENTRATIONS

A background NO_2 concentration must be estimated to account for NO_x sources which are not explicitly included in the atmospheric dispersion modeling analysis. In order to estimate a conservative background NO_2 concentration, a review of recent, available NO_2 monitoring data in the area of SCC was performed.

Presented in Table 4-1 is a summary of ambient NO_2 data available for 1996 and for January through September 1997, for all monitors located within Duval county. A total of one station is located in Duval county which has a continuous NO_2 monitor. The monitor is operated by the City of Jacksonville. Data recoveries exceed 93 percent for the station.

Annual average, and 1-hour maximums for NO_2 are shown in Table 4-1. Since the monitor is located in an area of multi source emissions (point and mobile sources), these concentrations are expected to include substantial contributions from sources in the area. These potential major contributing sources are explicitly included in the modeling analysis (refer to Section 6.0). As a result, these concentrations are not representative of actual background concentrations that would be expected to occur in conjunction with the worst-case meteorology. However, in order to be conservative, a 28 $\mu g/m^3$ annual average concentration, recorded at a site in Kooker Park was used as the background concentration in the modeling analysis.

Table 4-1. Summary of Ambient NO_2 Data for Sites in Duval County 1996 - 1997

SAROAD Site No.	City/Site	Monitoring Method	Period	No. of Obs.	Percent Data Recovery	NO_2 Concentration ($\mu g/m^3$) 1-Hour	Annual Average
1960-032-H02	Jacksonville	Continuous	1996	8,148	93.0	150	28
	Kooker Park		1997(Jan-Sep)	6,288	95.7	130	25

Note: No. = number.
Obs. = observations.
NO_2 = nitrogen dioxide.
$\mu g/m^3$ = micrograms per cubic meter.

Source: Florida DEP, 1996, 1997.

5.0 CONTROL TECHNOLOGY REVIEW

5.1 GENERAL

The control technology review requirements of the federal and state PSD regulations require that all applicable federal and state emission-limiting standards be met, and that BACT be applied to control emissions from the proposed or modified source. The BACT requirements are applicable to all regulated pollutants for which the increase in emissions from the new facility or modification exceeds the significant emission rate.

BACT is defined in 40 CFR 52.21 as:

> An emissions limitation, including a visible emission standard, based on the maximum degree of reduction of each pollutant emitted which the department, on a case by case basis, taking into account energy, environmental, and economic impacts, and other costs, determines is achievable through application of production processes and available methods, systems, and techniques (including fuel cleaning or treatment or innovative fuel combustion techniques) for control of such pollutant. If the Department determines that technological or economic limitations on the application of measurement methodology to a particular part of a source or facility would make the imposition of an emission standard infeasible, a design, equipment, work practice, operational standard or combination thereof, may be prescribed instead to satisfy the requirement for the application of BACT. Such standard shall, to the degree possible, set forth the emissions reductions achievable by implementation of such design, equipment, work practice, or operation.

The requirements for BACT were promulgated within the framework of PSD in the 1977 amendments of the CAA [Public Law 95-95; Part C, Section 165(a)(4)]. The primary purpose of BACT is to optimize consumption of PSD air quality increments and thereby enlarge the potential for future economic growth without significantly degrading air quality (EPA, 1978; 1980). Guidelines for the evaluation of BACT can be found in EPA's Guidelines for Determining Best Available Control Technology (BACT) (EPA, 1978) and in the PSD Workshop Manual (EPA, 1980). These guidelines were promulgated by EPA to provide a consistent approach to BACT and to ensure that the impacts of alternative emission control systems are measured by the same set of parameters. In addition, through implementation of these guidelines, BACT in one area may not be identical to BACT in another area. According to EPA (1980):

> BACT analyses for the same types of emissions unit and the same pollutants in different locations or situations may determine that different control strategies should be applied to the different sites, depending on site-specific factors. Therefore, BACT analyses must be conducted on a case-by-case basis.

The BACT requirements are intended to ensure that the control systems incorporated in the design of a proposed facility reflect the latest in control technologies used in a particular industry and take into consideration existing and future air quality in the vicinity of the proposed facility. BACT must, as a minimum, demonstrate compliance with NSPS for a source (if applicable). An evaluation of the air pollution control techniques and systems, including a cost-benefit analysis of alternative control technologies capable of achieving a higher degree of emission reduction than the proposed control technology, is required. The cost-benefit analysis requires the documentation of the materials, energy, and economic penalties associated with the proposed and alternative control systems, as well as the environmental benefits derived from these systems. A decision on BACT is to be based on sound judgment, balancing environmental benefits with energy, economic, and other impacts (EPA, 1978).

Historically, a bottom-up approach consistent with the BACT Guidelines and PSD Workshop Manual has been used. With this approach, an initial control level, which is usually NSPS, is evaluated against successively more stringent controls until a BACT level is selected. However, EPA developed a concern that the bottom-up approach was not providing the level of BACT decisions originally intended. As a result, in December 1987, the EPA Assistant Administrator for Air and Radiation mandated changes in the implementation of the PSD program including the adoption of a new "top-down" approach to BACT decision-making.

The top-down BACT approach essentially starts with the most stringent (or top) technology and emissions limits that have been applied elsewhere to the same or a similar source category. The applicant must next provide a basis for rejecting this technology in favor of the next most stringent technology or propose to use it. Rejection of control alternatives may be based on technical or economic infeasibility. Such decisions are made on the basis of physical differences (e.g., fuel type), locational differences (e.g., availability of water), or significant differences that may exist in the environmental, economic, or energy impacts. The differences between the proposed facility and the facility on which the control technique was applied previously must be justified. The EPA issued a draft guidance document on the top-down approach entitled Top-Down Best Available Control Technology Guidance Document (EPA, 1990). However, to date EPA has not promulgated the top-down approach for determining BACT.

5.2 APPLICABILITY

For the proposed SCC modification, NO_x emissions are subject to PSD review. As a result, NO_x emissions are subject to BACT review. According to the federal PSD regulations, a major modification must apply BACT for these pollutants for each emissions unit which is being physically modified, or for which there is a change in the method of operation due to the proposed modification [40 CFR 52.21(j)]. A change in the method of operation does not include an increase in the production rate or in the hours of operation, unless such increase would be prohibited by a federally enforceable permit condition established after January 6, 1975.

Package Boiler Nos. 1-3 will not be physically modified as part of the proposed increase in heat input and steam production. The existing package boilers are currently capable of the higher heat input and production rate. However there will be a change in the method of operation of the boilers. Therefore a BACT determination is required for Boiler Nos. 1-3 for NO_x emissions.

Boiler Nos. 1-3 are also subject to BACT for particulate matter (PM) and sulfur dioxide (SO_2). According to Rule 62-296.406 F.A.C, new and existing fossil fuel steam generators with less than 250 MMBtu/hr heat input are required to apply BACT for PM and SO_2.

5.3 BACT FOR NO_x EMISSIONS

Each of the existing Boiler Nos. 1-3 at SCC currently are permitted to operate at 174.5 MMBtu/hr and 125,000 lb of steam produced/hr, fired by natural gas and No. 6 fuel oil as backup. SCC is proposing to increase each of the boiler's maximum hourly heat input and steam production to 215 MMBtu/hr and 150,000 lb/hr, respectively, while maintaining the currently permitted emission limits.

5.3.1 Existing Control Technology

Package Boiler Nos. 1-3 are currently equipped with low-NO_x burners and utilize flue gas recirculation (FGR) to control NO_x emissions. Each the three boiler's currently permitted emission limits are 0.2 lb/MMBtu, 34.94 lb/hr and 153.1 TPY for NO_x. The current technology is adequate to meet the allowable emission limits.

SCC obtained permission from FDEP to conduct continuous NO_x emission monitor relative accuracy testing (RATA) while operating near the proposed increased steam rate of 150,000 lb/hr to determine emission estimates for this proposed project. The RATA test data is summarized in Table 5-1. NO_x emission rates ranged from 0.0918 to 0.1318 lb/MMBtu for steam rates ranging from approximately 141,000 lb/hr to 146,000 lb/hr.

5.3.2 Control Technology Review

A review of the RACT/BACT/LAER Clearinghouse (RBLC) was conducted to identify BACT determinations which have been issued for natural gas-fired boilers. A complete listing of these determinations is provided in Appendix C. This listing is presented chronologically, starting with the most recent determinations. Based on this listing, all determinations for boilers within the size range of 100 to 300 MMBtu/hr were identified. These determinations, which represent the size category of SCC's boilers, are presented in Table 5-2. These determinations are presented in the order of least stringent to most stringent emission rate. As shown, all BACT determinations, within the 100 to 300 MMBtu/hr range, were based on low-NO_x burners, flue gas recirculation, or a combination of both. Previous BACT determinations have ranged from 0.05 lb/MMBtu to 0.20 lb/MMBtu. These determinations are generally for new boilers, and not existing boilers which were undergoing a steam rate increase.

Selective catalytic reduction (SCR) and selective non-catalytic reduction (SNCR) control systems can be identified as having practical potential for this application. Both of these systems are based on the reduction of NOx to N_2, through a series of chemical reactions. SNCR has been determined as BACT for one boiler approximately four times as large as SCC's boilers, while no determinations were found requiring SCR as BACT for a natural gas-fired boiler. SCR and SNCR control systems are also costly to install. Therefore, SCR and SNCR were no longer considered feasible as BACT for Package Boiler Nos. 1-3.

5.3.3 Proposed BACT

SCC's proposed NO_x emission rate for Package Boiler Nos. 1-3 is 0.2 lb/MMBtu, 34.94 lb/hr and 153.1 TPY. Based on the RBLC, the proposed BACT for Package Boiler Nos. 1-3 is low-NOx burners and FGR.

5.4 BACT FOR PM/PM10 EMISSIONS

Based on the insignificant level of PM/PM10 emissions from Package Boiler Nos. 1-3, natural gas as the primary fuel was determined as BACT by PSD-FL-198 and is proposed as BACT for the proposed modification.

5.5 BACT FOR SO_2 EMISSIONS

Based on the insignificant level of SO_2 emissions from Package Boiler Nos. 1-3, natural gas as the primary fuel, and very low sulfur fuel oil with a maximum sulfur content of 0.05% as a backup fuel, was determined as BACT by PSD-FL-198 and is proposed as BACT for the proposed modification.

Table 5-1. Summary of 1998 RATA Test Data, Stone Container Corporation

Run No.	Steam Rate (lb/hr)	Emission Rate (lb/MMBtu)
Boiler No. 1		
1	143,261	0.0918
2	142,714	0.0923
3	144,105	0.0924
4	145,745	0.0918
5	145,468	0.0925
6	145,359	0.0925
7	145,464	0.0929
8	145,791	0.0925
9	144,891	0.0921
10	144,941	0.0927
Boiler No. 2		
1	142,480	0.1240
2	143,141	0.1283
3	143,900	0.1260
4	144,509	0.1277
5	144,459	0.1284
6	144,277	0.1277
7	143,955	0.1317
8	143,932	0.1318
9	144,264	0.1311
10	144,173	0.1301
Boiler No. 3		
1	141,764	0.1030
2	142,318	0.1025
3	142,745	0.1018
4	142,768	0.1028
5	142,932	0.1027
6	143,018	0.1036
7	143,609	0.1036
8	143,495	0.1036
9	143,559	0.1036
10	143,836	0.1030

Source: Source Testing and Consulting, Inc. (May 1998) and Stone Container Corporation

Table 5-2. Summary of BACT Determinations for NOx from 100 MMBtu/hr - 300 MMBtu/hr Boilers Fired by Natural Gas

Company	State	Permit No	Permit Issue Date	Throughput	Emssion Limit	Control Equipment	Control Efficiency
LOCKPORT COGEN FACILITY	NY	292600 0446/00001-00007	07/14/93	210 MMBtu/hr	0 2 lb/MMBtu	--	--
LAKEWOOD COGENERATION, L.P.	NJ	--	04/01/91	131 MMBtu/hr	0 2 lb/MMBtu	LOW NOX BURNERS	50
SARANAC ENERGY COMPANY	NY	5-942-106/1-9	07/31/92	249 MMBtu/hr	0.136 lb/MMBtu	LOW NOX BURNERS	--
MINNESOTA CORN PROCESSORS, INC.	MN	AMENDMENT 6 TO 1939-88-0T-1	06/25/91	178.7 MMBtu/hr	0 125 lb/MMBtu	LOW NOX BURNERS	--
GENERAL ELECTRIC CO.	IN	PSD (65) 1757	09/17/89	250 MMBtu/hr	0.12 lb/MMBtu	LOW NOX BURNERS, STAGED COMBUSTION AIR	--
BERMUDA HUNDRED ENERGY LIMITED PARTNERSHIP	VA	51020	03/03/92	250 MMBtu/hr	0.1 lb/MMBtu	LOW NOX BURNER	--
SCOTT PAPER COMPANY	AL	503-2012	09/17/91	220 5 MMBtu/hr	0 1 lb/MMBtu	FACILITY NOW SHUT DOWN	--
NEWARK BAY COGENERATION PARTNERSHIP, L.P.	NJ	01-92-5231 TO 01-92-5261	06/09/93	206 MMBtu/hr	0 1 lb/MMBtu	LOW NOX BURNERS, FLUE GAS RECIRCULATION (FGR)	--
PILGRIM ENERGY CENTER	NY	472800 2054	--	204 MMBtu/hr	0 1 lb/MMBtu	--	--
LAKEWOOD COGENERATION, L.P.	NJ	--	04/01/91	131 MMBtu/hr	0 1 lb/MMBtu	LOW NOX BURNERS	50
NORTHERN CONSOLIDATED POWER	PA	25-328-1	05/03/91	100.4 MMBtu/hr	0.1 lb/MMBtu	--	--
TRANSAMERICAN REFINING CORPORATION	LA	PSD-LA-571 (M-1)	02/10/95	244 MMBtu/hr	0.081 lb/MMBtu	LOW NOX BURNERS/COMBUSTION CONTROL	--
AMERICAN CRYSTAL SUGAR COMPANY	MN	29B-92-OT-1	12/15/92	200 1 MMBtu/hr	0 075 lb/MMBtu	LOW NOX BURNER WITH FLUE GAS RECIRCULATION	--
COURTAULDS FIBERS, INC.	AL	503-5002-X023 AND -X40	11/02/94	148 MMBtu/hr	0 070 lb/MMBtu	LOW NOX BURNERS WITH 8% FLUE GAS RECIRCULATION	87
JAMES RIVER CORP	MI	423-91	09/17/91	226.7 MMBtu/hr	0.06 lb/MMBtu	LOW NOX BURNERS AND FGR SYS	70
GRAIN PROCESSING CORP.	IN	CP 027-7239-00046	06/10/97	244 MMBtu/hr	0.05 lb/MMBtu	LOW NOX BURNERS AND FLUE GAS RECIRCULATION (FGR)	--
NEWARK BAY COGENERATION PARTNERSHIP, L.P.	NJ	01-92-5231 TO 01-92-5261	06/09/93	200 MMBtu/hr	0 05 lb/MMBtu	LOW NOX BURNERS, FLUE GAS RECIRCULATION (FGR)	--
ANITEC COGEN PLANT	NY	030200 0451	07/07/93	123 MMBtu/hr	0 05 lb/MMBtu	--	--

Source: EPA's RACT/BACT/LAER Clearinghouse, 1998

6.0 AIR QUALITY IMPACT ANALYSIS

6.1 SIGNIFICANT IMPACT ANALYSIS

The general modeling approach followed EPA and FDEP modeling guidelines for determining compliance with AAQS and PSD increments. For all criteria pollutants that will be emitted in excess of the PSD significant emission rate due to a proposed project, a significant impact analysis is performed to determine whether the emission and/or stack configuration changes due to the project alone will result in predicted impacts that are in excess of the EPA significant impact levels at any location beyond the plant property boundaries.

Generally, if the facility undergoing the modification also is within 200 kilometers of a PSD Class I area, then a significant impact analysis is also performed for the PSD Class I area. Currently, the National Park Service (NPS) has recommended significant impact levels for PSD Class I areas. The recommended levels have not been promulgated as rules.

If the project's impacts are above the significant impact levels, then a more detailed air modeling analysis that includes background sources is performed. Current FDEP policies stipulate that the highest annual average and highest short-term (i.e., 24 hours or less) concentrations are to be compared to the applicable significant impact levels. Based on the screening modeling analysis results, additional modeling refinements with a denser receptor grid are performed, as necessary, to obtain the maximum concentration. Modeling refinements are performed with a receptor grid spacing of 100 meters (m) or less.

6.2 AAQS/PSD MODELING ANALYSIS

For each pollutant for which a significant impact is predicted, a refined impact analysis is required. This analysis must consider other nearby sources and background concentrations and predict concentrations for comparison to ambient standards. In general, when 5 years of meteorological data are used in the analysis, the highest annual and the highest, second-highest (HSH) short-term concentrations are compared to the applicable AAQS and allowable PSD increments. The HSH concentration is calculated for a receptor field by:

1. Eliminating the highest concentration predicted at each receptor,
2. Identifying the second-highest concentration at each receptor, and
3. Selecting the highest concentration among these second-highest concentrations.

This approach is consistent with air quality standards and allowable PSD increments, which permit a short-term average concentration to be exceeded once per year at each receptor.

To develop the maximum short-term concentrations for the proposed project, the modeling approach was divided into screening and refined phases to reduce the computation time required to perform the modeling analysis. For this study, the only difference between the two modeling phases is the density of the receptor grid spacing employed when predicting concentrations. Concentrations are predicted for the screening phase using a coarse receptor grid and a 5-year meteorological data record.

If the original screening analysis indicates that the highest concentrations are occurring in a selected area(s) of the grid and, if the area's total coverage is too vast to directly apply a refined receptor grid, then an additional screening grid(s) will be used over that area. The additional screening grid(s) will employ a greater receptor density than the original screening grid, so refinements can be performed if necessary.

Refinements of the maximum predicted concentrations are typically performed for the receptors of the screening receptor grid at which the highest and/or HSH concentrations occurred over the 5-year period. Generally, if the maximum concentration from other years in the screening analysis are within 10 percent of the overall maximum concentration, then those other concentrations are refined as well. Typically, if the highest and HSH concentrations are in different locations, concentrations in both areas are refined.

Modeling refinements are performed for short-term averaging times by using a denser receptor grid, centered on the screening receptor to be refined. The angular spacing between radials is 2 degrees and the radial distance interval between receptors is 100 m. Annual modeling refinements employ an angular spacing between radials of 2 degrees and a distance interval from 100 to 300 m, depending on the concentration gradient in the vicinity of the screening receptor to be refined. If the maximum screening concentration is located on the plant property boundary, additional plant boundary receptors are input, spaced at a 2 degree angular interval and centered on the screening receptor. The domain of the refinement grid will extend to all adjacent screening receptors. The air dispersion model is then executed with the refined grid for the entire year of meteorology during which the screening concentration occurred. This approach is used to ensure that a valid HSH concentration is obtained. A more detailed description of the model, along with the emission inventory, meteorological data, and screening receptor grids, is presented in the following sections.

6.2.1 Model Selection

The Industrial Source Complex Short-term (ISCST3, Version 97363) dispersion model (EPA, 1995) was used to evaluate the pollutant impacts due to the proposed modification to Stone Container Corporation's (SCC) Jacksonville plant package boilers. This model is maintained on the EPA's Technical Transfer Network (TTN) internet web site. A listing of ISCST3 model features in presented in Table 6-1. The ISCST3 model is applicable to sources located in either flat or rolling terrain where terrain heights do not exceed stack heights. The ISCST3 model is designed to calculate hourly concentrations based on hourly meteorological parameters (i.e., wind direction, wind speed, atmospheric stability, ambient temperature, and mixing heights).

In this analysis, the EPA regulatory default options were used to predict all maximum impacts. Based on the land-use within a 3-km radius of the SCC site, the rural dispersion coefficients were used in the modeling analysis. The ISCST3 model was used to provide maximum concentrations for the annual and 24-hour averaging times.

6.2.2 Meteorological Data

Meteorological data used in the ISCST3 model to determine air quality impacts consisted of a concurrent 5-year period of hourly surface weather observations and twice-daily upper air soundings from the National Weather Service (NWS) stations at Jacksonville International Airport (JAX) and Waycross, GA, respectively. The 5-year period of meteorological data was from 1983 through 1987. The NWS station at Jacksonville International Airport, located approximately 12 km to the southwest of the SCC plant site, was selected for use in the study because it is the closest primary weather station to the study area that is representative of the plant site.

6.2.3 Emission Inventory

Significant Impact Analysis

The future NOx emission rate and the physical and operational stack parameters for the package boilers' stack are summarized in Table 6-2. This table is based on emission and stack parameter data presented in Section 2.0. Because the current actual emission rate for the package boilers is very small (< 10 TPY), the significant impact analysis was based on the future package boiler's emission rate of 310 TPY. All SCC sources were modeled at locations that are relative to the SCC plant baseline, which is the same modeling origin that was used in a previous PSD application for Seminole Kraft Corporation (KBN, 11/92).

AAQS Analysis

An emission inventory of updated competing NO_X facilities were obtained from the FDEP. Supplemental emission data from FDEP's 1993 APIS data were used to provide emission estimates for several sources whose potential or allowable NO_X emissions were not available in the latest FDEP data.

From these data, a list of competing NO_X facilities and their locations relative to the SCC plant location was developed and is provided in Table 6-3. An alphabetical listing of the inventory presented in Table 6-3 is included in Table D-1, Appendix D. All facilities were evaluated with the North Carolina screening technique to determine if they should be included in the AAQS or PSD Class II modeling analysis. Based on this technique, facilities whose maximum annual emissions in tons/year do not exceed the threshold quantity of 20 x (D-D1), where D1 is the proposed project's significant impact distance, were eliminated from air the modeling analysis.

A summary of the NO_X source data that was used for the AAQS analysis is presented in Attachment E, Tables E-1 and E-2. Table E-1 presents the source information for all modeled facility emission points. In Table E-2, some sources are combined based on EPA's method for merging sources (EPA, 1992). In general, prominent emission sources within a facility were kept separate (i.e., no merging was performed). Numerous small emission sources within a facility were usually

$$M = \frac{h_s V T_s}{Q}$$

merged into one source based on the following approach: for each stack, the mearged-stack parameter M was computed as follows:

where: M = merged stack parameter which accounts for the relative influence of stack height, plume rise, and emission rate on concentrations

h_s = stack height (m)

V = (/4) dv_s = stack gas volumetric flow rate (m^3/s)

d_s = inside stack diameter (m)

v_s = stack gas exit velocity (m/s)

T_s = stack gas exit temperature (K)

Q = pollutant emission rate (g/s)

The parameters for the stack with the lowest value of M were used for the representative stack in the air modeling analysis. Then, the sum of the emissions from all applicable sources was assumed to be emitted from the representative stack.

PSD Class II Analysis

Of the facilities considered in the air modeling analysis, only the SCC and Cedar Bay Cogeneration facilities affect the NO_2 PSD increment. The package boilers and the Cedar Bay facility are PSD increment consuming sources. There are also several SCC sources that have been shut down since the 1988 baseline date that would expand PSD increment in the vicinity of the plant. The Jacksonville Electric Authority's St. John's River Power Power is not a PSD source for NO_X, as the plant was under construction prior to the 1988 baseline date.

A summary of SCCs NO_x emissions and source stack parameters for the PSD baseline year (1988-89) are provided in Tables 6-4 and 6-5, respectively. These sources, together with the package boilers and the Cedar Bay sources, comprise the PSD Class II emission inventory for the proposed project.

PSD Class I Analysis

Because the proposed package boiler expansion's maximum air impacts do not exceed the recommended NPS significant impact levels for NO_x at the Okefenokee NWA PSD Class I area, a PSD Class I increment consumption modeling assessment was not required.

6.2.4 RECEPTOR LOCATIONS

6.2.4.1 Site Vicinity

To determine the NO_X significant impact area for the proposed project, concentrations were predicted for 180 regular and 170 discrete polar grid receptors located in a radial grid centered on SCC's plant baseline location, the selected modeling origin. Receptors were located in "rings" with 36 receptors per ring, spaced at 10-degree intervals and at distances of the fenceline 1.5, 2, 3, 4, and 5 km from the origin. Discrete receptors included 36 receptors located on the plant property boundary at 10 degree intervals, plus 134 additional off-property receptors at distances of 0.4, 0.6, 0.8, 1.0 and 1.2 km from the origin to cover the area between the property boundary and the closest regular receptor grid distance (i.e., 1.5 km). The 36 property boundary receptors used for the screening analysis are presented in Table 6-6.

Based on the results of the significant impact analysis, the proposed project was determined to be marginally over the significant impact level and out to a distance of approximately 600 m from the origin. Based on this results, a maximum receptor distance of 1 km was used for the screening grid for the AAQS and PSD Class II analysis.

6.2.4.2 Class I Area

Impacts for the proposed modification only were also compared to the Class I significance level recommended by the National Park Service (NPS). Maximum NO_X impacts at the Okefenokee and Wolf Island NWA's were predicted using 11 discrete receptors located along the southern and/or eastern borders of the respective PSD Class I areas. A listing of Class I receptors used in the air modeling analysis is provided in Table 6-7.

6.2.5 BACKGROUND CONCENTRATIONS

To estimate total air quality concentrations, a background concentration must be added to the modeling results. The background concentration is considered to be the air quality concentration contributed by sources not included in the modeling evaluation.

The derivation of the background concentration for the modeling analysis was presented in Section 4.0. The only ambient monitoring station currently measuring NO_2 in Duval County is located at Kooker Park in Jacksonville. Based on the analysis of these data, a NO_X background concentration of 28 $\mu g/m^3$ was selected. The background concentration was added to the maximum model-predicted concentration to estimate the total NO_X air quality level for comparison to the AAQS.

