Technical Evaluation
and
Preliminary Determination

SCM Corporation
Jacksonville, Florida
Duval County

Alternate Fuels For No. 7 Boiler
Proposed State Permit Number
AC 16-72140

Florida Department of Environmental Regulation
Bureau of Air Quality Management
Central Air Permitting

July 9, 1984

DRAFT

STATE OF FLORIDA

DEPARTMENT OF ENVIRONMENTAL REGULATION

TWIN TOWERS OFFICE BUILDING
2600 BLAIR STONE ROAD
TALLAHASSEE, FLORIDA 32301-8241

BOB GRAHAM
GOVERNOR

VICTORIA J. TSCHINKEL
SECRETARY

PERMITTEE:
SCM Corporation
P. O. Box 389
Jacksonville, Florida 32201

Permit Number:AC 16-72140
Date of Issue:
Expiration Date:November 1, 1984
County: Duval
Latitude/Longitude: 30° 22' 45"N/ 81° 39' 50"W
Project: Alternate fuels for No. 7 Boiler,

This permit is issued under the provisions of Chapter 403, Florida Statutes, and Florida Administrative Code Rule(s) 17-2 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 and made a part hereof and specifically described as follows:

Authorizes the use of new No. 6 fuel oil or a blend oil, consisting of new No. 6 fuel oil and by-product oil, that has a maximum sulfur content of 1.5 percent in the existing 49 million Btu/hr No. 7 boiler. The UTM coordinates of the No. 7 boiler are 17-436.170E and 3360.75 N.

The revised limitations on the fuel oil usage in the existing No. 7 boiler shall be in accordance with the application for permit to construct that was signed by Mr. R. W. Harrell on November 29, 1983, and the additional information supplied in Sholtes & Koogler letters dated January 20, 1984, and May 10, 1984, except for the changes discussed in the Technical Evaluation and Preliminary Determination and listed in the specific conditions of this construction permit.

DRAFT

PERMITTEE:
SCM Corporation

I. D. Number:
Permit Number:AC 16-72140
Date of Issue:
Expiration Date:November 1, 1984

GENERAL CONDITIONS:

1. The terms, conditions, requirements, limitations, and restrictions set forth herein are "Permit Conditions" and as such are binding upon the permittee and enforceable pursuant to the authority of Sections 403.161, 403.727, or 403.859 through 403.861, Florida Statutes. The permittee is hereby placed on notice that the department will review this permit periodically and may initiate enforcement action for any violation of the "Permit Conditions" by the permittee, its agents, employees, servants or representatives.

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), Florida Statutes, the issuance of this permit does not convey any vested rights or any exclusive privileges. Nor 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 does not constitute 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, plant or aquatic life or property and penalties therefore caused by the construction or operation of this permitted source, nor does it allow the permittee to cause pollution in contravention of Florida Statutes and department rules, unless specifically authorized by an order from the department.

DRAFT

PERMITTEE:
SCM Corporation

I. D. Number:
Permit Number: AC 16-72140
Date of Issue:
Expiration Date: November 1, 1984

GENERAL CONDITIONS:

6. The permittee shall at all times 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, access to the premises, at reasonable times, where the permitted activity is located or conducted for the purpose of:

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

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

c. Sampling or monitoring 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 notify and provide the department with the following information:

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

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

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PERMITTEE:
SCM Corporation

I. D. Number:
Permit Number:AC 16-72140
Date of Issue:
Expiration Date:November 1, 1984

GENERAL CONDITIONS:

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 revocation of this permit.

9. In accepting this permit, the permittee understands and agrees that all records, notes, monitoring data and other information relating to the construction or operation of this permitted source, which are submitted to the department, may be used by the department as evidence in any enforcement case arising under the Florida Statutes or department rules, except where such use is proscribed by Sections 403.73 and 403.111, Florida Statutes.

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

11. This permit is transferable only upon department approval in accordance with Florida Administrative Code Rules 17-4.12 and 17-30.30, 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 is required to be kept at the work site of the permitted activity during the entire period of construction or operation.

13. This permit also constitutes:

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

14. The permittee shall comply with the following monitoring and record keeping requirements:

a. Upon request, the permittee shall furnish all records and plans required under department rules. The retention period for all records will be extended automatically, unless otherwise stipulated by the department, during the course of any unresolved enforcement action.

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PERMITTEE:
SCM Corporation

I. D. Number:
Permit Number: AC 16-72140
Date of Issue:
Expiration Date: November 1, 1984

GENERAL CONDITIONS:

b. The permittee shall retain 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), copies of all reports required by this permit, and records of all data used to complete the application for this permit. The time period of retention shall be 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 date(s) 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 submitted or corrected promptly.

SPECIFIC CONDITIONS:

1. The sulfur content of any new No. 6 fuel oil used in the No. 7 boiler shall not exceed 1.5 percent.

2. The sulfur content of any blended oils used in the No. 7 boiler shall not exceed 1.5 percent.

3. A daily composite sample of the No. 6 fuel oil and each batch of the blended oils used in the No. 7 boiler shall be analyzed for its sulfur content and records of these results kept by the Company for at least two year for regulatory agency inspection.

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PERMITTEE:
SCM Corporation

I. D. Number:
Permit Number: AC 16-72140
Date of Issue:
Expiration Date: November 1, 1984

SPECIFIC CONDITIONS:

4. Compliance with the sulfur content restrictions in the fuel oils shall be determined by the latest sampling and analytical procedures specified in ASTM D-270 and ASTM D-219 procedures. Results shall be certified by the laboratory.

5. Not more than 1,158,333 gallons of oils (total of blended and new No. 6 oil) shall be burned in the No. 7 boiler during any calendar year. New No. 6 oil means an oil that has been refined from crude oil and has not been used for other purposes. It may contain additives.

6. An integrating oil meter shall be installed, calibrated (semi-annually), and maintained to determine the amount of oil burned in the No. 7 boiler. The piping arrangement shall be approved by the Bio-Environmental Services. No by-pass line shall be installed around the integrating oil meter.

7. Daily records of the integrating oil meter readings shall be kept by the Company for at least two years for regulatory agency inspection.

8. The No. 7 boiler may operate continuously, 8760 hours per year, provided no limits in this construction permit are exceeded.

9. The No. 7 boiler is allowed to burn natural gas (maximum of 46,800 CF/hr), new No. 6 fuel oil (maximum 327 gal/hr), and blended oils (mixture of new No. 6 fuel oil and plant by-product oil-maximum 344 gal/hr) at a rate not to exceed 49 million Btu/hr heat input.

10. The maximum allowable emissions from the No. 7 boiler while it is burning oil fuels shall be:

Pollutant	lb/hr	TPY
Particulate matter	6.2	10.4
Sulfur dioxide	83.6	139.3
Nitrogen Oxides	18.9	31.9

Visible Emissions: Maximum of 15 percent opacity during any 6 minute period except for two consecutive minutes in any hour where visible emissions of up to 40 percent opacity are allowed.

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PERMITTEE:
SCM Corporation

Permit Number: AC 16-72140
Date of Issue:
Expiration Date:November 1, 1984

SPECIFIC CONDITIONS:

11. The No. 7 boiler will be assumed to be in compliance with the sulfur dioxide emission limit if it is burning less than 344 gal/hr and 1,158,333 gallons per year of oil containing less than 1.5 percent sulfur.

12. The No. 7 boiler will be assumed to be in compliance with the particulate matter and nitrogen oxide emission limits if the visible emissions are less than 15 percent opacity except fo two minutes in any hour when visible emissions of up to 40 percent opacity are allowed.

13. A visible emission test by DER Method 9 as described in Rule 17-2.700(6)(c)9., FAC, shall be conducted on the No. 7 boiler annually, at a time approved by the Bio-Environmental Services, while the boiler is burning fuel oil and operating at 90 to 100 percent capacity.

14. No objectionable odors shall be discharged from the No. 7 boiler.

15. The No. 3 blend oil tank shall be repaired to prevent any emissions of objectionable odors prior to being used with the No. 7 boiler.

16. An annual operation report for the No. 7 boiler shall be submitted to the Bio-Environmental Services that gives, as a minimum, the amount of No. 6 fuel oil and blended oil consumed during the year, the average and maximum sulfur contents of the oils burned in the boiler, the amount of natural gas consumed in the boiler, the maximum heat input to the boiler, and the latest visible emission test report for the No. 7 boiler.

17. At least 90 days prior to the expiration date of this construction permit, SCM Corporation shall submit a complete application for permit to operate the No. 7 boiler to the Bio-Environmental Services.

DRAFT

PERMITTEE:
SCM Corporation

Permit Number: AC 16-72140
Date of Issue:
Expiration Date:November 1, 1984

SPECIFIC CONDITIONS:

Issued this_____day of_____, 19__

STATE OF FLORIDA DEPARTMENT OF
ENVIRONMENTAL REGULATION

____
VICTORIA J. TSCHINKEL, Secretary

____ pages attached.

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D. BACT
E. Draft State Permit

State of Florida
Department of Environmental Regulation
Notice of Proposed Agency Action
on Permit Application

The department gives notice of its intent to issue a permit to SCM Corporation to burn fuels with 1.5 percent sulfur in their existing No. 7 boiler. This boiler is located at SCM Corporation's plant on West 61st Street in Jacksonville, Duval County, Florida.

SCM Corporation will be allowed to increase the sulfur content of the fuels burned in the No. 7 boiler from 0.75 to 1.5 percent. This new limit was established by a BACT determination. Particulate matter emissions from the boiler will increase by 17 TPY. The sulfur dioxide emissions from the boiler will increase by 39 TPY. Emission of other criteria pollutants will decrease. This increase in particulate matter and sulfur dioxide emissions will not have a significant impact on the ambient air quality in Duval County.

Persons whose substantial interest are affected by the department's proposed permitting decision may petition for an administrative proceeding (hearing) in accordance with Section 120.57, Florida Statutes. The petition must conform to the requirements of Chapters 17-103 and 28-5, Florida Administrative Code, and must be filed (received) in the Office of General Counsel of the Department at 2600 Blair Stone Road, Twin Towers Office Building, Tallahassee, Florida 32301, within fourteen (14) days of publication of this notice. Failure to file a request for hearing within this time period shall constitutes a waiver any right such person may hae to request an administrative determination (hearing) under Section 120.57, Florida Statutes.

If a petition is filed, the administrative hearing process is designed to formulate agency action. Accordingly, the Department's final action may be different from the position taken by it in this preliminary statement. Therefore, persons who may not object to the proposed agency action may wish to intervene in the proceeding. A petition for intervention must be filed pursuant to Model Rule 28-5.207 at least five (5) days before the final hearing and be filed with the hearing officer is one has been assigned at the Division of Administrative Hearings, Department of Administration, 2009, Apalachee Parkway, Tallahassee, Florida 32301. If no hearing officer has been assigned, the peitition is to be filed with the Department's Office of General Counsel, 2600 Blair Stone Road, Tallahassee, Florida 32301. Failure to petition to intervene within the allowed time frame constitutes a waiver of any right such person has to request a hearing under Section 120.57, Florida Statutes.

The application is available for public inspection during normal business hours, 8:00 a.m. to 5:00 p.m., Monday through Friday, except legal holidays, at:

Dept. of Environmental Regulation
Northeast District
3426 Bills Road
Jacksonville, Florida 32207

Bio Environmental Services
515 West 6th Street
Jacksonville, Florida
32206

Dept. of Environmental Regulation
Bureau of Air Quality Management
2600 Blair Stone Road
Tallahassee, Florida 32301

Any person may send written comments on the proposed action to Mr. Bill Thomas at the department's Tallahassee address. All comments mailed within 30 days of the publication of this notice will be considered in the department's final determination.

RULES OF THE ADMINISTRATIVE COMMISSION
MODEL RULES OF PROCEDURE
CHAPTER 28-5
DECISIONS DETERMINING SUBSTANTIAL INTERESTS

28-5.15 Requests for Formal and Informal Proceedings

(1) Requests for proceedings shall be made by petition to the agency involved. Each petition shall be printed typewritten or otherwise duplicated in legible form on white paper of standard legal size. Unless printed, the impression shall be on one side of the paper only and lines shall be double spaced and indented.

(2) All petitions filed under these rules should contain:

(a) The name and address of each agency affected and each agency's file or identification number, if known;

(b) The name and address of the petitioner or petitioners;

(c) All disputed issues of material fact. If there are none, the petition must so indicate;

(d) A concise statement of the ultimate facts alleged, and the rules, regulations and constitutional provisions which entitle the petitioner to relief;

(e) A statement summarizing any informal action taken to resolve the issues, and the results of that action;

(f) A demand for the relief to which the petitioner deems himself entitled; and

(g) Such other information which the petitioner contends is material.

I. Project Description

A. Applicant

SCM Corporation
P. O. Box 389
Jacksonville, Florida 32201

B. Project and Location

SCM Corporation has requested permission to increase the maximum sulfur content of the fuels used in their existing 49 million Btu/hr No. 7 boiler from 0.75 percent to 1.5 percent and restrict the fuel burned in this boiler to 1,213,169 gallons per year to limit the increase in sulfur dioxide emissions. The No. 7 boiler, which replaced their 40 million Btu/hr No. 3 boiler, is located at SCM Corporation plant on West 61st Street, Jacksonville, Duval County, Florida.

C. Process and Controls

The 49 million Btu/hr No. 7 boiler is permitted to burn natural gas, No. 6 fuel oil and a blend of No. 6 fuel oil with a by-product oil. Currently, the oils contain 0.75 percent sulfur. The Company is requesting permission to burn oils with up to 1.5 percent sulfur. The Company will comply with the limit on the sulfur content of the fuel oils by using No. 6 fuel oil with a maximum of 1.5 percent or by blending No. 6 fuel oil with a by-product oil in such a ratio that the sulfur content will not exceed 1.5 percent. Each 25,000 gallon batch of blended oil will be analyzed by the Company to confirm that the sulfur content limit is not exceeded.

II. Rule Applicability

A. State Regulations

The proposed project, increasing the sulfur content of the fuel oils used in an existing 49 million But/hr fossil fuel steam generator that replaced a 40 million Btu/hr boiler, is subject to preconstruction review under the provisions of Chapter 403, Florida Statutes, and Chapter 17-2, Florida Administrative Code.

The plant site is in an area designated nonattainment for ozone (Rule 17-2.410(1), FAC) and attainment for the other criteria pollutants (Rule 17-2.420, FAC). It is in the area of influence of the Duval County particulate matter nonattainment area (Rule 17-2.410(2), FAC).

The plant is a major facility for the criteria pollutant sulfur dioxide (Rule 17-2.100(98), FAC). The No. 7 boiler is a major source of sulfur dioxide (Rule 17-2.100(99), FAC). The oil usage by the boiler will be restricted by permit conditions so that the increase in permitted sulfur dioxide emissions, above the actual emissions from the No. 3 boiler that was replaced, will not exceed the significant emission rate of 40 TPY listed in Table 500-2 of Chapter 17-2, FAC. Thus, the proposed project is not subject ot Prevention Significant Deterioration Regulations (PSD) because there will be no significant increase in sulfur dioxide emissions (Rule 17-2.500(2)(d)4.a.(ii), FAC.

The project is exempt from new source review for nonattainment areas (Rule 17-2.510, FAC) for particulate matter and volatile organic compounds because the proposed modification will not result in a significant net emissions increase of these criteria pollutants as specified in Table 500-2 of Chapter 17-2, FAC (Rule 17-2.510(4)a., FAC).

The project is subject to Rule 17-2.520, FAC, Sources Not Subject to PSD or Nonattainment Requirements. Emission standards shall be established by a Best Available Control Technology Determination, Rule 17-2.630, FAC, for fossil fuel steam generators of less than 250 million Btu/hr heat input (Rule 17-2.600(6), FAC).

B. Federal Regulations

This project is not subject to federal PSD regulations, Section 52.21 of Title 40 of the Code of Federal Regulations (40 CFR 52.21), because the modification will not result in a significant net emission increase of any pollutants.