6.2.6 BUILDING DOWNWASH EFFECTS

All significant building structures within SCC's and Cedar Bay's existing plant area were determined by inspection of a site plot plan. A total of 6 building structures were evaluated. All building structures were processed in the EPA Building Input Profile (BPIP, Version 95086) program to determine direction-specific building heights and projected widths for each 10-degree azimuth direction for each source that was included in the modeling analysis. A listing of dimensions for each structure is presented in Table 6-8.

6.3 MODEL RESULTS

6.3.1 SIGNIFICANT IMPACT ANALYSIS

Site Vicinity

A summary of the predicted maximum NO_X concentration for the proposed modification only for the screening analysis is presented in Table 6-9. The modeling results indicate that the maximum screening analysis concentration of 1.23 $\mu g/m^3$ is above the significance level of 1.0 $\mu g/m^3$. It was further determined that the significant impact area for the proposed modification extends out approximately 600 m from the SCC plant baseline location.

Okefenokee and Wolf Island NWA

A summary of the predicted maximum NO_X concentration for the proposed modification only at the two PSD Class I areas is presented in Table 6-10. The results indicate that the maximum predicted impact of 0.009 $\mu g/m^3$, annual average, is below the NPS recommended significant impact level of 0.03 $\mu g/m^3$, annual average.

6.4 AAQS ANALYSIS

A summary of the maximum annual NO_x concentration predicted for all sources for the screening analysis is presented in Table 6-11. Based on the proximity of the screening analysis maximum impact, additional modeling refinements were not performed. The maximum total NO_X impact is compared to the AAQS in Table 6-12. The maximum predicted annual concentration is 39 $\mu g/m^3$, which includes a non-modeled background concentration of 28 $\mu g/m^3$. The total NO_X concentration is less than the AAQS of 100 $\mu g/m^3$.

6.5 PSD CLASS II ANALYSIS

A summary of the maximum NO_2 PSD increment consumption for the screening analysis is presented in Table 6-13. The screening analysis results indicate that the PSD increment is less than zero (i.e., increment expansion) in all areas in the vicinity of the SCC plant. Therefore, additional modeling refinements were not performed.

6.6 PSD CLASS I ANALYSIS

The maximum annual NO_2 concentration at the Okefenokee and Wolf Island NWAs due to the proposed project are below the NPS' recommended PSD Class I significant impact level. Therefore, a full PSD Class I incremental analysis is not required.

Table 1.3-10. EMISSION FACTORS FOR METALS FROM NO. 6 FUEL OIL COMBUSTION[a]

Metal	Average Emission Factor[b] (lb/10^3 Gal)	EMISSION FACTOR RATING
Antimony	5.25E-03[c]	E
Arsenic	1.32E-03	C
Barium	2.57E-03	D
Beryllium	2.78E-05	C
Cadmium	3.98E-04	C
Chloride	3.47E-01	D
Chromium	8.45E-04	C
Chromium VI	2.48E-04	C
Cobalt	6.02E-03	D
Copper	1.76E-03	C
Fluoride	3.73E-02	D
Lead	1.51E-03	C
Manganese	3.00E-03	C
Mercury	1.13E-04	C
Molybdenum	7.87E-04	D
Nickel	8.45E-02	C
Phosphorous	9.46E-03	D
Selenium	6.83E-04	C
Vanadium	3.18E-02	D
Zinc	2.91E-02	D

[a] Data are for residual oil fired boilers, Source Classification Codes (SCCs) 1-01-004-01/04.
[b] References 64-72. To convert from lb/10^3 gal to kg/10^3 L, multiply by 0.12.
[c] References 29-32,40-44.

Table 1.3-11. DEFAULT CO_2 EMISSION FACTORS FOR LIQUID FUELS[a]

EMISSION FACTOR RATING: B

Fuel Type	%C[b]	Density[c] (lb/gal)	Emission Factor (lb/10^3 gal)
No. 1 (kerosene)	86.25	6.88	21,500
No. 2	87.25	7.05	22,300
Low Sulfur No. 6	87.26	7.88	25,000
High Sulfur No. 6	85.14	7.88	24,400

[a] Based on 99% conversion of fuel carbon content to CO_2. To convert from lb/gal to gram/cm^3, multiply by 0.12. To convert from lb/10^3 gal to kg/m^3, multiply by 0.12.
[b] Based on an average of fuel carbon contents given in references 73-74.
[c] References 73, 75.

Table 6-1. Major Features of the ISCST3 Model

ISCST3 Model Features
• Polar or Cartesian coordinate systems for receptor locations
• Rural or one of three urban options which affect wind speed profile exponent, dispersion rates, and mixing height calculations
• Plume rise due to momentum and buoyancy as a function of downwind distance for stack emissions (Briggs, 1969, 1971, 1972, and 1975; Bowers, et al., 1979).
• Procedures suggested by Huber and Snyder (1976); Huber (1977); and Schulman and Scire (1980) for evaluating building wake effects
• Procedures suggested by Briggs (1974) for evaluating stack-tip downwash
• Separation of multiple emission sources
• Consideration of the effects of gravitational settling and dry deposition on ambient particulate concentrations
• Capability of simulating point, line, volume, area, and open pit sources
• Capability to calculate dry and wet deposition, including both gaseous and particulate precipitation scavenging for wet deposition
• Variation of wind speed with height (wind speed-profile exponent law)
• Concentration estimates for 1-hour to annual average times
• Terrain-adjustment procedures for elevated terrain including a terrain truncation algorithm for ISCST3; a built-in algorithm for predicting concentrations in complex terrain
• Consideration of time-dependent exponential decay of pollutants
• The method of Pasquill (1976) to account for buoyancy-induced dispersion
• A regulatory default option to set various model options and parameters to EPA recommended values (see text for regulatory options used)
• Procedure for calm-wind processing including setting wind speeds less than 1 m/s to 1 m/s.

Note: ISCST3 = Industrial Source Complex Short-Term.

Source: EPA, 1995.

Table 6-2. Summary of Stack Parameters and NOx Emissions for the Modified Package Boilers, Stone Container

Source	Stack Height (ft)	Stack Height (m)	Stack Diameter (ft)	Stack Diameter (m)	Flowrate (acfm)	Stack Velocity (f/s)	Stack Velocity (m/s)	Stack Temp. (deg F)	Stack Temp. (deg K)	NOx Emissions (TPY)	NOx Emissions (g/s)
Package Boilers 1-3	200	61.0	8.0	2.44	204,900	67.94	20.71	330	438.7	310	8.92

Legend
ft = feet
m = meters
acfm = actual cubic feet per minute
f/s = feet per second
m,/s = meters per second
deg F = degrees Fahrenheit
deg K = degrees Kelvin
TPY = tons per year
g/s = grams per second

Table 6-3. NO_X Screening Analysis for the AAQS and PSD Class II Inventories for Stone Container Corporation

Facility Name	UTM Coordinates (km) E	UTM Coordinates (km) N	Relative to Stone Container Facility X (km)	Y (km)	Distance (km)	Direction (degrees)	Screening Emission Threshold (TPY)(a)	Maximum Allowable Emissions (TPY)	AAQS and/or PSD Class II Modeling Analysis?
Amerada Hess Jacksonville	442.7	3365.0	0.7	-0.6	0.9	131	SIA	28.8	YES
Cedar Bay Cogeneration, Inc.	441.1	3365.1	-0.9	-0.5	1.1	240	1	3,788	YES
Anheuser Busch, Inc. - Jacksonville	440.6	3366.8	-1.4	1.2	1.9	310	17	1,038	YES
Atlantic Coast Asphalt - Heckscher	440.0	3364.1	-2.0	-1.5	2.5	233	30	NA	NO
Stone Container Corp	439.2	3365.5	-2.8	-0.1	2.8	269	36	NA	NO
Quickrete-Jacksonville	439.8	3363.3	-2.2	-2.3	3.2	224	44	9	NO
J.B. Coxwell Contracting, Inc.	446.0	3365.9	4.0	0.3	4.0	85	59	47	NO
Interstate Brands Corporation	437.2	3366.3	-4.8	0.7	4.9	278	77	NA	NO
Jacksonville Electric Authority - SJRPP	446.9	3366.3	4.9	0.7	4.9	82	79	32,289	YES
City of Jacksonville - Solid Waste Division	446.5	3367.7	4.5	2.1	5.0	65	80	23	NO
U S Gypsum Co	438.9	3361.2	-3.1	-4.4	5.4	215	88	353	YES
Celotex Corp	446.4	3362.4	4.4	-3.2	5.5	126	90	76	NO
Jacksonville Electric Authority - Northside	447.7	3364.9	5.7	-0.7	5.7	97	95	15,286	YES
Support Terminal Operg. Part.,L.P.	438.5	3360.5	-3.5	-5.1	6.2	214	104	9	NO
PCS Phosphate- Jacksonville	439.3	3359.8	-2.7	-5.8	6.4	205	108	27	NO
Jefferson Smurfit Corp (U.S.) - Jacksonville	439.9	3359.3	-2.1	-6.3	6.6	198	113	1,200	YES
Jacksonville Electric Authority - Kennedy	440.0	3359.2	-2.0	-6.4	6.7	197	114	4,245	YES
Millennium Specialty Chemicals	436.8	3360.7	-5.2	-4.9	7.1	227	122	189	YES
Coastal Fuels Marketing, Inc.	439.7	3358.7	-2.3	-6.9	7.3	198	125	16	NO
Jefferson Smurfit Corporation	440.0	3358.1	-2.0	-7.5	7.8	195	135	7	NO
BF Goodrich Co.Engineered Polymer Product	450.0	3365.5	8.0	-0.1	8.0	91	140	16	NO
Jacksonville Buckman Sewage Tretmnt Plnt	439.4	3357.7	-2.6	-7.9	8.3	198	146	NA	NO
Castleton Beverage Co	438.4	3373.9	-3.6	8.3	9.0	337	160	3	NO
Industrial Water Services, Inc.	439.5	3356.8	-2.5	-8.8	9.1	196	163	2	NO
Mulliniks Construction Co., Inc. - Portable Cr	433.7	3361.4	-8.4	-4.2	9.3	243	167	NA	NO
Turner Electric Works	438.2	3357.0	-3.8	-8.6	9.4	204	168	1	NO
Owens-Corning - Jacksonville	439.3	3356.0	-2.7	-9.6	10.0	196	179	15	NO
University Medical Center	436.5	3357.2	-5.5	-8.4	10.0	213	181	39	NO
Cookson Matthey Eagle	433.0	3358.5	-9.0	-7.1	11.5	232	209	NA	NO
Kraft Foods	437.5	3354.7	-4.5	-10.9	11.8	202	215	16	NO
Jacksonville Electric Authority - Southside	437.7	3353.9	-4.4	-11.8	12.5	200	231	1,349	YES
Gate Riverplace Co.	436.8	3354.2	-5.2	-11.4	12.6	204	231	74	NO
Pan Coatings Of Florida, Inc.	434.8	3355.1	-7.2	-10.5	12.7	214	234	NA	NO
Hardage Giddens Funeral Homes Of Jackson	434.8	3354.5	-7.2	-11.1	13.2	213	245	1	NO
Anchor Glass Container Corporation	431.3	3357.5	-10.7	-8.1	13.4	233	248	789	YES
Chemrock Corp	429.7	3359.6	-12.3	-6.0	13.7	244	254	2	NO
Atlantic Dry Dock Corporation	455.8	3361.7	13.8	-3.9	14.3	106	267	7	NO

Table 6-3. NO_X Screening Analysis for the AAQS and PSD Class II Inventories for Stone Container Corporation

Facility Name	UTM Coordinates (km) E	UTM Coordinates (km) N	Relative to Stone Container Facility X (km)	Relative to Stone Container Facility Y (km)	Relative to Stone Container Facility Distance (km)	Relative to Stone Container Facility Direction (degrees)	Screening Emission Threshold (TPY)(a)	Maximum Allowable Emissions (TPY)	AAQS and/or PSD Class II Modeling Analysis?
St Vincents Medical Center	434.6	3353.0	-7.4	-12.6	14.6	211	273	48	NO
Con Agra Feed Company	431.4	3355.3	-10.6	-10.3	14.8	226	276	NA	NO
Electro-Mechanical South, Inc.	427.0	3364.5	-15.0	-1.1	15.0	266	280	NA	NO
Baptist Medical Center	435.4	3352.0	-6.6	-13.6	15.1	206	282	773	YES
Wincup	428.2	3357.8	-13.8	-7.8	15.9	241	297	NA	NO
Metalplate Galvanizing	426.5	3362.0	-15.5	-3.6	15.9	257	298	NA	NO
General Electric Co	458.1	3364.5	16.1	-1.2	16.1	94	302	1	NO
Metal Container Corporation	428.4	3356.4	-13.6	-9.2	16.4	236	308	7	NO
Bush Boake Allen, Inc.	427.6	3357.3	-14.4	-8.3	16.6	240	312	96	NO
City Of Jacksonville(Girvin Rd Landfill)	455.4	3355.6	13.4	-10.0	16.7	127	315	77	NO
D-Graphics Div. Jefferson Smurfit Corp.	440.1	3348.4	-1.9	-17.2	17.3	186	326	NA	NO
Reichhold Chemicals, Inc.	428.2	3355.0	-13.8	-10.7	17.4	232	329	14	NO
St Luke's Hospital Association	443.8	3346.9	1.8	-18.8	18.8	175	357	9	NO
U S Naval Station Mayport	460.4	3361.6	18.4	-4.0	18.8	102	357	56	NO
S & G Packaging L.L.C.	442.5	3386.1	0.5	20.5	20.5	1	390	2	NO
First Union Bank Of Florida	444.0	3342.8	2.0	-22.8	22.9	175	438	357	NO
E 3 Thermal Remediation Group - Nas Jax	434.2	3343.7	-7.8	-21.9	23.2	200	444	4	NO
United States Navy - Nas Jacksonville	434.2	3342.8	-7.8	-22.8	24.1	199	462	276	NO
Mayo Clinic Jacksonville	458.0	3347.5	16.0	-18.1	24.2	139	463	39	NO
Refuse Services, Inc.	442.3	3341.2	0.3	-24.4	24.5	179	469	14	NO
Ring Power Corp - Sunbeam Road	442.0	3341.0	0.0	-24.6	24.6	180	472	79	NO
David Coxwell	420.0	3353.7	-22.0	-11.9	25.0	242	481	23	NO
Duval Asphalt Products - Phillips Highway	441.8	3340.0	-0.2	-25.6	25.6	181	492	18	NO
Atlantic Coast Asphalt -,Shad	445.3	3339.7	3.3	-25.9	26.2	173	503	19	NO
Champion International Corp	416.5	3353.2	-25.5	-12.4	28.4	244	547	16	NO
Rayonier Inc.	454.7	3392.2	12.7	26.6	29.5	26	570	1,582	YES
J.B. Coxwell Contracting, Inc.	448.1	3336.6	6.1	-29.0	29.7	168	573	47	NO
Anderson Columbia, Inc. - #7	448.1	3336.5	6.1	-29.1	29.7	168	575	7	NO
Jefferson Smurfit Corp-Fernandina Beach	456.2	3394.2	14.2	28.6	31.9	26	619	5,058	YES
U S Naval Air Station - Cecil Field	415.2	3344.5	-26.8	-21.1	34.1	232	662	71	NO
Dawson Land Development, Co., Inc.	463.2	3335.6	21.2	-30.0	36.8	145	715	NA	NO
Dustcoating, Inc,	413.1	3342.9	-28.9	-22.7	36.8	232	715	8	NO
Ameristeel, Jacksonville,Mill Div.	405.9	3350.2	-36.1	-15.4	39.2	247	765	307	NO
Florida Solite Company	427.4	3326.5	-14.6	-39.1	41.7	200	815	108	NO
Tamko Roofing Products, Inc.	435.2	3316.8	-6.8	-48.8	49.3	188	965	NA	NO
E.I. Dupont DE Nemours & CO- Highland	398.7	3325.0	-43.3	-40.6	59.4	227	1167	NA	NO

Table 6-3. NO_x Screening Analysis for the AAQS and PSD Class II Inventories for Stone Container Corporation

Facility Name	UTM Coordinates (km)		Relative to Stone Container Facility				Screening Emission Threshold (TPY)(a)	Maximum Allowable Emissions (TPY)	AAQS and/or PSD Class II Modeling Analysis?
	E	N	X (km)	Y (km)	Distance (km)	Direction (degrees)			

NA = Emissions not provided

(a) Screening emissions threshold is 20 x [Distance (km) to facility -1 km], based on North Carolina Screening Method.
A significant impact distance of 1 km was assumed for including competing NOx facilities into the inventory.
Total screening area is 51 km from the SCC facility. All facilities emitting <1 TPY have been omitted.

(b) Indicates PSD sources at this facility
Stone Container Corporation Jacksonville facility UTM coordinates (km):
442.0 3365.6

(c) Sources within 1 km of the SCC site are modeled without regard to the screening criteria.

Source: Golder Associates, 1998

Table 6-4. PSD Baseline (1989) NOx Emission Data for the Stone Container Corporation [a], Jacksonville

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	5.2
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
Recovery Boiler No. 1	28.8 lb/hr; 1991 stack test	8,203	118.1	3.4
Recovery Boiler No. 2	31.8 lb/hr; 1991 stack test	8,023	127.6	3.67
Recovery Boiler No. 3	34.3 lb/hr; 1991 stack test	8,019	137.5	3.96
Smelt Dissolving Tank No. 1	--	--	0	0
Smelt Dissolving Tank No. 2	--	--	0	0
Smelt Dissolving Tank No. 3	--	--	0	0
Lime Kiln No. 1	15.3 lb/hr; 1991 stack test	1,781	13.6	0.39
Lime Kiln No. 2	10.7 lb/hr; 1991 stack test	7,284	39	1.12
Lime Kiln No. 3	15.9 lb/hr; 1991 stack test	7,460	59.3	1.71
		TOTALS	1,830.60	52.67

Note:

gal = gallon.
g/s = gram per second.
lb/hr = pound per hour.
PSD = prevention of significant deterioration.
tons/yr = tons per year.

[a] Formerly Seminole Kraft Corporation

Source: 1989/1990 Annual Operating Reports submitted to FDER and stack tests.

Table 6-5. PSD Baseline (1989) Stack and Operating Data for the Stone Container[a] Facility - Jacksonville

	Stack Height		Stack Diameter		Velocity		Temperature		
Unit Description	(ft)	(m)	(ft)	(m)	(ft/s)	(m/s)	(deg F)	(K)	Basis
Bark Boiler No. 1	136	41.45	8.08	2.46	42.7	13.01	138	332	1991 stack test data
Bark Boiler No. 2	136	41.45	8.08	2.46	42.7	13.01	138	332	1991 stack test data
Power Boiler No. 1	106	32.31	6	1.83	46	14.02	360	455	1991 stack test data
Power Boiler No. 2	106	32.31	7	2.13	47.6	14.51	330	439	1991 stack test data
Power Boiler No. 3	106	32.31	7	2.13	47.6	14.51	330	439	1991 stack test data
Recovery Boiler No. 1	126	38.4	8.5	2.59	52.4	15.97	155	341	1991 stack test data
Recovery Boiler No. 2	126	38.4	9	2.74	51.2	15.61	162	345	1991 stack test data
Recovery Boiler No. 3	126	38.4	9	2.74	47.9	14.6	159	344	1991 stack test data
Smelt Dissolving Tank No. 1	120	36.58	3.5	1.07	13	3.96	160	344	AES Cedar Bay SCA
Smelt Dissolving Tank No. 2	124	37.8	4	1.22	14	4.27	160	344	AES Cedar Bay SCA
Smelt Dissolving Tank No. 3	124	37.8	4	1.22	14	4.27	160	344	AES Cedar Bay SCA
Lime Kiln No. 1	69	21.03	5.8	1.77	10.2	3.11	158	343	Various stack test data
Lime Kiln No. 2	75	22.86	4.67	1.42	21.4	6.52	145	336	Various stack test data
Lime Kiln No. 3	75	22.86	3.67	1.12	26.8	8.17	145	336	Various stack test data

Note:

ft = feet.
PSD = prevention of significant deterioration.
m = meter.
ft/s = feet per second.
deg F = degrees Fahrenheit.
K = Kelvin.

[a] Formerly Seminole Kraft Corporation

Table 6-6. SCC Property Boundary Receptors Used in the Modeling Analysis

Direction (deg)	Distance (m)	Direction (deg)	Distance (m)
10	657	190	289
20	636	200	276
30	491	210	269
40	410	220	271
50	361	230	280
60	332	240	270
70	316	250	403
80	310	260	427
90	314	270	469
100	328	280	482
110	355	290	483
120	400	300	450
130	696	310	500
140	678	320	595
150	440	330	764
160	346	340	1,113
170	315	350	1,285
180	297	360	1,243

Note: Distances are relative to the SCC plant baseline location.
deg = degree.
m = meter.

Table 6-7. Wolf Island and Okefenokee Wilderness Area Receptors Used in the Modeling Analysis

UTM Coordinates (km)		
East	North	PSD Class I Area
470.5	3,459.0	Wolf Island
391.0	3,417.0	Okefenokee
390.0	3,410.0	Okefenokee
392.0	3,400.0	Okefenokee
390.0	3,395.0	Okefenokee
391.0	3,390.0	Okefenokee
390.0	3,384.0	Okefenokee
383.0	3,382.0	Okefenokee
378.0	3,382.0	Okefenokee
374.0	3,383.0	Okefenokee
370.0	3,383.0	Okefenokee

Table 6-8. Building Structures Considered in the SCC Modeling Analysis

Structure	Height		Length		Width	
	(ft)	(m)	(ft)	(m)	(ft)	(m)
Recovery Boilers	90	27.43	156.7	47.78	80	24.38
Pulp Mill	72	21.95	212.5	64.77	225	68.60
Power Boilers	60	18.29	115	35.05	201	61.34
Bark Boilers	60	18.29	75	22.86	67.5	20.57
Package Boilers	20	6.10	90	27.43	40	12.19
Ceder Bay Boilers	161	49.07	248	75.70	110	33.50

Source Golder Associates Inc., 1998

Table 6-9. Maximum Predicted NO_X Concentrations for the Proposed Package Boilers Only

Averaging Time	Concentration[a] ($\mu g/m^3$)	Receptor Location[b] Direction (degrees)	Receptor Location[b] Distance (m)	Period Ending (YYMMDDHH)
Annual	1.14	120	400	83123124
	0.84	110	438	84123124
	1.23	120	400	85123124
	0.81	110	438	86123124
	1.07	120	400	87123124
HIGH 24-Hour	18.1	120	400	83042424
	18.3	110	438	84022924
	22.8	110	438	85021224
	16.2	110	438	86030224
	16.4	120	400	87010224
HIGH 8-Hour	43.	120	400	83041708
	27.	120	400	84032924
	34.	110	438	85011508
	42.	110	438	86030208
	36.	110	355	87031008
HIGH 3-Hour	81.	120	400	83041706
	53.	130	696	84110524
	63.	110	438	85051703
	70.	110	438	86030206
	55.	110	355	87031003
HIGH 1-Hour	115.	110	355	83071723
	114.	110	355	84091105
	115.	110	355	85060202
	112.	120	400	86050224
	110.	110	355	87102902

Note: YY=Year, MM=Month, DD=Day, HH=Hour

[a] Maximum concentrations indicated are for the proposed package boilers only with no offsets.
[b] All receptor coordinates are reported with respect to the SKC plant baseline location.

Table 6-10. Maximum Predicted NO_X Impacts Due to the Proposed Package Only at the Okefenokee and Wolf Island NWAs

Averaging Time	Concentration ($\mu g/m^3$)	Receptor Location[a] Direction (degrees)	Distance (m)	Period Ending (YYMMDDHH)
Annual	0.008	391000	3417000	83123124
	0.009	392000	3400000	84123124
	0.008	391000	3390000	85123124
	0.009	390000	3395000	86123124
	0.009	391000	3417000	87123124
High 24-Hour	0.13	390000	3384000	83080124
	0.16	391000	3417000	84061424
	0.20	391000	3390000	85022324
	0.17	391000	3417000	86030924
	0.16	392000	3400000	87051124
HIGH 8-Hour	0.39	390000	3410000	83022208
	0.45	390000	3395000	84072124
	0.38	390000	3395000	85050124
	0.39	392000	3400000	86111124
	0.40	392000	3400000	87091424
HIGH 3-Hour	0.61	390000	3410000	83081721
	0.84	390000	3395000	84072121
	0.75	391000	3417000	85112624
	0.70	392000	3400000	86102421
	0.80	392000	3400000	87091421
HIGH 1-Hour	1.52	390000	3384000	83091223
	1.60	392000	3400000	84101719
	1.71	391000	3390000	85080720
	1.70	391000	3390000	86012119
	1.47	391000	3390000	87082121

Note: YY=Year, MM=Month, DD=Day, HH=Hour.

[a] All receptor coordinates are reported with respect to the SCC plant baseline location.

Table 6-11 Maximum Predicted NO_X Impacts in the Vicinity of the SCC Mill, Due to All Sources - Screening Analysis

		Receptor Location[a]		Period
Averaging Time	Concentration ($\mu g/m^3$)	Direction (degrees)	Distance (m)	Ending (YYMMDDHH)
Annual	10.86	250	185	83123124
	11.04	240	235	84123124
	10.90	250	185	85123124
	10.10	240	235	86123124
	10.94	320	800	87123124

Note: YY=Year, MM=Month, DD=Day, HH=Hour.
[a] All receptor coordinates are reported with respect the SCC plant baseline location.

Table 6-12. Maximum Predicted NO_2 Concentrations Compared to the AAQS

Averaging Time	Total Concentration ($\mu g/m^3$)	Modeled Concentration ($\mu g/m^3$)	Background Concentration ($\mu g/m^3$)	Receptor Location[a] Direction (degrees)	Receptor Location[a] Distance (m)	AAQS ($\mu g/m^3$)
Annual	39	11	28	240	235	100

Note: YY=Year, MM=Month, DD=Day, HH=Hour

[a] Receptor coordinates are with respect to the SCC plant baseline location.