III. Technical Evaluation

A. Emission Increase

Air pollution from small oil fired boilers is controlled by using clean fuels and good operation practices. The actual emissions are a function of the grade of fuel oil burned and its sulfur content. SCM proposal to burn fuel oils with a higher sulfur content will increase sulfur dioxide emissions. Based on an estimate of the actual emissions from boiler No. 3, which this boiler (No. 7) replaced, the increase in emissions (using AP-42 factors for industrial boilers burning residual oils) are summarized in the following table.

Emissions (TPY) From Fuel Oil

	Part. matter	Sulfur dioxide	Nitrogen Oxides	CO	VOC
Permitted emissions from No. 7 boiler (1,158,333 gal/fuel/yr)	10.4	139.3	31.9	2.9	0.2
Actual emissions from No. 3 boiler (1,301,229 gal/fuel/yr)	8.7	100.3	35.7	3.3	0.2
Emission change	1.7	39.0	-3.8	-0.4	0
Significant net emission increase (Table 500-2)	25	40	40	100	40

B. Emission Limitations

Emission of air pollutants from boiler No. 7 will be controlled by limiting the fuel oils consumption to a maximum of 1,158,333 gallons per year and 344 gallons per hour. Sulfur content in any No. 6 fuel oil obtained for this facility or any blended fuel oil used in the No. 7 boiler will be limited to a maximum of 1.5 percent. Routine records and fuel analysis will be required to confirm that the limits are not exceeded.

Particulate matter and nitrogen oxides emissions shall be controlled by limiting the visual emissions from the boiler to 15 percent opacity except for 2 minutes per hour in which the visual emissions can be up to 40 percent opacity.

IV. Conclusion

Based on a review of the information submitted by SCM Corporation, the Department concludes that the Company can burn up to 1,158,333 gallons of No. 6 or blended (No. 6 and by-product oil) with a maximum of 1.5 percent sulfur in the No. 7 boiler in compliance will all air pollution control regulations. Extensive monitoring of fuel consumption and fuel sulfur content will be required to assure compliance with these conditions. The General and Specific Conditions listed in proposed permit AC 16-72140 will assure compliance of this source with the air pollution control regulations.

APPENDIX A

AC 16-72140

STATE OF FLORIDA

DEPARTMENT OF ENVIRONMENTAL REGULATION

ST. JOHNS RIVER DISTRICT

3319 MAGUIRE BOULEVARD
SUITE 232
ORLANDO, FLORIDA 32803

BOB GRAHAM
GOVERNOR

VICTORIA J. TSCHINKEL
SECRETARY

ALEX SENKEVICH
DISTRICT MANAGER

APPLICATION TO OPERATE/CONSTRUCT AIR POLLUTION SOURCES

SOURCE TYPE: Fossil Fuel Steam Generator [ ] New[1] [X] Existing[1]

APPLICATION TYPE: [ ] Construction [ ] Operation [X] Modification

COMPANY NAME: SCM Corporation, Organic Chemicals Group COUNTY: Duval

Identify the specific emission point source(s) addressed in this application (i.e. Lime Kiln No. 4 with Venturi Scrubber; Peaking Unit No. 2, Gas Fired) No. 7 Boiler

SOURCE LOCATION: Street Foot of West 61st Street City Jacksonville

UTM: East 17-435.600 North 3360.750

Latitude 32 ° 72 ' 45 "N Longitude 81 ° 39 ' 50 "W

APPLICANT NAME AND TITLE: R.W. Harrell, Manager of Engineering

APPLICANT ADDRESS: Post Office Box 389, Jacksonville, FL 32201

SECTION I: STATEMENTS BY APPLICANT AND ENGINEER

A. APPLICANT

I am the undersigned owner or authorized representative* of SCM Corporation

I certify that the statements made in this application for an Operating permit are true, correct and complete to the best of my knowledge and belief. Further, I agree to maintain and operate the pollution control source and pollution control facilities in such a manner as to comply with the provision of Chapter 403, Florida Statutes, and all the rules and regulations of the department and revisions thereof. I also understand that a permit, if granted by the department, will be non-transferable and I will promptly notify the department upon sale or legal transfer of the permitted establishment.

*Attach letter of authorization

Signed: RW Harrell

R.W. Harrell, Manager of Engineering
Name and Title (Please Type)

Date: 11-29-83 Telephone No. (904)/764-1711

B. PROFESSIONAL ENGINEER REGISTERED IN FLORIDA (where required by Chapter 471, F.S.)

This is to certify that the engineering features of this pollution control project have been ~~designed~~/examined by me and found to be in conformity with modern engineering principles applicable to the treatment and disposal of pollutants characterized in the permit application. There is reasonable assurance, in my professional judgment, that

[1] See Florida Administrative Code Rule 17-2.100(57) and (104)

DER Form 17-1.202(1)
Effective October 31, 1982

the pollution control facilities, when properly maintained and operated, will discharge an effluent that complies with all applicable statutes of the State of Florida and the rules and regulations of the department. It is also agreed that the undersigned will furnish, if authorized by the owner, the applicant a set of instructions for the proper maintenance and operation of the pollution control facilities and, if applicable, pollution sources.

Signed ____________________

John B. Koogler, Ph.D., P.E.
Name (Please Type)

Sholtes & Koogler Environmental Consultants, Inc.
Company Name (Please Type)

1213 N.W. 6th Street, Gainesville, Florida 32601
Mailing Address (Please Type)

Florida Registration No. 12925 Date: 11/22/83 Telephone No. (904)/377-5822

SECTION II: GENERAL PROJECT INFORMATION

A. Describe the nature and extent of the project. Refer to pollution control equipment, and expected improvements in source performance as a result of installation. State whether the project will result in full compliance. Attach additional sheet if necessary.

The No. 7 boiler is presently permitted (AO16-66308) to be fired with fuel or blended oil containing 0.75% sulfur. This is an application to modify the permit to allow the use of fuel or blended oil with 1.5% sulfur. Emission rate increases of all pollutants affected will be less than the de minimus emission rate increase. (Also see Section V,1 - Attachment 1).

B. Schedule of project covered in this application (Construction Permit Application Only)

Start of Construction January, 1984 Completion of Construction January, 1984

C. Costs of pollution control system(s): (Note: Show breakdown of estimated costs only for individual components/units of the project serving pollution control purposes. Information on actual costs shall be furnished with the application for operation permit.)

None

D. Indicate any previous DER permits, orders and notices associated with the emission point, including permit issuance and expiration dates.

Construction Permit AC16-32394 issued 12/01/80 for boiler No. 7 to replace boiler No. 3 (AC16-24871); expired 04/30/83

Operating Permit AO16-66308 issued 05/10/83; expires 03/31/88

E. Requested permitted equipment operating time: hrs/day 24 ; days/wk 7 ; wks/yr 52 ;

if power plant, hrs/yr _____ ; if seasonal, describe: Annual hours of operation on fuel oil with 1.5% sulfur will not exceed 4783 full-load hours. Total hours of operation, including hours when fired with gas may reach 8760 hours per year.

F. If this is a new source or major modification, answer the following questions. (Yes or No) (Not Applicable)

1. Is this source in a non-attainment area for a particular pollutant? _____

   a. If yes, has "offset" been applied? _____

   b. If yes, has "Lowest Achievable Emission Rate" been applied? _____

   c. If yes, list non-attainment pollutants. _____

2. Does best available control technology (BACT) apply to this source? If yes, see Section VI. _____

3. Does the State "Prevention of Significant Deterioriation" (PSD) requirement apply to this source? If yes, see Sections VI and VII. _____

4. Do "Standards of Performance for New Stationary Sources" (NSPS) apply to this source? _____

5. Do "National Emission Standards for Hazardous Air Pollutants" (NESHAP) apply to this source? _____

H. Do "Reasonably Available Control Technology" (RACT) requirements apply to this source? _____

   a. If yes, for what pollutants? _____

   b. If yes, in addition to the information required in this form, any information requested in Rule 17-2.650 must be submitted.

Attach all supportive information related to any answer of "Yes". Attach any justification for any answer of "No" that might be considered questionable.

SECTION III: AIR POLLUTION SOURCES & CONTROL DEVICES (Other than Incinerators)

A. Raw Materials and Chemicals Used in your Process, if applicable:

Description	Contaminants		Utilization Rate - lbs/hr	Relate to Flow Diagram
	Type	% Wt		
Not Applicable -	Fuel Combust	on Only		

B. Process Rate, if applicable: (See Section V, Item 1) (Not Applicable)

1. Total Process Input Rate (lbs/hr):______________________

2. Product Weight (lbs/hr):______________________

C. Airborne Contaminants Emitted: (Information in this table must be submitted for each emission point, use additional sheets as necessary)

Name of Contaminant	Emission[1]		Allowed[2] Emission Rate per Rule 17-2	Allowable[3] Emission lbs/hr	Potential[4] Emission		Relate to Flow Diagram
	Maximum lbs/hr	Actual T/yr			lbs/yr	T/yr	
SO_2	82.5	197.0	NA	82.5	82.5	197.0	1
Part. Matter	6.2	14.8	NA	6.2	6.2	14.8	1
NOx	18.9	45.1	NA	18.9	18.9	45.1	1
CO	1.7	4.1	NA	1.7	1.7	4.1	1
Non Meth. VOC	0.1	0.2	NA	0.1	0.1	0.2	1

[1] See Section V, Item 2.

[2] Reference applicable emission standards and units (e.g. Rule 17-2.600(5)(b)2. Table II, E. (1) - 0.1 pounds per million BTU heat input)

[3] Calculated from operating rate and applicable standard.

[4] Emission, if source operated without control (See Section V, Item 3).

D. Control Devices: (See Section V, Item 4)

Name and Type (Model & Serial No.)	Contaminant	Efficiency	Range of Particles Size Collected (in microns) (If applicable)	Basis for Efficiency (Section V Item 5)
None				

E. Fuels

Type (Be Specific)	Consumption*		Maximum Heat Input (MMBTU/hr)
	avg/hr	max./hr	
Natural Gas	0.0234	0.0468	49
No. 6 Oil	167	335	49
No. 6 Oil Blended with By-Product Oil	172	344	49

*Units: Natural Gas--MMCF/hr; Fuel Oils--gallons/hr; Coal, wood, refuse, other--lbs/hr.

Fuel Analysis: Gas/No. 6/Blend

Percent Sulfur: Nil/1.5/1.5 Percent Ash: --/0.1/0.1

Density: --/8.0/8.0 lbs/gal Typical Percent Nitrogen: --/0.1/0.1

Heat Capacity: --/18300/19000 BTU/lb 1047 BTU/ft^3/146400/142500 BTU/gal

Other Fuel Contaminants (which may cause air pollution): None

F. If applicable, indicate the percent of fuel used for space heating.

Annual Average NA Maximum NA

G. Indicate liquid or solid wastes generated and method of disposal.

No solid waste. Liquid waste, consisting of boiler blow-down is discharged through NPDES discharge point.

H. Emission Stack Geometry and Flow Characteristics (Provide data for each stack):

Stack Height: 45 ft. Stack Diameter: 4.0 ft.

Gas Flow Rate: 14100 ACFM 8557 DSCFM Gas Exit Temperature: 350 °F.

Water Vapor Content: 6.9 % Velocity: 18.7 FPS

SECTION IV: INCINERATOR INFORMATION

(Not Applicable)

Type of Waste	Type O (Plastics)	Type I (Rubbish)	Type II (Refuse)	Type III (Garbage)	Type IV (Pathological)	Type V (Liq.& Gas By-prod.)	Type VI (Solid By-prod.)
Actual lb/hr Incinerated							
Uncontrolled (lbs/hr)							

Description of Waste ______

Total Weight Incinerated (lbs/hr) ______ Design Capacity (lbs/hr) ______

Approximate Number of Hours of Operation per day ______ day/wk ______ wks/yr. ______

Manufacturer ______

Date Constructed ______ Model No. ______

	Volume $(ft)^3$	Heat Release (BTU/hr)	Fuel		Temperature (°F)
			Type	BTU/hr	
Primary Chamber					
Secondary Chamber					

Stack Height: ______ ft. Stack Diamter: ______ Stack Temp. ______

Gas Flow Rate: ______ ACFM ______ DSCFM* Velocity: ______ FPS

*If 50 or more tons per day design capacity, submit the emissions rate in grains per standard cubic foot dry gas corrected to 50% excess air.

Type of pollution control device: [ ] Cyclone [ ] Wet Scrubber [ ] Afterburner

[ ] Other (specify) ______

Brief description of operating characteristics of control devices: ______________________

____

____

____

____

Ultimate disposal of any effluent other than that emitted from the stack (scrubber water, ash, etc.):

____

____

____

____

NOTE: Items 2, 3, 4, 6, 7, 8, and 10 in Section V must be included where applicable.

SECTION V: SUPPLEMENTAL REQUIREMENTS

(See Attachment 1)

Please provide the following supplements where required for this application.

1. Total process input rate and product weight -- show derivation [Rule 17-2.100(127)]

2. To a construction application, attach basis of emission estimate (e.g., design calculations, design drawings, pertinent manufacturer's test data, etc.) and attach proposed methods (e.g., FR Part 60 Methods 1, 2, 3, 4, 5) to show proof of compliance with applicable standards. To an operation application, attach test results or methods used to show proof of compliance. Information provided when applying for an operation permit from a construction permit shall be indicative of the time at which the test was made.

3. Attach basis of potential discharge (e.g., emission factor, that is, AP42 test).

4. With construction permit application, include design details for all air pollution control systems (e.g., for baghouse include cloth to air ratio; for scrubber include cross-section sketch, design pressure drop, etc.)

5. With construction permit application, attach derivation of control device(s) efficiency. Include test or design data. Items 2, 3 and 5 should be consistent: actual emissions = potential (1-efficiency).

6. An 8 1/2" x 11" flow diagram which will, without revealing trade secrets, identify the individual operations and/or processes. Indicate where raw materials enter, where solid and liquid waste exit, where gaseous emissions and/or airborne particles are evolved and where finished products are obtained.

7. An 8 1/2" x 11" plot plan showing the location of the establishment, and points of airborne emissions, in relation to the surrounding area, residences and other permanent structures and roadways (Example: Copy of relevant portion of USGS topographic map).

8. An 8 1/2" x 11" plot plan of facility showing the location of manufacturing processes and outlets for airborne emissions. Relate all flows to the flow diagram.

9. The appropriate application fee in accordance with Rule 17-4.05. The check should be made payable to the Department of Environmental Regulation.

10. With an application for operation permit, attach a Certificate of Completion of Construction indicating that the source was constructed as shown in the construction permit.

SECTION VI: BEST AVAILABLE CONTROL TECHNOLOGY

(Not Applicable)

A. Are standards of performance for new stationary sources pursuant to 40 C.F.R. Part 60 applicable to the source?

[ ] Yes [ ] No

Contaminant	Rate or Concentration

B. Has EPA declared the best available control technology for this class of sources (If yes, attach copy)

[ ] Yes [ ] No

Contaminant	Rate or Concentration

C. What emission levels do you propose as best available control technology?

Contaminant	Rate or Concentration

D. Describe the existing control and treatment technology (if any).

1. Control Device/System:
2. Operating Principles:
3. Efficiency:*
4. Capital Costs:

*Explain method of determining

5. Useful Life:

6. Operating Costs:

7. Energy:

8. Maintenance Cost:

9. Emissions:

Contaminant	Rate or Concentration

10. Stack Parameters

a. Height: ft.

b. Diameter: ft.

c. Flow Rate: ACFM

d. Temperature: °F.

e. Velocity: FPS

E. Describe the control and treatment technology available (As many types as applicable, use additional pages if necessary).

1.

a. Control Device:

b. Operating Principles:

c. Efficiency:[1]

d. Capital Cost:

e. Useful Life:

f. Operating Cost:

g. Energy:[2]

h. Maintenance Cost:

i. Availability of construction materials and process chemicals:

j. Applicability to manufacturing processes:

k. Ability to construct with control device, install in available space, and operate within proposed levels:

2.

a. Control Device:

b. Operating Principles:

c. Efficiency:[1]

d. Capital Cost:

e. Useful Life:

f. Operating Cost:

g. Energy:[2]

h. Maintenance Cost:

i. Availability of construction materials and process chemicals:

[1]Explain method of determining efficiency.
[2]Energy to be reported in units of electrical power - KWH design rate.

j. Applicability to manufacturing processes:

k. Ability to construct with control device, install in available space, and operate within proposed levels:

3.

a. Control Device:

b. Operating Principles:

c. Efficiency:[1]

d. Capital Cost:

e. Useful Life:

f. Operating Cost:

g. Energy:[2]

h. Maintenance Cost:

i. Availability of construction materials and process chemicals:

j. Applicability to manufacturing processes:

k. Ability to construct with control device, install in available space, and operate within proposed levels:

4.

a. Control Device:

b. Operating Principles:

c. Efficiency:[1]

d. Capital Costs:

e. Useful Life:

f. Operating Cost:

g. Energy:[2]

h. Maintenance Cost:

i. Availability of construction materials and process chemicals:

j. Applicability to manufacturing processes:

k. Ability to construct with control device, install in available space, and operate within proposed levels:

F. Describe the control technology selected:

1. Control Device:

2. Efficiency:[1]

3. Capital Cost:

4. Useful Life:

5. Operating Cost:

6. Energy:[2]

7. Maintenance Cost:

8. Manufacturer:

9. Other locations where employed on similar processes:

a. (1) Company:

(2) Mailing Address:

(3) City:

(4) State:

[1]Explain method of determining efficiency.
[2]Energy to be reported in units of electrical power - KWH design rate.

(5) Environmental Manager:

(6) Telephone No.:

(7) Emissions:[1]

Contaminant	Rate or Concentration

(8) Process Rate:[1]

b. (1) Company:

(2) Mailing Address:

(3) City: (4) State:

(5) Environmental Manager:

(6) Telephone No.:

(7) Emissions:[1]

Contaminant	Rate or Concentration

(8) Process Rate:[1]

10. Reason for selection and description of systems:

[1]Applicant must provide this information when available. Should this information not be available, applicant must state the reason(s) why.

SECTION VII - PREVENTION OF SIGNIFICANT DETERIORATION

(Not Applicable)

A. Company Monitored Data

1. ____________ no. sites ____________ TSP ____________ ( ) SO^2* ____________ Wind spd/dir

Period of Monitoring ______ / ______ / ______ to ______ / ______ / ______
month day year month day year

Other data recorded ____

Attach all data or statistical summaries to this application.

*Specify bubbler (B) or continuous (C).

2. Instrumentation, Field and Laboratory

a. Was instrumentation EPA referenced or its equivalent? [ ] Yes [ ] No

b. Was instrumentation calibrated in accordance with Department procedures?

[ ] Yes [ ] No [ ] Unknown

B. Meteorological Data Used for Air Quality Modeling

1. _____ Year(s) of data from ____/____/____ to ____/____/____
month day year month day year

2. Surface data obtained from (location)________________________________

3. Upper air (mixing height) data obtained from (location)________________

4. Stability wind rose (STAR) data obtained from (location)________________

C. Computer Models Used

1. ________________________________ Modified? If yes, attach description.

2. ________________________________ Modified? If yes, attach description.

3. ________________________________ Modified? If yes, attach description.

4. ________________________________ Modified? If yes, attach description.

Attach copies of all final model runs showing input data, receptor locations, and principle output tables.

D. Applicants Maximum Allowable Emission Data

Pollutant	Emission Rate	
TSP	________________________	grams/sec
SO^2	________________________	grams/sec

E. Emission Data Used in Modeling

Attach list of emission sources. Emission data required is source name, description of point source (on NEDS point number), UTM coordinates, stack data, allowable emissions, and normal operating time.

F. Attach all other information supportive to the PSD review.

G. Discuss the social and economic impact of the selected technology versus other applicable technologies (i.e., jobs, payroll, production, taxes, energy, etc.). Include assessment of the environmental impact of the sources.

H. Attach scientific, engineering, and technical material, reports, publications, journals, and other competent relevant information describing the theory and application of the requested best available control technology.

SECTION V

SUPPLEMENTAL REQUIREMENTS

1. Not Applicable; fuel combustion only

2,3. Emission Rate Calculations

Boiler No. 7 was permitted on December 1, 1980, under Construction Permit AC16-32394, as a replacement for Boiler No. 3 which was operating under Permit AO16-24871. The No. 7 boiler is a fossil fuel fired steam generator with a rated heat input of 49,000,000 BTU per hour. The boiler is permitted to operate on three alternative fuels or combinations of these fuels; No. 6 fuel oil, a blend oil consisting of by-product oil with a varying sulfur content and No. 6 fuel oil, or natural gas. The boiler is also permitted to operated on a mix of No. 6 fuel oil and natural gas, or a mix of blend oil and natural gas. The maximum sulfur content of the No. 6 fuel oil and the blend oil is limited to a maximum of 0.75 percent. The boiler is permitted to operated 8760 hours per year.

On May 10, 1983, Operating Permit AO16-66308 was issued for the No. 7 boiler. The conditions of this permit were identical to those in the construction permit issued for the boiler.

It is now proposed to modify the operating permit for the No. 7 boiler to permit the use of No. 6 fuel oil or blend oil with a maximum sulfur content of 1.5 percent. It is also proposed that the natural gas firing provision and the provision to fire the boiler simultaneously with No. 6 fuel oil and natural gas or blend oil and natural gas be retained as permit conditions.

In evaluating the effect of the proposed modification on air pollutant emission rates, both actual emission rates and permitted emission rates were considered as a baseline. The actual emissions used were those resulting from the firing of the No. 3 boiler (the boiler that the No. 7 boiler replaced) during the periods 1979-1980 and 1980-1981. These fiscal SCM years were used as a baseline for actual emissions since they represented the maximum historical operationing rate for the No. 3 boiler. Subsequent to 1981, the operations of the No. 3 boiler (or replacement Boiler No. 7) were reduced due to a slow-down in the economy.

In the following sections the actual historical fuel used and air pollutant emission rates are calculated, the permitted emissions rates for the No. 7 boiler are presented, and the proposed air pollutant emission rates and fuel use for the No. 7 boiler are presented. The emission rate increases resulting from the proposed fuel modifications are presented and it is demonstrated that none of the emission rate increases exceed de minimus emission rate increases defined in Chapter 17-2, Florida Administrative Code.

It should be emphasized that the proposed fuel modification for the No. 7 boiler will in no way affect the operations or permit conditions of SCM boilers 4, 5 and 6.

The reason for requesting the fuel modification for the No. 7 boiler is to allow the use of a common fuel in all SCM boilers; Boiler Nos. 4, 5, 6 and 7. The use of a common fuel in all boilers will eliminate the cumbersome necessity to maintain a separate fuel tank for the No. 7 boiler and to create a separate blend oil for use in the No. 7 boiler. Present and proposed fuel blending practices and fuel flows are diagramed in Attachment 2.

A. <u>ACTUAL FUEL USE (No. 3 Boiler)</u>

<u>1980-81</u>

1702802 therms from Blend Oil
<u>44544 therms from No. 6 Oil</u>
1747346 therms Total

Average heating value of fuel = 142,600 BTU/gal
Density = 8.0 lb/gal

Fuel Use = $(1,747,346 \times 10^5)/142,600$
= 1,225,348 gal/year

<u>1979-80</u>

1777137 therms from Blend Oil
<u>223174 therms from No. 6 Oil</u>
2000311 therms Total

Average heating value of fuel = 142,935 BTU/gal
Density = 8.0 lb/gal

Fuel Use = $(2,000,311 \times 10^5)/142,935$
= 1,399,455 gal/year

Average Annual Fuel Use

= 1,312,402 gal/year of 1.5% sulfur No. 6 oil and Blend oil. The Blend oil, a combination of No. 6 oil and high and low sulfur by-product oils, averaged 1.5% sulfur

B. ACTUAL EMISSIONS (No. 3 Boiler; 1979-1981))

Sulfur Dioxide

= 1,312,402 gal/yr x 8 lb/gal x (0.015 x 2) lb SO_2/lb fuel x 1/2000
= 157.5 tons/year
and
= 49 x 10^6 BTU/hr x 1/142,770 BTU/gal x 8 lb/gal x (0.015 x 2)
= 343.2 gal/hr x 8 lb/gal x 0.03
= 82.4 lb/hr

Particulate Matter (AP-42)

= 0.018 lb/gal x 1,312,402/2000
= 11.8 tons/year
and
= 0.018 x 343.2 gal/hr
= 6.2 lb/hr

Nitrogen Oxides (AP-42)

= 0.055 lb/gal x 1,312,402/2000
= 36.1 tons/year
and
= 0.055 x 343.2
= 18.9 lb/hour

Carbon Monoxide (AP-42)

= 0.005 lb/gal x 1,312,402/2000
= 3.3 tons/year
and
= 0.005 x 343.2
= 1.7 lb/hour

Non-Methane VOC (AP-42)

= 0.00028 lb/gal x 1,312,402/2000
= 0.2 tons/year
and
= 0.00028 x 343.2
= 0.1 lb/hr

C. PERMITTED EMISSIONS (No. 7 Boiler, AC16-32394 & A016-66308)

Pollutant	lb/hr	tons/yr
Sulfur Dioxide	38.5	168.6
Particulate Matter	3.4	14.8
Nitric Oxides	8.5	37.2

D. PROPOSED EMISSIONS (No. 7 Boiler)

Sulfur Dioxide

SO_2 = Actual historic emissions + 39.5 tons/year*
= 157.5 + 39.5
= 197.0 tons/year

Corresponding fuel use at 1.5% sulfur
= 197.0 ton/yr x 2000 lb/ton x 1/(0.015 x 2) lb/fuel/lb SO_2
x 1/8 lb/gal
= 1,641,667 gal/year

Full load hours of operation or 1.5% sulfur fuel
= (1.64 x 10^6 gal/yr) x (142,770 BTU/gal**) x (1/49 x 10^6 BTU/hr)
= 4783 full load hours/year

Hourly SO_2

= 49 x 10^6 BTU/hr x 1/142,500 BTU/gal x 8 lb/gal x (0.015 x2)
lb SO_2 lb/fuel
= 82.5 lb/hr

Particulate Matter (AP-42)

= 0.018 lb PM/gal x 1,641,667 gal/year x 1/2000
= 14.8 tons/year
x 2000/4783 hr/yr
= 6.2 lb/hour

* Emission rate increase is less than de minimus
** Average heat content during 1979-81 period

Nitrogen Oxides (AP-42)

= 0.055 lb/gal x 1,641,667 gal/yr x 1/2000
= 45.1 tons/year
x 2000/4783
= 18.9 lb/hr

Carbon Monoxide (AP-42)

= 0.005 lb/gal x 1,641,667 gal/yr x 1/2000
= 4.1 tons/year
x 2000/4783
= 1.7 lb/hr

Non-Methane VOC (AP-42)

= 0.00028 lb/gal x 1,641,667 gal/yr x 1/2000
= 0.2 tons/year
x 2000/4783
= 0.1 lb/hr

E. EMISSIONS SUMMARY

	Emission Rate (tons/year)				
Pollutant	Actual[1]	Permitted[2]	Proposed	Increase[3]	Significant Increase
SO_2	157.5	168.6	197.0	39.5	40[5]
Part. Matter	11.8	14.8	14.8	3.0	25[6]
NOx	36.1	37.2	45.1	9.0	40[5]
CO	3.3	—	4.1	0.8	100[5]
VOC[4]	0.2	—	0.2	0.0	40[6]

(1) Actual emissions from No. 3 boiler during 1979-81
(2) Permitted emissions from No. 7 boiler (AC16-32394 & A016-66308)
(3) Increase over Actual or Permitted; whichever is greatest
(4) Non-volatile VOC
(5) Defined in 17-2.500(2)(e)2, FAC
(6) Defined in 17-2.510(2)(e)2, FAC

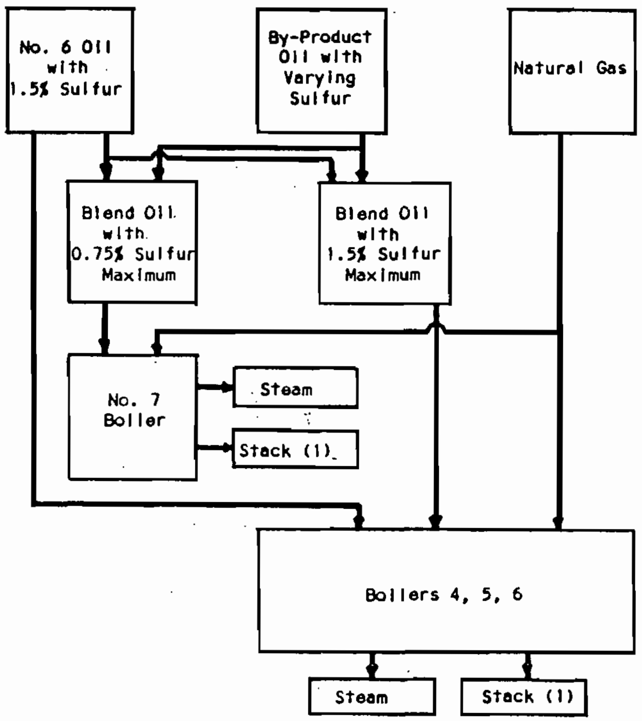
4. There is no air pollution control equipment associated with the boiler

5. Efficiency not applicable since there is no control equipment

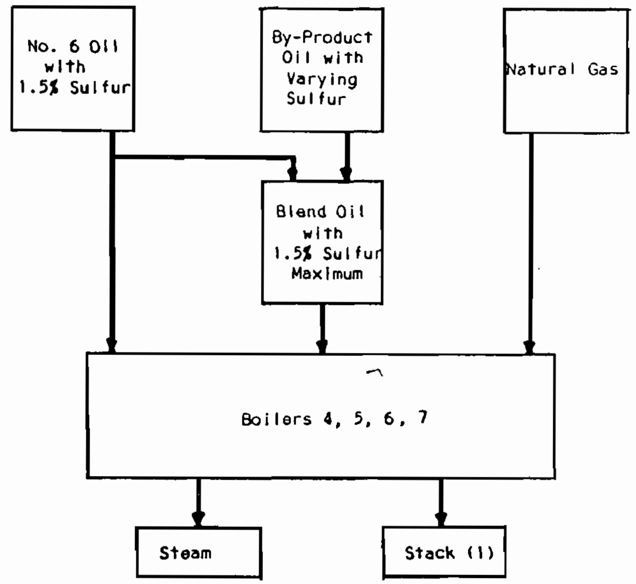
6. Process Flow Diagram - See Attachment 2