Table 6-13. Maximum Predicted NO_2 PSD Class II Increment Consumption in the Vicinity of the SCC Plant Site - Screening Analysis

Averaging Time	Concentration ($\mu g/m^3$)	Receptor Location[b] Direction (degrees)	Receptor Location[b] Distance (m)	Period Ending (YYMMDDHH)
Annual	< 0.0	-	-	83123124
	< 0.0	-	-	84123124
	< 0.0	-	-	85123124
	< 0.0	-	-	86123124
	< 0.0	-	-	87123124

Note: m = meter.
PDS = prevention of significant deterioration.
NO_2 = nitrogen dioxide.
$\mu g/m^3$ = micrograms per cubic meter.
YYMMDDHH = year, month, day, hour.

[a] Relative to the location of the SCC plant base line location.

7.0 ADDITIONAL IMPACT ANALYSIS

7.1 INTRODUCTION

SCC is proposing to increase the steam rate of its existing boilers at the Jacksonville mill. The modification is subject to the PSD new source review requirements for NO_x. The additional impact analysis and the Class I area analysis address this pollutant.

The analysis addresses the potential impacts on vegetation, soils, and wildlife of the surrounding area and the nearby Class I area due to SCC's proposed modification. The nearest Class I area is the Okefenokee National Wilderness Area (NWA), located in the Okefenokee National Wildlife Refuge located approximately 60 kilometers (km) northwest of the SCC plant. The next closest Class I area to SCC is Wolf Island, located approximately 98 km north of SCC. Due to the distance from SCC, the Okefenokee Class I area would potentially receive much higher impacts than Wolf Island. Therefore, only the Okefenokee NWA is addressed in this analysis.

The analysis will demonstrate that the increase in impacts due to the proposed increase in emissions is extremely low. Regardless of the existing conditions in the vicinity of the site or in the Class I areas, the proposed project will not cause any adverse impacts due to the predicted low impacts upon these areas.

7.2 SOIL, VEGETATION, AND AQRV ANALYSIS METHODOLOGY

In the foregoing analysis, the maximum air quality impacts predicted to occur in the vicinity of the SCC plant and in the Class I area due to the increase in emissions are used. The air modeling analysis which predicts the impacts on these areas was presented in Section 6.0.

The analysis involved predicting worst-case maximum short- and long-term concentrations of pollutants in the vicinity of the plant and in the Class I areas and comparing the maximum predicted concentrations to lowest observed effect levels for AQRVs or analogous organisms. In conducting the assessment, several assumptions were made as to how pollutants interact with the different matrices, i.e., vegetation, soils, wildlife, and aquatic environment.

A screening approach was used to evaluate potential effects which compared the maximum predicted ambient concentrations of air pollutants of concern with effect threshold limits for both vegetation and wildlife as reported in the scientific literature. A literature search was conducted which specifically addressed the effects of air contaminants on plant species reported to occur in the vicinity of the plant and the Class I area. It was recognized that effects threshold information is not available for all species found in the Okefenokee NWA, although studies have been performed on a few of the common species and on other similar species which can be used as models. In conducting the assessment, both direct (fumigation) and indirect (soil accumulation/uptake) exposures were considered for flora, and direct exposure (inhalation) was considered for wildlife.

7.3 IMPACTS TO SOILS, VEGETATION, AND VISIBILITY IN VICINITY OF THE SCC PLANT

7.3.1 PREDICTED AIR QUALITY IMPACTS

The results of the ambient air quality modeling for the proposed SCC modification, in the vicinity of the plant, were presented in Table 6-9. Maximum predicted concentrations were presented for the annual, 24-hour, 8-hour, 3-hour, and 1-hour averaging times.

7.3.2 IMPACTS TO SOILS

Soils in the vicinity of the SCC site consist primarily of tidal lands and poorly drained sands with organic pans. The tidal lands occur along the coast, and consist of mucky fine sand to dark-gray fine sand overlying gray fine sand, mixed with broken and whole shells. These soils will not be affected by NO_2 concentrations resulting from facility emissions, because both the underlying substrate and the sea spray from the nearby St. Johns river are neutral to alkaline and would neutralize any acidifying effects of NO_2 deposition.

The poorly drained sands are already strongly acidic. Normal liming practices currently used on soils in the vicinity of SCC by agricultural interests will effectively mitigate the small effects of any increased NO_2 deposition resulting from the increased NO_2 emissions from the proposed project.

Based on the small ambient NO_2 impacts due to the proposed project (1.23 $\mu g/m^3$), annual average, and the low existing air quality (28$\mu g/m^3$) compared to the AAQS, no adverse impacts to soils is expected.

7.3.3 IMPACTS TO VEGETATION

Vegetation Analysis

In general, the effects of air pollutants on vegetation occur primarily from SO_2, NO_2, O_3, and PM. Effects from minor air contaminants such as fluoride, chlorine, hydrogen chloride, ethylene, ammonia, hydrogen sulfide, CO, and pesticides have also been reported in the literature. The effects of air pollutants are dependent both on the concentration of the contaminant and the duration of the exposure. The term "injury," as opposed to damage, is commonly used to describe all plant responses to air contaminants and will be used in the context of this analysis. Air contaminants are thought to interact primarily with plant foliage which is considered to be the major pathway of exposure. For purposes of this analysis, it was assumed that 100 percent of each air contaminant of concern is accessible to the plants.

Injury to vegetation from exposure to various levels or air contaminants can be termed acute, physiological, or chronic. Acute injury occurs as a result of a short-term exposure to a high contaminant concentration and is typically manifested by visible injury symptoms ranging from chlorosis (discoloration) to necrosis (dead areas). Physiological or latent injury occurs as the result of a long-term exposure to contaminant concentrations below that which results in acute injury symptoms. Chronic injury results from repeated exposure to low concentrations over extended periods of time, often without any visible symptoms, but with some effect on the overall growth and productivity of the plant. In this assessment, 100 percent of the particular air pollutant in the ambient air was assumed to interact with the vegetation. This is a conservative approach.

A review of the literature indicates great variability in NO_2 dose-response relationship in vegetation. Acute NO_2 injury symptoms are manifested as water-soaked lesions, which first appear on the upper surface, followed by rapid tissue collapse. Low-concentration, long-term exposures as frequently encountered in polluted atmospheres often do not induce the lesions associated with acute exposures but may still result in some growth suppression. Citrus trees exposed to 470 $\mu g/m^3$ of NO_2 for 290 days showed injury (Thompson *et al.*, 1970). Sphagnum exposed for 18 months at an average concentration of 11.7 $\mu g/m^3$ showed reduced growth (Press *et al.*, 1986)

The maximum ground-level NO_2 concentrations (1-hour and annual average) predicted to occur in the vicinity of the plant during the operation of the proposed project are 115 $\mu g/m^3$ and 39 $\mu g/m^3$, AQRVs of this Class I area are defined as those important attributes of the Okefenokee NWA which are dependent upon the air environment, including water, soil, vegetation resources, and wildlife resources. Important aquatic, vegetation, and wildlife attributes of these areas which make the Okefenokee NWA significant are presented in Table 7-1. All terrestrial vegetation, including threatened and endangered plant species of the Okefenokee NWA, are dependent upon the air environment and are considered AQRVs. Some terrestrial wildlife and endangered and threatened wildlife are also considered AQRVs for Okefenokee NWA . Threatened and endangered species associated with terrestrial habitats of the Okefenokee NWA are listed in Table 7-2.

7.4.3 REPORTED AIR QUALITY EFFECTS ON OKEFENOKEE NWA

No ecological effects to the attributes of the Okefenokee NWA have been reported to date (Sara Brown, USFWS, Folkston, GA; Robin Goodlow, USFWS, Brunswick, GA; and Ellen Porter, USFWS, Denver, CO, pers. comm., 1994). In 1991, a lichen study was completed (Wetmore, 1991) which did not find any damage to lichens from SO_2. The trace element content including Cd, Cr, and Pb in six species of lichens and Spanish moss were considered normal. The range in concentrations of these trace metals found in lichens and Spanish moss from the Okefenokee National Wildlife Refuge is presented in Table 7-3. In addition, the general concern regarding potential effects of mercury (Hg) were raised. (Ellen Porter, USFWS, Denver, CO, pers. comm., 1994). The reported general effects on aquatic, vegetation, and wildlife resources from significant degradation in air quality are described in Table 7-4.

7.4.4 PREDICTED AIR QUALITY IMPACTS IN THE CLASS I AREA

The results of the air quality modeling for the increase in emissions due to the SCC modification are presented in Table 7-5. Predicted air quality concentrations are presented for Okefenokee NWA for the annual, 24-hour, 8-hour, 3-hour, and 1-hour averaging times. These concentrations reflect only the increase in emissions due to the proposed project.

7.4.5 VEGETATION AQRVS ANALYSIS

In general, the effects of air pollutants on vegetation occur primarily from SO_2, NO_2, O_3, and PM. Effects from minor air contaminants such as fluoride, chlorine, hydrogen chloride, ethylene, ammonia, hydrogen sulfide, CO, and pesticides have been also reported in the literature. The effects of air pollutants are dependent both on the concentration of the contaminant and the duration of the exposure. The term "injury," as opposed to damage, is commonly used to describe all plant responses to air contaminants and will be used in the context of this analysis. Air contaminants are thought to interact primarily with plant foliage which is considered to be the major pathway of exposure. For purposes of this analysis, it was assumed that 100 percent of each air contaminant of concern is accessible to the plants.

Injury to vegetation from exposure to various levels or air contaminants can be termed acute, physiological, or chronic. Acute injury occurs as a result of a short-term exposure to a high contaminant concentration and is typically manifested by visible injury symptoms ranging from chlorosis (discoloration) to necrosis (dead areas). Physiological or latent injury occurs as the result of a long-term exposure to contaminant concentrations below that which results in acute injury symptoms. Chronic injury results from repeated exposure to low concentrations over extended periods of time, often without any visible symptoms, but with some effect on the overall growth and productivity of the plant. In this assessment, 100 percent of the particular air pollutant in the ambient air was assumed to interact with the vegetation. This is a conservative approach.

A review of the literature indicates great variability in NO_x dose-response relationship in vegetation. Acute NO_2 injury symptoms are manifested as water-soaked lesions, which first appear on the upper surface, followed by rapid tissue collapse. Low-concentration, long-term exposures as frequently encountered in polluted atmospheres often do not induce the lesions associated with acute exposures but may still result in some growth suppression. Citrus trees exposed to 470 $\mu g/m^3$ for 290 days showed injury (Thompson *et al.*, 1970). Sphagnum moss exposed for 18 months at an average concentration of 11.7 $\mu g/m^3$ showed reduced growth (Press *et al.*, 1986).

The maximum ground-level NO_2 concentrations (1-hour and annual average) predicted to occur at the Class I area boundary due to the increase in emissions are 1.7 and 0.009 $\mu g/m^3$ respectively. These values are well below reported effect concentrations and no effects are predicted to occur.

7.4.6 SOILS AQRV ANALYSIS

Air contaminants can affect soils through fumigation by gaseous forms, accumulation of compounds transformed from the gaseous state, or by the direct deposition of particulate matter or particulate matter to which certain contaminants are absorbed. Gaseous fumigation of soils does not directly affect the soil but rather the organisms found in the soil. Concentrations several orders of magnitude higher than the predicted value are required before any adverse effects from fumigation are observed. It is more likely that effects on soils and the organisms (plants and animals) found in the soils could occur from the deposition of trace elements over the life of the project. Thus, this analysis of effects on soils specifically addresses the deposition of trace elements and potential pathways for movements into the vegetation.

The maximum predicted NO_2 concentration at the Class I Area due to the proposed project is 0.009 $\mu g/m^3$, annual average. This impact is consider negligible, and no effects are predicted.

7.4.7 WILDLIFE AQRV ANALYSIS

The predicted NO_2 concentrations are also well below the lowest observed effects levels in animals (Table 7-6) and pose no risk to wildlife AQRVs in the Class I area. Because predicted levels are below those known to cause effects to vegetation, there is also no risk to their habitat.

7.4.8 VISIBILITY IMPACTS

The visibility impacts of the proposed boiler's maximum future emissions are provided in Table 7-7. The modeling results, using the VISCREEN model, indicate that the maximum visibility impacts caused by the future plant's total emissions do not exceed the screening criteria inside or outside the Class I area. As a result, the proposed project is predicted to have no adverse effects to visibility in the Class I area.

7.4.9 SUMMARY

In summary, it is apparent that very large margins of safety exist for all matrices examined with respect to the effects of the predicted increase in emissions on the Class I areas. No significant adverse effects will occur to the AQRVs in the Okefenokee NWA due to the modification of the SCC plant.

Table 7-1. Important Aquatic, Vegetational, and Wildlife Resource Attributes or AQRVs of Okefenokee NWA Dependent Upon the Air Environment

Attribute	Location
Aquatic	
Blackwater rivers, ponds, sloughs	Okefenokee NWA
Vegetation	
Ecological communities including:	
Cypress wetlands	Okefenokee NWA
Wet flatwoods	Okefenokee NWA
Bay-shrub bogs	Okefenokee NWA
Basin marshes	Okefenokee NWA
Mixed hardwood swamp	Okefenokee NWA
Unique ecological communities	
Old-growth cypress swamp	Okefenokee NWA
Unique plants	
Threatened and endangered species	Okefenokee NWA
Ephiphytic plants including orchids and bromeliads	Okefenokee NWA
Air quality bioindicators - lichens	Okefenokee NWA
Wildlife	
Birds, mammals, reptiles and amphibians	Okefenokee NWA
Threatened and endangered species (see Table 7-3)	Okefenokee NWA

Note: NWA = National Wilderness Area.

Source: KBN, 1995.

Table 7-2. Federal and State Listed Endangered and Threatened Animals in the Okefenokee NWA Dependent Upon the Air Environment

Species	Designated Status State[a]	Designated Status USFWS[b]
Florida Black Bear	S4	C2
Arctic Peregrine Falcon	S1	-
Bachman's Warbler	E	E
Bald Eagle	E	E
Piping Plover	S1/S2	T
Red-Cockaded Woodpecker	E	E
Wood Stork	S2	E
American Alligator	-	T(S/A)
Eastern Indigo Snake	S3	T

[a] State (Georgia) Status:
E = endangered.
S1 = regionally endangered.
S2 = regionally threatened.
S3 = regionally of concern.
S4 = regionally apparently secure.

[b] USFWS Status:
C2 = candidate for listing, with some evidence of vulnerability, but for which not enough data exist to support listing.
E = endangered.
T = threatened.
T(S/A) = threatened due to similarity of appearance.

Sources: U.S. Fish and Wildlife Service.
Georgia Freshwater Wetlands and Heritage Inventory Program.

Table 7-3. Reported Representative Trace Metal Concentrations in Lichens and Spanish Moss in Okefenokee National Wildlife Refuge

	Concentration (ppm dry weight)					
Species	Cd	Cr	Pb	Mn	Cu	Zn
Lichens						
Usnea baileyi[a]	ND — 0.3	ND — 0.3	2.6 — 4.9	12.3 — 50.7	1.0 — 1.6	16.3 — 29.7
Usnea mutabilis[a]	ND	0.2	4.9	55.1	1.8	20.7
Parmelia rampoddensis[a]	ND — 0.6	0.3 — 0.6	4.7 — 10.0	8.0 — 88.0	1.4 — 3.2	21.9 — 31.6
Parmelia tinctorum[a]	0.5	0.5	7.3	25.0	2.6	25.9
Cladina substygia[b]	ND	0.2 — 0.6	1.9 — 2.3	7.4 — 12.0	0.9 — 1.1	9.1 — 10.7
Cladina leporina[b]	ND	1.4 — 1.6	7.5 — 7.8	7.9 — 9.2	1.4 — 1.5	11.4 — 11.6
Spanish Moss						
Tillandsia usneoides	ND — 0.5	0.7 — 1.0	4.6 — 8.4	37.3 — 284.3	2.4 — 3.7	17.3 — 31.4

[a] Range in means.
[b] Range in single values.

Source: Wetmore, 1991.

Table 7-4. Reported General Effects on Aquatic, Vegetation, and Wildlife Resources From Significant Degradation in Air Quality

Attribute	Potential Effects and Associated Air Quality Change
Aquatic Resources	Acidification of waters and subsequent changes (loss and replacement) of ecological components; sensitive systems have low buffering capacity
Vegetation Resources	Most common effects include reduced growth, injury, and species replacement; species show specific sensitivity
Wildlife Resources	Potential effects include avoidance and increased body burdens of contaminants

Source: KBN, 1995.

Table 7-5. Predicted Increase in Maximum NO_2 Concentrations at the Okefenokee Class I Area Due to the Proposed Modification

Averaging Time	Predicted Concentration ($\mu g/m^3$)[a]
Highest 1-hour	1.7
Highest 3-hour	0.8
Highest 8-hour	0.5
Highest 24-hour	0.2
Annual	0.009

[a] Highest predicted impact.

Table 7-6. Lowest Observed Effect Levels of NO_2 in Animals

Pollutant	Reported Effect	Concentration ($\mu g/m^3$)	Exposure
Nitrogen Dioxide	Respiratory stress in mice	1,917	3 hours
	Respiratory stress in guinea pigs	95 to 950	8 hr/day for[a] 122 days

[a] Used to compare as a range between 3-hour and 24-hour averaging times.

Source: Adapted from Newman (1980) and Newman and Schreiber (1988).

Table 7-7. Visual Effects Screening Analysis for Source:
STONE CONTAINER CORP - JACKSONVILLE
Class I Area: OKEFENOKEE NWA

*** Level-1 Screening ***

Input Emissions for

Particulates	4.35 LB /HR
NOx (as NO2)	104.80 LB /HR
Primary NO2	.00 LB /HR
Soot	.00 LB /HR
Primary SO4	.00 LB /HR

**** Default Particle Characteristics Assumed

Transport Scenario Specifications:

Background Ozone:	.04 ppm
Background Visual Range:	65.00 km
Source-Observer Distance:	61.00 km
Min. Source-Class I Distance:	61.00 km
Max. Source-Class I Distance:	80.00 km
Plume-Source-Observer Angle:	11.25 degrees
Stability:	6
Wind Speed:	1.00 m/s

R E S U L T S

Asterisks (*) indicate plume impacts that exceed screening criteria

Maximum Visual Impacts INSIDE Class I Area
Screening Criteria ARE NOT Exceeded

					Delta E		Contrast	
Backgrnd	Theta	Azi	Distance	Alpha	Crit	Plume	Crit	Plume
SKY	10.	84.	61.0	84.	2.00	.725.	05	-.002
SKY	140.	84.	61.0	84.	2.00	.303.	05	-.004

Maximum Visual Impacts OUTSIDE Class I Area
Screening Criteria ARE NOT Exceeded

					Delta E		Contrast	
Backgrnd	Theta	Azi	Distance	Alpha	Crit	Plume	Crit	Plume
SKY	10.	35.	48.4	134.	2.00	.860	.05	-.003
SKY	140.	35.	48.4	134.	2.00	.355	.05	-.005

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APPENDIX A

EXISTING SCC PERMITS

JAN 11 1996

FLORIDA

Department of Environmental Protection

Lawton Chiles
Governor

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

Virginia B. Wetherell
Secretary

December 8, 1995

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. John L. West
Stone Container Corporation
9469 East Port Road
Jacksonville, Florida 32229

Dear Mr. West:

RE: Request for Permit Modification
Stone Container Corporation (Formerly Seminole Kraft Corp.)
AC16-222359, PSD-FL-198 (A); Duval County

The Department received your requests of June 15 and August 9, 1995, to modify the above referenced construction permit by maximizing steam generation from the three boilers, and increasing the hourly and annual nitrogen oxides (NO_x) emission rate for each boiler based on 0.2 lb/MMBtu and the maximum allowable heat input rate. The modification, which also extends the expiration date of the construction permit referenced above, is as follows:

Permit No. AC16-222359, PSD-FL-198 (A), Stone Container Corporation.

Current Expiration Date: August 31, 1995

New Expiration Date: April 1, 1996

The Department is also modifying the specific conditions as follows:

1. The construction and operation of these sources shall be in accordance with the capacities stated in the **Revised** ~~Technical-Evaluation-and-Preliminary-Determination~~ application dated June 1995.

2. The ~~packaged~~ package boilers may be operated continuously (8760 hrs/yr).

3. The maximum heat input rate to each boiler shall neither exceed 174.7 MMBtu/hr while firing natural gas nor 164.5 MMBtu/hr while firing No. 2 fuel oil.

4. In accordance with the terms of the Cedar Bay Cogeneration Project (CBCP) site certification, Stone Container Corporation (SCC) is limited to producing 375,000 lbs/hr of steam from its three package boilers.

~~3.~~ 5. The maximum allowable NO_x emissions shall not exceed 0.2 lb/MMBtu, ~~23.6~~ 34.94 lbs/hr and ~~103.4~~ 153.1 tons/yr per boiler. The total NO_x emissions from the three package boilers, in accordance with the terms of the CBCP site certification, shall not exceed 310 tons per year.

~~4.~~ 6. The three ~~packaged~~ package boilers are permitted to fire both natural gas and No. 2 fuel oil, with the primary fuel being natural gas. The sulfur content of the No. 2 fuel oil shall not exceed 0.05 percent, by weight. Any delivery of No. 2 fuel oil shall be accompanied by a laboratory analysis quantifying the density and percent sulfur, by weight. Annual SO_2 emissions from No. 2 fuel oil firing, totaling all three boilers, shall not exceed 25 tons/year. In the event that the ceiling for SO_2 is expected to be exceeded due to unavailability of natural gas caused by factors beyond the control of ~~SKC~~ SCC, ~~SKC~~ SCC shall notify the Department that it anticipates exceeding the ceiling as provided herein; and, the emissions of SO_2 during the period of such curtailment shall not be counted against the yearly emissions ceiling of 25 tons unless administrative proceedings result in a finding that the exceedance was within ~~SKC's~~ SCC's control. In no event shall the total annual emissions of SO_2 from the three steam boilers exceed 41 tons/year. The notice shall include a statement or reasons for the request and supporting documentation, and shall be published by ~~SKC~~ SCC, without supporting documents, in a newspaper of general circulation in Jacksonville, Florida, as defined in Section 403.5115(2), F.S. The filing and publication of the notice no later than 7 days following the date of exceedance, shall preclude any finding of violation by the Department until final disposition of any administrative proceedings.

~~5.~~ 7. Visible emissions (VE) shall not exceed 5 percent(%) opacity during natural gas firing and 10% opacity during fuel oil firing.

~~6.~~ 8. In accordance with the requirements of 40 CFR 60.48b(b), a continuous emission monitoring system (CEMs) for nitrogen oxides shall be installed, operated, and maintained. Also, the natural gas, fuel oil and steam flows (both from the ~~packaged~~ package boilers and from the CBCP facility) shall be metered and continuously recorded. The data shall be logged daily and maintained so that it can be provided to the Department upon request.

~~7.~~ 9. Before this construction permit expires, each ~~packaged~~ package boiler shall be tested and monitored for compliance with the emission limits in Specific Conditions No. 5, 6 and 7. Compliance tests for NO_x shall be conducted in accordance with 40 CFR 60.46b(e)~~(3)~~(4). Compliance with SO_2 limits shall be in accordance with 40 CFR 60.49b(r), and a stoichiometric quantification for SO_2 emissions shall be utilized using the actual density and sulfur weight percent and the quantity of fuel oil fired monthly. Compliance with visible emission limits shall be demonstrated initially and annually in accordance with EPA Method 9.

~~8.~~ 10. The Department's Northeast District office and the RESD (City of Jacksonville's Regulatory and Environmental Services Department) office shall be notified at least 15 days prior to the compliance tests. Compliance test results shall be submitted to the Department's Northeast District and Bureau of Air Regulation offices and the RESD office within 45 days after completion of the tests. Sampling facilities, methods and reporting shall be in accordance with 40 CFR 60.49b, F.A.C ~~Rule 17-2.700~~ Chapter 62-297 and 40 CFR 60, Appendix A.

~~9.~~ 11. The following ~~Seminole Kraft Corporation (SKC)~~ SCC sources shall be permanently shut down and made incapable of operation: the No. 1 PB (power boiler), the No. 2 PB, the No. 3 PB, the No. 1 BB (bark boiler) and the No. 2 BB; and, ~~SKC~~ SCC shall turn in their operation permits to the Department's Bureau of Air Regulation, within 30 days of written confirmation by the Department of the successful completion of the initial compliance tests on the Cedar Bay Cogeneration Plant's boilers. The RESD office shall be specifically informed in writing within thirty days after each individual shut down of the above referenced equipment.

~~10.~~ 12. The permittee, for good cause, may request that this construction permit be extended. Such a request shall be submitted to the Department's Bureau of Air Regulation prior to 60 days before the expiration of the permit. (Rule ~~17~~ 62-4.090 F.A.C.)

~~11.~~ 13. If Florida is granted interim or full approval for the Title V operation permit program prior to January 1, 1996, this condition is negated. An application for an operation permit must be submitted to the Department's Northeast District office and the RESD office at least 90 days prior to the expiration date of this construction permit. To properly apply for an operation permit, the applicant shall submit the appropriate application form, fee, certification that construction was completed noting any deviations from the conditions in the construction permit, and compliance test reports as required by this permit. (Rules ~~17~~ 62-4.055 and ~~17~~ 62-4.220, F.A.C.)

~~12~~. 14. Pursuant to 40 CFR 60.49b(r), quarterly reports shall be submitted to the RESD office (i.e., Administrator) certifying that only very low sulfur oil (i.e., ≤0.05% sulfur, by weight) meeting this definition was combusted in the affected facility during the preceding quarter. The firing of any fuel oil and its associated SO_2 emissions shall be quantified on a monthly and per boiler basis and submitted to the RESD office by the end of the month following the end of each quarter. The quarters are defined as January-March, April-June, July-September and October-December; also, and per boiler, the final quarterly report shall include the total amount of the fuel oil fired and the quantified associated SO_2 emissions ~~from~~ for the year.