7. Location Map - See Attachment 3

8. Site Map - See Attachment 3



PERMITTED FLOW DIAGRAM



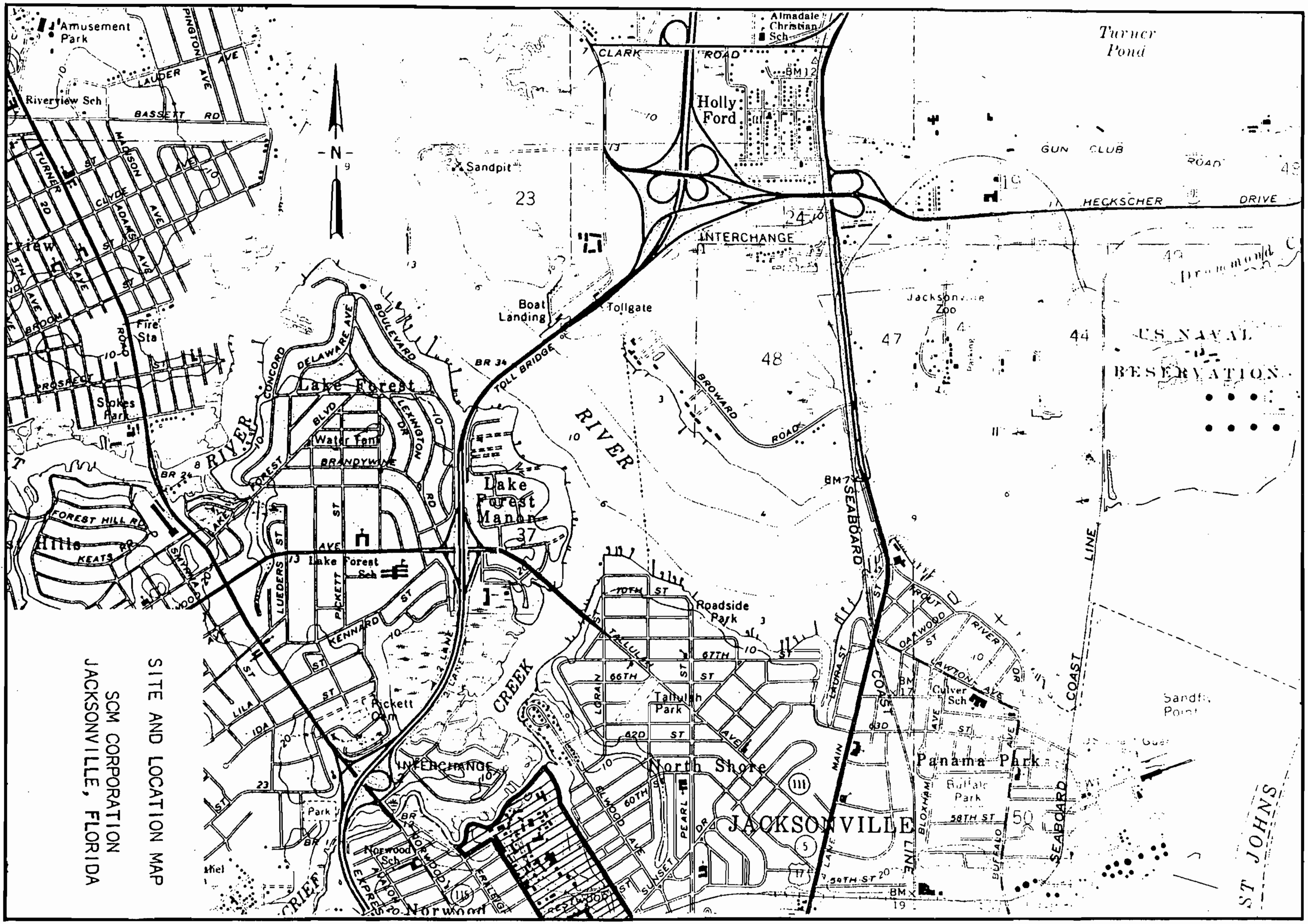
PROPOSED FLOW DIAGRAM

ATTACHMENT 2

PROCESS FLOW DIAGRAMS

SCM CORPORATION
JACKSONVILLE, FLORIDA

Best Available Copy



SITE AND LOCATION MAP
SCM CORPORATION
JACKSONVILLE, FLORIDA

SHOLTES & KOOGLER

APPENDIX B

SHOLTES & KOOGLER, ENVIRONMENTAL CONSULTANTS
1213 N.W. 6th Street Gainesville, Florida 32601 (904) 377-5822

SKEC 246-83-01

January 20, 1984

DER
JAN 23 1984
BAQM

Mr. Clair H. Fancy
Deputy Chief, Bureau of
Air Quality Management
Florida Department of
Environmental Regulation
2600 Blair Stone Road
Tallahassee, Florida 32301

Subject: SCM Corporation
Duval County
Modification of Boiler Operating Permit A016-66308

Dear Mr. Fancy:

In response to your letter of December 20, 1983, we have compiled the following information to complete the permit application to modify the operating conditions of the existing No. 7 boiler at the SCM Corporation facility in Jacksonville, Florida. The modification requested to the subject permit will allow the use of fuel oil with a maximum of 1.5 percent sulfur in the boiler rather than a fuel oil with a maximum of 0.75 percent sulfur as is presently permitted. The responses to your specific comments are addressed in the following paragraphs.

Annual Sulfur Dioxide Emissions From Boiler No. 3 - The annual sulfur dioxide emissions from the No. 3 boiler for the period 1979-1981, as presented in the permit application submitted to the Department on November 29, 1983 were found to be in error. The sulfur dioxide emission rate for this period has been recalculated and is presented in the attached revised sheets to the permit application.

The error resulted from the assumption that the blend oil burned in the No. 3 boiler during the 1979-1981 period had a sulfur content of 1.5 percent. A review of blend oil analyses for this period showed the blend oil to have an average sulfur content for the period of 1.0 percent.

The sulfur dioxide emissions for the period were calculated based on actual plant records for the quantities of the No. 6 fuel oil at 1.5 percent sulfur and blend oil at 1.0 percent sulfur burned in the No. 3 boiler during the 1979-1981 period.

The actual sulfur dioxide emission rate from the No. 3 boiler during the 1979-1981 period was calculated to be 107.9 tons per year. This is still considerably greater than the 28.5 tons per year average reported in the Annual Fuel Reports for 1979, 1980 and 1981. This discrepancy can be explained in terms of the method used for calculating annual sulfur dioxide emissions for the Fuel Report. For purposes of the fuel report, SCM calculated total facility sulfur dioxide emissions based on No. 6 fuel oil consumption at 1.5 percent sulfur and blend oil consumption at 0.75 percent sulfur. This total sulfur dioxide emission rate was then proportioned between the operating boilers based upon the steam production of each boiler.

The use of actual records to calculate annual sulfur dioxide emissions from a particular boiler, as was done in calculating the sulfur dioxide emissions from the No. 3 boiler for the permit modification, is a very detailed and time consuming procedure. This review did demonstrate, however, that No. 6 oil and blend oil were actually used in the No. 3 boiler at a much greater rate than would be expected by proportioning fuel use based on steam production. The actual consumption of blend oil and No. 6 oil for the 1979-1981 period for the No. 3 boiler is included in the permit application.

<u>Facility Modifications Since December, 1977</u> - Since December 27, 1977, (the sulfur dioxide baseline date) there have been no modifications to the SCM facility that would affect sulfur dioxide emission rates other than the replacement of the No. 3 boiler by the No. 7 boiler.

<u>Best Available Control Technology</u> - The request to modify the permit conditions for the No. 7 boiler to allow the use of No. 6 fuel oil or a blend oil with a maximum of 1.5 percent sulfur is based on improving the reliability of the fuel supply for the boiler without an unreasonable expenditure of funds. It will be demonstrated that, under actual operating conditions of the four SCM boilers, there will be essentially no increase in sulfur dioxide emissions from the SCM facility as a result of the proposed modification.

Presently the No. 7 boiler is permitted to operate on natural gas, No. 6 fuel oil (0.75 percent sulfur, maximum), a blend oil (0.75 percent sulfur, maximum) or a combination of these fuels. Existing boiler Nos. 4, 5 and 6 are permitted to operate on gas, No. 6 fuel (1.5 percent sulfur, maximum), a blend oil (1.5 percent sulfur, maximum) or a combination of these fuels.

Presently, SCM does not have separate blending facilities to produce both a 0.75 percent sulfur and a 1.5 percent sulfur blend oil nor do they have separate fuel oil storage tanks to store both 0.75 percent sulfur and 1.5 percent sulfur fuel oil.

During the SCM fiscal years 1981-1982 and 1982-1983, the economy of the country resulted in a reduced production capacity at SCM; and a corresponding reduction in boiler operations. The reduced boiler operating schedule allowed SCM to operate all four boilers (4, 5, 6 and 7) on either natural gas or on a blend oil with approximately 0.7 percent sulfur. No No. 6 oil at 1.5 percent sulfur was fired to boilers 4, 5 and 6.

As the economy improves, SCM will increase production capacity and increase the operating capacity of the boilers. Under these conditions, SCM will not be able to satisfy the fuel requirements of all boilers with the low sulfur blend oil. They will again be in the position of firing 1.5 percent sulfur No. 6 oil or blend oil to boilers 4, 5 and 6; firing 0.75 sulfur No. 6 oil or blend oil to boiler No. 7; or of firing natural gas to all boilers.

The natural gas supply at SCM is interruptible, therefore it cannot be depended upon as a fuel for the boilers under all circumstances. This necessitates, under current permit conditions, that SCM have available two supplies of fuel oil; one for boilers 4, 5 and 6 and a separate supply for boiler No. 7. With present storage facilities, SCM can provide a fuel supply for only one group of boilers. Since boilers 4, 5 and 6 have a greater capacity that boiler No. 7, it is assumed that the present storage facilities will be used to store No. 6 fuel oil with a maximum 1.5 percent sulfur content, a blend oil with a maximum 1.5 percent sulfur content and plant by-product oil. New storage facilities will be required, under present permit conditions, for the 0.75 percent sulfur blend oil and/or 0.75 percent sulfur No. 6 oil for boiler No. 7.

Assume that SCM will construct, to meet present permit conditions, one 25,0000 gallon storage tank for 0.75 percent sulfur fuel. The tank, with the required foundation, dikes, pumps and piping, will cost $80,000.00. Under normal operating conditions, this tank will be used to store a blend oil with 0.75 percent sulfur; a three day supply of fuel for boiler No. 7 when operating at rated capacity. This blend oil will be produced by combining 46 percent No. 6 fuel oil with 1.5 percent sulfur with 54 percent of plant by-product oil containing 0.1 percent sulfur. Assuming that a 0.75 percent blend oil cannot be produced under all conditions, the storage tank can also be used to store purchased 0.75 percent sulfur No. 6 fuel oil.

For evaluating Best Available Control Technology (BACT), it will be assumed that the four boilers will operate annually with a 0.85 operating factor. Based on plant records for the period 1976-1981, it will be further assumed that 73 percent of the total heat input to the boilers will be provided by gas, that 20 percent of the heat input will be provided by a blend oil and that seven percent of the heat input will be provided by No. 6 oil. During the period 1979-1981, the baseline period for establishing fuel consumption by the No. 7 boiler (or the replaced No. 3 boiler), the blend oil fired to boilers 4, 5 and 6 contained an average of 1.0 percent sulfur.

To establish a set of conditions under which to begin the evaluation of Best Available Control Technology it will be assumed that:

1. The four boilers will operate with a 0.85 annual operating factor,

2. Gas will provide 73 percent of the heat input to the boilers, blend oil will provide 20 percent of the heat input to the boilers and No. 6 fuel oil will provide seven percent of the heat input to the boilers,

3. The No. 7 boiler, while fired with oil under permitted conditions, will be fired 100 percent of the time with a blend oil. The oil will contain 0.75 percent sulfur,

4. Boilers No. 4, 5 and 6, while being fired with blend oil will be fired with a blend containing 1.0 percent sulfur,

5. Boilers No. 4, 5, 6 and 7 when fired with No. 6 fuel oil, will be fired with a fuel oil containing 1.5 percent sulfur. (This applies to boiler No. 7 under proposed conditions),

6. SCM, while running at a production capacity that will require the boilers to operate with a 0.85 annual operating factor, will produce 1.34 million gallons per year of by-product oil which, in turn, will be used to produce a blend oil fuel. (This is based on a by-product oil production of 0.88 million gallons per year at a 0.656 operating factor during the period 1979-1981).

The above defined set of operating conditions will be evaluated both under presently permitted conditions and under proposed conditions. Under proposed conditions, that is with the No. 7 boiler allowed to burn fuel oil with 1.5 percent sulfur, operating conditions will be changed to allow the No. 7 boiler to be fired with a blend oil containing 1.0 percent sulfur and to be fired with a fuel oil containing 1.5 percent sulfur.

Under presently permitted conditions, the No. 7 boiler will operate 27 percent of 7446 hours per year (the blend oil plus No. 6 oil heat input fraction) on a blend oil containing 0.75 percent sulfur. This blend will be produced from 378,644 gallons of by-product oil with 0.1 percent sulfur and 322,549 gallons of No. 6 fuel with 1.5 percent sulfur. The by-product oil remaining will be used to produce a 1.0 percent sulfur blend oil for use in boilers 4, 5 and 6. This blend oil, 2,670,433 gallons per year, will contain 961,356 gallons of by-product oil and 1,709,077 gallons of No. 6 fuel at 1.5 percent sulfur. The remaining heat that is to be supplied to boilers 4, 5 and 6 from oil (blend plus No. 6) will be provided by 1,880,517 gallons per year of No. 6 fuel oil at 1.5 percent sulfur. The total fuel consumed under this set of conditions will be 3,912,142 gallons per year of No. 6 fuel oil at 1.5 percent sulfur and 1.34 million gallons per year by-product oil. The total sulfur dioxide emissions generated from burning these fuels will be 483.9 tons per year.

Under proposed conditions, that is with boilers 4, 5, 6 and 7 being allowed to operate on 1.5 percent sulfur No. 6 oil or blend oil, the entire by-product oil production, or 1.34 million gallons per year, will be used to produce a blend oil with 1.0 percent sulfur. The blend oil will contain 1.34 million gallons of by-product oil and 2,382,222 gallons of No. 6 fuel oil at 1.5 percent sulfur. The remaining heat input that is to be supplied to boilers 4, 5, 6, and 7 by oil (blend plus No. 6) will be supplied with No. 6 fuel oil with 1.5 percent sulfur. The amount of fuel required to provide this heat will be 1,529,920 gallons per year. The total annual fuel consumption will be 3,912,142 gallons per year of No. 6 fuel oil at 1.5 percent sulfur and 1.34 million gallons per year of by-product oil; quantities of fuel that are identical to the quantities required under presently permitted conditions. Since the oil consumptions are identical under both permitted and proposed conditions, the sulfur dioxide emission rates will likewise be identical.

The example cited above produced results that would be repeated by the evaluation of any fuel consumption scenario, with the exception of scenarios that would result in extremely low boiler operating rates.

This example shows that, although proposed permitted conditions indicate there could be a 39+ ton per year increase in sulfur dioxide emissions from the No. 7 boiler, under actual conditions there will be no increase in sulfur dioxide conditions from the SCM facility if 1.5 percent sulfur fuel is permitted for use in the No. 7 boiler. The sulfur dioxide emissions from the facility (all four boilers) that exist under presently permitted conditions result from reduced emissions from boiler No. 7 and elevated emissions from boilers 4, 5 and 6 that result from burning a proportionately greater amount of 1.5 percent No. 6 oil. Under proposed conditions, emissions from boiler No. 7 will be greater but emissions from boilers 4, 5 and 6 will be decreased since more by-product oil will be burned in these boilers.

An exception to the zero sulfur dioxide emission increase scenario will develop if No. 6 fuel with a 0.75 percent sulfur is purchased during a period of time when a 0.75 percent sulfur blend oil could not be produced under presently permitted conditions. Under such a condition, there will be a reduction in sulfur dioxide emissions proportional to the difference in the sulfur content of 1.5 and 0.75 percent sulfur fuel oil (or 0.75 percent) and the quantity of fuel oil purchased. For example, if 100,000 gallons a year of 0.75 percent sulfur fuel had to be purchased, under present conditions, the increase in sulfur dioxide emissions that would occur in going to the proposed permit conditions would be 6.0 tons per year. The cost savings associated with this sulfur dioxide emission differential would be equal to the cost differential between 1.5 and 0.75 percent sulfur fuel oil. For the 100,000 gallons of oil assumed, the cost differential would be $5,000 per year, based on September, 1983 fuel oil prices from Seaboard Petroleum in Jacksonville, Florida.

In addition to the fuel cost differential that might exist, SCM will be required to install a separate fuel oil storage tank, to meet presently permitted conditions, at a capital cost of $80,000; or an annual cost, including capital recovery and, maintenance and blending costs, of approximately $38,500.

To summarize, the permit modification that will allow the use of 1.5 percent sulfur fuel in the No. 7 boiler will result in a permitted sulfur dioxide emission rate increase of 39+ tons per year. Under actual operating conditions, however, there will be no sulfur dioxide emission rate increase from the SCM facility (all four boilers). An exception to this would result if SCM were required to buy some No. 6 fuel with a 0.75 percent sulfur to supplement the fuel oil requirement to the No. 7. boiler under presently permitted conditions. If this condition occurred, the actual sulfur dioxide emission rate under presently permitted conditions would be less than emissions under proposed conditions by 0-10 tons per year. To achieve this actual emission rate reduction (0-10 tons per year) SCM would be required to install a fuel oil storage facility for 0.75 percent sulfur fuel at an annual cost of approximately $38,500 and pay a fuel oil price premium of 0-$8,300 per year; a total cost which is not justified considering the actual sulfur dioxide emission rate reduction that will be achieved.