A copy of this letter shall be attached to the above mentioned permit, AC16-222359, PSD-FL-198 (A), and shall become a part of the permit.

Sincerely,

Howard L Rhodes

Howard L. Rhodes, Director
Division of Air Resources
Management

HLR/sa/t

cc: C. Kirts, NED
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J. Harper, EPA
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Lawton Chiles
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Twin Towers Office Building
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Virginia B. Wetherell
Secretary

PERMITTEE:
Seminole Kraft Corporation
9469 East Port Road
Jacksonville, Florida 32229

Permit Number: AC 16-222359
PSD-FL-198
Expiration Date: April 30, 1995
County: Duval
Latitude/Longitude: 30°25'15"N
-81°36'00"W
Project: Three Packaged Steam Boilers

This permit is issued under the provisions of Chapter 403, Florida Statutes, and Florida Administrative Code Chapters 17-210 through 297 and 17-4. The above named permittee is hereby authorized to perform the work or operate the facility shown on the application and approved drawings, plans, and other documents attached hereto or on file with the Department of Environmental Protection (Department) and made a part hereof and specifically described as follows:

For the construction of three 125,000 lbs/hr packaged process steam boilers. The facility is located at 9469 East Port Road, Jacksonville, Duval County, Florida. UTM coordinates of the site are: Zone 17, 441.8 km E and 3,365.6 km N.

Emissions shall be controlled by using clean fuels and good combustion practices.

The source shall be constructed in accordance with the permit application, plans, documents, amendments and drawings, except as otherwise noted in the General and Specific Conditions.

<u>Attachments are listed below:</u>

1. Letter (with proposed gas contract) from Oertel to Pennington (12/3/92).
2. Letter from KBN to the Department (12/9/92).
3. Letter from Georgia DNR to the Department (12/10/92).
4. Letter from KBN to the Department (12/22/92).
5. Incompleteness letter from the Department to SKC (12/23/92).
6. Letter from KBN to the Department (12/23/92).
7. Second Incompleteness letter from the Department to SKC (1/5/93).
8. Letter from KBN to the Department (1/8/93).
9. Letter from EPA to the Department (1/15/93).
10. Letter from Oertel to the Department (1/19/93).
11. Third Incompleteness letter from the Department to SKC (1/25/93).
12. Letter from Oertel to the Department (1/29/93).
13. Letter from Oertel to the Department (1/29/93).
14. Completeness letter from the Department to SKC (2/10/93).
15. Technical Evaluation and Preliminary Determination (TE&PD) mailed 4/2/93.

Attachments cont.:

16. Mr. Ronald L. Roberson's letter received 4/20/93.
17. Mr. Brian L. Beals's letter received 4/22/93.
18. Revised TE&PD mailed 4/21/93.
19. Public Notice received 5/7/93 (incomplete).
20. Mr. James W. Pulliam, Jr.'s letter received 5/21/93.
21. Public Notice received 5/27/93.
22. Ms. Jewell A. Harper's letter received 6/11/93.
23. Final Determination dated 7/7/93.

GENERAL CONDITIONS:

1. The terms, conditions, requirements, limitations, and restrictions set forth in this permit are "Permit Conditions" and are binding and enforceable pursuant to Sections 403.161, 403.727, or 403.859 through 403.861, Florida Statutes (F.S.). The permittee is placed on notice that the Department will review this permit periodically and may initiate enforcement action for any violation of these conditions.

2. This permit is valid only for the specific processes and operations applied for and indicated in the approved drawings or exhibits. Any unauthorized deviation from the approved drawings, exhibits, specifications, or conditions of this permit may constitute grounds for revocation and enforcement action by the Department.

3. As provided in Subsections 403.087(6) and 403.722(5), F.S., the issuance of this permit does not convey any vested rights or any exclusive privileges. Neither does it authorize any injury to public or private property or any invasion of personal rights, nor any infringement of federal, state or local laws or regulations. This permit is not a waiver of or approval of any other Department permit that may be required for other aspects of the total project which are not addressed in the permit.

4. This permit conveys no title to land or water, does not constitute State recognition or acknowledgement of title, and does not constitute authority for the use of submerged lands unless herein provided and the necessary title or leasehold interests have been obtained from the State. Only the Trustees of the Internal Improvement Trust Fund may express State opinion as to title.

5. This permit does not relieve the permittee from liability for harm or injury to human health or welfare, animal, or plant life, or property caused by the construction or operation of this permitted source, or from penalties therefore; nor does it allow the permittee to cause pollution in contravention of F.S. and Department rules, unless specifically authorized by an order from the Department.

PERMITTEE:
Seminole Kraft Corp.

Permit Number: AC 16-222359
PSD-FL-198
Expiration Date: April 30, 1995

GENERAL CONDITIONS:

6. The permittee shall properly operate and maintain the facility and systems of treatment and control (and related appurtenances) that are installed or used by the permittee to achieve compliance with the conditions of this permit, as required by Department rules. This provision includes the operation of backup or auxiliary facilities or similar systems when necessary to achieve compliance with the conditions of the permit and when required by Department rules.

7. The permittee, by accepting this permit, specifically agrees to allow authorized Department personnel, upon presentation of credentials or other documents as may be required by law and at a reasonable time, access to the premises, where the permitted activity is located or conducted to:

a. Have access to and copy any records that must be kept under the conditions of the permit;

b. Inspect the facility, equipment, practices, or operations regulated or required under this permit; and,

c. Sample or monitor any substances or parameters at any location reasonably necessary to assure compliance with this permit or Department rules.

Reasonable time may depend on the nature of the concern being investigated.

8. If, for any reason, the permittee does not comply with or will be unable to comply with any condition or limitation specified in this permit, the permittee shall immediately provide the Department with the following information:

a. a description of and cause of non-compliance; and,

b. the period of noncompliance, including dates and times; or, if not corrected, the anticipated time the non-compliance is expected to continue, and steps being taken to reduce, eliminate, and prevent recurrence of the non-compliance.

The permittee shall be responsible for any and all damages which may result and may be subject to enforcement action by the Department for penalties or for revocation of this permit.

9. In accepting this permit, the permittee understands and agrees that all records, notes, monitoring data and other information relating to the construction or operation of this permitted source

GENERAL CONDITIONS:

which are submitted to the Department may be used by the Department as evidence in any enforcement case involving the permitted source arising under the F.S. or Department rules, except where such use is prescribed by Sections 403.73 and 403.111, F.S. Such evidence shall only be used to the extent it is consistent with the Florida Rules of Civil Procedure and appropriate evidentiary rules.

10. The permittee agrees to comply with changes in Department rules and F.S. after a reasonable time for compliance, provided, however, the permittee does not waive any other rights granted by F.S. or Department rules.

11. This permit is transferable only upon Department approval in accordance with Florida Administrative Code (F.A.C.) Rules 17-4.120 and 17-730.300, as applicable. The permittee shall be liable for any non-compliance of the permitted activity until the transfer is approved by the Department.

12. This permit or a copy thereof shall be kept at the work site of the permitted activity.

13. This permit also constitutes:

- (x) Determination of Best Available Control Technology (BACT);
- (x) Determination of Prevention of Significant Deterioration; and,
- (x) Compliance with New Source Performance Standards (NSPS).

14. The permittee shall comply with the following:

a. Upon request, the permittee shall furnish all records and plans required under Department rules. During enforcement actions, the retention period for all records will be extended automatically unless otherwise stipulated by the Department.

b. The permittee shall hold at the facility or other location designated by this permit records of all monitoring information (including all calibration and maintenance records and all original strip chart recordings for continuous monitoring instrumentation) required by the permit, copies of all reports required by this permit, and records of all data used to complete the application for this permit. These materials shall be retained at least three years from the date of the sample, measurement, report, or application unless otherwise specified by Department rule.

c. Records of monitoring information shall include:

- the date, exact place, and time of sampling or measurements;
- the person responsible for performing the sampling or measurements;
- the dates analyses were performed;
- the person responsible for performing the analyses;
- the analytical techniques or methods used; and,
- the results of such analyses.

15. When requested by the Department, the permittee shall within a reasonable time furnish any information required by law which is needed to determine compliance with the permit. If the permittee becomes aware that relevant facts were not submitted or were incorrect in the permit application or in any report to the Department, such facts or information shall be corrected promptly.

SPECIFIC CONDITIONS:

1. The construction and operation of these sources shall be in accordance with the capacities stated in the Revised Technical Evaluation and Preliminary Determination.

2. The packaged boilers may be operated continuously (8760 hrs/yr).

3. The maximum allowable NOx emissions shall not exceed 0.2 lb/MMBtu, 23.6 lbs/hr, and 103.4 tons/yr per boiler.

4. The three packaged boilers are permitted to fire both natural gas and No. 2 fuel oil, with the primary fuel being natural gas. The sulfur content of the No. 2 fuel oil shall not exceed 0.05 percent, by weight. Any delivery of No. 2 fuel oil shall be accompanied by a laboratory analysis quantifying the density and percent sulfur, by weight. Annual SO_2 emissions from No. 2 fuel oil firing, total all three boilers, shall not exceed 25 tons/year. In the event that the ceiling for SO_2 is expected to be exceeded due to unavailability of natural gas caused by factors beyond the control of SKC, SKC shall notify the Department that it anticipates exceeding the ceiling as provided herein; and, the emissions of SO_2 during the period of such curtailment shall not be counted against the yearly emissions ceiling of 25 tons unless administrative proceedings result in a finding that the exceedance was within SKC's control. In no event shall the total annual emissions of SO_2 from the three steam boilers exceed 41 tons/year. The notice shall include a statement or reasons for the request and supporting documentation, and shall be published by SKC, without supporting documents, in a newspaper of general circulation in Jacksonville,

SPECIFIC CONDITIONS:

Florida, as defined in Section 403.5115(2), F.S. The filing and publication of the notice no later than 7 days following the date of exceedance, shall preclude any finding of violation by the Department until final disposition of any administrative proceedings.

5. Visible emissions (VE) shall not exceed 5% opacity during natural gas firing and 10% opacity during fuel oil firing.

6. In accordance with requirements of 40 CFR 60.48(b),a monitoring system (CEMS) for nitrogen oxides shall be installed, operated, and maintained. Also, the natural gas, fuel oil and steam flows (both from the packaged boilers and from the CBCP facility) shall be metered and continuously recorded. The data shall be logged daily and maintained so that it can be provided to the Department upon request.

7. Before this construction permit expires, each packaged boiler shall be tested and monitored for compliance with the emission limits in Specific Conditions No. 4, 5, and 6. Compliance tests for NOx shall be conducted in accordance with 40 CFR 60.46b(e)(3). Compliance with SO_2 limits shall be in accordance with 40 CFR 60.49b(r); and, a stoichiometric quantification for SO_2 emissions shall be utilized using the actual density and sulfur weight percent and the quantity of fuel oil fired monthly. Compliance with visible emission limits shall be demonstrated initially and annually in accordance with EPA Method 9.

8. The Department's Northeast District office and the RESD (City of Jacksonville's Regulatory and Environmental Services Department) office shall be notified at least 15 days prior to the compliance tests. Compliance test results shall be submitted to the Department's Northeast District and Bureau of Air Regulation offices and the RESD office within 45 days after completion of the tests. Sampling facilities, methods, and reporting shall be in accordance with 40 CFR 60.49b, F.A.C. Rule 17-2.700 and 40 CFR 60, Appendix A.

9. The following Seminole Kraft Corporation (SKC) sources shall be permanently shut down and made incapable of operation: the No. 1 PB (power boiler), the No. 2 PB, the No. 3 PB, the No. 1 BB (bark boiler), and the No. 2 BB; and, SKC shall turn in their operation permits to the Department's Bureau of Air Regulation, within 30 days of written confirmation by the Department of the successful completion of the initial compliance tests on the Cedar Bay Cogeneration Plant's boilers. The RESD office shall be specifically informed in writing within thirty days after each individual shut down of the above referenced equipment.

PERMITTEE:
Seminole Kraft Corp.

Permit Number: AC 16-222359
PSD-FL-198
Expiration Date: April 30, 1995

SPECIFIC CONDITIONS:

10. The permittee, for good cause, may request that this construction permit be extended. Such a request shall be submitted to the Department's Bureau of Air Regulation prior to 60 days before the expiration of the permit (F.A.C. Rule 17-4.090).

11. An application for an operation permit must be submitted to the Department's Northeast District office and the RESD office at least 90 days prior to the expiration date of this construction permit. To properly apply for an operation permit, the applicant shall submit the appropriate application form, fee, certification that construction was completed noting any deviations from the conditions in the construction permit, and compliance test reports as required by this permit (F.A.C. Rules 17-4.055 and 17-4.220).

12. Pursuant to 40 CFR 49b(r), quarterly reports shall be submitted to the RESD office (i.e., Administrator) certifying that only very low sulfur oil (i.e., $\leq$0.05% sulfur, by weight) meeting this definition was combusted in the affected facility during the preceding quarter. The firing of any fuel oil and its associated SO_2 emissions shall be quantified on a monthly and per boiler basis and submitted to the RESD office by the end of the month following the end of each quarter. The quarters are defined as January-March, April-June, July-September, and October-December; also, and per boiler, the final quarterly report shall include the total amount of the fuel oil fired and the quantified associated SO_2 emissions from the year.

Issued this 7th day

of July, 1993

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL PROTECTION

Virginia B. Wetherell, Secretary

Revised Best Available Control Technology (BACT) Determination
Seminole Kraft Corporation
Duval County
PSD-FL-198
AC 16-222359

The applicant proposes to install three packaged boilers at their recycled fiber paper mill facility in Jacksonville, Duval County, Florida. Each of the three boilers will be sized to provide up to 125,000 lbs/hr of process steam for Seminole Kraft Corporation's (SKC) paper machines. SKC will also receive process steam from the adjacent Cedar Bay Cogeneration Project (CBCP). According to terms of the CBCP Site Certification proceedings, SKC is to be limited to a total steam production of 640,000 lbs/hr which includes 380,000 lbs/hr imported from the CBCP facility. This leaves 260,000 lbs/hr to be produced by the three packaged boilers under normal operating conditions. During periods when CBCP is not operating or operating at reduced rates, SKC will be allowed to make up the difference between the 380,000 lbs/hr and the steam production level that CBCP provides. This is equivalent to a maximum firing rate of 524 MMBTU/hr for all three SKC packaged boilers when the CBCP facility is down.

Date of Receipt of a Complete Application

February 10, 1993

BACT Determination Requested by Applicant

SKC's application called for the firing of fuel oil on a full time or as needed basis since a firm natural gas contract had not been obtained at the time of filing. Consequently, the application required a BACT determination for SO2 and beryllium since these pollutants would be emitted in amounts exceeding PSD-significant levels. BACT was proposed by the applicant as firing fuel oil with a 0.5 percent maximum sulfur content (0.3 average). Since there are no specific control technologies for beryllium, an uncontrolled beryllium emission level was proposed.

BACT Determination by the Department

During initial permitting discussions with SKC, the Department of Environmental Protection (Department) indicated to them that BACT would require the use of natural gas as the primary fuel, if available. Subsequently, SKC obtained a natural gas contract.

Therefore, the Department's determination of BACT is three packaged steam boilers being allowed to fire both natural gas and No. 2 fuel oil (maximum 0.05% sulfur, by weight), with the primary fuel being natural gas. Allowable emissions under normal operating conditions (i.e. 380,000 lbs/hr steam supplied by CBCP) are listed below for each boiler along with the limit basis:

Pollutant	Emission Limits	Basis
NO_x	23.6 lbs/hr and 103.4 tons/yr	Subpart D_b (0.2 lb/mm BTU)
SO_2	25 tons/yr total-3 boilers*	BACT ($\leq$0.05% S, by wt. #2 Fuel Oil)
VE	Natural Gas - 5% opacity	BACT
VE	No. 2 Fuel Oil - 10% opacity	BACT

* In the event that the ceiling for SO_2 is expected to be exceeded due to unavailability of natural gas caused by factors beyond the control of SKC, SKC shall notify the Department that it anticipates exceeding the ceiling as provided herein; and, the emissions of SO_2 during the period of such curtailment shall not be counted against the yearly emissions ceiling of 25 tons unless administrative proceedings result in a finding that the exceedance was within SKC's control. In no event shall the total annual emissions of SO_2 from the three steam boilers exceed 41 tons/year. The notice shall include a statement or reasons for the request and supporting documentation, and shall be published by SKC, without supporting documents, in a newspaper of general circulation in Jacksonville, Florida, as defined in Section 403.5115(2), Florida Statutes. The filing and publication of the notice no later than 7 days following the date of exceedance, shall preclude any finding of violation by the Department until final disposition of any administrative proceedings.

BACT Determination Procedure

In accordance with Florida Administrative Code (F.A.C.) Rules 17-210 through 297, this BACT determination is based on the maximum degree of reduction of each pollutant emitted which the Department, on a case by case basis, taking into account energy, environmental and economic impacts, and other costs, determines is achievable through application of production processes and available control methods, systems and techniques. In addition, the regulations require that in making the BACT determination the Department shall give consideration to:

(a) Any Environmental Protection Agency determination of BACT pursuant to Section 169, and any emission limitation contained in 40 CFR Part 60 (Standards of Performance for New Stationary Sources) or 40 CFR Part 61 (National Emission Standards for Hazardous Air Pollutants).

(b) All scientific, engineering and technical material and other information available to the Department.

(c) The emission limiting standards or BACT determinations of any other State.

(d) The social and economic impact of the application of such technology.

The EPA currently stresses that BACT should be determined using the "top-down" approach. The first step in this approach is to determine for the emission source in question the most stringent control available for a similar or identical source or source category. If it is shown that this level of control is technically or economically infeasible for the source in question, then the next most stringent level of control is determined and similarly evaluated. This process continues until the BACT level under consideration cannot be eliminated by any substantial or unique technical, environmental, or economic objections.

BACT Determination Rationale

BACT review for particulate emissions and sulfur-dioxide are required under F.A.C. Rule 17-296.406. Visible emissions may be regulated as a surrogate parameter for PM/PM_{10} and have been established at 5% opacity for natural gas fired boilers (10% opacity for No. 2 fuel oil).

For SO_2 emissions from oil firing, only two alternatives exist that would result in stringent SO_2 emissions; using low sulfur content fuel oil or flue gas desulfurization (FGD). EPA has recognized that FGD technology is inappropriate to apply to these combustion units. Sludge would be generated that would have to be disposed of properly, and there would be greatly increased costs associated with the construction and operation of a FGD system. Finally, there is no information in the literature to indicate that FGD has ever been applied to burning distillate oil. This leaves the use of natural gas and low sulfur fuel oil as backup as the best option for this project. Due to the anticipated availability of very low sulfur oil by October 1993, the Department will require the use of No. 2 fuel oil with 0.05% sulfur by weight as BACT.

Details of the Analysis May be Obtained by Contacting:

Preston Lewis, P.E., BACT Coordinator
Department of Environmental Protection
Bureau of Air Regulation
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Recommended by:	Approved by:
C. H. Fancy, P.E., Chief Bureau of Air Regulation	Virginia B. Wetherell, Secretary Dept. of Environmental Protection
July 7 1993 Date	7 July 1993 Date

APPENDIX B

AP-42 EMISSION FACTORS

1.4 Natural Gas Combustion

1.4.1 General[1-2]

Natural gas is one of the major fuels used throughout the country. It is used mainly for industrial process steam and heat production; for residential and commercial space heating; and for electric power generation. Natural gas consists of a high percentage of methane (generally above 85 percent) and varying amounts of ethane, propane, butane, and inerts (typically nitrogen, carbon dioxide, and helium). Gas processing plants are required for the recovery of liquefiable constituents and removal of hydrogen sulfide before the gas is used (see Section 5.3, Natural Gas Processing). The average gross heating value of natural gas is approximately 1020 British thermal units per standard cubic foot (Btu/scf), usually varying from 950 to 1050 Btu/scf.

1.4.2 Firing Practices[3-5]

There are three major types of boilers used for natural gas combustion in the industrial, commercial, and utility sectors: watertube, firetube, and cast iron. Natural gas is also used in residential furnaces. Watertube boilers are designed to pass water through the inside of heat transfer tubes while the outside of the tubes is heated by direct contact with the hot combustion gases. The watertube design is the most common mechanism used for heat transfer in utility and large industrial boilers. Watertube boilers are used for a variety of applications, ranging from the provision of large amounts of process steam, to providing hot water or steam for space heating, to the generation of high-temperature, high-pressure steam for electricity production.

In firetube boilers, the hot combustion gases flow through the tubes, and the water being heated circulates outside of the tubes. These boilers are used primarily for heating systems, industrial process steam, and portable power boilers. Firetube boilers are almost exclusively packaged units. The two major types of firetube units are firebox boilers and Scotch Marine boilers.

In cast iron boilers, as in firetube boilers, the hot gases are contained inside the tubes and the water being heated circulates outside the tubes. However, the units are constructed of cast iron rather than steel. Virtually all cast iron boilers are constructed as package boilers. These boilers are used to produce either low-pressure steam or hot water, and are most commonly used in small commercial applications.

In residential furnaces, natural gas and air are combined in a burner and mixed to promote efficient combustion. Combustion air is supplied by a small fan in forced air furnaces. Hot combustion gases exchange heat with circulating air before being exhausted from a vent or chimney. A variety of burner types may be used in residential furnaces, including single port, multiport, inshot, ribbon, and slotted. Heat exchangers are typically of the sectional or drum types. Materials of construction for burners and heat exchangers include cast iron, stamped steel, and tube steel.

1.4.3 Emissions[3-4]

Natural gas is considered to be one of the cleanest of the commonly used fossil fuels. The emissions from natural gas-fired boilers and furnaces include nitrogen oxides (NO_x), carbon monoxide (CO), and carbon dioxide (CO_2), and trace amounts of sulfur dioxide (SO_2), particulate matter (PM), organic compounds, and other greenhouse gases.

Nitrogen Oxides -

Nitrogen oxides are the major pollutants of concern when burning natural gas. NO_x formed in combustion processes are due either to thermal fixation of atmospheric nitrogen in the combustion air, resulting in the formation of thermal NO_x, or to the conversion of chemically bound nitrogen in the fuel, resulting in fuel NO_x. Due to its characteristically low fuel nitrogen content, nearly all NO_x emissions from natural gas combustion are thermal NO_x. The formation of thermal NO_x is affected by four furnace-zone factors: (1) nitrogen concentration, (2) oxygen concentration, (3) peak temperature, and (4) time of exposure at peak temperature. The emission trends due to changes in these factors are fairly consistent for all types of natural gas-fired boilers and furnaces. Emission levels vary considerably with the type and size of combustor and with operating conditions (particularly combustion air temperature, load, and excess air level in boilers).

Carbon Monoxide -

The rate of CO emissions from boilers depends on the efficiency of natural gas combustion. In some cases, the addition of NO_x control systems such as low NO_x burners and flue gas recirculation (FGR) will reduce combustion efficiency, resulting in higher CO (and trace organics) emissions relative to uncontrolled boilers.

Sulfur Oxides -

Emissions of SO_2 from natural gas-fired boilers are low because natural gas typically contains less than 0.1 percent sulfur. Sulfur-containing mercaptan, however, is added to natural gas for detection purposes, leading to small amounts of SO_2 emissions.

Particulate Matter -

Because natural gas is a gaseous fuel, filterable particulate matter emissions are typically low. Particulate matter (PM) from natural gas combustion has been estimated to be less than 1 micrometer in size. Particulate matter is composed of filterable and condensable fractions, based on the EPA Method 5. Filterable and condensable emission rates are of the same order of magnitude for boilers; for residential furnaces, most of the PM is in the form of condensable material.

Organics -

The rate of trace organic emissions from boilers and furnaces also depends on combustion efficiency. Organic emissions are minimized by combustion practices that promote high combustion temperatures, long residence times at those temperatures, and turbulent mixing of fuel and combustion air. Trace amounts of organic species in the natural gas fuel (e. g., ethylene and benzene) may also contribute to organic species emissions if they are not completely combusted in the boiler.

Greenhouse Gases -[6-11]

Carbon dioxide (CO_2), methane (CH_4), and nitrous oxide (N_2O) emissions are all produced during natural gas combustion. In properly tuned boilers, nearly all of the fuel carbon (99 percent) in natural gas is converted to CO_2 during the combustion process. This conversion is relatively independent of firing configuration. Although the formation of CO acts to reduce CO_2 emissions, the amount of CO produced is insignificant compared to the amount of CO_2 produced. The majority of the fuel carbon not converted to CO_2 is due to incomplete combustion.

Formation of N_2O during the combustion process is governed by a complex series of reactions and its formation is dependent upon many factors. Formation of N_2O is minimized when combustion temperatures are kept high (above 1475°F) and excess air is kept to a minimum (less than 1 percent).

Methane emissions are highest during periods of low-temperature combustion or incomplete combustion, such as the start-up or shut-down cycle for boilers. Typically, conditions that favor formation of N_2O also favor emissions of CH_4.

1.4.4 Controls[4,12]

NO_x Controls -

Currently, the two most prevalent combustion NO_x control techniques being applied to natural gas-fired boilers (which result in characteristic changes in emission rates) are low NO_x burners and flue gas recirculation. Low NO_x burners reduce NO_x by accomplishing the combustion process in stages. Staging partially delays the combustion process, resulting in a cooler flame which suppresses NO_x formation. The two most common types of low NO_x burners being applied to natural gas-fired boilers are staged air burners and staged fuel burners. NO_x emission reductions of 40 to 85 percent (relative to uncontrolled emission levels) have been observed with low NO_x burners. Other combustion staging techniques which have been applied to natural gas-fired boilers include low excess air, reduced air preheat, and staged combustion (e. g., burners-out-of-service and overfire air). The degree of staging is a key operating parameter influencing NO_x emission rates for these systems.