Heat Input to the No. 3 Boiler - The design heat input to the No. 3 boiler, the boiler that was replaced by boiler No. 7, was 40,000,000 BTU per hour. The No. 7 replacement boiler has a design heat input of 49,000,000 BTU per hour. The sulfur dioxide emission rate from the No. 3 boiler for the baseline period (1979-1981) was based on actual fuel consumption in the No. 3 boiler with the boiler operating at the permitted heat input rate of 40,000,000 BTU per hour or some fraction thereof.

We hope that the information provided herein will satisfy all questions that you have regarding the subject permit application. If you have any questions regarding the data, please do not hesitate to contact me.

Very truly yours,

SHOLTES & KOOGLER,
ENVIRONMENTAL CONSULTANTS, INC.

John B. Koogler, Ph.D., P.E.

JBK:ldh

cc: Mr. R. W. Harrell

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STATE OF FLORIDA

DEPARTMENT OF ENVIRONMENTAL REGULATION

ST. JOHNS RIVER DISTRICT

3319 MAGUIRE BOULEVARD
SUITE 232
ORLANDO, FLORIDA 32803

BOB GRAHAM
GOVERNOR

VICTORIA J. TSCHINKEL
SECRETARY

ALEX SENKEVICH
DISTRICT MANAGER

NOTE CORRECTION TO LATITUDE AND EASTERLY UTM COORDINATE

APPLICATION TO OPERATE/CONSTRUCT AIR POLLUTION SOURCES

SOURCE TYPE: ______________________ [ ] New[1] [ ] Existing[1]

APPLICATION TYPE: [ ] Construction [ ] Operation [ ] Modification

COMPANY NAME: ______________________ COUNTY: __________

Identify the specific emission point source(s) addressed in this application (i.e. Lime Kiln No. 4 with Venturi Scrubber; Peaking Unit No. 2, Gas Fired) __________

SOURCE LOCATION: Street ______________________ City __________

UTM: East 17-436.170 North __________

Latitude 30 ° 22 ' 45 "N Longitude ____ ° ____ ' ____ "W

APPLICANT NAME AND TITLE: ______________________

APPLICANT ADDRESS: ______________________

SECTION I: STATEMENTS BY APPLICANT AND ENGINEER

A. APPLICANT

I am the undersigned owner or authorized representative* of __________

I certify that the statements made in this application for a __________ permit are true, correct and complete to the best of my knowledge and belief. Further, I agree to maintain and operate the pollution control source and pollution control facilities in such a manner as to comply with the provision of Chapter 403, Florida Statutes, and all the rules and regulations of the department and revisions thereof. I also understand that a permit, if granted by the department, will be non-transferable and I will promptly notify the department upon sale or legal transfer of the permitted establishment.

*Attach letter of authorization

Signed: ______________________

____
Name and Title (Please Type)

Date: __________ Telephone No. __________

B. PROFESSIONAL ENGINEER REGISTERED IN FLORIDA (where required by Chapter 471, F.S.)

This is to certify that the engineering features of this pollution control project have been designed/examined by me and found to be in conformity with modern engineering principles applicable to the treatment and disposal of pollutants characterized in the permit application. There is reasonable assurance, in my professional judgment, that

[1] See Florida Administrative Code Rule 17-2.100(57) and (104)

the pollution control facilities, when properly maintained and operated, will discharge an effluent that complies with all applicable statutes of the State of Florida and the rules and regulations of the department. It is also agreed that the undersigned will furnish, if authorized by the owner, the applicant a set of instructions for the proper maintenance and operation of the pollution control facilities and, if applicable, pollution sources.

Signed ______________________

John B. Koogler, Ph.D., P.E.
Name (Please Type)

Sholtes & Koogler Environmental Consultants, Inc.
Company Name (Please Type)

1213 N.W. 6th Street, Gainesville, Florida 32601
Mailing Address (Please Type)

Florida Registration No. 12925 Date: __________ Telephone No. (904)/377-5822

SECTION II: GENERAL PROJECT INFORMATION

A. Describe the nature and extent of the project. Refer to pollution control equipment, and expected improvements in source performance as a result of installation. State whether the project will result in full compliance. Attach additional sheet if necessary.

The No. 7 boiler is presently permitted (AC16-32394 & AO16-66308) to be fired with No. 6 fuel oil, a blend oil consisting of No. 6 oil and a plant by-product oil, or natural gas; either singularly or in combination. The maximum sulfur content of the oils is not to exceed 0.75%. The purpose of this application is to modify existing permit conditions to allow the use of No. 6 fuel oil or blend oil with a maximum sulfur content of 1.5% or natural gas, and to allow the three fuels to be fired either singularly or in combination. (Also see Section V, - Attachment 1).

B. Schedule of project covered in this application (Construction Permit Application Only)

Start of Construction January, 1984 Completion of Construction January, 1984

C. Costs of pollution control system(s): (Note: Show breakdown of estimated costs only for individual components/units of the project serving pollution control purposes. Information on actual costs shall be furnished with the application for operation permit.)

None

D. Indicate any previous DER permits, orders and notices associated with the emission point, including permit issuance and expiration dates.

Construction Permit AC16-32394 issued 12/01/80 for boiler No. 7 to replace boiler No. 3 (AC16-24871); expired 04/30/83

Operating Permit AO16-66308 issued 05/10/83; expires 03/31/88

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E. Requested permitted equipment operating time: hrs/day 24 ; days/wk 7 ; wks/yr 52 ; if power plant, hrs/yr _____; if seasonal, describe: Annual hours of operation on fuel oil with 1.5% sulfur will not exceed 3708 full-load hours. Total hours of operation, including hours when fired with gas may reach 8760 hours per year.

F. If this is a new source or major modification, answer the following questions. (Yes or No) (Not Applicable, except F2)

1. Is this source in a non-attainment area for a particular pollutant? _____

   a. If yes, has "offset" been applied? _____

   b. If yes, has "Lowest Achievable Emission Rate" been applied? _____

   c. If yes, list non-attainment pollutants. _____

2. Does best available control technology (BACT) apply to this source? If yes, see Section VI. YES

3. Does the State "Prevention of Significant Deterioriation" (PSD) requirement apply to this source? If yes, see Sections VI and VII. _____

4. Do "Standards of Performance for New Stationary Sources" (NSPS) apply to this source? _____

5. Do "National Emission Standards for Hazardous Air Pollutants" (NESHAP) apply to this source? _____

H. Do "Reasonably Available Control Technology" (RACT) requirements apply to this source? _____

   a. If yes, for what pollutants? _____

   b. If yes, in addition to the information required in this form, any information requested in Rule 17-2.650 must be submitted.

Attach all supportive information related to any answer of "Yes". Attach any justification for any answer of "No" that might be considered questionable.

SECTION III: AIR POLLUTION SOURCES & CONTROL DEVICES (Other than Incinerators)

A. Raw Materials and Chemicals Used in your Process, if applicable:

Description	Contaminants		Utilization Rate - lbs/hr	Relate to Flow Diagram
	Type	% Wt		
Not Applicable -	Fuel Combustion Only			

B. Process Rate, if applicable: (See Section V, Item 1) (Not Applicable)

1. Total Process Input Rate (lbs/hr): ______________________

2. Product Weight (lbs/hr): ______________________

C. Airborne Contaminants Emitted: (Information in this table must be submitted for each emission point, use additional sheets as necessary)

Name of Contaminant	Emission[1]		Allowed[2] Emission Rate per Rule 17-2	Allowable[3] Emission lbs/hr	Potential[4] Emission		Relate to Flow Diagram
	Maximum lbs/hr	Actual T/yr			lbs/yr	T/yr	
SO_2	79.5	147.4	BACT	79.5	79.5	147.4	1
Part. Matter	6.1	17.7	NA	6.1	6.1	17.7	1
NOx	18.8	54.0	NA	18.8	18.8	54.0	1
CO	1.7	4.9	NA	1.7	1.7	4.9	1
Non Meth. VOC	0.1	0.3	NA	0.1	0.1	0.3	1

[1] See Section V, Item 2.

[2] Reference applicable emission standards and units (e.g. Rule 17-2.600(5)(b)2. Table II, E. (1) - 0.1 pounds per million BTU heat input)

[3] Calculated from operating rate and applicable standard.

[4] Emission, if source operated without control (See Section V, Item 3).

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D. Control Devices: (See Section V, Item 4)

Name and Type (Model & Serial No.)	Contaminant	Efficiency	Range of Particles Size Collected (in microns) (If applicable)	Basis for Efficiency (Section V Item 5)
None				

E. Fuels

Type (Be Specific)	Consumption*		Maximum Heat Input (MMBTU/hr)
	avg/hr	max./hr	
Natural Gas	0.0234	0.0468	49
No. 6 Oil	164	327	49
No. 6 Oil Blended with By-Product Oil	170	341	49

*Units: Natural Gas--MMCF/hr; Fuel Oils--gallons/hr; Coal, wood, refuse, other--lbs/hr.

Fuel Analysis: Gas/No. 6/Blend

Percent Sulfur: Nil/1.5/1.5 Percent Ash: --/0.1/0.1

Density: --/8.1/7.5 lbs/gal Typical Percent Nitrogen: --/0.1/0.1

Heat Capacity: --/18488/19144 BTU/lb 1047 BTU/ft^3/149760/143580 BTU/gal

Other Fuel Contaminants (which may cause air pollution): None

F. If applicable, indicate the percent of fuel used for space heating.

Annual Average NA Maximum NA

G. Indicate liquid or solid wastes generated and method of disposal.

No solid waste. Liquid waste, consisting of boiler blow-down is discharged through NPDES discharge point.

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for the No. 7 boiler are presented. The emission rate increases resulting from the proposed fuel modifications are presented and it is demonstrated that none of the emission rate increases exceed de minimus emission rate increases defined in Chapter 17-2, Florida Administrative Code.

It should be emphasized that the proposed fuel modification for the No. 7 boiler will in no way affect the operations or permit conditions of SCM boilers 4, 5 and 6.

The reason for requesting the fuel modification for the No. 7 boiler is to allow the use of a common fuel in all SCM boilers; Boiler Nos. 4, 5, 6 and 7. The use of a common fuel in all boilers will eliminate the cumbersome necessity to maintain a separate fuel tank for the No. 7 boiler and to create a separate blend oil for use in the No. 7 boiler. Present and proposed fuel blending practices and fuel flows are diagramed in Attachment 2.

A. ACTUAL FUEL USE (No. 3 Boiler)

1980-81

1702802 therms from Blend Oil @ 1.0% sulfur, 7.5 lb/gal, 143,580 Btu/gal
44544 therms from No. 6 Oil @ 1.5% sulfur, 8.1 lb/gal, 149,760 Btu/gal

1979-80

1777137 therms from Blend Oil @ 1.0% sulfur, 7.5 lb/gal, 143,580 Btu/gal
223174 therms from No. 6 Oil @ 1.5% sulfur, 8.1 lb/gal, 149,760 Btu/gal

Average

Blend = 1739970 therms/year
= 0.174×10^{12} Btu/year
x 1/143580
= 1211847 gal/year
= (775582 gal No. 6 @ 1.5% S + 436265 gal by-product @ 0.1% S).

No. 6 = 133859 therms/year
= 0.013×10^{12} Btu/year
x 1/149760
= 89382 gal/year

Total Oil No. 6 = 864964 gal/yr @ 1.5% S
By-Prod = 436265 gal/yr @ 0.1% S

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B. <u>ACTUAL EMISSIONS</u> (No. 3 Boiler; 1979-1981))

<u>Sulfur Dioxide</u>

= [864964 gal/yr x 8.1 x (0.015 x 2) + 436265 gal/yr x 6.4 x (0.001 x 2)]/2000
= 107.9 tons/year
and
= 40.6 x 10^6 Btu/hr x 1/149760 Btu/gal x 8.1 lb/gal x (0.015 x 2)
= 271.1 gal/hr x 8.1 x 0.03
= 65.9 lb/hr

<u>Particulate Matter (AP-42)</u>

= 0.018 lb/gal x 1,301,229/2000
= 11.7 tons/year
and
= 0.018 x 271.1 gal/hr
= 4.9 lb/hr

<u>Nitrogen Oxides (AP-42)</u>

= 0.055 lb/gal x 1,301,229/2000
= 35.8 tons/year
and
= 0.055 x 271.1
= 14.9 lb/hour

<u>Carbon Monoxide (AP-42)</u>

= 0.005 lb/gal x 1,301,229/2000
= 3.3 tons/year
and
= 0.005 x 271.1
= 1.4 lb/hour

<u>Non-Methane VOC (AP-42)</u>

= 0.00028 lb/gal x 1,301,229/2000
= 0.2 tons/year
and
= 0.00028 x 271.1
= 0.1 lb/hr

C. PERMITTED EMISSIONS (No. 7 Boiler, AC16-32394 & A016-66308)

Pollutant	lb/hr	tons/yr
Sulfur Dioxide	38.5	168.6
Particulate Matter	3.4	14.8
Nitric Oxides	8.5	37.2

D. PROPOSED EMISSIONS (No. 7 Boiler)

Sulfur Dioxide

SO_2 = Actual historic emissions + 39.5 tons/year*
= 107.9 + 39.5
= 147.4 tons/year

Corresponding No. 6 fuel use at 1.5% sulfur
= 147.4 ton/yr x 2000 lb/ton x 1/(0.015 x 2) lb/fuel/lb SO_2
x 1/8.1 lb/gal
= 1,213,169 gal/year
or 1,965,333 gal/year Blend @ 1.0% S.

Full load hours of operation or 1.5% sulfur fuel
= (1.21 x 10^6 gal/yr) x (149,760 BTU/gal**) x (1/49 x 10^6 BTU/hr)
= 3708 full load hours/year on 1.5% No. 6
or 5759 full load hour/year on 1.0% S Blend.

Hourly SO_2

= 49 x 10^6 BTU/hr x 1/149,760 BTU/gal x 8.1 lb/gal x (0.015 x2)
lb SO_2 lb/fuel
= 79.5 lb/hr

Particulate Matter (AP-42)

= 0.018 lb PM/gal x 1,965,333 gal/year x 1/2000
= 17.7 tons/year
x 2000/5759 hr/yr
= 6.1 lb/hour

* Emission rate increase is less than de minimus
** Average heat content during 1979-81 period

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Nitrogen Oxides (AP-42)

= 0.055 lb/gal x 1,965,333 gal/yr x 1/2000
= 54.0 tons/year
x 2000/5759
= 18.8 lb/hr

Carbon Monoxide (AP-42)

= 0.005 lb/gal x 1,965,333 gal/yr x 1/2000
= 4.9 tons/year
x 2000/5759
= 1.7 lb/hr

Non-Methane VOC (AP-42)

= 0.00028 lb/gal x 1,965,333 gal/yr x 1/2000
= 0.3 tons/year
x 2000/5759
= 0.1 lb/hr

E. EMISSIONS SUMMARY

	Emission Rate (tons/year)				
Pollutant	Actual (1)	Permitted (2)	Proposed	Increase (3)	Significant Increase
SO_2	107.9	168.6	147.4	39.5	40 (5)
Part. Matter	11.7	14.8	17.7	6.0	25 (6)
NOx	35.8	37.2	54.0	18.2	40 (5)
CO	3.3	--	--	1.6	100 (5)
VOC (4)	0.2	--	--	0.1	40 (6)

(1) Actual emissions from No. 3 boiler during 1979-81
(2) Permitted emissions from No. 7 boiler (AC16-32394 & AO16-66308)
(3) Increase over Actual or Permitted; whichever is greatest
(4) Non-methane VOC
(5) Defined in 17-2.500(2)(e)2, FAC
(6) Defined in 17-2.510(2)(e)2, FAC

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APPENDIX C

SHOLTES & KOOGLER, ENVIRONMENTAL CONSULTANTS
1213 N.W. 6th Street Gainesville, Florida 32601 (904) 377-5822

SKEC 246-83-01

May 10, 1984

Mr. Clair Fancy
Florida Department of
Environmental Regulation
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32301

Subject: Duval County - AP
SCM Corporation
Boiler No. 7 Permit Application

Dear Mr. Fancy:

In response to your letter of incompleteness referencing the subject permit application and dated February 17, 1984, the following information has been prepared. The information includes responses to each of the specific issues addressed in your letter and further includes pages of the permit application which were modified to be consistent with the new information (Attachment 1). The information is set forth in the following sections.