In a flue gas recirculation (FGR) system, a portion of the flue gas is recycled from the stack to the burner windbox. Upon entering the windbox, the gas is mixed with combustion air prior to being fed to the burner. The FGR system reduces NO_x emissions by two mechanisms. The recycled flue gas comprises combustion products which act as inerts during combustion of the fuel/air mixture. This additional mass is heated in the combustion zone, thereby lowering the peak flame temperature and reducing the amount of NO_x formed. To a lesser extent, FGR also reduces NO_x formation by lowering the oxygen concentration in the primary flame zone. The amount of flue gas recirculated is a key operating parameter influencing NO_x emission rates for these systems. Flue gas recirculation is normally used in combination with specially designed low NO_x burners capable of improved flame holding. When used in combination, these techniques are capable of reducing uncontrolled NO_x emissions by 60 to 90 percent.

Two postcombustion technologies that may be applied to natural gas-fired boilers to reduce NO_x emissions by further amounts are selective noncatalytic reduction (SNCR) and selective catalytic reduction (SCR). The SNCR system involves injecting ammonia (or urea) into combustion flue gases (in a specific temperature zone) to reduce NO_x emission. The SCR system involves injecting NH_3 in the presence of a catalyst to reduce NO_x emissions.

Emission factors for natural gas combustion in boilers and furnaces are presented in Tables 1.4-1, 1.4-2, 1.4-3, 1.4-4, and 1.4-5.[13] Tables in this section present emission factors on a volume basis ($lb/10^6ft^3$). To convert to an energy basis (lb/MMBtu), divide by a heating value of 1000 $MMBtu/10^6ft^3$. For the purposes of developing emission factors, natural gas combustors have been organized into four general categories: utility/large industrial boilers, small industrial boilers, commercial boilers, and residential furnaces. Boilers and furnaces within these categories share the same general design and operating characteristics and hence have similar emission characteristics when combusting natural gas. The primary factor used to demarcate the individual combustor categories is heat input.

1.4.5 Updates Since the Fifth Edition

The Fifth Edition was released in January 1995. Revisions to this section since that date are summarized below. For further detail, consult the memoranda describing each supplement or the background report for this section. These and other documents can be found on the CHIEF electronic bulletin board (919-541-5742), or on the new EFIG home page (http://www.epa.gov/oar/oaqps/efig/).

Supplement A, February 1996

- The CO emission factor was changed from 27 to 15 $lb/10^6\ ft^3$.

Supplement B, October 1996

- Text was added concerning firing practices.
- Text was added concerning emissions of NO_x, SO_x, CO, CO_2, and organics.
- Text was added concerning controls from utility boilers.
- CO emission factors were updated for commercial LNB and NO_x for large and small industrial and utility boilers.
- The condensable PM emission factors was updated for small industrial and commercial boilers, and the filterable PM emission factor was updated for residential boilers. A CO_2 emission factor was added for utility boilers.
- In the table with NO_x emission factors, the Low NO_x burner factor for utility/large industrial boilers changed from 81 to 79 $lb/10^6$ BTU, and the footnote for the uncontrolled factor was corrected.
- Figure 1.4-1, the load reduction coefficient as a function of boiler load, was removed.
- N_2O emission factors were added.
- New factors were added for toxic organic and toxic metals emissions.

Table 1.4-1. EMISSION FACTORS FOR SULFUR DIOXIDE (SO_2), NITROGEN OXIDES (NO_x), AND CARBON MONOXIDE (CO) FROM NATURAL GAS COMBUSTION[a]

Combustor Type (Size, 10^6 Btu/hr Heat Input) (SCC)	SO_2[b]		NO_x[c]		CO[d]		N_2O[e]	
	Emission Factor ($lb/10^6 ft^3$)	EMISSION FACTOR RATING	Emission Factor ($lb/10^6 ft^3$)	EMISSION FACTOR RATING	Emission Factor ($lb/10^6 ft^3$)	EMISSION FACTOR RATING	Emission Factor ($lb/10^6 ft^3$)	EMISSION FACTOR RATING
Utility/large Industrial Boilers (>100) (1-01-006-01, 1-01-006-04)								
Uncontrolled	0.6	A	550[f]	A	40	A	2.2	C
Controlled - Low NO_x burners	0.6	A	79	D	ND	NA	0.64	E
Controlled - Flue gas recirculation	0.6	A	53	D	ND	NA	NA	NA
Small Industrial Boilers (10 - 100) (1-02-006-02)								
Uncontrolled	0.6	A	140	A	35	A	2.2[g]	E
Controlled - Low NO_x burners	0.6	A	83	D	61	D	0.64[g]	E
Controlled - Flue gas recirculation	0.6	A	30	C	34	C	NA	NA
Commercial Boilers (0.3 - <10) (1-03-006-03)								
Uncontrolled	0.6	A	100	B	21	C	2.2[g]	E
Controlled - Low NO_x burners	0.6	A	17	C	15	C	0.64[g]	E
Controlled - Flue gas recirculation	0.6	A	36	D	ND	NA	NA	NA
Residential Furnaces (<0.3) (No SCC)								
Uncontrolled	0.6	A	94	B	40	B	NA	NA

[a] Units are lb of pollutant/10^6 cubic feet natural gas fired. To convert from $lb/10^6 ft^3$ to $kg/10^6 m^3$, multiply by 16.0. Based on an average natural gas fired higher heating value of 1000 Btu/scf. The emission factors in this table may be converted to other natural gas heating values by multiplying the given emission factor by the ratio of the specified heating value to this average heating value. SCC = Source Classification Code. ND = no data. NA = not applicable.

[b] References 13-14. Based on average sulfur content of natural gas, 2000 gr/10^6 scf.

[c] References 12-13,15-19. Expressed as NO_2.

[d] References 5,12-13,17-18,20-21.

[e] References 6-7.

[f] For tangentially fired units, use 275 $lb/10^6 ft^3$. Note: This number was originally developed for AP-42 based on limited data. No additional data are available to refine this number.

[g] No data; based on the factors for utility boilers.

Table 1.4-2. EMISSION FACTORS FOR PARTICULATE MATTER (PM) FROM NATURAL GAS COMBUSTION[a]

Combustor Type (Size, 10^6 Btu/hr Heat Input) (SCC)	Filterable PM[b]		Condensable PM[c]	
	Emission Factor ($lb/10^6 ft^3$)	EMISSION FACTOR RATING	Emission Factor ($lb/10^6 ft^3$)	EMISSION FACTOR RATING
Utility/large industrial boilers (>100) (1-01-006-01, 1-01-006-04)	1 - 5	B	ND	NA
Small industrial boilers (10 - 100) (1-02-006-02)	6.2	B	7.8	D
Commercial boilers (0.3 - <10) (1-03-006-03)	4.5	C	7.4	C
Residential furnaces (<0.3) (No SCC)	0.17	C	11	D

[a] References 5,15,22-25. All factors represent uncontrolled emissions. Units are lb of pollutant/10^6 cubic feet natural gas fired. To convert from $lb/10^6 ft^3$ to $kg/10^6 m^3$, multiply by 16.0. Based on an average natural gas higher heating value of 1000 Btu/scf. The emission factors in this table may be converted to other natural gas heating values by multiplying the given emission factor by the ratio of the specified heating value to this average heating value. SCC = Source Classification Code. ND = no data. NA = not applicable.

[b] Filterable PM is that particulate matter collected on or prior to the filter of an EPA Method 5 (or equivalent) sampling train.

[c] Condensable PM is that particulate matter collected using EPA Method 202 (or equivalent). Total PM is the sum of the filterable PM and condensable PM. All PM emissions can be assumed to be less than 10 micrometers in aerodynamic equivalent diameter (PM-10).

Table 1.4-3. EMISSION FACTORS FOR CARBON DIOXIDE (CO_2) AND TOTAL ORGANIC COMPOUNDS (TOC) FROM NATURAL GAS COMBUSTION[a]

Combustor Type (Size, 10^6 Btu/hr Heat Input) (SCC)	CO_2[b]		TOC[c]	
	Emission Factor (lb/10^6 ft^3)	EMISSION FACTOR RATING	Emission Factor (lb/10^6 ft^3)	EMISSION FACTOR RATING
Utility/large industrial boilers (>100) (1-01-006-01, 1-01-006-04)	1.2 E+05	B	1.7[d]	C
Small industrial boilers (10 - 100) (1-02-006-02)	1.2 E+05	B	5.8[e]	C
Commercial boilers (0.3 - <10) (1-03-006-03)	1.2 E+05	B	5.8[e]	C
Residential furnaces (No SCC)	1.2 E+05	B	11	D

[a] All factors represent uncontrolled emissions. Units are lb of pollutant/10^6 cubic feet. To convert from lb/10^6 ft^3 to kg/10^6 m^3, multiply by 16.0. Based on an average natural gas higher heating value of 1000 Btu/scf. The emission factors in this table may be converted to other natural gas heating values by multiplying the given factor by the ratio of the specified heating value to this average heating value. SCC = Source Classification Code. ND = no data. NA = not applicable.

[b] References 8,15,27-29.

[c] References 5,13,15,30.

[d] Reference 30: methane comprises 17% of organic compounds.

[e] Reference 30: methane comprises 52% of organic compounds.

Table 1.4-4. EMISSION FACTORS FOR SPECIATED ORGANIC COMPOUNDS FROM NATURAL GAS COMBUSTION[a]

Organic Compound	Average Emission Factor (lb/million ft^3)	Emission Factor Rating
Formaldehyde	1.55E-01[b]	C
Toluene	2.20E-03[c]	E
2-Methylnaphthalene	9.02E-06[c]	E
Naphthalene	2.40E-04[c]	E
Fluoranthene	3.01E-06[c]	E
Phenanthrene	1.00E-05[c]	E
Pyrene	5.01E-06[c]	E

[a] Data are based on boilers that were both controlled and uncontrolled for criteria pollutant emissions. Source Classification Codes 1-01-006-01, 1-01-006-04. To convert from lb/million ft^3 to kg/million m^3, multiply by 16.0.

[b] References 31-36.

[c] Reference 32. Based on data from one source test.

Table 1.4-5. EMISSION FACTORS FOR METALS FROM NATURAL GAS COMBUSTION[a]

EMISSION FACTOR RATING: E

Metal	Average Emission Factor[b] (lb/million ft^3)
Arsenic	2.30E-04
Barium	2.40E-03
Chromium	1.10E-03
Cobalt	1.20E-04
Copper	2.51E-04
Lead	2.71E-04
Manganese	3.81E-04
Molybdenum	5.81E-04
Nickel	3.61E-03
Vanadium	3.21E-03

[a] Data are for natural gas boilers controlled with overfire air and flue gas recirculation. Source Classification Codes 1-01-006-04.

[b] Reference 32. Based on data from one source test. To convert from lb/million ft^3 to kg/million m^3, multiply by 16.0.

1.3 Fuel Oil Combustion

1.3.1 General[1-3]

Two major categories of fuel oil are burned by combustion sources: distillate oils and residual oils. These oils are further distinguished by grade numbers, with Nos. 1 and 2 being distillate oils; Nos. 5 and 6 being residual oils; and No. 4 being either distillate oil or a mixture of distillate and residual oils. No. 6 fuel oil is sometimes referred to as Bunker C. Distillate oils are more volatile and less viscous than residual oils. They have negligible nitrogen and ash contents and usually contain less than 0.3 percent sulfur (by weight). Distillate oils are used mainly in domestic and small commercial applications, and include kerosene and diesel fuels. Being more viscous and less volatile than distillate oils, the heavier residual oils (Nos. 5 and 6) may need to be heated for ease of handling and to facilitate proper atomization. Because residual oils are produced from the residue remaining after the lighter fractions (gasoline, kerosene, and distillate oils) have been removed from the crude oil, they contain significant quantities of ash, nitrogen, and sulfur. Residual oils are used mainly in utility, industrial, and large commercial applications.

1.3.2 Firing Practices[4]

The major boiler configurations for fuel oil-fired combustors are watertube, firetube, cast iron, and tubeless design. Boilers are classified according to design and orientation of heat transfer surfaces, burner configuration, and size. These factors can all strongly influence emissions as well as the potential for controlling emissions.

Watertube boilers are used in a variety of applications ranging from supplying large amounts of process steam to providing space heat for industrial facilities. In a watertube boiler, combustion heat is transferred to water flowing through tubes which line the furnace walls and boiler passes. The tube surfaces in the furnace (which houses the burner flame) absorb heat primarily by radiation from the flames. The tube surfaces in the boiler passes (adjacent to the primary furnace) absorb heat primarily by convective heat transfer.

Firetube boilers are used primarily for heating systems, industrial process steam generators, and portable power boilers. In firetube boilers, the hot combustion gases flow through the tubes while the water being heated circulates outside of the tubes. At high pressures and when subjected to large variations in steam demand, firetube units are more susceptible to structural failure than watertube boilers. This is because the high-pressure steam in firetube units is contained by the boiler walls rather than by multiple small-diameter watertubes, which are inherently stronger. As a consequence, firetube boilers are typically small and are used primarily where boiler loads are relatively constant. Nearly all firetube boilers are sold as packaged units because of their relatively small size.

A cast iron boiler is one in which combustion gases rise through a vertical heat exchanger and out through an exhaust duct. Water in the heat exchanger tubes is heated as it moves upward through the tubes. Cast iron boilers produce low pressure steam or hot water, and generally burn oil or natural gas. They are used primarily in the residential and commercial sectors.

Another type of heat transfer configuration used on smaller boilers is the tubeless design. This design incorporates nested pressure vessels with water in between the shells. Combustion gases are fired into the inner pressure vessel and are then sometimes recirculated outside the second vessel.

1.3.3 Emissions[5]

Emissions from fuel oil combustion depend on the grade and composition of the fuel, the type and size of the boiler, the firing and loading practices used, and the level of equipment maintenance. Because the combustion characteristics of distillate and residual oils are different, their combustion can produce significantly different emissions. In general, the baseline emissions of criteria and noncriteria pollutants are those from uncontrolled combustion sources. Uncontrolled sources are those without add-on air pollution control (APC) equipment or other combustion modifications designed for emission control. Baseline emissions for sulfur dioxide (SO_2) and particulate matter (PM) can also be obtained from measurements taken upstream of APC equipment.

1.3.3.1 Particulate Matter Emissions[6-15] -

Particulate matter emissions depend predominantly on the grade of fuel fired. Combustion of lighter distillate oils results in significantly lower PM formation than does combustion of heavier residual oils. Among residual oils, firing of No. 4 or No. 5 oil usually produces less PM than does the firing of heavier No. 6 oil.

In general, PM emissions depend on the completeness of combustion as well as on the oil ash content. The PM emitted by distillate oil-fired boilers primarily comprises carbonaceous particles resulting from incomplete combustion of oil and is not correlated to the ash or sulfur content of the oil. However, PM emissions from residual oil burning are related to the oil sulfur content. This is because low-sulfur No. 6 oil, either refined from naturally low-sulfur crude oil or desulfurized by one of several processes, exhibits substantially lower viscosity and reduced asphaltene, ash, and sulfur contents, which results in better atomization and more complete combustion.

Boiler load can also affect particulate emissions in units firing No. 6 oil. At low load (50 percent of maximum rating) conditions, particulate emissions from utility boilers may be lowered by 30 to 40 percent and by as much as 60 percent from small industrial and commercial units. However, no significant particulate emission reductions have been noted at low loads from boilers firing any of the lighter grades. At very low load conditions (approximately 30 percent of maximum rating), proper combustion conditions may be difficult to maintain and particulate emissions may increase significantly.

1.3.3.2 Sulfur Oxides Emissions[1-2,6-9,16] -

Sulfur oxides (SO_x) emissions are generated during oil combustion from the oxidation of sulfur contained in the fuel. The emissions of SO_x from conventional combustion systems are predominantly in the form of SO_2. Uncontrolled SO_x emissions are almost entirely dependent on the sulfur content of the fuel and are not affected by boiler size, burner design, or grade of fuel being fired. On average, more than 95 percent of the fuel sulfur is converted to SO_2, about 1 to 5 percent is further oxidized to sulfur trioxide (SO_3), and 1 to 3 percent is emitted as sulfate particulate. SO_3 readily reacts with water vapor (both in the atmosphere and in flue gases) to form a sulfuric acid mist.

1.3.3.3 Nitrogen Oxides Emissions[1-2,6-10,15,17-27] -

Oxides of nitrogen (NO_x) formed in combustion processes are due either to thermal fixation of atmospheric nitrogen in the combustion air ("thermal NO_x"), or to the conversion of chemically bound nitrogen in the fuel ("fuel NO_x"). The term NO_x refers to the composite of nitric oxide (NO) and nitrogen dioxide (NO_2). Test data have shown that for most external fossil fuel combustion systems, over 95 percent of the emitted NO_x is in the form of nitric oxide (NO). Nitrous oxide (N_2O) is not included in NO_x but has recently received increased interest because of atmospheric effects.

Experimental measurements of thermal NO_x formation have shown that NO_x concentration is exponentially dependent on temperature, and proportional to N_2 concentration in the flame, the square root of O_2 concentration in the flame, and the residence time. Thus, the formation of thermal NO_x is affected by four factors: (1) peak temperature, (2) fuel nitrogen concentration, (3) oxygen concentration, and (4) time of exposure at peak temperature. The emission trends due to changes in these factors are generally consistent for all types of boilers: an increase in flame temperature, oxygen availability, and/or residence time at high temperatures leads to an increase in NO_x production.

Fuel nitrogen conversion is the more important NO_x-forming mechanism in residual oil boilers. It can account for 50 percent of the total NO_x emissions from residual oil firing. The percent conversion of fuel nitrogen to NO_x varies greatly, however; typically from 20 to 90 percent of nitrogen in oil is converted to NO_x. Except in certain large units having unusually high peak flame temperatures, or in units firing a low nitrogen content residual oil, fuel NO_x generally accounts for over 50 percent of the total NO_x generated. Thermal fixation, on the other hand, is the dominant NO_x-forming mechanism in units firing distillate oils, primarily because of the negligible nitrogen content in these lighter oils. Because distillate oil-fired boilers are usually smaller and have lower heat release rates, the quantity of thermal NO_x formed in them is less than that of larger units which typically burn residual oil.[28]

A number of variables influence how much NO_x is formed by these two mechanisms. One important variable is firing configuration. NO_x emissions from tangentially (corner) fired boilers are, on the average, less than those of horizontally opposed units. Also important are the firing practices employed during boiler operation. Low excess air (LEA) firing, flue gas recirculation (FGR), staged combustion (SC), reduced air preheat (RAP), low NO_x burners (LNBs), or some combination thereof may result in NO_x reductions of 5 to 60 percent. Load reduction (LR) can likewise decrease NO_x production. Nitrogen oxide emissions may be reduced from 0.5 to 1 percent for each percentage reduction in load from full load operation. It should be noted that most of these variables, with the exception of excess air, only influence the NO_x emissions of large oil-fired boilers. Low excess air-firing is possible in many small boilers, but the resulting NO_x reductions are less significant.

1.3.3.4 Carbon Monoxide Emissions[29-32] -

The rate of carbon monoxide (CO) emissions from combustion sources depends on the oxidation efficiency of the fuel. By controlling the combustion process carefully, CO emissions can be minimized. Thus if a unit is operated improperly or not well maintained, the resulting concentrations of CO (as well as organic compounds) may increase by several orders of magnitude. Smaller boilers, heaters, and furnaces tend to emit more of these pollutants than larger combustors. This is because smaller units usually have a higher ratio of heat transfer surface area to flame volume than larger combustors have; this leads to reduced flame temperature and combustion intensity and, therefore, lower combustion efficiency.

The presence of CO in the exhaust gases of combustion systems results principally from incomplete fuel combustion. Several conditions can lead to incomplete combustion, including insufficient oxygen (O_2) availability; poor fuel/air mixing; cold-wall flame quenching; reduced combustion temperature; decreased combustion gas residence time; and load reduction (i. e., reduced combustion intensity). Since various combustion modifications for NO_x reduction can produce one or more of the above conditions, the possibility of increased CO emissions is a concern for environmental, energy efficiency, and operational reasons.

1.3.3.5 Organic Compound Emissions[29-39] -

Small amounts of organic compounds are emitted from combustion. As with CO emissions, the rate at which organic compounds are emitted depends, to some extent, on the combustion efficiency of the boiler. Therefore, any combustion modification which reduces the combustion efficiency will most likely increase the concentrations of organic compounds in the flue gases.

Total organic compounds (TOCs) include VOCs, semi-volatile organic compounds, and condensable organic compounds. Emissions of VOCs are primarily characterized by the criteria pollutant class of unburned vapor phase hydrocarbons. Unburned hydrocarbon emissions can include essentially all vapor phase organic compounds emitted from a combustion source. These are primarily emissions of aliphatic, oxygenated, and low molecular weight aromatic compounds which exist in the vapor phase at flue gas temperatures. These emissions include all alkanes, alkenes, aldehydes, carboxylic acids, and substituted benzenes (e. g., benzene, toluene, xylene, and ethyl benzene).

The remaining organic emissions are composed largely of compounds emitted from combustion sources in a condensed phase. These compounds can almost exclusively be classed into a group known as polycyclic organic matter (POM), and a subset of compounds called polynuclear aromatic hydrocarbons (PAH or PNA). There are also PAH-nitrogen analogs. Information available in the literature on POM compounds generally pertains to these PAH groups.

Formaldehyde is formed and emitted during combustion of hydrocarbon-based fuels including coal and oil. Formaldehyde is present in the vapor phase of the flue gas. Formaldehyde is subject to oxidation and decomposition at the high temperatures encountered during combustion. Thus, larger units with efficient combustion (resulting from closely regulated air-fuel ratios, uniformly high combustion chamber temperatures, and relatively long gas retention times) have lower formaldehyde emission rates than do smaller, less efficient combustion units.

1.3.3.6 Trace Element Emissions[29-32,40-44] -

Trace elements are also emitted from the combustion of oil. For this update of AP-42, trace metals included in the list of 189 hazardous air pollutants under Title III of the 1990 Clean Air Act Amendments are considered. The quantity of trace elements entering the combustion device depends solely on the fuel composition. The quantity of trace metals emitted from the source depends on combustion temperature, fuel feed mechanism, and the composition of the fuel. The temperature determines the degree of volatilization of specific compounds contained in the fuel. The fuel feed mechanism affects the separation of emissions into bottom ash and fly ash. In general, the quantity of any given metal emitted depends on the physical and chemical properties of the element itself; concentration of the metal in the fuel; the combustion conditions; and the type of particulate control device used, and its collection efficiency as a function of particle size.

Some trace metals concentrate in certain waste particle streams from a combustor (bottom ash, collector ash, flue gas particulate), while others do not. Various classification schemes to describe this partitioning have been developed. The classification scheme used by Baig, et al.[44] is as follows:

- Class 1: Elements which are approximately equally distributed between fly ash and bottom ash, or show little or no small particle enrichment.

- Class 2: Elements which are enriched in fly ash relative to bottom ash, or show increasing enrichment with decreasing particle size.

- Class 3: Elements which are emitted in the gas phase.

By understanding trace metal partitioning and concentration in fine particulate, it is possible to postulate the effects of combustion controls on incremental trace metal emissions. For example, several NO_x controls for boilers reduce peak flame temperatures (e. g., SC, FGR, RAP, and LR). If combustion temperatures are reduced, fewer Class 2 metals will initially volatilize, and fewer will be available for subsequent condensation and enrichment on fine PM. Therefore, for combustors with particulate controls, lower volatile metal emissions should result due to improved particulate removal. Flue gas emissions of Class 1 metals (the non-segregating trace metals) should remain relatively unchanged.

Lower local O_2 concentrations is also expected to affect segregating metal emissions from boilers with particle controls. Lower O_2 availability decreases the possibility of volatile metal oxidation to less volatile oxides. Under these conditions, Class 2 metals should remain in the vapor phase as they enter the cooler sections of the boiler. More redistribution to small particles should occur and emissions should increase. Again, Class 1 metal emissions should remain unchanged.

1.3.3.7 Greenhouse Gases[45-50] -

Carbon dioxide (CO_2), methane (CH_4), and nitrous oxide (N_2O) emissions are all produced during fuel oil combustion. Nearly all of the fuel carbon (99 percent) in fuel oil is converted to CO_2 during the combustion process. This conversion is relatively independent of firing configuration. Although the formation of CO acts to reduce CO_2 emissions, the amount of CO produced is insignificant compared to the amount of CO_2 produced. The majority of the fuel carbon not converted to CO_2 is due to incomplete combustion in the fuel stream.

Formation of N_2O during the combustion process is governed by a complex series of reactions and its formation is dependent upon many factors. Formation of N_2O is minimized when combustion temperatures are kept high (above 1475°F) and excess air is kept to a minimum (less than 1 percent). Additional sampling and research is needed to fully characterize N_2O emissions and to understand the N_2O formation mechanism. Emissions can vary widely from unit to unit, or even from the same unit at different operating conditions. Average emission factors based on reported test data have been developed for conventional oil combustion systems.

Methane emissions vary with the type of fuel and firing configuration, but are highest during periods of incomplete combustion or low-temperature combustion, such as the start-up or shut-down cycle for oil-fired boilers. Typically, conditions that favor formation of N_2O also favor emissions of CH_4.

1.3.4 Controls

Control techniques for criteria pollutants from fuel oil combustion may be classified into three broad categories: fuel substitution, combustion modification, and postcombustion control. Emissions of noncriteria pollutants such as particulate phase metals have been controlled through the use of post combustion controls designed for criteria pollutants. Fuel substitution reduces SO_2 or NO_x and involves burning a fuel with a lower sulfur or nitrogen content, respectively. Particulate matter will generally be reduced when a lighter grade of fuel oil is burned.[6,8,11] Combustion modification includes any physical or operational change in the furnace or boiler and is applied primarily for NO_x control purposes, although for small units, some reduction in PM emissions may be available through improved combustion practice. Postcombustion control is a device after the combustion of the fuel and is applied to control emissions of PM, SO_2, and NO_x.