1. Baseline Air Pollutant Emissions

The period of time selected for establishing baseline air pollutant emissions from Boiler 3 (the boiler that replaced Boiler 7) was the period July 1979 through June 1981. This two year period of time represents two successive fiscal years for the SCM Corporation. Boiler 3 fuel consumption records for this period of time have been provided to Mr. Jerry Woosley of Duval County Bio-Environmental Services Division for review. The records consisted of monthly hours of operation and heat input to Boiler 3 for each of three fuels; natural gas, blend oil, and fuel oil, and monthly average blend oil sulfur contents.

The fuel oil used during the baseline period, except for July and August 1979, was No. 6 fuel oil with a 1.5 percent sulfur content. During the period July-August 1979, No. 5 fuel oil with a 0.75 percent sulfur content was used.

The blend oil consists nominally of a mixture of 42 percent No. 6 fuel oil (except during the period July-August, 1979), 55 percent low sulfur (0.4 percent, average) by-product oil, and 3 percent high sulfur (19 percent, average) by-product oil. The long-term average blend oil sulfur content has been 1.0 percent.

Based upon the information provided, Mr. Woosley calculated an annual sulfur dioxide emission rate from Boiler 3 of 101.30 tons for SCM fiscal year July 1979-June 1980 and an annual sulfur dioxide emission rate of 99.25 tons for SCM fiscal year July 1980-June 1981. The average annual sulfur dioxide emission rate for the two year period was 100.3 tons per year.

This emission rate compares with an emission rate of 107.9 tons per year reported in the Sholtes & Koogler, Environmental Consultants (SKEC) letter of January 20, 1984. The difference in emissions rates resulted from the use of the average blend oil sulfur content and total blend oil consumption use to calculate the sulfur dioxide emission rate in one case and the use of monthly average blend oil sulfur contents and monthly blend oil use rates to calculate the sulfur dioxide emission rate in the second case. The emission rate of 100.3 tons per year, as calculated by Mr. Woosley, using monthly average blend oil sulfur contents and monthly average fuel consumption is probably the most accurate representation of sulfur dioxide emissions and is accepted as the baseline sulfur dioxide emission rate for Boiler 3; the boiler replaced by the No. 7 boiler.

The total fuel use (blend oil plus No. 6 fuel) as used in the SKEC letter of January 20, 1984, has been confirmed by records reviewed by Mr. Woosley. The baseline emission rates of particulate matter, nitrogen oxides, carbon monoxide and non methane hydrocarbons which were based on total fuel use and AP-42 emission factors, are therefore correct as reported in the permit application for Boiler 7 as revised January 20, 1984.

2. Basis of Present 0.75 Percent Sulfur fuel Limit for Boiler 7

When permitting Boiler 7 (the boiler that replaced Boiler 3) in 1980, SCM was given the impression that the only way the boiler could be permitted without triggering a PSD review was to permit the boiler for use with 0.75 percent sulfur fuel. SCM is now attempting to change the permit condition which limits the sulfur content of the fuel to a condition that reflects their original intent for boiler operation.

3. Use of Existing Oil Storage Tanks

SCM presently has six oil storage tanks to store the fuel oil and blend oil used to fire four boilers. Five of the tanks have capacities of 25,000 gallons and one tank has a capacity of 100,000 gallons. Presently, one of the 25,000 gallon tanks is out of service because of a hole in the roof. This tank will be returned to service as soon as the hole is repaired.

Under normal operation conditions (with six functional storage tanks) three of the 25,000 gallon tanks are used to store blend oil and the remaining tanks are used to store No. 6 fuel oil with a 1.5 percent sulfur content. This results in storage capacities of 75,000 gallons for blend oil and 150,000 gallons for No. 6 fuel oil.

During normal plant operations, it is the intent of SCM to burn blend oil as first choice (for economic reasons), natural gas as second choice and No. 6 fuel oil as third choice. During a typical operating day, the fuel oil requirements for the plant are 29,000 gallons. Over an extended three-day weekend, this results in a fuel requirement of 87,000 gallons; a requirement somewhat in excess of the 75,000 gallon storage capacity for blend oil. SCM needs at least a 75,000 gallon storage capacity for blend oil to operate through three-day weekend periods; periods when oil is not blended daily. The company also needs a 150,000 gallon storage capacity for No. 6 fuel oil. Since the six existing fuel oil tanks are dedicated to either blend oil or fuel oil with a 1.5 percent sulfur content, a new storage tank will be required to store 0.75 percent sulfur fuel oil if this oil must be burned in the No. 7 boiler.

The capacity of the storage tank required for the 0.75 percent sulfur fuel would be 25,000 gallons as reported in the SKEC letter of January 20, 1984. The capital cost of this tank will be $80,000 and the annual cost; including maintenance, ammortization of capital, etc., will be $38,500, also as reported in our letter dated January 20, 1984.

4. Fuel Use and Sulfur Content of Fuel in No. 7 Boiler

Under revised baseline sulfur dioxide emission condition; that is a condition reflecting a 100.3 tons per year sulfur dioxide emission rate, Boiler 7 can burn no more than 1,146,500 gallons of fuel per year with a sulfur content of 1.5 percent or 1,857,300 gallons of fuel per year with a sulfur content of 1.0 percent (see revisions to Section V of permit application in Attachment 3). If these fuel consumption rates are exceeded, the boiler will be subject to a full PSD review.

To assure the Department that these fuel use rates and sulfur contents will not be exceeded, SCM proposes the following:

A. Monthly records of fuel consumption for natural gas, blend oil and No. 6 fuel oil will be maintained for Boiler 7 and reported to the Department. The fuel flow rate to the boiler will be measured with a fuel flow meter which will be calibrated periodically.

B. The sulfur content of each fuel will be provided to the Department monthly. The sulfur content of the blend oil will be determined by compositing samples of the fuel over a monthly period and analyzing the composite sample monthly. The sulfur content of the No. 6 fuel oil will be obtained from the fuel oil supplier.

C. Based on the monthly fuel consumption and the sulfur contents of the fuels, SCM will provide the Department with a monthly sulfur dioxide emission rate from Boiler 7 and a cumulative sulfur dioxide emission rate for the preceding 12-month period.

D. When the cumulative sulfur dioxide emission rate for the preceeding 12-month period exceeds approximately 80 percent of the 139 ton per year sulfur dioxide emission cap on Boiler 7, or 110 tons per year, SCM will provide the Department with semi-monthly reports of fuel use and fuel sulfur content for Boiler 7. (During a two-week period, Boiler 7, when operating at capacity with 1.5 percent sulfur fuel, will emit 13.4 tons of sulfur dioxide. This emission rate when added to the 80 percent limit of 110 tons of sulfur dioxide results in a level which is still adequately below the 139 tons per year emission cap for Boiler 7). The blend oil sulfur contents presented in the semi-monthly reports will be based on analyses that SCM conducts in-house for purposes of fuel blending.

E. When the cumulative sulfur dioxide emission rate for the preceding 12-month period from Boiler 7 exceeds approximately 90 percent of the 139 tons per year emission cap (or 125 tons per year), SCM will submit weekly reports of fuel consumption and fuel sulfur contents to the Department. The blend oil sulfur contents presented in the weekly reports will be based on analyses conducted in-house by SCM for purposes of fuel blending.

5. Fuel Requirements

In the Department's letter of February 17, 1984, it is suggested that SCM could limit sulfur dioxide emissions from Boiler 7 to no more than 0.8 pounds per million BTU heat input if a combination of natural gas and fuel oil with up to 1.5 percent sulfur is burned in Boiler 7. The limit of 0.8 pounds of sulfur dioxide per million BTU heat input can be achieved under this condition *if* natural gas is available to SCM at all times. SCM anticipates the condition developing however, when natural gas is curtailed; a situation which has occurred several times in the past during the winter months. During periods of gas curtailment, SCM could not meet the 0.8 pound of sulfur dioxide per million BTU heat input limit unless fuel oil with a 0.75 percent sulfur content was available. The availability of this low sulfur fuel oil would require the installation of a new fuel oil storage tank and a separate fuel oil feed system to Boiler 7 as stated previously.

Summarizing the information provided in the preceding paragraph and in direct response to the question in the Department's February 17, 1984 letter, SCM does anticipate a situation developing that would require the combustion of an oil with greater than 0.75 percent sulfur content in Boiler 7.

6. Best Available Control Technology

SCM is proposing emission levels for three pollutants as Best Available Control Technology (BACT) for Boiler 7. These emission levels are:

Sulfur Dioxide - 1.62 pounds per million BTU, maximum,

Particulate Matter - 0.12 pounds per million BTU, maximum, and

Nitrogen Oxides - 0.37 pounds per million BTU, maximum.

These maximum emission levels will occur when Boiler 7 is fired with No. 6 fuel oil with a 1.5 percent sulfur content; a firing condition that will exist approximately 7 percent of the time based upon historic fuel use records. During the remainder of the time, Boiler 7 will be fired with either natural gas or a blend oil consisting of by-product oil and No. 6 oil. Natural gas will be fired to Boiler 7 approximately 73 percent of the total operating time and blend oil, with an average sulfur content of 1.0 percent, will be fired approximately 20 percent of the total operating time.

The data and information supporting the proposed BACT have been presented, in part, in the SKEC letter to the Department dated January 20, 1984, in preceding Sections of this letter and in the following paragraphs. The basis for the proposed BACT is to allow SCM to fire its four operating boilers (Boilers 4-7) on common fuels rather than to require fuel oils with one sulfur content, and the associated storage and firing system, for Boilers 4-6 and fuel oils with a lower sulfur content, and the associated storage and firing system, for Boiler 7.

Information has been provided (SKEC letter dated January 20, 1984) on the capital cost and annual cost of the fuel oil system that will be required to fire Boiler 7 with a low sulfur fuel oil. In the following paragraph information will be provided on fuel costs and the sulfur dioxide emission rates that can be expected as a result of firing fuel oils with varying sulfur content to Boiler 7

In evaluating the proposed BACT for sulfur dioxide emissions from Boiler 7, the Department is required, on a case-by-case basis, to evaluate energy requirements, environmental impacts and economic impacts. In the case of SCM, the environmental impacts associated with sulfur dioxide emissions from Boiler 7 are very much interrelated with sulfur dioxide emissions from Boilers 4-6. It is recognized that the SCM boilers are not permitted under a bubble and that Boiler 7 is to be permitted separate and apart from Boilers 4-6. However, for purposes of establishing BACT for Boiler 7, sulfur dioxide emissions from the entire SCM facility must be taken into consideration, as explained in the following paragraphs.

Emissions from all boilers must be taken into consideration because SCM produces by-product oils which can be blended in various proportions with No. 6 fuel oil to produce blend oils which are used as boiler fuel. Over a long-term period the by-product oils consist of approximately 98.7 percent low sulfur oil (0.4 percent sulfur) and 1.3 percent high sulfur by-product oil (19 percent sulfur). It is SCM's intent to burn all of the by-product oils for two reasons; (1) they provide an economical fuel, and (2) burning the oils as a fuel is a means of disposing of a by-product.

The blend oil produced for Boilers 4-6, boilers which are permitted to burn the oil with a maximum 1.5 percent sulfur content, is produced by blending approximately 42.0 percent No. 6 oil, 57.3 percent low sulfur by-product oil, and 0.7 percent high sulfur by-product oil. This is a long-term blending average and has resulted in a blend oil with a 1.0 percent long-term average sulfur content. Historically, this blend oil has provided 20 percent of the total heat input to Boilers 4-6; with natural gas providing 73 percent heat input and No. 6 fuel oil providing 7 percent of the heat input.

If Boiler 7 can be fired with fuel oil with up to 1.5 percent sulfur (as requested by SCM as BACT), approximately 20 percent of the total heat input to the boiler will also be provided with the blend oil with approximately 1.0 percent sulfur content. No. 6 fuel oil with a 1.5 percent sulfur content will provide 7 percent of the heat input and natural gas the remainder. Under this scenario, all of the low sulfur and high sulfur by-product oil will be blended to produce a blend oil with an average sulfur content of 1.0 percent and this fuel will be fired uniformly to all boilers. When neither blend oil nor natural gas are available, a condition which has existed approximately 7 percent of the time, all boilers will be uniformly fired with No. 6 oil with a 1.5 percent sulfur content.

If Boiler 7 is required to burn low sulfur fuel (0.75 percent) a blend oil can be produced by blending 68 percent low sulfur by-product oil and 32 percent No. 6 oil with a 1.5 percent sulfur content. A sufficient quantity of this low sulfur blend oil can be produced to provide 27 percent of the heat input to Boiler 7; the total heat input historically provided to the boilers by blend oil plus fuel oil. The remaining low sulfur and high sulfur by-product oils will be blended with No. 6 oil with 1.5 percent sulfur content to produce a higher sulfur blend oil (approximately 1.0 percent sulfur content) for Boilers 4-6. The fuel oil required to make up the difference between the heat provided by the blend oil and 27 percent of the total heat input to Boilers 4-6 will be No. 6 fuel oil with 1.5 percent sulfur content.

It is apparent from the scenarios described in the preceding paragraphs that the heat input to all boilers (Boilers 4-7) resulting from the firing of fuel oil will remain unchanged regardless of the sulfur content of the oils fired to individual boilers. It is also apparent that at a set operating capacity SCM will produce, and will therefore consume, a constant amount of by-product oils. Since the heat input provided to all boilers by oil is constant and the amount of by-product oils produced and consumed is constant, it follows that the amount of No. 6 fuel oil with a 1.5 percent sulfur content that is purchased and consumed must also be constant. It further follows that fuel costs for the facility will be constant and sulfur dioxide emissions will be unchanged. The cost to SCM to maintain this status quo condition, (assuming low sulfur fuel is required in Boiler 7) is the annualized cost of the fuel oil storage tank for Boiler 7; or $38,500 per year.

In the preceding scenario (assuming low sulfur fuel is required for Boiler 7), it has been assumed that all of the heat input to Boiler 7 normally supplied by oils will be supplied with a blend oil. Under this scenario, sulfur dioxide emissions and fuel costs for the entire SCM facility will be the same as in the scenario that permitted the use of fuel with up to 1.5 percent sulfur in Boiler 7. Another set of scenarios which has been investigated is that in which the heat input to Boiler 7 normally provided by oil (27 percent of the total heat input) is provided by purchased fuel oil with a sulfur content ranging from 0.75 - 1.0 percent. In evaluating these scenarios it should be recognized that the same quantity of by-product oils will be produced and, hence, consumed. It should also be recognized that the total heat input to all boilers (Boilers 4-7) will remain unchanged. The only thing that will change, therefore, is that some of the heat input that was provided in the preceding scenarios by No. 6 fuel oil with a 1.5 percent sulfur content will be provided with No. 6 fuel oil with a lower sulfur content.

Under these scenarios, sulfur dioxide emissions from the facility will be reduced by an amount proportional to the amount of low sulfur fuel purchased and the difference in sulfur content between the low sulfur fuel and the 1.5 percent sulfur No. 6 fuel oil. Associated with this decrease in sulfur dioxide emissions will be an increase in fuel cost which will be proportional to the amount of low sulfur fuel oil purchased and the difference in the price of low sulfur fuel and the price of No. 6 fuel with 1.5 percent sulfur content.

The attached table summarizes five scenarios for providing fuel oils to the boilers at SCM. In preparing the scenarios it was assumed that 73 percent of all the heat input to the boilers will be provided by natural gas. The cost of this fuel is constant and is not considered in the scenarios. Other assumptions are consistent with the assumptions stated in the SKEC letter of January 20, 1984. In summary these are:

* All boilers will operate with a 0.85 annual operating factor,

* 27 percent of the heat input to all boilers will be provided by oil (blend oil or No. 6 fuel oil),

* With all boilers permitted to burn No. 6 fuel oil with a maximum of 1.5 percent sulfur content, it was assumed that 20 percent of the heat input will be provided by blend oil (with an average sulfur content of 1.0 percent) and 7 percent will be provided by No. 6 fuel oil with a sulfur content of 1.5 percent.

* SCM, while operating at production capacity consistent with a 0.85 annual operating factor for the boilers, will produce 1.34 million gallons per year of by-product oil. Low sulfur by-product oil with a sulfur content averaging 0.4 percent was assumed to account for 98.7 percent of the total by-product oil and 1.3 percent of the by-product oil was assumed to be a high sulfur oil with a sulfur content averaging 19 percent. The cost of these fuels was also assumed to be constant and is not considered in the scenarios.

Other assumptions used in preparing the scenarios are:

* The heat input (at a 0.85 annual operating factor, to Boiler 7 is 0.365 million million BTU per year,

* The heat input to Boilers 4-6 is 2.463 million million BTU per year, and

* Fuel oil costs, based on annual average costs in northeast Florida are:

  No. 6 oil at 1.5 percent sulfur - $0.736 per gallon,

  No. 6 oil at 1.0 percent sulfur - $0.747 per gallon, and

  No. 6 oil at 0.75 percent sulfur - $0.794 per gallon.

The calculations supporting the data in the summary table are included as Attachment 2.

In reviewing the data in the summary table, it will be noted that for the scenario proposed as Best Available Control Technology; that is, with all boilers permitted to burn fuel oil with a maximum 1.5 percent sulfur, sulfur dioxide emissions from Boiler 7 will be 60.5 tons per year and total facility sulfur dioxide emissions will be 533.5 tons per year. There will be no added cost associated with this scenario in terms of fuel oil storage and supply systems or in added fuel cost.

In Scenario 2 it was assumed that Boiler 7 will be limited to fuel oil with a 0.75 percent sulfur content and that all of this fuel oil would be provided in the form of a low sulfur blend oil. Under the conditions of this scenario, sulfur dioxide emissions from the No. 7 boiler will be 40.1 tons per year, but total facility sulfur dioxide emissions will be the same as in Scenario 1; or 533.5 tons per year. The cost associated with this scenario will be the annual cost of $38,500 to install and maintain a separate fuel storage and supply system for the low sulfur fuel oil. There will be no additional cost associated with fuel since all of low sulfur fuel provided to Boiler 7 is provided in the form of a low sulfur blend oil.

Scenario 4 is similar to Scenario 2 except that it was assumed that Boiler 7 would be fired with fuel oil with a maximum sulfur content of 1.0 percent. Under this scenario, it was further assumed that all of the low sulfur oil required by Boiler 7 would be provided in the form of 1.0 percent sulfur blend oil. Under this scenario, sulfur dioxide emissions from Boiler 7 will be 53.8 tons per year and total sulfur dioxide emissions from the facility will remain at 533.5 tons per year. Again, the cost associated with this scenario will be the cost of installing and maintaining the separate storage and supply system for the low sulfur oil in Boiler 7; an annual cost of $38,500. There will be no added fuel cost.

In Scenarios 3 and 5, it was assumed that a low sulfur fuel oil will be required for Boiler 7 and that all of the low sulfur oil will be purchased as No. 6 oil. In Scenario 3 it was assumed that the low sulfur oil will be 0.75 percent sulfur oil while in Scenario 5 it was assumed that the oil will be 1.0 percent sulfur oil.

In Scenario 3, sulfur dioxide emissions from Boiler 7 are 38.8 tons per year and total facility sulfur dioxide emissions are 492.5 tons per year; a 41.0 tons per year reduction from Scenario 1. The costs associated with this scenario are the $38,500 required for the separate oil storage and supply system and a $61,000 additional cost for purchasing the low sulfur fuel oil for Boiler 7. The total annual cost of this scenario is $99,500 per year above the cost of Scenario 1; the scenario proposed as Best Available Control Technology. For this annual cost, sulfur dioxide emissions will be reduced 41.0 tons per year; a cost of $2,427 per ton of sulfur dioxide removed.

In Scenario 5; that is with Boiler 7 being fired with purchased 1.0 percent sulfur oil, the sulfur dioxide emissions from Boiler 7 will be 52.2 tons per year and emissions from the entire facility will be 505.9 tons per year; a 27.6 ton per year sulfur dioxide emission reduction. The costs associated with this scenario are the $38,500 required for the fuel oil storage and supply system and $22,000 per year additional cost for purchasing the low sulfur fuel for Boiler 7. The total cost of this scenario, over and above the costs associated with Scenario 1 (the BACT Scenario) is $60,500 per year; a cost of $2,192 per ton of sulfur dioxide removed.

The cost of reducing sulfur dioxide emissions by one ton per year for Scenarios 3 and 5 are in the range of $2,200 to $2,400. The cost associated with sulfur dioxide reduction for Scenarios 2 and

4 are infinite since total facility sulfur dioxide emissions will not change even though $38,500 per year is spent for the separate fuel oil storage and firing system for Boiler 7.

As lesser quantities of low sulfur fuel oil are purchased for use in Boiler 7 in Scenarios 3 and 5 (i.e., as more low sulfur blend is used), the cost per ton of sulfur dioxide removed increases, and approaches infinity when no low sulfur oil is purchased. For example, if half of the 0.75 percent sulfur oil is purchased in Scenario 3 and half is provided by low sulfur blend, the cost of removing a ton of sulfur dioxide increases to $3,120 per ton.

Based upon the information provided in this section and previous sections of this letter and upon information provided in the SKEC letter of January 20, 1984, we respectfully request that the Department establish a sulfur dioxide emission level of 1.62 pounds per million BTU as BACT for SCM Boiler 7. This maximum emission level will result when No. 6 fuel oil with a maximum sulfur content of 1.5 percent is fired to Boiler 7; a condition that is expected to occur approximately 7 percent of the time. Under these same firing conditions, a particulate matter emission level of 0.12 pounds per million BTU and a nitrogen oxides emission level of 0.37 pounds per million BTU (both based on AP 42 emission factors) will result. These emission levels are also requested as BACT for SCM Boiler 7.

I hope that the information provided herein and in previous correspondence will provide sufficient information for you to complete your review of the permit application for SCM Boiler 7. If there are any additional questions, please do not hesitate to contact me.

Very truly yours,

SHOLTES & KOOGLER,
ENVIRONMENTAL CONSULTANTS

John B. Koogler, Ph.D., P.E.

JBK:ldh
Enclosures

Mr. Robert W. Harrell

SUMMARY OF SULFUR DIOXIDE EMISSIONS AND FUEL COSTS
FOR FIVE FUEL OIL SCENARIOS

SCM CORPORATION
JACKSONVILLE, FLORIDA

	Purchased Fuel Oil Cost[2] ($/year)			Sulfur Dioxide Emissions (tons/year)			Costs[3] ($/year)			SO_2[4]
Scenario[1]	#7 Boiler	#4-6 Boilers	Total	#7 Boiler	#4-6 Boilers	Total	Equipment	Fuel	Total	Reduction (tpy)
1	282,000	2,554,000	2,836,000	60.5	473.0	533.5	0	--	--	---
2	163,000	2,673,000	2,836,000	40.1	493.4	533.5	38,500	0	38,500	0
3	544,000	2,352,000	2,896,000	38.8	453.7	492.5	38,500	61,000	99,500	41.0
4	212,000	2,624,000	2,836,000	53.8	479.7	533.5	38,500	0	38,500	0
5	505,000	2,352,000	2,857,000	52.2	453.7	505.9	38,500	22,000	60,500	27.6

(1) Scenario 1 - 1.5% Sulfur No. 6 oil or 1.0% sulfur blend oil in all boilers.
Scenario 2 - 0.75% Sulfur blend oil in boiler #7 (no low sulfur oil purchased); as in Scenario 1 for boilers #4-6.
Scenario 3 - 0.75% Sulfur No. 6 oil in boiler #7 (all low sulfur oil purchased); as in Scenario 1 for boilers #4-6.
Scenario 4 - 1.0% Sulfur blend oil in boiler #7 (no low sulfur oil purchased); as in Scenario 1 for boilers #4-6.
Scenario 5 - 1.0% Sulfur No. 6 oil in boiler #7 (all low sulfur oil purchased); as in Scenario 1 for boilers #4-6.

(2) Cost of purchased No. 6 fuel oil only. The cost of by-product oils and natural gas were assumed to be constant for all scenarios.

(3) Cost of each scenario when compared with scenario 1; the scenario proposed as BACT.

(4) Sulfur dioxide reductions relative to scenario 1; the scenario proposed as BACT.

ATTACHMENT 1

MODIFICATIONS TO PERMIT APPLICATION

9. The appropriate application fee in accordance with Rule 17-4.05. The check should be made payable to the Department of Environmental Regulation.

10. With an application for operation permit, attach a Certificate of Completion of Construction indicating that the source was constructed as shown in the construction permit.

SECTION VI: BEST AVAILABLE CONTROL TECHNOLOGY

A. Are standards of performance for new stationary sources pursuant to 40 C.F.R. Part 60 applicable to the source?

[ ] Yes [X] No

Contaminant	Rate or Concentration

B. Has EPA declared the best available control technology for this class of sources (If yes, attach copy)

[ ] Yes [X] No

Contaminant	Rate or Concentration

C. What emission levels do you propose as best available control technology?

Contaminant	Rate or Concentration
Sulfur Dioxide	1.62 lbs/10^6 BTU; max.
Particulate Matter	0.12 lbs/10^6 BTU; max.
Nitrogen Oxides	0.37 lbs/10^6 BTU; max.

(See SKEC letters dated 1/20/84 and 5/9/84 for supporting data)

D. Describe the existing control and treatment technology (if any).

1. Control Device/System:
2. Operating Principles:
3. Efficiency:*
4. Capital Costs:

*Explain method of determining

BEST AVAILABLE CONTROL TECHNOLOGY EMISSION LIMITS

Sulfur Dioxide from 1.5% Sulfur No. 6 Oil

$$
\begin{aligned}
SO_2 &= 49 \times 10^6 \times 1/18{,}488 \\
&\quad \times (0.015 \times 2) \text{ lbs } SO_2/\text{lbs} \\
&= 79.5 \text{ lbs/hour/49 million BTU/hour} \\
&= 1.62 \text{ lb}/10^6 \text{ BTU.}
\end{aligned}
$$

Particulate Matter at 0.018 lb/gallon (with 1.5% sulfur oil)

$$
\begin{aligned}
PM &= 40 \times 10^6 \times 1/149{,}750 \times 0.018 \text{ lb PM} \\
&= 5.9 \text{ lbs/hour} \\
&= 0.12 \text{ lbs}/10^6 \text{ BTU.}
\end{aligned}
$$

Nitrogen Oxides at 0.055 lbs/gallon

$$
\begin{aligned}
NOx &= 49 \times 10^6 \times 1/149{,}750 \times 0.055 \text{ lb NOx/gallon} \\
&= 18.0 \text{ lbs/hour} \\
&= 0.37 \text{ lbs}/10^6 \text{ BTU.}
\end{aligned}
$$

ADDED 5/9/84

for the No. 7 boiler are presented. The emission rate increases resulting from the proposed fuel modifications are presented and it is demonstrated that none of the emission rate increases exceed de minimus emission rate increases defined in Chapter 17-2, Florida Administrative Code.

It should be emphasized that the proposed fuel modification for the No. 7 boiler will in no way affect the operations or permit conditions of SCM boilers 4, 5 and 6.

The reason for requesting the fuel modification for the No. 7 boiler is to allow the use of a common fuel in all SCM boilers; Boiler Nos. 4, 5, 6 and 7. The use of a common fuel in all boilers will eliminate the cumbersome necessity to maintain a separate fuel tank for the No. 7 boiler and to create a separate blend oil for use in the No. 7 boiler. Present and proposed fuel blending practices and fuel flows are diagramed in Attachment 2.

A. <u>ACTUAL FUEL USE (No. 3 Boiler)</u>

<u>1980-81</u>

1702802 therms from Blend Oil @ 1.0% sulfur, 7.5 lb/gal, 143,872 Btu/gal
<u>44544 therms from No. 6 Oil</u> @ 1.5% sulfur, 8.1 lb/gal, 149,750 Btu/gal

<u>1979-80</u>

1777137 therms from Blend Oil @ 1.0% sulfur, 7.5 lb/gal, 143,872 Btu/gal
<u>223174 therms from No. 6 Oil</u> @ 1.5% sulfur, 8.1 lb/gal, 149,750 Btu/gal

<u>Average</u>

Blend	=	1739970 therms/year
	=	0.174×10^{12} Btu/year
		x 1/143,872
	=	1209388 gal/year
	=	
No. 6	=	133859 therms/year
	=	0.013×10^{12} Btu/year
		x 1/149,750
	=	89388 gal/year

Total Oil No. 6 = 89388 gal/yr @ 1.5% S
<u>Blend = 1209388 gal/yr @ 1.0% S</u>

Total = 1,298,776 gal/year

REVISED 1/20/84
REVISED 5/9/84

SHOLTES & KOOGLER

B. ACTUAL EMISSIONS (No. 3 Boiler; 1979-1981))

Sulfur Dioxide
Annual - By J. Woosley, Duval County Bio-Environmental Services Division

1979-1980 = 101.3
1980-1981 = 99.3

Average = 100.3 tons/year

Max. Hourly @ 1.5% Sulfur No. 6 oil
= 40.6×10^6 BTU/hr x 1/149,750 BTU/gal x 8.1 x (0.015 x 2)
= 65.9 lbs/hour.

Particulate Matter (AP-42)
= [0.013 x 1209388 + 0.018 x 89388]/2000
= 8.7 tons/year
and
= 0.018 x 271.1 gal/hr
= 4.9 lb/hr, max.

Nitrogen Oxides (AP-42)

= 0.055 lb/gal x 1298776/2000
= 35.7 tons/year
and
= 0.055 x 271.1
= 14.9 lb/hour

Carbon Monoxide (AP-42)

= 0.005 lb/gal x 1298776/2000
= 3.3 tons/year
and
= 0.005 x 271.1
= 1.4 lb/hour

Non-Methane VOC (AP-42)

= 0.00028 lb/gal x 1,301,229/2000
= 0.2 tons/year
and
= 0.00028 x 271.1
= 0.1 lb/hr

C. PERMITTED EMISSIONS (No. 7 Boiler, AC16-32394 & A016-66308)

Pollutant	lb/hr	tons/yr
Sulfur Dioxide	38.5	168.6
Particulate Matter	3.4	14.8
Nitric Oxides	8.5	37.2

D. PROPOSED EMISSIONS (No. 7 Boiler)

Sulfur Dioxide

SO_2 = Actual historic emissions + 39 tons/year*
= 100.3 + 39.0
= 139.3 tons/year

Corresponding No. 6 fuel use at 1.5% sulfur
= 139.3 ton/yr x 2000 lb/ton x 1/(0.015 x 2) lb/fuel/lb SO_2
x 1/8.1 lb/gal
= 1,146,500 gal/year No. 6 @ 1.5% sulfur
or 1,857,300 gal/year Blend @ 1.0% S.

Full load hours of operation or 1.5% sulfur fuel
= (1.146 x 10^6 gal/yr) x (149,750 BTU/gal**) x (1/49 x 10^6 BTU/hr)
= 3500 full load hours/year on 1.5% No. 6
or 5450 full load hour/year on 1.0% S Blend.