1.3.4.1 Particulate Matter Controls[51] -

Control of PM emissions from residential and commercial units is accomplished by improving burner servicing and by incorporating appropriate equipment design changes to improve oil atomization and combustion aerodynamics. Optimization of combustion aerodynamics using a flame retention device, swirl, and/or recirculation is considered to be the best approach toward achieving the triple goals of low PM emissions, low NO_x emissions, and high thermal efficiency.

Large industrial and utility boilers are generally well-designed and well-maintained so that soot and condensable organic compound emissions are minimized. Particulate matter emissions are more a result of emitted fly ash with a carbon component in such units. Therefore, postcombustion controls (mechanical collectors, ESP, fabric filters, etc.) are necessary to reduce PM emissions from these sources where local regulations dictate.

Mechanical collectors, a prevalent type of control device, are primarily useful in controlling particulates generated during soot blowing, during upset conditions, or when a very dirty heavy oil is fired. For these situations, high-efficiency cyclonic collectors can achieve up to 85 percent control of particulate. Under normal firing conditions, or when a clean oil is combusted, cyclonic collectors are not nearly so effective because of the high percentage of small particles (less than 3 micrometers in diameter) emitted.

Electrostatic precipitators (ESPs) are commonly used in oil-fired power plants. Older precipitators, usually small, typically remove 40 to 60 percent of the emitted PM. Because of the low ash content of the oil, greater collection efficiency may not be required. Currently, new or rebuilt ESPs can achieve collection efficiencies of up to 90 percent.

In fabric filtration, a number of filtering elements (bags) along with a bag cleaning system are contained in a main shell structure incorporating dust hoppers. The particulate removal efficiency of the fabric filter system is dependent on a variety of particle and operational characteristics including particle size distribution, particle cohesion characteristics, and particle electrical resistivity. Operational parameters that affect collection efficiency include air-to-cloth ratio, operating pressure loss, cleaning sequence, interval between cleaning, and cleaning intensity. The structure of the fabric filter, filter composition, and bag properties also affect collection efficiency. Collection efficiencies of baghouses may be more than 99 percent.

Scrubbing systems have also been installed on oil-fired boilers to control both sulfur oxides and particulate. These systems can achieve SO_2 removal efficiencies of 90 to 95 percent and particulate control efficiencies of 50 to 60 percent.

1.3.4.2 SO_2 Controls[52-53] -

Commercialized postcombustion flue gas desulfurization (FGD) processes use an alkaline reagent to absorb SO_2 in the flue gas and produce a sodium or a calcium sulfate compound. These solid sulfate compounds are then removed in downstream equipment. Flue gas desulfurization technologies are categorized as wet, semi-dry, or dry depending on the state of the reagent as it leaves the absorber vessel. These processes are either regenerable (such that the reagent material can be treated and reused) or nonregenerable (in which case all waste streams are de-watered and discarded).

Wet regenerable FGD processes are attractive because they have the potential for better than 95 percent sulfur removal efficiency, have minimal waste water discharges, and produce a saleable sulfur product. Some of the current nonregenerable calcium-based processes can, however, produce a saleable gypsum product.

To date, wet systems are the most commonly applied. Wet systems generally use alkali slurries as the SO_x absorbent medium and can be designed to remove greater than 90 percent of the incoming SO_x. Lime/limestone scrubbers, sodium scrubbers, and dual alkali scrubbing are among the commercially proven wet FGD systems. Effectiveness of these devices depends not only on control device design but also on operating variables.

1.3.4.3 NO_x Controls[41,54-55] -

In boilers fired on crude oil or residual oil, the control of fuel NO_x is very important in achieving the desired degree of NO_x reduction since fuel NO_x typically accounts for 60 to 80 percent of the total NO_x formed. Fuel nitrogen conversion to NO_x is highly dependent on the fuel-to-air ratio in the combustion zone and, in contrast to thermal NO_x formation, is relatively insensitive to small changes in combustion zone temperature. In general, increased mixing of fuel and air increases nitrogen conversion which, in turn, increases fuel NO_x. Thus, to reduce fuel NO_x formation, the most common combustion modification technique is to suppress combustion air levels below the theoretical amount required for complete combustion. The lack of oxygen creates reducing conditions that, given sufficient time at high temperatures, cause volatile fuel nitrogen to convert to N_2 rather than NO.

Several techniques are used to reduce NO_x emissions from fuel oil combustion. In addition to fuel substitution, the primary techniques can be classified into one of two fundamentally different methods — combustion controls and postcombustion controls. Combustion controls reduce NO_x by suppressing NO_x formation during the combustion process while postcombustion controls reduce NO_x emissions after their formation. Combustion controls are the most widely used method of controlling NO_x formation in all types of boilers and include low excess air, burners out of service, biased-burner firing, flue gas recirculation, overfire air, and low-NO_x burners. Postcombustion control methods include selective noncatalytic reduction (SNCR) and selective catalytic reduction (SCR). These controls can be used separately, or combined to achieve greater NO_x reduction.

Operating at low excess air involves reducing the amount of combustion air to the lowest possible level while maintaining efficient and environmentally compliant boiler operation. NO_x formation is inhibited because less oxygen is available in the combustion zone. Burners out of service involves withholding fuel flow to all or part of the top row of burners so that only air is allowed to pass through. This method simulates air staging, or overfire air conditions, and limits NO_x formation by lowering the oxygen level in the burner area. Biased-burner firing involves firing the lower rows of burners more fuel-rich than the upper row of burners. This method provides a form of air staging and limits NO_x formation by limiting the amount of oxygen in the firing zone. These methods may change the normal operation of the boiler and the effectiveness is boiler-specific. Implementation of these techniques may also reduce operational flexibility; however, they may reduce NO_x by 10 to 20 percent from uncontrolled levels.

Flue gas recirculation involves extracting a portion of the flue gas from the economizer section or air heater outlet and readmitting it to the furnace through the furnace hopper, the burner windbox, or both. This method reduces the concentration of oxygen in the combustion zone and may reduce NO_x by as much as 40 to 50 percent in some boilers.

Overfire air is a technique in which a percentage of the total combustion air is diverted from the burners and injected through ports above the top burner level. Overfire air limits NO_x by (1) suppressing thermal NO_x by partially delaying and extending the combustion process resulting in less intense combustion and cooler flame temperatures; (2) a reduced flame temperature that limits thermal NO_x formation, and/or (3) a reduced residence time at peak temperature which also limits thermal NO_x formation.

Low NO_x burners are applicable to tangential and wall-fired boilers of various sizes. They have been used as a retrofit NO_x control for existing boilers and can achieve approximately 35 to 55 percent reduction from uncontrolled levels. They are also used in new boilers to meet NSPS limits. Low NO_x burners can be combined with overfire air to achieve even greater NO_x reduction (40 to 60 percent reduction from uncontrolled levels).

SNCR is a postcombustion technique that involves injecting ammonia or urea into specific temperature zones in the upper furnace or convective pass. The ammonia or urea reacts with NO_x in the flue gas to produce nitrogen and water. The effectiveness of SNCR depends on the temperature where reagents are injected; mixing of the reagent in the flue gas; residence time of the reagent within the required temperature window; ratio of reagent to NO_x; and the sulfur content of the fuel that may create sulfur compound that deposit in downstream equipment. There is not as much commercial experience to base effectiveness on a wide range of boiler types; however, in limited applications, NO_x reductions of 25 to 40 percent have been achieved.

SCR is another postcombustion technique that involves injecting ammonia into the flue gas in the presence of a catalyst to reduce NO_x to nitrogen and water. The SCR reactor can be located at various positions in the process including before an air heater and particulate control device, or downstream of the air heater, particulate control device, and flue gas desulfurization systems. The performance of SCR is influenced by flue gas temperature, fuel sulfur content, ammonia to NO_x ratio, inlet NO_x concentration, space velocity, and catalyst condition. NO_x emission reductions of 75 to 85 percent have been achieved through the use of SCR on oil-fired boilers operating in the U.S.

Tables 1.3-1 and 1.3-2 present emission factors for uncontrolled criteria pollutants from fuel oil combustion. Tables in this section present emission factors on a volume basis (lb/10^3gal). To convert to an energy basis (lb/MMBtu), divide by a heating value of 150 MMBtu/10^3gal for Nos. 4, 5, 6, and residual fuel oil, and 140 MMBtu/10^3gal for No. 2 and distillate fuel oil. Tables 1.3-3, 1.3-4, 1.3-5, and 1.3-6 present cumulative size distribution data and size-specific emission factors for particulate emissions from uncontrolled and controlled fuel oil combustion. Figures 1.3-1, 1.3-2, 1.3-3, and 1.3-4 present size-specific emission factors for particulate emissions from uncontrolled and controlled fuel oil combustion. Emission factors for N_2O, POM, and formaldehyde are presented in Table 1.3-7. Emission factors for speciated organic compounds are presented in Table 1.3-8. Emission factors for trace elements are given in Table 1.3-9. Emission factors for metals are given in Table 1.3-10. Default emission factors for CO_2 are presented in Table 1.3-11. A summary of various SO_2 and NO_x controls for fuel-oil-fired boilers is presented in Table 1.3-12 and 1.3-13, respectively.

1.3.5 Updates Since the Fifth Edition

The Fifth Edition was released in January 1995. Revisions to this section since that date are summarized below. For further detail, consult the memoranda describing each supplement or the background report for this section. These and other documents can be found on the CHIEF electronic bulletin board (919-541-5742), or on the new EFIG home page (http://www.epa.gov/oar/oaqps/efig/).

Supplement A, February 1996

The formulas presented in the footnotes for filterable PM were moved into the table.

For SO_2 and SO_3 emission factors, text was added to the table footnotes to clarify that "S" is a weight percent and not a fraction. A similar clarification was made to the CO and NO_x footnotes. SCC A2104004/A2104011 was provided for residential furnaces.

For industrial boilers firing No. 6 and No. 5 oil, the methane emission factor was changed from 1 to 1.0 to show two significant figures.

For SO_2 and SO_3 factors, text was added to the table footnotes to clarify that "S" is a weight percent and not a fraction.

- The N_2O, POM, and formaldehyde factors were corrected.
- Table 1.3-10 was incorrectly labeled 1.1-10. This was corrected.

Supplement B, October 1996

- Text was added concerning firing practices.

Factors for N_2O, POM, and formaldehyde were added.

New data for filterable PM were used to create a new PM factor for residential oil-fired furnaces.

Many new factors were added for toxic organics, toxic metals from distillate oil, and toxic metals from residual oil.

A table was added for new CO_2 emission factors.

Table 1.3-1. CRITERIA POLLUTANT EMISSION FACTORS FOR UNCONTROLLED FUEL OIL COMBUSTION[a]

Firing Configuration (SCC)[a]	SO_2[b]		SO_3[c]		NO_x[d]		CO[c,f]		Filterable PM[g]	
	Emission Factor (lb/10^3 gal)	EMISSION FACTOR RATING	Emission Factor (lb/10^3 gal)	EMISSION FACTOR RATING	Emission Factor (lb/10^3 gal)	EMISSION FACTOR RATING	Emission Factor (lb/10^3 gal)	EMISSION FACTOR RATING	Emission Factor (lb/10^3 gal)	EMISSION FACTOR RATING
Utility boilers										
No. 6 oil fired, normal firing (1-01-004-01)	157S	A	5.7S	C	67	A	5	A	9.19(S)+3.22	A
No. 6 oil fired, tangential firing (1-01-004-04)	157S	A	5.7S	C	42	A	5	A	9.19(S)+3.22	A
No. 5 oil fired, normal firing (1-01-004-05)	157S	A	5.7S	C	67	A	5	A	10	B
No. 5 oil fired, tangential firing (1-01-004-06)	157S	A	5.7S	C	42	A	5	A	10	B
No. 4 oil fired, normal firing (1-01-005-04)	150S	A	5.7S	C	67	A	5	A	7	B
No. 4 oil fired, tangential firing (1-01-005-05)	150S	A	5.7S	C	42	A	5	A	7	B
Industrial										
No. 6 oil fired (1-02-004-01/02/03)	157S	A	2S	A	55	A	5	A	9.19(S)+3.22	A
No. 5 oil fired (1-02-004-04)	157S	A	2S	A	55	A	5	A	10	B
Distillate oil fired (1-02-005-01/02/03)	142S	A	2S	A	20	A	5	A	2	A
No. 4 oil fired (1-02-005-04)	150S	A	2S	A	20	A	5	A	7	B
Commercial/institutional										
No. 6 oil fired (1-03-004-01/02/03)	157S	A	2S	A	55	A	5	A	9.19(S)+3.22	A
No. 5 oil fired (1-03-004-04)	157S	A	2S	A	55	A	5	A	10	B
Distillate oil fired (1-03-005-01/02/03)	142S	A	2S	A	20	A	5	A	2	A
No. 4 oil fired (1-03-005-04)	150S	A	2S	A	20	A	5	A	7	B
Residential furnace (A2104004/A2104011)	142S	A	2S	A	18	A	5	A	0.4[h]	B

Table 1.3-1 (cont.).

[a] To convert from $lb/10^3$ gal to $kg/10^3$ L, multiply by 0.120. SCC = Source Classification Code.

[b] References 1-2,6-9,14,56-60. S indicates that the weight % of sulfur in the oil should be multiplied by the value given. For example, if the fuel is 1% sulfur, then S = 1.

[c] References 1-2,6-8,16,57-60. S indicates that the weight % of sulfur in the oil should be multiplied by the value given. For example, if the fuel is 1% sulfur, then S = 1.

[d] References 6-7,15,19,22,56-62. Expressed as NO_2. Test results indicate that at least 95% by weight of NO_x is NO for all boiler types except residential furnaces, where about 75% is NO. For utility vertical fired boilers use 105 $lb/10^3$ gal at full load and normal (>15%) excess air. Nitrogen oxides emissions from residual oil combustion in industrial and commercial boilers are related to fuel nitrogen content, estimated by the following empirical relationship: lb NO_2 $/10^3$ gal = 20.54 + 104.39(N), where N is the weight % of nitrogen in the oil. For example, if the fuel is 1% nitrogen, then N = 1.

[e] References 6-8,14,17-19,56-61. CO emissions may increase by factors of 10 to 100 if the unit is improperly operated or not well maintained.

[f] Emission factors for CO_2 from oil combustion should be calculated using lb $CO_2/10^3$ gal oil = 256C (Distillate), 286C (Residual), or 250C (Kerosene) where C indicates weight % of carbon in the oil. For example, if the fuel is 86% carbon, then C = 86.

[g] References 6-8,10,13-15,56-60,62-63. Filterable PM is that particulate collected on or prior to the filter of an EPA Method 5 (or equivalent) sampling train. Particulate emission factors for residual oil combustion are, on average, a function of fuel oil sulfur content where S is the weight % of sulfur in oil. For example, if fuel oil is 1% sulfur, then S = 1.

[h] Based on data from new burner designs. Pre-1970's burner designs may emit filterable PM as high as 3.0 $lb/10^3$ gal.

Table 1.3-2. EMISSION FACTORS FOR TOTAL ORGANIC COMPOUNDS (TOC), METHANE, AND NONMETHANE TOC (NMTOC) FROM UNCONTROLLED FUEL OIL COMBUSTION[a]

EMISSION FACTOR RATING: A

Firing Configuration (SCC)	TOC[b] Emission Factor (lb/10^3 gal)	Methane[b] Emission Factor (lb/10^3 gal)	NMTOC[b] Emission Factor (lb/10^3 gal)
Utility boilers			
No. 6 oil fired, normal firing (1-01-004-01)	1.04	0.28	0.76
No. 6 oil fired, tangential firing (1-01-004-04)	1.04	0.28	0.76
No. 5 oil fired, normal firing (1-01-004-05)	1.04	0.28	0.76
No. 5 oil fired, tangential firing (1-01-004-06)	1.04	0.28	0.76
No. 4 oil fired, normal firing (1-01-005-04)	1.04	0.28	0.76
No. 4 oil fired, tangential firing (1-01-005-05)	1.04	0.28	0.76
Industrial boilers			
No. 6 oil fired (1-02-004-01/02/03)	1.28	1.00	0.28
No. 5 oil fired (1-02-004-04)	1.28	1.00	0.28
Distillate oil fired (1-02-005-01/02/03)	0.252	0.052	0.2
No. 4 oil fired (1-02-005-04)	0.252	0.052	0.2
Commercial/institutional/residential combustors			
No. 6 oil fired (1-03-004-01/02/03)	1.605	0.475	1.13
No. 5 oil fired (1-03-004-04)	1.605	0.475	1.13
Distillate oil fired (1-03-005-01/02/03)	0.556	0.216	0.34
No. 4 oil fired (1-03-005-04)	0.556	0.216	0.34
Residential furnace (A2104004/A2104011)	2.493	1.78	0.713

[a] To convert from lb/10^3 gal to kg/10^3 L, multiply by 0.12. SCC = Source Classification Code.
[b] References 29-32. Volatile organic compound emissions can increase by several orders of magnitude if the boiler is improperly operated or is not well maintained.

Table 1.3-3. CUMULATIVE PARTICLE SIZE DISTRIBUTION AND SIZE-SPECIFIC EMISSION FACTORS FOR UTILITY BOILERS FIRING RESIDUAL OIL[a]

Particle Size[b] (µm)	Cumulative Mass % ≤ Stated Size			Cumulative Emission Factor (lb/10^3 gal)					
	Uncon-trolled	Controlled		Uncontrolled[c]		ESP Controlled[d]		Scrubber Controlled[e]	
		ESP	Scrubber	Emission Factor	EMISSION FACTOR RATING	Emission Factor	EMISSION FACTOR RATING	Emission Factor	EMISSION FACTOR RATING
15	80	75	100	6.7A	C	0.05A	E	0.50A	D
10	71	63	100	5.9A	C	0.042A	E	0.50A ~~0.050A~~	D
6	58	52	100	4.8A	C	0.035A	E	0.50A	D
2.5	52	41	97	4.3A	C	0.028A	E	0.48A	D
1.25	43	31	91	3.6A	C	0.021A	E	0.46A	D
1.00	39	28	84	3.3A	C	0.018A	E	0.42A	D
0.625	20	20	64	1.74	C	0.007A	E	0.32A	D
TOTAL	100	100	100	8.3A	C	0.067A	E	0.50A	D

[a] Reference 26. Source Classification Codes 1-01-004-01/04/05/06 and 1-01-005-04/05. To convert from lb/10^3 gal to kg/m^3, multiply by 0.120. ESP = electrostatic precipitator.

[b] Expressed as aerodynamic equivalent diameter.

[c] Particulate emission factors for residual oil combustion without emission controls are, on average, a function of fuel oil grade and sulfur content where S is the weight % of sulfur in the oil. For example, if the fuel is 1.00% sulfur, then S = 1.

No. 6 oil: A = ~~9.19(S) + 3.22~~ lb/10^3 gal   1.12(S) + 0.37

No. 5 oil: A = 10 lb/10^3 gal

No. 4 oil: A = 7 lb/10^3 gal

[d] Estimated control efficiency for ESP is 99.2%.

[e] Estimated control efficiency for scrubber is 94%

Table 1.3-4. CUMULATIVE PARTICLE SIZE DISTRIBUTION AND SIZE-SPECIFIC EMISSION FACTORS FOR INDUSTRIAL BOILERS FIRING RESIDUAL OIL[a]

Particle Size[b] (μm)	Cumulative Mass % ≤ Stated Size		Cumulative Emission Factor[c] ($lb/10^3$ gal)			
			Uncontrolled		Multiple Cyclone Controlled[d]	
	Uncontrolled	Multiple Cyclone Controlled	Emission Factor	EMISSION FACTOR RATING	Emission Factor	EMISSION FACTOR RATING
15	91	100	7.59A	D	1.67A	E
10	86	95	7.17A	D	1.58A	E
6	77	72	6.42A	D	1.17A	E
2.5	56	22	4.67A	D	0.33A	E
1.25	39	21	3.25A	D	0.33A	E
1.00	36	21	3.00A	D	0.33A	E
0.625	30	—[e]	2.50A	D	—[e]	NA
TOTAL	100	100	8.34A	D	1.67A	E

[a] Reference 26. Source Classification Codes 1-02-004-01/02/03/04 and 1-02-005-04. To convert from $lb/10^3$ gal to $kg/10^3$ L, multiply by 0.120. NA = not applicable.

[b] Expressed as aerodynamic equivalent diameter.

[c] Particulate emission factors for residual oil combustion without emission controls are, on average, a function of fuel oil grade and sulfur content where S is the weight % of sulfur in the oil. For example, if the fuel is 1.0% sulfur, then S = 1.

No. 6 oil: A = 9.19(S) + 3.22 $lb/10^3$ gal

No. 5 oil: A = 10 $lb/10^3$ gal

No. 4 oil: A = 7 $lb/10^3$ gal

[d] Estimated control efficiency for multiple cyclone is 80%.

[e] Insufficient data.

Table 1.3-5. CUMULATIVE PARTICLE SIZE DISTRIBUTION AND SIZE-SPECIFIC EMISSION FACTORS FOR UNCONTROLLED INDUSTRIAL BOILERS FIRING DISTILLATE OIL[a]

EMISSION FACTOR RATING: E

Particle Size[b] (μm)	Cumulative Mass % ≤ Stated Size	Cumulative Emission Factor ($lb/10^3$ gal)
15	68	1.33
10	50	1.00
6	30	0.58
2.5	12	0.25
1.25	9	0.17
1.00	8	0.17
0.625	2	0.04
TOTAL	100	2.00

[a] Reference 26. Source Classification Codes 1-02-005-01/02/03. To convert from $lb/10^3$ gal to $kg/10^3$ L, multiply by 0.12.
[b] Expressed as aerodynamic equivalent diameter.

Table 1.3-6. CUMULATIVE PARTICLE SIZE DISTRIBUTION AND SIZE-SPECIFIC EMISSION FACTORS FOR UNCONTROLLED COMMERCIAL BOILERS BURNING RESIDUAL OR DISTILLATE OIL[a]

EMISSION FACTOR RATING: D

	Cumulative Mass % ≤ Stated Size		Cumulative Emission Factor[c] ($lb/10^3$ gal)	
Particle Size[b] (μm)	Residual Oil	Distillate Oil	Residual Oil	Distillate Oil
15	78	60	6.50A	1.17
10	62	55	5.17A	1.08
6	44	49	3.67A	1.00
2.5	23	42	1.92A	0.83
1.25	16	38	1.33A	0.75
1.00	14	37	1.17A	0.75
0.625	13	35	1.08A	0.67
TOTAL	100	100	8.34A	2.00

[a] Reference 26. Source Classification Codes: 1-03-004-01/02/03/04 and 1-03-005-01/02/03/04. To convert from $lb/10^3$ gal to $kg/10^3$ L, multiply by 0.12.
[b] Expressed as aerodynamic equivalent diameter.
[c] Particulate emission factors for residual oil combustion without emission controls are, on average, a function of fuel oil grade and sulfur content where S is the weight % of sulfur in the fuel. For example, if the fuel is 1.0% sulfur, then S = 1.
No. 6 oil: $A = 9.19(S) + 3.22$ $lb/10^3$ gal.
No. 5 oil: $A = 10$ $lb/10^3$ gal
No. 4 oil: $A = 7$ $lb/10^3$ gal
No. 2 oil: $A = 2$ $lb/10^3$ gal

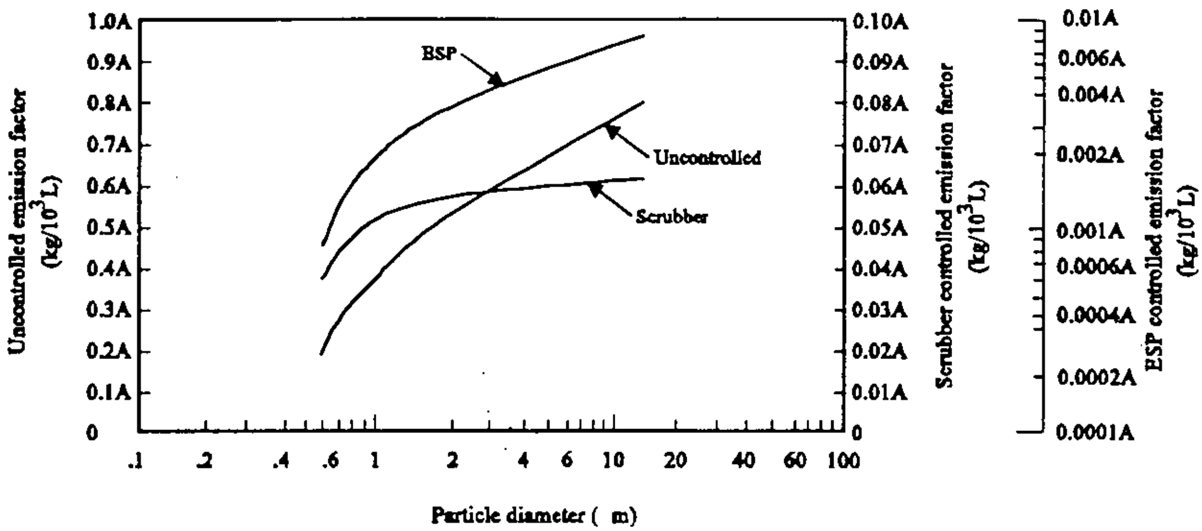

Figure 1.3-1. Cumulative size-specific emission factors for utility boilers firing residual oil.