Hourly SO_2

= 49 x 10^6 BTU/hr x 1/149,750 BTU/gal x 8.1 lb/gal x (0.015 x2)
lb SO_2 lb/fuel
= 79.5 lb/hr

Particulate Matter (AP-42)-Max. emission rate with 1.5% sulfur fuel

= 0.018 lb PM/gal x 1,146,500 gal/year x 1/2000
= 10.3 tons/year
x 2000/3500 hr/yr
= 5.9 lb/hour

* Emission rate increase is less than de minimus
** Average heat content during 1979-81 period

Nitrogen Oxides (AP-42)

= 0.055 lb/gal x 1,857,300 gal/yr x 1/2000
= 51.1 tons/year
x 2000/5450
= 18.7 lb/hr

Carbon Monoxide (AP-42)

= 0.005 lb/gal x 1,857,300 gal/yr x 1/2000
= 4.6 tons/year
x 2000/5450
= 1.7 lb/hr

Non-Methane VOC (AP-42)

= 0.00028 lb/gal x 1,857,300 gal/yr x 1/2000
= 0.3 tons/year
x 2000/5450
= 0.1 lb/hr

E. EMISSIONS SUMMARY

	Emission Rate (tons/year)				
Pollutant	Actual (1)	Permitted (2)	Proposed	Increase (3)	Significant Increase
SO_2	100.3 (7)	168.6	139.3	39.0	40 (5)
Part. Matter	8.7	14.8	10.3	(1.6)	25 (6)
NOx	35.7	37.2	51.1	15.4	40 (5)
CO	3.3	--	4.6	1.3	100 (5)
VOC (4)	0.2	--	0.3	0.1	40 (6)

(1) Actual emissions from No. 3 boiler during 1979-81
(2) Permitted emissions from No. 7 boiler (AC16-32394 & AO16-66308)
(3) Increase over Actual or Permitted; whichever is greatest
(4) Non-methane VOC
(5) Defined in 17-2.500(2)(e)2, FAC
(6) Defined in 17-2.510(2)(a)2, FAC
(7) Calculated by J. Woosley, Duval Co. BES

REVISED 1/20/84
REVISED 5/9/84

FUEL USE SCENARIOS

Fuel Data, Boiler Heat Input & other Data Used in Analysis of Fuel Costs and SO_2 Emissions

Fuel oil characteristics

Fuel	Heat Value (BTU/gal)	Heat Value (BTU/lb)	Density (lb/gal)
No 6 oil			
1.5 % sulfur	149750	18488	8.10
1.0 % sulfur	145782	18884	7.72
0.75 % sulfur	143803	19072	7.54
Blend oil			
1.0 % sulfur	143872	19183	7.50
0.75 % sulfur	142790	19322	7.39
By-Product oil			
Low sulfur (0.4%)	138990	19715	7.05
High sulfur (19%)	148375	17456	8.50

Boiler Heat Requirements

Historically: 73% of heat input has been supplied by gas
20% of heat input has been supplied by blend oil
7% of heat input has been supplied by No 6 oil

Boiler	Heat Input (BTU/hr)
4	111.8
5	101.0
6	118.0
7	49.0

By-product oil availability

At a plant production rate that would require all boilers to operate annually at a 0.85 factor:

Low sulfur by-product oil	–	1,322,580 gal/yr
High sulfur by-product oil	–	17,420 gal/yr
Total	–	1,340,000 gal/yr

Proposed ; 1.5 % #6 fuel & 1.0 % Blend oil

#7 boiler

20 % of heat input from 1.0 % S. blend
7 % " " " " 1.5 % S #6

Blend oil

$= 0.20(0.365\times10^{12}) / 143872$ BTU/gal
$= 507395$ gal/yr
× 0.420 = 213,106 gal #6
× 0.573 = 290,738 gal L.S. by-prod.
× 0.007 = 3,552 gal H.S. by-product

#6 Fuel

$= 0.07(0.365\times10^{12})/149750$ BTU/gal
$= 170,618$ gal

#4-6 boilers

27 % of heat input from "oils"

Low sulfur by-product

$= 1322580 - 290,738 = 1031842$ gal
$\times 138990$ BTU/gal $= 0.143\times10^{12}$ BTU

High sulfur by-product

$= 17,420 - 3552 = 13,868$ gal
$\times 148375$ BTU/gal $= 0.002\times10^{12}$ BTU

#6 Fuel @ 1.5 % S

$= [0.27(2.463\times10^{12}) - (0.143+0.002)\times10^{12}] / 149750$
$= 3469360$ gal

SO₂ Emissions

$$= [\underbrace{(290,738+1031842)}_{\times 7.05\times0.004\times2/2000} + \underbrace{(3552+13868)}_{\times 8.5\times0.19\times2/2000} + \underbrace{(\overset{213,106+}{170,618} + 3469360)}_{\times 8.1\times0.015\times2/2000}]$$

$= 37.3 + 28.1 + 468.1$
$= 533.5$ tpy (60.5 tpy from #7 & 473.0 tpy from #4-6)

#6 Fuel Cost

$= (3853084$ gal/yr$) \times 0.736 = \$2,835,870$/yr

Permitted ; No 0.75% Sulfur oil purchased

#7 boiler

27% of heat input from blend oil @ 0.75% S
73% " " " " natural gas

Blend oil
= 0.27 × (0.365 × 10^{12} BTU/yr) / 142790 BTU/gal
= 690174 gal/yr
× 0.68 = 469318 gal L.S. by-product
× 0.32 = 220856 gal #6 @ 1.5% S

#4-6 boilers

73% of heat input from natural gas
27% of " " " "oil"

Low sulfur by-product
= 1322580 − 469318 used by #7
= 853262 gal
× 138990 BTU/gal = 0.118 × 10^{12} BTU/yr

High sulfur by-product
= 17,420 gal × 148375 = 0.002 × 10^{12} BTU/yr

No. 6 @ 1.5% S
= 0.27 (2.463 × 10^{12} BTU/yr) − (0.118 + 0.002) × 10^{12}
= 0.544 × 10^{12} BTU/yr
÷ 149750 = 3,631,589 gal/yr

SO_2 Emissions

= [1,322,580 (7.05 lb/gal) × 0.004 × 2/2000 + 17420 (8.50 lb/gal) × 0.19 × 2/2000 + (3,631,589 + 220856) 8.11 lb/gal × 0.015 × 2/2000]

= 37.3 + 28.1 + 468.1

= 533.5 tpy (40.1 tpy from #7 & 493.4 tpy from #4-6)

#6 Fuel Cost

= (3,631,589 + 220856)(0.736) = $2,835,400/yr

Permitted ; All 0.75% Sulfur oil purchased

7 boiler

27% of heat input from purchased oil w/ 0.75% S

0.75% Oil Requirements

= 0.27 × (0.365 × 10^{12}) / 143803 BTU/gal

= 685313 gal/yr @ 0.75% S

#4-6 boilers.

27% of heat input from "oils" (0.665 × 10^{12} BTU/yr)

Blend oil @ 1.0% S

Must consume all low- and high-sulfur by-product oil with excess heat input provided by #6 oil @ 1.5% S

Low sulfur by-product

= 1322580 gal × 138990 BTU/gal = 0.184 × 10^{12} BTU

High sulfur by-product

= 17,420 × 148375 BTU/gal = 0.003 × 10^{12} BTU

0.186 × 10^{12} BTU

No 6 @ 1.5% S

= [0.665 − 0.186] × 10^{12} /149750 BTU/gal

= 3,195,993 gal /yr

SO_2 Emissions

= [(685313 × 7.54 lb/gal × 0.0075 × 2) + (1322580 × 7.05 × 0.004 × 2)
+ (17420 × 8.50 × 0.19 × 2) + (3,195,993 × 8.1 × 0.015 × 2)] / 2000

= 492.5 tpy (38.8 tpy from #7 & 453.7 tpy from #4-6)

Purchased Fuel Cost

#6 @ 0.75% S

= 685313 × 0.794 = $ 544,139

#6 @ 1.5% S

= 3195993 × 0.736 = 2,352,251

$ 2,896,389 /yr

1.0% Sulfur Blend or Fuel in #7; Purchase no low sulfur fuel oil

#7 boiler

27% of heat input from blend @ 1.0% S

Blend oil

$= 0.27\,(0.365 \times 10^{12}) / 143872$

$= 684984$ gal

$\times\ 0.420 = 287693$ gal #6 @ 1.5% S

$\times\ 0.573 = 392496$ gal L.S. by-product

$\times\ 0.007 = 4795$ gal H.S. by-product

#4-6 boilers

Must consume remainder of by-product oils with remainder of heat input supplied with #6 fuel oil @ 1.5% Sulfur (to 27% of total heat req.)

Low sulfur by-product

$= 1322580 - 392496 = 930084$ gal

$\times\ 138990 = 0.129 \times 10^{12}$ BTU

High sulfur by-product

$= 17420 - 4795 = 12625$ gal

$\times\ 148375 = 0.002 \times 10^{12}$ BTU

0.131×10^{12} BTU

No. 6 @ 1.5% S

$= [0.665 - 0.131] \times 10^{12} / 149750$

$= 3565943$ gal

SO_2 Emissions

$= [(287693 + 3565943) \times 8.10 \times 0.015 \times 2 + 1322580 \times 7.05 \times 0.004 \times 2$

$+ 17420 \times 8.50 \times 0.19 \times 2] / 2000$

$= 533.5$ tpy (53.8 tpy from #7 & 479.7 tpy from #4-6)

Fuel Cost

$= (287693 + 3565943) \times 0.736$

$=$ \$2,836,276/yr

1.0% Sulfur Blend or Fuel in #7 boiler;
Purchase all 1.0% #6 Fuel oil for #7 boiler

#7 boiler

27% of heat input from purchased 1.0% S. #6 oil

Fuel Oil
= 0.27 (0.365 x 10^{12}) / 145782
= 676009 gal @ 1.0% S.

#4-6 boilers

27% of heat input from "oils". must consume all by-product oil with additional heat supplied with #6 fuel oil @ 1.5% S.

Same as #3

Low sulfur by-product	=	1322580 gal
High sulfur by-product	=	17420 gal
No. 6 @ 1.5% S	=	3195933 gal

SO_2 Emissions

= [(676009 x 7.72 x 0.01 x 2) + (1322580 x 7.05 x 0.004 x 2)
+ (17420 x 8.50 x 0.19 x 2) + (3195933 x 8.1 x 0.015 x 2)] / 2000

= 505.9 tpy (52.2 tpy from #7 & 453.7 tpy from #4-6)

Fuel Cost

= 676009 x 0.747 = $504979/yr No 6 @ 1.0% S

+ 3195993 x 0.736 = 2,352,251/yr No 6 @ 1.5% S

Total = $2857230/yr

APPENDIX D

Best Available Control Technology (BACT) Determination

SCM Corporation

Duval County

The applicant is requesting that specific condition number four in their construction permit number AC 16-32394, be changed to allow the firing of 1.5 percent sulfur content oil in No. 7 boiler. The construction permit was issued December 1980 for the installation of a 49 million Btu/hour heat input steam generator. The boiler, No. 7, was permitted to fire natural gas, 0.75% sulfur content by-product oils, and 0.75% sulfur content No. 6 residual oil as orginally requested by the applicant.

The requested change in fuel sulfur content will increase the potential sulfur dioxide emissions from 34 to 69 pounds per hour when fired at design capacity. Specific source emission limiting standards in Florida Administrative Code Rule 17-2.600(b) requires a BACT determination for the air pollutants particulate matter and sulfur dioxide.

<u>BACT Determination Requested by the Applicant:</u>

Pollutant	Emission Limiit
SO_2	1.62 lb/million Btu input
Particulates	.12 lb/million Btu input
NOx	.37 lb/million Btu input

Date of Receipt of BACT Application:

May 11, 1984

Date of Publication in the Florida Administrative Weekly:

June 1, 1984

Review Group Members:

Comments were obtained from the New Source Review Section, the Air Modeling Section, and Jacksonville Division of Bio-Environmental Services.

BACT Determined by DER:

The air pollutant, particulates, will be limited by good operating practice and the firing of natural gas, No. 6 new [1] residual oil or a plant by-product oil blend having a sulfur content not to exceed 1.50 percent by weight.

The air pollutant, sulfur dioxide, will be limited by firing natural gas, No. 6 new [1] residual oil or a plant by-product oil blend having a sulfur content not to exceed 1.50 percent by weight, and, the annual consumption of liquid fuels shall be limited to 1,158,333 gallons.

[1] The term "new" means an oil which has been refined from crude oil and has not been used, and which may or may not contain additives.

The applicant's No. 6 residual oil supplier's certified analysis of the sulfur content, by weight, of each purchased shipment may be used to show compliance with the SO_2 and particulate emission limits when firing residual oil.

Each fuel lot of blended plant by-product oils shall be sampled following the practices outlined in the ASTM procedure D-270.[2]

Each fuel lot of blended plant by-product oils shall be analyzed to determined the percent sulfur content (%S) using ASTM D-219.[2]

[2] Use the most recent revision or designation of the ASTM procedure specified.

A department approved recording volumetric or displacement type flow meter will be installed and the amount of fuel oil consumed reported to Jacksonville Bio-Environmental Services on a quarterly basis.

Visible Emissions	Not a exceed 15% opacity. 40% opacity is permitted for not more than two minutes in any one hour.

DER Method 9 (17-2.700(6)(a)9. FAC) will be used to determine compliance with the opacity standard.

BACT Determination Rationale:

The applicant received a permit in 1980 to construct No. 7 steam generator to replace an existing unit No. 3. The fuel sulfur content for the No. 7 unit was limited by permit to 0.75 percent as requested by the applicant. A construction permit was submitted to the department to change the sulfur content of the oil fired and restrict unit operational hours to limit SO_2 emissions to an increase of 39 TPY above the retired unit No. 3 baseline.

The applicant is permitted to fire 1.5% percent sulfur content oil in their 3 existing boilers and the 0.75 percent sulfur requirement will require the installation of separate storage facilities. SO_2 emissions would be limited, by hours of operation, to an increase of 39 TPY to avoid a prevention of significant deterioration determination.

The plants steam requirements, based on past boiler heat input data, are supplied by firing natural gas, blended by-product oils and No. 6 residual oil at a ratio of 73%, 20% and 7%, respectively. The process by-product oil is blended with residual oil to provide an economical fuel and is a method of waste disposal.

The department agrees, that based upon the applicants information, that in this case the 0.75 percent fuel sulfur content is unduely restrictive. The department does not agree with the applicant's BACT for SO_2 of 1.62 lb/million Btu heat input. This process-rate standard would require the gross calorific value of each fuel and would require an extra analysis of each fuel lot of the blended oils prior to firing. This would require additional fuel storage which the applicant has stated is not available.

The department did not require the installation of a continuous SO_2 emission monitor for the same reason, that is the gross calorific value is required to determine the F factor. This system, however, remains a viable option.

The firing of low sulfur content fuel is one method of controlling the amount of SO_2 emissions from a steam generator of this size, where the installation of a FGD unit would not be economical. In this case the annual emissions must not exceed 139 tons, therefore, the department has determined BACT to be a fuel sulfur content limit of 1.5 percent and an annual fuel oil consumption limit of 1,158,333 gallons.

Particulate emissions when firing residual oil, on the average, is a function of the sulfur content of the oil. The BACT for SO_2 emissions will also limit particulate emissions.

Compliance with this BACT determination will require the installation of an integrating fuel oil flow meter in series with the furnace oil nozzles. The proposed piping arrangement shall be approved by DER before installation.

The conditions of this determination will provide the operating flexibility requested by the applicant. Steam generator No. 7 will be able to fire fuel oil for 3458 hours at maximum fuel consumption, or 39%, which is greater than the historic hour average of 27% which was based upon past fuel records.

The term "new oil" is included to prevent the use of waste oil as fuel, emissions from which were not considered in this BACT analysis. This provision applies only to the fuel oil purchased by the applicant.

<u>Details of the Analysis May be Obtained by Contacting:</u>

Edward Palagyi, BACT Coordinator
Department of Environmental Regulation
Bureau of Air Quality Management
2600 Blair Stone Road
Tallahassee, Florida 32301

Recommended By:

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Steve Smallwood, Chief BAQM

Date:________________________

Approved:

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Victoria J. Tschinkel, Secretary

Date:________________________

APPENDIX E