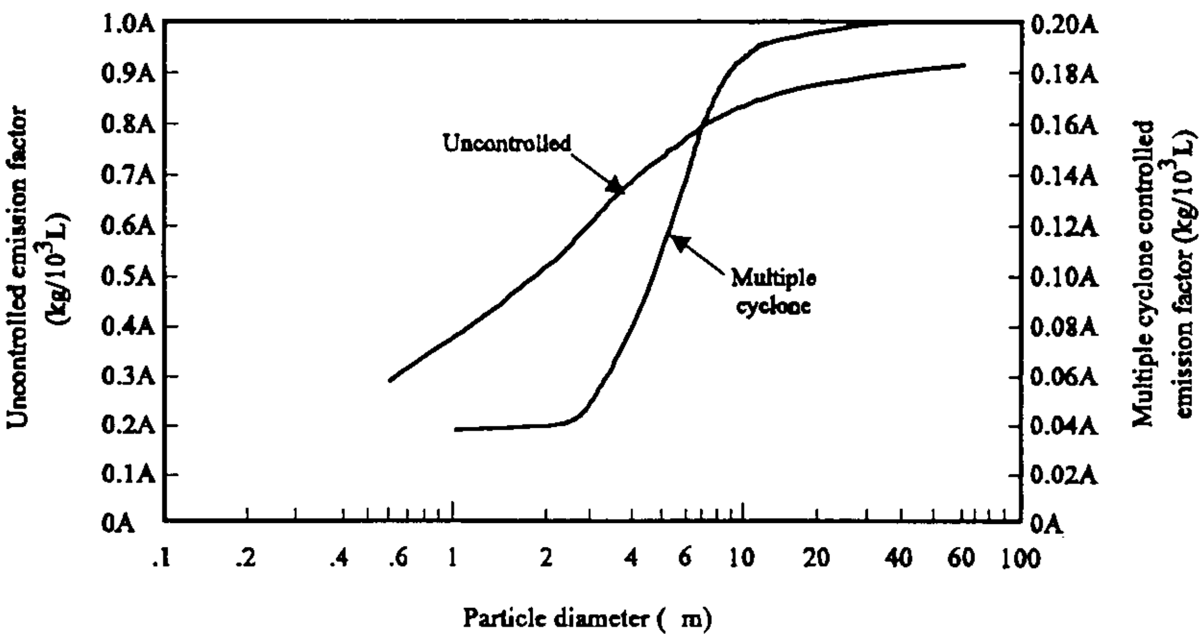

Figure 1.3-2. Cumulative size-specific emission factors for industrial boilers firing residual oil.

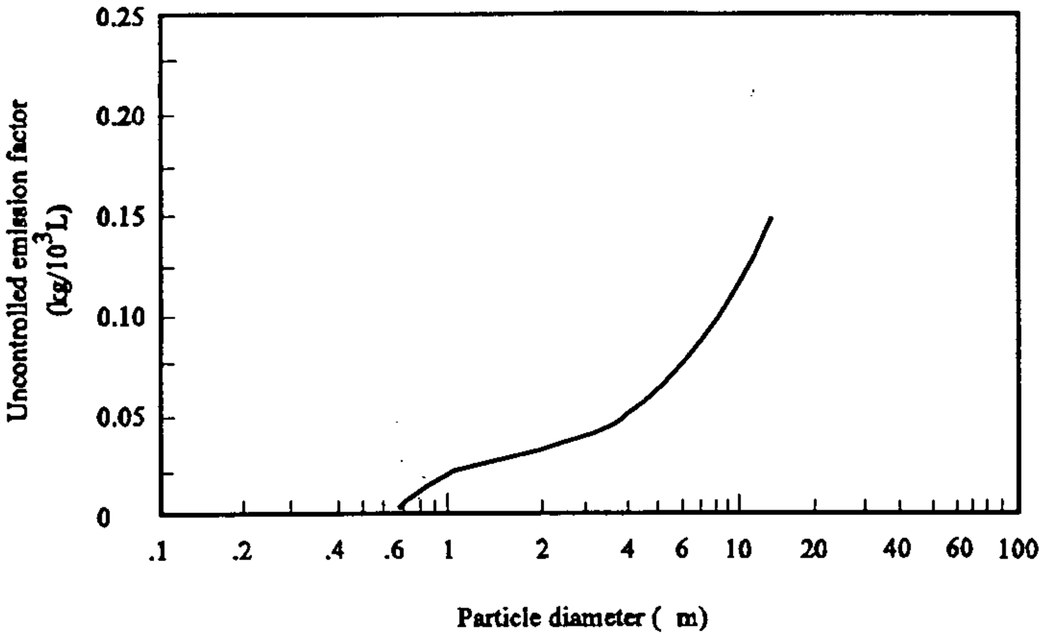

Figure 1.3-3. Cumulative size-specific emission factors for uncontrolled industrial boilers firing distillate oil.

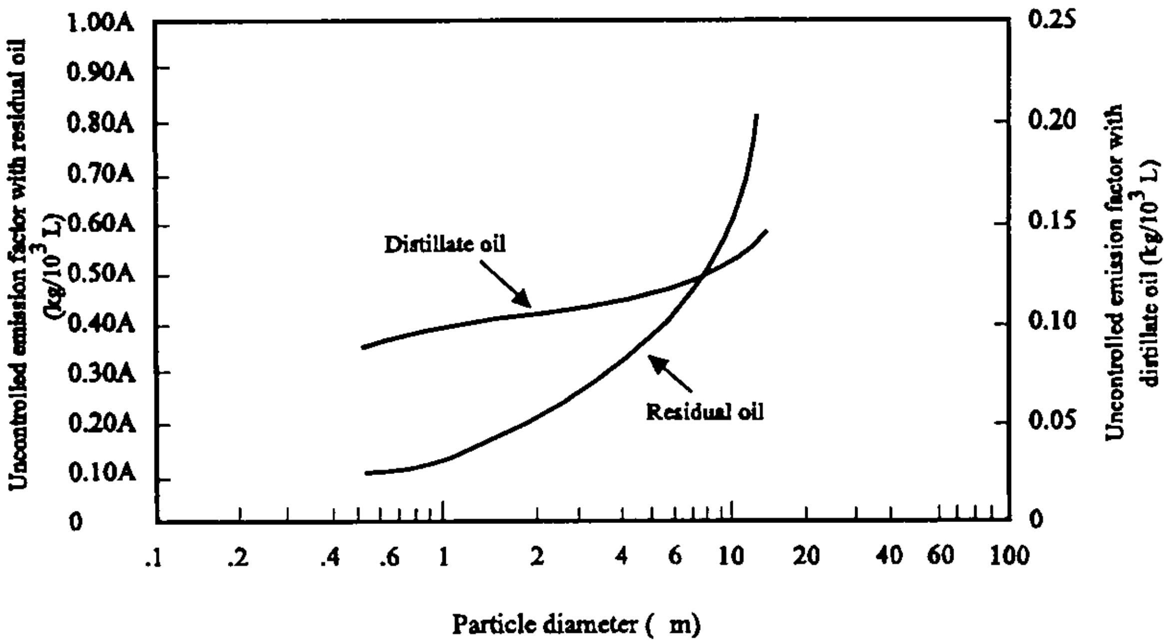

Figure 1.3-4. Cumulative size-specific emission factors for uncontrolled commercial boilers burning residual and distillate oil.

Table 1.3-7. EMISSION FACTORS FOR NITROUS OXIDE (N_2O), POLYCYCLIC ORGANIC MATTER (POM), AND FORMALDEHYDE (HCOH) FROM FUEL OIL COMBUSTION[a]

EMISSION FACTOR RATING: E

Firing Configuration (SCC)	Emission Factor (lb/10^3 gal)		
	N_2O[b]	POM[c]	HCOH[c]
Utility/industrial/commercial boilers			
No. 6 oil fired (1-01-004-01, 1-02-004-01, 1-03-004-01)	0.11	0.0011 - 0.0013[d]	0.024 - 0.061
Distillate oil fired (1-01-005-01, 1-02-005-01, 1-03-005-01)	0.11	0.0033[e]	0.035 - 0.061
Residential furnaces (A2104004/A2104011)	0.05	ND	ND

[a] To convert from lb/10^3 gal to kg/10^3L, multiply by 0.12. SCC = Source Classification Code. ND = no data.
[b] References 45-46. EMISSION FACTOR RATING = B.
[c] References 29-32.
[d] Particulate and gaseous POM.
[e] Particulate POM only.

Table 1.3-8. EMISSION FACTORS FOR SPECIATED ORGANIC COMPOUNDS FROM FUEL OIL COMBUSTION[a]

Organic Compound	Average Emission Factor[b] (lb/10^3 Gal)	EMISSION FACTOR RATING
Benzene	2.14E-04	C
Ethylbenzene	6.36E-05[c]	E
Formaldehyde[d]	3.30E-02	C
Naphthalene	1.13E-03	C
1,1,1-Trichloroethane	2.36E-04[c]	E
Toluene	6.20E-03	D
o-Xylene	1.09E-04[c]	E
Acenaphthene	2.11E-05	C
Acenaphthylene	2.53E-07	D
Anthracene	1.22E-06	C
Benz(a)anthracene	4.01E-06	C
Benzo(b,k)fluoranthene	1.48E-06	C
Benzo(g,h,i)perylene	2.26E-06	C
Chrysene	2.38E-06	C
Dibenzo(a,h) anthracene	1.67E-06	D
Fluoranthene	4.84E-06	C
Fluorene	4.47E-06	C
Indo(1,2,3-cd)pyrene	2.14E-06	C
Phenanthrene	1.05E-05	C
Pyrene	4.25E-06	C
OCDD	3.10E-09[c]	E

[a] Data are for residual oil fired boilers, Source Classification Codes (SCCs) 1-01-004-01/04.
[b] References 64-72. To convert from lb/10^3 gal to kg/10^3 L, multiply by 0.12.
[c] Based on data from one source test (Reference 67).
[d] The formaldehyde number presented here is based only on data from utilities using No. 6 oil. The number presented in Table 1.3-7 is based on utility, commercial, and industrial boilers.

Table 1.3-9. EMISSION FACTORS FOR TRACE ELEMENTS FROM DISTILLATE FUEL OIL COMBUSTION SOURCES[a]

EMISSION FACTOR RATING: E

Firing Configuration (SCC)	Emission Factor (lb/10^{12} Btu)										
	As	Be	Cd	Co	Cr	Hg	Mn	Ni	Pb	Sb	Se
Distillate oil fired (1-01-005-01, 1-02-005-01, 1-03-005-01)	4.2	2.5	11	ND	48-67	3.0	14	~~18~~ 170	8.9	ND	ND

[a] References 29-32,40-44. The emission factors in this table represent the ranges of factors reported in the literature. If only one data point was found, it is still reported in this table. To convert from lb/10^{12} Btu to pg/J, multiply by 0.43. SCC = Source Classification Code. ND = no data.

Table C-1. Summary of BACT Determinations for NOx from Boilers Fired by Natural Gas

Company	State	Permit No.	Permit Issue Date	Throughput	Emssion Limit	Control Equipment	Control Efficiency
BUCKNELL UNIVERSITY	PA	60-0001A	11/26/97	24000 lb/hr Steam	0.1 lb/MMBtu	–	--
GRAIN PROCESSING CORP.	IN	CP 027-7239-00046	06/10/97	244 MMBtu/hr	0.05 lb/MMBtu	LOW NOX BURNERS AND FLUE GAS RECIRCULATION (FGR)	–
KERN MEDICAL CENTER	CA	S-1678-11-0	01/27/97	3 MMBtu/hr	- -	OPERATION LIMITED TO 80% UTILIZATION RECORDKEEPING REQUIRED FOR COMPLIANCE	–
CALIFORNIA STATE PRISON, CORCORAN	CA	C-0214-32-0	01/15/97	8 1 MMBtu/hr	0.012 MMBtu/hr	PREMIXED LEAN BURN COMBUSTION TECHNOLOGY	–
DARLING INTERNATIONAL	CA	C-406-3-1	12/30/96	31 2 MMBtu/hr	0.036 lb/MMBtu	LOW-NOX BURNER, FLUE GAS RECIRCULATION (FGR)	–
IMC-AGRICO COMPANY - FAUSTINA PLANT	LA	PSD-LA-602	10/16/96	320 MMBtu/hr	0 08 lb/MMBtu	LOW NOX BURNERS	–
O.H. KRUSE GRAIN AND MILLING	CA	S-160-13-0	09/19/96	10 MMBtu/hr	0.106 lb/MMBtu	--	–
WEYERHAEUSER COMPANY	MS	1680-44	09/10/96	7 MMBtu/hr	80 PPMVD @ 8% O2	STAGED COMBUSTION	–
WEYERHAEUSER COMPANY	MS	1680-44	09/10/96	1600 MMBtu/hr	0 5 lb/MMBtu	CONTINUED EFFICIENT OPERATION WITH LOW NOX BURNERS	–
WEYERHAEUSER COMPANY	MS	1680-44	09/10/96	400 MMBtu/hr	0.1 lb/MMBtu	LOW NOX BURNERS WITH FLUE GAS RECIRCULATION (FGR)	–
TOYOTA MOTOR CORPORATION SVCS OF N A	IN	CP-051-5391-00037	08/09/96	58 MMBtu/hr	0 1 lb/MMBtu	LOW NOX BURNERS & FUEL SPEC USE OF NATURAL GAS 111 AS FUEL	--
BOISE CASCADE CORP.	AL	102-1	05/10/96	346 4 MMBtu/hr	0 05 lb/MMBtu	LOW NOX BURNERS AND FLUE GAS RECIRCULATION (FGR)	--
MID-GEORGIA COGEN.	GA	4911-76-11753	04/03/96	60 MMBtu/hr	0.1 lb/MMBtu	DRY LOW NOX BURNER WITH FGR	--
EXXON COMPANY, USA SANTA YNEZ UNIT PROJECT	CA	ATC-9517	02/05/96	95 MMBtu/hr - each	27 PPMVD AT 3% O2	FLUE-GAS RECIRCULATION (FGR), STEAM INJECTION	–
SITIX OF PHOENIX, INC.	AZ	950460	02/01/96	42 MMBtu/hr	49 TPY	FLUE GAS RECIRCULATION (FGR)-NOX NOT TO EXCEED 30 PPM	–
MINNESOTA CORN PROCESSORS	MN	8300038-19	08/09/95	- -	24.1 lb/hr	USE OF LOW NOX MULTISTAGE COMBUSTION COMBINED WITHINDUCED FLUE GAS RECIRCULATION (FGR)	--
GEORGIA PACIFIC CORP (MONTICELLO MILL)	MS	1500-7	07/11/95	776 MMBtu/hr	- -	NO PHYSICAL MODIFICATION TO BOILER. BACT NOT REQUIRED.	–
TRANSAMERICAN REFINING CORPORATION	LA	PSD-LA-571 (M-1)	02/10/95	244 MMBtu/hr	19 8 lb/hr	LOW NOX BURNERS/COMBUSTION CONTROL	–
KAMINE/BESICORP SYRACUSE LP	NY	313201 2010/00001-00007	12/10/94	2 5 MMBtu/hr	0 12 lb/MMBtu	–	–
KAMINE/BESICORP SYRACUSE LP	NY	313201 2010/00001-00007	12/10/94	33 MMBtu/hr	0 035 lb/MMBtu	INDUCED FLUE GAS RECIRCULATION (FGR)	70 9
COURTAULDS FIBERS, INC	AL	503-5002-X023 AND -X24	11/02/94	148 MMBtu/hr	10 4 lb/hr	LOW NOX BURNERS WITH 8% FLUE GAS RECIRCULATION	87
JVC MAGNETICS AMERICA CO	AL	413-0040-X001,X002,X003,X006	06/16/94	5 2 MMBtu/hr	40 TPY	FUEL SPEC: NATURAL GAS W/ MAX 0 5% SULFUR FUEL OILAS BACKUP	–
PORTLAND GENERAL ELECTRIC CO.	OR	25-31	05/31/94	361 MMBtu/hr	0.1 lb/MMBtu	LOW NOX BURNER AND FLUE GAS RECIRCULATION	–
INTEL CORPORATION	AZ	93-46	04/10/94	50 MMBtu/hr	- -	LOW NOX BURNERS	--
CHAMPION INTERNATIONAL CORP	FL	PSD-FL-200	03/25/94	533 MMBtu/hr	0.06 lb/MMBtu	COEN LOW NOX BURNERS AND FGR	--
STAFFORD RAILSTEEL CORPORATION	AR	1471-A	08/17/93	46 5 MMBtu/hr	7.1 TPY	FUEL SPEC: USE OF NATURAL GAS & LOW NOX BURNERS	--
LOCKPORT COGEN FACILITY	NY	292600 0446/00001-00007	07/14/93	210 MMBtu/hr	0.2 lb/MMBtu	--	–
ANITEC COGEN PLANT	NY	030200 0451	07/07/93	123 MMBtu/hr	0 05 lb/MMBtu	--	--
NEWARK BAY COGENERATION PARTNERSHIP, L.P.	NJ	01-92-5231 TO 01-92-5261	06/09/93	206 MMBtu/hr	0.1 lb/MMBtu	LOW NOX BURNERS, FLUE GAS RECIRCULATION (FGR)	–
NEWARK BAY COGENERATION PARTNERSHIP, L P.	NJ	01-92-5231 TO 01-92-5261	06/09/93	200 MMBtu/hr	0.05 lb/MMBtu	LOW NOX BURNERS, FLUE GAS RECIRCULATION (FGR)	–
INDECK ENERGY COMPANY	NY	563203 0099	05/12/93	0 MMBtu/hr	0 2 lb/MMBtu	--	--
CNG TRANSMISSION CORPORATION	WV	R13-1471/R14-9	05/03/93	10 MMBtu/hr	140 LB/MM cu ft	--	–
INDELK ENERGY SERVICES OF OTSEGO	MI	143-90	03/16/93	778 MMBtu/hr	0 25 lb/MMBtu	SNCR/DRY CONTROL	50
INDELK ENERGY SERVICES OF OTSEGO	MI	143-90	03/16/93	99 MMBtu/hr	0 06 lb/MMBtu	FLUE GAS RECIRCULATION	40
TRANSAMERICAN REFINING CORPORATION (TARC)	LA	PSD-LA-571	01/15/93	1 2 MMBtu/hr	0 14 lb/hr	GOOD COMBUSTION PRACTICES	–
AMERICAN CRYSTAL SUGAR COMPANY	MN	298-92-OT-1	12/15/92	200 1 MMBtu/hr	0.075 lb/MMBtu	LOW NOX BURNER WITH FLUE GAS RECIRCULATION BOILER INSTALLATION	–
KAMINE/BESICORP CORNING L P	NY	8-4638-22/1-0	11/05/92	33 5 MMBtu/hr	0 32 lb/MMBtu	LOW NOX BURNER, FGR	–
SUNLAND REFINERY	CA	S-0207-0085-00 & -0036-00	09/24/92	12.6 MMBtu/hr	0 036 lb/MMBtu	FGR/LOW NOX BURNER	–
CPC - CORN PRODUCTS DIVISION	IL	91020069/ID 031012ABI	08/06/92	600 MMBtu/hr	0 05 lb/MMBtu	LOW NOX BURNER & FLUE GAS RECIRCULATION	85
SARANAC ENERGY COMPANY	NY	5-942-106/1-9	07/31/92	249 MMBtu/hr	0 136 lb/MMBtu	LOW NOX BURNERS	–
INDECK-YERKES ENERGY SERVICES	NY	146400 0133	06/24/92	99 MMBtu/hr	0 2 lb/MMBtu	--	–
BOISE CASCADE CORPORATION	AL	102-1	04/01/92	343 4 MMBtu/hr	0 05 lb/MMBtu	--	–
BERMUDA HUNDRED ENERGY LIMITED PARTNERSHIP	VA	51020	03/03/92	250 MMBtu/hr	0.1 lb/MMBtu	LOW NOX BURNER	–
KALAMAZOO POWER LIMITED	MI	1234-90	12/03/91	500 KW	0 02 lb/MMBtu	–	–
SCOTT PAPER COMPANY	AL	503-2012	09/17/91	220 5 MMBtu/hr	0 1 lb/MMBtu	FACILITY NOW SHUT DOWN	--
JAMES RIVER CORP	MI	423-91	09/17/91	226.7 MMBtu/hr	0 06 lb/MMBtu	LOW NOX BURNERS AND FGR SYS	70
MINNESOTA CORN PROCESSORS, INC.	MN	AMENDMENT 6 TO 1939-88-0T-1	06/25/91	178 7 MMBtu/hr	0 125 lb/MMBtu	LOW NOX BURNERS	–
CHAMPION INTERNATIONAL	AL	707-1-U54	05/08/91	5 8 MMBtu/hr	0 05 lb/MMBtu	FLUE GAS RECIRCULATION	–
NORTHERN CONSOLIDATED POWER	PA	25-328-1	05/03/91	100 4 MMBtu/hr	0 1 lb/MMBtu	--	--
LAKEWOOD COGENERATION, L.P.	NJ	–	04/01/91	131 MMBtu/hr	0.2 lb/MMBtu	LOW NOX BURNERS	50
LAKEWOOD COGENERATION, L.P.	NJ	–	04/01/91	131 MMBtu/hr	0.1 lb/MMBtu	LOW NOX BURNERS	50
DEL MONTE FOODS, USA	CA	3040000000	09/26/90	20 9 MMBtu/hr	40 PPMVD @ 3% O2	BURNER, JOHNSTON	–
I/N KOTE	IN	PC (71) 1822	11/20/89	70 8 MMBtu/hr	0 05 lb/MMBtu	FUEL SPEC: USE OF NATURAL GAS & FLUE GAS RECIRC ULATION (FGR)	–
GENERAL ELECTRIC CO	IN	PSD (65) 1757	09/17/89	93 MMBtu/hr	0.133 lb/MMBtu	STAGED COMBUSTION AIR & LOW EXCESS AIR	–
GENERAL ELECTRIC CO.	IN	PSD (65) 1757	09/17/89	250 MMBtu/hr	0.12 lb/MMBtu	LOW NOX BURNERS, STAGED COMBUSTION AIR	--
		472800 2054					

Source: EPA's RACT/BACT/LAER Clearinghouse, 1998

APPENDIX D

NO_X SOURCE INVENTORY

Table D-1. NO_X Screening Analysis for the AAQS and PSD Class II Inventories for Stone Container Corporation (alphabetical listing)

Facility Name	UTM Coordinates (km) E	UTM Coordinates (km) N	Relative to Stone Container Facility X (km)	Y (km)	Distance (km)	Direction (degrees)	Screening Emission Threshold (TPY)(a)	Maximum Allowable Emissions (TPY)	AAQS and/or PSD Class II Modeling Analysis?
Amerada Hess Jacksonville	442.7	3365.0	0.7	-0.6	0.9	131	SIA	28.8	YES
Cedar Bay Cogeneration, Inc.	441.1	3365.1	-0.9	-0.5	1.1	240	1	3,788	YES
Anheuser Busch, Inc. - Jacksonville	440.6	3366.8	-1.4	1.2	1.9	310	17	1,038	YES
Atlantic Coast Asphalt - Heckscher	440.0	3364.1	-2.0	-1.5	2.5	233	30	NA	NO
Stone Container Corp	439.2	3365.5	-2.8	-0.1	2.8	269	36	NA	NO
Quickrete-Jacksonville	439.8	3363.3	-2.2	-2 3	3.2	224	44	9	NO
J.B. Coxwell Contracting, Inc.	446.0	3365.9	4.0	0.3	4.0	85	59	47	NO
Interstate Brands Corporation	437.2	3366.3	-4.8	0.7	4.9	278	77	NA	NO
Jacksonville Electric Authority - SJRPP	446.9	3366.3	4.9	0.7	4.9	82	79	32,289	YES
City of Jacksonville - Solid Waste Division	446.5	3367.7	4.5	2.1	5.0	65	80	23	NO
U S Gypsum Co	438.9	3361.2	-3.1	-4.4	5.4	215	88	353	YES
Celotex Corp	446.4	3362.4	4.4	-3.2	5.5	126	90	76	NO
Jacksonville Electric Authority - Northside	447.7	3364.9	5.7	-0.7	5.7	97	95	15,286	YES
Support Terminal Operg. Part.,L.P.	438.5	3360.5	-3.5	-5.1	6.2	214	104	9	NO
PCS Phosphate- Jacksonville	439.3	3359.8	-2.7	-5.8	6.4	205	108	27	NO
Jefferson Smurfit Corp (U.S.) - Jacksonville	439.9	3359.3	-2.1	-6.3	6.6	198	113	1,200	YES
Jacksonville Electric Authority - Kennedy	440.0	3359.2	-2.0	-6.4	6.7	197	114	4,245	YES
Millennium Specialty Chemicals	436.8	3360.7	-5.2	-4.9	7.1	227	122	189	YES
Coastal Fuels Marketing, Inc.	439.7	3358.7	-2.3	-6.9	7.3	198	125	16	NO
Jefferson Smurfit Corporation	440.0	3358.1	-2.0	-7.5	7.8	195	135	7	NO
BF Goodrich Co.Engineered Polymer Product	450.0	3365.5	8.0	-0.1	8.0	91	140	16	NO
Jacksonville Buckman Sewage Tretmnt Plnt	439.4	3357.7	-2.6	-7.9	8.3	198	146	NA	NO
Castleton Beverage Co	438.4	3373.9	-3.6	8.3	9.0	337	160	3	NO
Industrial Water Services, Inc.	439.5	3356.8	-2.5	-8.8	9.1	196	163	2	NO
Mulliniks Construction Co., Inc. - Portable Cr	433.7	3361.4	-8.4	-4.2	9.3	243	167	NA	NO
Turner Electric Works	438.2	3357.0	-3.8	-8.6	9.4	204	168	1	NO
Owens-Corning - Jacksonville	439.3	3356.0	-2.7	-9.6	10.0	196	179	15	NO
University Medical Center	436.5	3357.2	-5.5	-8.4	10.0	213	181	39	NO
Cookson Matthey Eagle	433.0	3358.5	-9.0	-7.1	11.5	232	209	NA	NO
Kraft Foods	437.5	3354.7	-4.5	-10.9	11.8	202	215	16	NO
Jacksonville Electric Authority - Southside	437.7	3353.9	-4.4	-11.8	12.5	200	231	1,349	YES
Gate Riverplace Co.	436.8	3354.2	-5.2	-11.4	12.6	204	231	74	NO
Pan Coatings Of Florida, Inc.	434.8	3355.1	-7.2	-10.5	12.7	214	234	NA	NO
Hardage Giddens Funeral Homes Of Jackson	434.8	3354.5	-7.2	-11.1	13.2	213	245	1	NO
Anchor Glass Container Corporation	431.3	3357.5	-10.7	-8.1	13.4	233	248	789	YES
Chemrock Corp	429.7	3359.6	-12.3	-6.0	13.7	244	254	2	NO

Table D-1. NO_X Screening Analysis for the AAQS and PSD Class II Inventories for Stone Container Corporation (alphabetical listing)

Facility Name	UTM Coordinates (km) E	UTM Coordinates (km) N	Relative to Stone Container Facility X (km)	Relative to Stone Container Facility Y (km)	Relative to Stone Container Facility Distance (km)	Relative to Stone Container Facility Direction (degrees)	Screening Emission Threshold (TPY)(a)	Maximum Allowable Emissions (TPY)	AAQS and/or PSD Class II Modeling Analysis?
Atlantic Dry Dock Corporation	455.8	3361.7	13.8	-3.9	14.3	106	267	7	NO
St Vincents Medical Center	434.6	3353.0	-7.4	-12.6	14.6	211	273	48	NO
Con Agra Feed Company	431.4	3355.3	-10.6	-10.3	14.8	226	276	NA	NO
Electro-Mechanical South, Inc.	427.0	3364.5	-15.0	-1.1	15.0	266	280	NA	NO
Baptist Medical Center	435.4	3352.0	-6.6	-13.6	15.1	206	282	773	YES
Wincup	428.2	3357.8	-13.8	-7.8	15.9	241	297	NA	NO
Metalplate Galvanizing	426.5	3362.0	-15.5	-3.6	15.9	257	298	NA	NO
General Electric Co	458.1	3364.5	16.1	-1.2	16.1	94	302	1	NO
Metal Container Corporation	428.4	3356.4	-13.6	-9.2	16.4	236	308	7	NO
Bush Boake Allen, Inc.	427.6	3357.3	-14.4	-8.3	16.6	240	312	96	NO
City Of Jacksonville(Girvin Rd Landfill)	455.4	3355.6	13.4	-10.0	16.7	127	315	77	NO
D-Graphics Div. Jefferson Smurfit Corp.	440.1	3348.4	-1.9	-17.2	17.3	186	326	NA	NO
Reichhold Chemicals, Inc.	428.2	3355.0	-13.8	-10.7	17.4	232	329	14	NO
St Luke's Hospital Association	443.8	3346.9	1.8	-18.8	18.8	175	357	9	NO
U S Naval Station Mayport	460.4	3361.6	18.4	-4.0	18.8	102	357	56	NO
S & G Packaging L.L.C.	442.5	3386.1	0.5	20.5	20.5	1	390	2	NO
First Union Bank Of Florida	444.0	3342.8	2.0	-22.8	22.9	175	438	357	NO
E 3 Thermal Remediation Group - Nas Jax	434.2	3343.7	-7.8	-21.9	23.2	200	444	4	NO
United States Navy - Nas Jacksonville	434.2	3342.8	-7.8	-22.8	24.1	199	462	276	NO
Mayo Clinic Jacksonville	458.0	3347.5	16.0	-18.1	24.2	139	463	39	NO
Refuse Services, Inc.	442.3	3341.2	0.3	-24.4	24.5	179	469	14	NO
Ring Power Corp - Sunbeam Road	442.0	3341.0	0.0	-24.6	24.6	180	472	79	NO
David Coxwell	420.0	3353.7	-22.0	-11.9	25.0	242	481	23	NO
Duval Asphalt Products - Phillips Highway	441.8	3340.0	-0.2	-25.6	25.6	181	492	18	NO
Atlantic Coast Asphalt -,Shad	445.3	3339.7	3.3	-25.9	26.2	173	503	19	NO
Champion International Corp	416.5	3353.2	-25.5	-12.4	28.4	244	547	16	NO
Rayonier Inc.	454.7	3392.2	12.7	26.6	29.5	26	570	1,582	YES
J.B. Coxwell Contracting, Inc.	448.1	3336.6	6.1	-29.0	29.7	168	573	47	NO
Anderson Columbia, Inc. - #7	448.1	3336.5	6.1	-29.1	29.7	168	575	7	NO
Jefferson Smurfit Corp-Fernandina Beach	456.2	3394.2	14.2	28.6	31.9	26	619	5,058	YES
U S Naval Air Station - Cecil Field	415.2	3344.5	-26.8	-21.1	34.1	232	662	71	NO
Dawson Land Development, Co., Inc.	463.2	3335.6	21.2	-30.0	36.8	145	715	NA	NO
Dustcoating, Inc,	413.1	3342.9	-28.9	-22.7	36.8	232	715	8	NO
Ameristeel, Jacksonville,Mill Div.	405.9	3350.2	-36.1	-15.4	39.2	247	765	307	NO
Florida Solite Company	427.4	3326.5	-14.6	-39.1	41.7	200	815	108	NO
Tamko Roofing Products, Inc.	435.2	3316.8	-6.8	-48.8	49.3	188	965	NA	NO

Table D-1. NO_X Screening Analysis for the AAQS and PSD Class II Inventories for Stone Container Corporation (alphabetical listing)

	UTM Coordinates (km)		Relative to Stone Container Facility				Screening Emission	Maximum Allowable	AAQS and/or PSD Class II
			X	Y	Distance	Direction	Threshold	Emissions	Modeling
Facility Name	E	N	(km)	(km)	(km)	(degrees)	(TPY)(a)	(TPY)	Analysis?
E.I. Dupont DE Nemours & CO- Highland	398.7	3325.0	-43.3	-40.6	59.4	227	1167	NA	NO

NA = Emissions not provided

(a) Screening emissions threshold is 20 x [Distance (km) to facility -1 km], based on North Carolina Screening Method.
A significant impact distance of 1 km was assumed for including competing NOx facilities into the inventory.
Total screening area is 51 km from the SCC facility. All facilities emitting <1 TPY have been omitted.

(b) Indicates PSD sources at this facility
Stone Container Corporation Jacksonville facility UTM coordinates (km):
442.0 3365.6

(c) Sources within 1 km of the SCC site are modeled without regard to the screening criteria.

Source: Golder Associates, 1998

APPENDIX E

NO_X SOURCES USED IN THE AAQS ANALYSIS

Table E-1. Summary of Individual Source Emission and Operating Parameters for the NO_X AAQS Modeling Analysis

Facility ID Number	Facility Name	Facility Location UTM E,N (km) Relative X,Y (m) ^a		APIS Src #	Stack Height (ft)	Stack Height (m)	Stack Diam. (ft)	Stack Diam. (m)	Exit Velocity (ft/s)	Exit Velocity (m/s)	Temperature (°F)	Temperature (K)	Allowable NO_X Emissions lb/hr	Allowable NO_X Emissions TPY
0310001	Jacksonville Elect. Auth. - SJRPP	446.9	3366.3	1	640	195.1	22.3	6.80	72.5	22.10	156	342.0	3686.0	16144.68
		4900	700	2	640	195.1	22.3	6.80	72.5	22.10	156	342.0	3686.0	16144.68
														32289
0310003	Jefferson Smurfit Corp - Jacksonville	439.9	3359.3	5	175	53.3	10.5	3.20	75	22.86	278	409.8	52.5	229.77
		-2100	-6300	13	200	61.0	10	3.05	35	10.67	143	334.8	373.1	1634
														1864
0310005	Anchor Glass Container Corp.	431.3	3357.51	1	57	17.4	3	0.91	64	19.51	461	511.5	34.5	151.24
		-10700	-8090	2	57	17.4	2.7	0.82	46	14.02	481	522.6	18.3	80
				3	109	33.2	5.6	1.71	38	11.58	314	429.8	73.0	319.92
				4	117	35.7	5.2	1.58	39	11.89	460	510.9	54.3	237.62
														789
0310006	Anheuser Busch, Inc. - Jacksonville	440.58	3366.79	1	100	30.5	3.5	1.07	57.2	17.43	410	483.2	36.8	161.18
		-1420	1190	2	100	30.5	3.5	1.07	57.2	17.43	410	483.2	36.8	161.18
				3	100	30.5	3.5	1.07	57.2	17.43	410	483.2	36.8	161.18
				4	100	30.5	3.5	1.07	57.2	17.43	410	483.2	36.8	161.18
				27	100	30.5	5.8	1.77	64.7	19.72	285	413.7	75.0	328.5
				28	100	30.5	5.5	1.68	50	15.24	275	408.2	5.2	22.95
				31	20	6.1	2	0.61	6.9	2.10	1000	810.9	4.7	20.8
				32	20	6.1	2	0.61	6.9	2.10	1000	810.9	4.7	20.8
														1038
0310010	Baptist Medical Center	435.4	3352.0	2	39	11.9	2.5	0.76	8.5	2.59	448	504.3	6.2	26.98
		-6600	-13600	3	50	15.2	3	0.91	150.9	45.99	325	435.9	17.1	74.77
				5	50	15.2	3.5	1.07	81.2	24.75	325	435.9	16.5	72.36
				7	35	10.7	0.7	0.21	142	43.28	350	449.8	22.8	99.96
				8	35	10.7	0.7	0.21	142	43.28	350	449.8	22.8	99.96
				9	35	10.7	0.7	0.21	142	43.28	350	449.8	22.8	99.96
				10	35	10.7	0.7	0.21	142	43.28	350	449.8	22.8	99.96
				11	39	11.9	2.5	0.76	8.5	2.59	448	504.3	6.2	26.98
				12	50	15.2	3.5	1.07	70.5	21.49	325	435.9	17.4	76.12
				13	50	15.2	3.5	1.07	84.6	25.79	325	435.9	22.0	96.36
														773
0310039	Millennium Speciality Chemicals (formerly SCM Glidco Organics)	436.79	3360.74	4	40	12.2	3.6	1.10	46	14.02	270	405.4	13.0	57
		-5210	-4860	5	50	15.2	3.6	1.10	42	12.80	505	535.9	4.3	19
				6	50	15.2	4	1.22	34	10.36	465	513.7	18.5	81
				11	45	13.7	4	1.22	18	5.49	350	449.8	7.3	31.9
														189
0310045	Jacksonville Elect. Auth. - Northside	447.7	3364.9	1	250	76.2	16.5	5.03	65	19.81	262	400.9	1485.0	6504.3
		5700	-700	3	350	106.7	23	7.01	62	18.90	330	438.7	1509.8	6613
				6	33	10.1	19.1	5.82	7	2.13	944	779.8	143.2	627.3
				7	33	10.1	19.1	5.82	7	2.13	944	779.8	143.2	627.3
				8	33	10.1	19.1	5.82	7	2.13	944	779.8	143.2	627.3
				9	33	10.1	19.1	5.82	7	2.13	944	779.8	38.8	170
				14	240	73.2	16.5	5.03	4	1.22	750	672.0	65.4	286.67
														15456

Table E-1. Summary of Individual Source Emission and Operating Parameters for the NO_X AAQS Modeling Analysis

Facility ID Number	Facility Name	Facility Location UTM E,N (km) Relative X,Y (m) *a		APIS Src #	Stack Height (ft)	Stack Height (m)	Stack Diam. (ft)	Stack Diam. (m)	Exit Velocity (ft/s)	Exit Velocity (m/s)	Temperature (°F)	Temperature (K)	Allowable NO_X Emissions lb/hr	Allowable NO_X Emissions TPY
0310046	Jacksonville Elect. Auth. - Southside	437.65	3353.85	4	144	43.9	11	3.35	39	11.89	305	424.8	117.8	516
		-4350	-11750	5	145	44.2	10	3.05	88	26.82	293	418.2	189.5	830
				10	22	6.7	1.6	0.49	58	17.68	429	493.7	0.7	3
														1349
0310047	Jacksonville Elect. Auth. - Kennedy	440	3359.2	3	45	13.7	19.1	5.82	11	3.35	826	714.3	3.0	13
		-2000	-6400	4	45	13.7	9.1	2.77	52	15.85	826	714.3	22.3	97.76
				5	45	13.7	9.1	2.77	52	15.85	826	714.3	22.3	97.76
				6	45	13.7	9.1	2.77	52	15.85	826	714.3	1.1	5
				9	136	41.5	9	2.74	90	27.43	280	410.9	917.7	4019.5
				13	33	10.1	1.6	0.49	58	17.68	429	493.7	2.7	11.78
														4245
0310074	U S Gypsum Co	438.9	3361.2	48	88	26.8	1.6	0.49	194.8	59.38	151	339.3	2.3	10
		-3100	-4400	55	80	24.4	4	1.22	10.6	3.23	400	477.6	12.5	54.75
				59	95	29.0	6.7	2.04	5.3	1.62	205	369.3	63.0	276
				74	31	9.4	3	0.91	41.1	12.53	315	430.4	0.9	4
				75	30	9.1	3	0.91	51.2	15.61	339	443.7	0.9	4
				76	39	11.9	3.6	1.10	49	14.94	218	376.5	0.9	4
														353
0310180	Amerada Hess Jacksonville	442.7	3365	10	40	12.2	1.5	0.46	37.7	11.49	300	422.0	6.6	29
0310337	Cedar Bay Cogeneration, Inc.*b	441.08	3365.06	1	403	122.8	13.3	4.05	120.4	36.70	130	327.6	286.7	1255.67
		-920	-540	2	403	122.8	13.3	4.05	120.4	36.70	130	327.6	286.7	1255.67
				3	403	122.8	13.3	4.05	120.4	36.70	130	327.6	286.7	1255.67
				4	63	19.2	4.2	1.28	93.1	28.38	82	300.9	2.4	10.5
				5	63	19.2	4.2	1.28	93.1	28.38	82	300.9	2.4	10.5
														3788
0890003	Jefferson Smurfit Corp. - Fernandina Beach - (formerly Container Corp. of America)	456.2	3394.2	6	257	78.3	11	3.35	50	15.24	358	454.3	258.0	1130
		14200	28600	7	265	80.8	11.5	3.51	61	18.59	428	493.2	45.8	200.75
				11	289	88.1	12.7	3.87	62	18.90	411	483.7	51.1	223.9
				15	340	103.6	14.8	4.51	42	12.80	335	441.5	612.6	2683.19
				21	75	22.9	5.5	1.68	55	16.76	325	435.9	187.2	819.9
														5058
0890004	Rayonier Inc.	454.7	3392.2	1	180	54.9	10	3.05	32	9.75	145	335.9	28.0	122.68
		12700	26600	2	180	54.9	10	3.05	32	9.75	145	335.9	16.6	72.69
				3	180	54.9	10	3.05	32	9.75	133	329.3	24.9	109
				6	250	76.2	7.5	2.29	57	17.37	125	324.8	291.8	1278
														1582

Notes:
*a Stone Container Facility location is (East, North UTM location (km) are 442.0, 3365.6)
*b NO_X PSD increment consuming source

Stone Container Facility Location	442.0	3365.6

Table E-2. Summary of Individual Source Emission and Operating Parameters for the NO_X AAQS Modeling Analysis

Facility ID Number	Facility Name	Facility Location Relative X,Y (m) ^a		ISCST3 Source I.D. Name	Stack Height (ft)	Stack Height (m)	Stack Diam. (ft)	Stack Diam. (m)	Exit Velocity (ft/s)	Exit Velocity (m/s)	Temperature (°F)	Temperature (K)	Allowable NO_X Emissions lb/hr	Allowable NO_X Emissions g/s	M-factor	
0310001	Jacksonville Elect. Auth. - SJRPP				640	195.1	22.3	6.80	72.5	22.10	156	342.0	3686.0	464.44	3,175	
					640	195.1	22.3	6.80	72.5	22.10	156	342.0	3686.0	464.44	3,175	
		4900	700	0310001	640	195.1	22.3	6.80	72.5	22.10	156	342.0		928.87		
0310003	Jefferson Smurfit Corp - Jacksonville				175	53.3	10.5	3.20	75	22.86	278	409.8	52.5	6.61	75,601	
					200	61.0	10	3.05	35	10.67	143	334.8	373.1	47.01	4,632	Lowest
		-2100	-6300	0310003	200	61.0	10	3.05	35	10.67	143	334.8		53.62		
0310005	Anchor Glass Container Corp.				57	17.4	3	0.91	64	19.51	461	511.5	34.5	4.35	39,843	
					57	17.4	2.7	0.82	46	14.02	481	522.6	18.3	2.30	55,315	
					109	33.2	5.6	1.71	38	11.58	314	429.8	73.0	9.20	17,972	Lowest
					117	35.7	5.2	1.58	39	11.89	460	510.9	54.3	6.84	31,685	
		-10700	-8090	0310005	109	33.2	5.6	1.71	38	11.58	314	429.8		22.69		
0310006	Anheuser Busch, Inc. - Jacksonville				100	30.5	3.5	1.07	57.2	17.43	410	483.2	36.8	4.64	55,373	
					100	30.5	3.5	1.07	57.2	17.43	410	483.2	36.8	4.64	55,373	
					100	30.5	3.5	1.07	57.2	17.43	410	483.2	36.8	4.64	55,373	
					100	30.5	3.5	1.07	57.2	17.43	410	483.2	36.8	4.64	55,373	
		-1420	1190	0310006A	100	30.5	3.5	1.07	57.2	17.43	410	483.2		18.55		
					100	30.5	5.8	1.77	64.7	19.72	285	413.7	75.0	9.45	26,314	Lowest
					100	30.5	5.5	1.68	50	15.24	275	408.2	5.2	0.66	287,171	
		-1420	1190	0310006B	100	30.5	5.8	1.77	64.7	19.72	285	413.7		10.11		
					20	6.1	2	0.61	6.9	2.10	1000	810.9	4.7	0.60	17,375	
					20	6.1	2	0.61	6.9	2.10	1000	810.9	4.7	0.60	17,375	
		-1420	1190	0310006C	21	6.4	2	0.61	6.9	2.10	1000	810.9		1.20		
0310010	Baptist Medical Center				39	11.9	2.5	0.76	8.5	2.59	448	504.3	6.2	0.78	20,009	Lowest
					50	15.2	3	0.91	150.9	45.99	325	435.9	17.1	2.15	142,063	
					50	15.2	3.5	1.07	81.2	24.75	325	435.9	16.5	2.08	78,991	
					35	10.7	0.7	0.21	142	43.28	350	449.8	22.8	2.88	72,227	
					35	10.7	0.7	0.21	142	43.28	350	449.8	22.8	2.88	72,227	
					35	10.7	0.7	0.21	142	43.28	350	449.8	22.8	2.88	72,227	
					35	10.7	0.7	0.21	142	43.28	350	449.8	22.8	2.88	72,227	
		-6600	-13600	0310010A	35	10.7	0.7	0.21	142	43.28	350	449.8		11.50		
					39	11.9	2.5	0.76	8.5	2.59	448	504.3	6.2	0.78	20,009	
					50	15.2	3.5	1.07	70.5	21.49	325	435.9	17.4	2.19	65,194	
					50	15.2	3.5	1.07	84.6	25.79	325	435.9	22.0	2.77	61,800	
		-6600	-13600	0310010B	39	11.9	2.5	0.76	8.5	2.59	448	504.3		10.75	6 sources	
0310039	Millennium Speciality Chemicals (formerly SCM Glidco Organics)				40	12.2	3.6	1.10	46	14.02	270	405.4	13.0	1.64	42,260	
					50	15.2	3.6	1.10	42	12.80	505	535.9	4.3	0.55	191,296	
					50	15.2	4	1.22	34	10.36	465	513.7	18.5	2.33	34,819	Lowest
					45	13.7	4	1.22	18	5.49	350	449.8	7.3	0.92	36,886	
		-5210	-4860	0310039	50	15.2	4	1.22	34	10.36	465	513.7		5.43		
0310045	Jacksonville Elect. Auth. - Northside	5700	-700	0310045A	250	76.2	16.5	5.03	65	19.81	262	400.9	1485.0	187.11	3,235	
		5700	-700	0310045B	350	106.7	23	7.01	62	18.90	330	438.7	1509.8	190.24	4,649	
					33	10.1	19.1	5.82	7	2.13	944	779.8	143.2	18.05	927	Lowest
					33	10.1	19.1	5.82	7	2.13	944	779.8	143.2	18.05	927	
					33	10.1	19.1	5.82	7	2.13	944	779.8	143.2	18.05	927	
					33	10.1	19.1	5.82	7	2.13	944	779.8	38.8	4.89	3,422	
					240	73.2	16.5	5.03	4	1.22	750	672.0	65.4	8.25	7,268	
		5700	-700	0310045C	33	10.1	19.1	5.82	7	2.13	944	779.8		67.27		

Table E-2. Summary of Individual Source Emission and Operating Parameters for the NO_x AAQS Modeling Analysis

Facility ID Number	Facility Name	Facility Location Relative X,Y (m) *a		ISCST3 Source I.D. Name	Stack Height (ft)	Stack Height (m)	Stack Diam. (ft)	Stack Diam. (m)	Exit Velocity (ft/s)	Exit Velocity (m/s)	Temperature (°F)	Temperature (K)	Allowable NO_x Emissions lb/hr	Allowable NO_x Emissions g/s	M-factor	
0310046	Jacksonville Elect. Auth. - Southside				144	43.9	11	3.35	39	11.89	305	424.8	117.8	14.84	14,932	Lowest
					145	44.2	10	3.05	88	26.82	293	418.2	189.5	23.88	20,761	
					22	6.7	1.6	0.49	58	17.68	429	493.7	0.7	0.09	678,158	
		-4350	-11750	0310046	144	43.9	11	3.35	39	11.89	305	424.8		38.81		
0310047	Jacksonville Elect. Auth. - Kennedy				45	13.7	19.1	5.82	11	3.35	826	714.3	3.0	0.37	87,832	
					45	13.7	9.1	2.77	52	15.85	826	714.3	22.3	2.81	55,213	
					45	13.7	9.1	2.77	52	15.85	826	714.3	22.3	2.81	55,213	
					45	13.7	9.1	2.77	52	15.85	826	714.3	1.1	0.14	1,079,534	
					136	41.5	9	2.74	90	27.43	280	410.9	917.7	115.63	4,041	Lowest
					33	10.1	1.6	0.49	58	17.68	429	493.7	2.7	0.34	259,059	
		-2000	-6400	0310047	136	41.5	9	2.74	90	27.43	280	410.9		122.11		
0310074	U S Gypsum Co				88	26.8	1.6	0.49	194.8	59.38	151	339.3	2.3	0.29	1,878,189	
					80	24.4	4	1.22	10.6	3.23	400	477.6	12.5	1.58	23,889	
					95	29.0	6.7	2.04	5.3	1.62	205	369.3	63.0	7.94	2,175	Lowest
					31	9.4	3	0.91	41.1	12.53	315	430.4	0.9	0.12	442,712	
					30	9.1	3	0.91	51.2	15.61	339	443.7	0.9	0.12	550,249	
					39	11.9	3.6	1.10	49	14.94	218	376.5	0.9	0.12	580,871	
		-3100	-4400	0310074	95	29.0	6.7	2.04	5.3	1.62	205	369.3		10.15		
0310180	Amerada Hess Jacksonville	442.7	3365	0310180	40	12.2	1.5	0.46	37.7	11.49	300	422.0	6.6	0.83	71,367	
0310337	Cedar Bay Cogeneration, Inc.*b				403	122.8	13.3	4.05	120.4	36.70	130	327.6	286.7	36.12	40,881	
					403	122.8	13.3	4.05	120.4	36.70	130	327.6	286.7	36.12	40,881	
					403	122.8	13.3	4.05	120.4	36.70	130	327.6	286.7	36.12	40,881	
		-198	16	0310337A	403	122.8	13.3	4.05	120.4	36.70	130	327.6		108.37		
					63	19.2	4.2	1.28	93.1	28.38	82	300.9	2.4	0.30	542,871	
					63	19.2	4.2	1.28	93.1	28.38	82	300.9	2.4	0.30	542,871	
		-252	-67	0310337B	63	19.2	4.2	1.28	93.1	28.38	82	300.9		0.60		
0890003	Jefferson Smurfit Corp. - Fernandina Beach - (formerly Container Corp. of America)				257	78.3	11	3.35	50	15.24	358	454.3	258.0	32.51	16,683	
					265	80.8	11.5	3.51	61	18.59	428	493.2	45.8	5.78	128,243	
					289	88.1	12.7	3.87	62	18.90	411	483.7	51.1	6.44	125,012	
					75	22.9	5.5	1.68	55	16.76	325	435.9	187.2	23.59	7,083	Lowest
		14200	28600	0890003A	75	22.9	5.5	1.68	55	16.76	325	435.9		68.31		
		14200	28600	0890003B	340	103.6	14.8	4.51	42	12.80	335	441.5	612.6	77.19	7,588	
0890004	Rayonier Inc.				180	54.9	10	3.05	32	9.75	145	335.9	28.0	3.53	50,936	
					180	54.9	10	3.05	32	9.75	145	335.9	16.6	2.09	85,966	
					180	54.9	10	3.05	32	9.75	133	329.3	24.9	3.14	56,191	
					250	76.2	7.5	2.29	57	17.37	125	324.8	291.8	36.76	11,696	Lowest
		12700	26600	0890004	250	76.2	7.5	2.29	57	17.37	125	324.8		45.52		

Notes:
*a Stone Container Facility location is (East, North UTM location (km) are 442.0, 3365.6)
*b NO_x PSD increment consuming source