

TITLE V APPLICATION REVIEW

Facility Name: Shaw Industries, Inc., Plant No. 4

City: Dalton, Georgia

County: Whitfield

AIRS #: 04-13-313-00084

Application #: TV- 9251

Date Application Received: October 17, 1996

Date Application Deemed
Administratively Complete: December 10, 1996

Date of Draft Permit: June 5, 2001

Permit No: 2273-313-0084-V-01-0

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Introduction

This narrative is being provided to assist the reader in understanding the content of the attached draft Part 70 operating permit. Complex issues and unusual items are explained in simpler terms and/or greater detail than is sometimes possible in the actual permit. This permit is being proposed pursuant to: (1) Section 391-3-1-.03(10) of the Georgia Rules for Air Quality Control, (2) Part 70 of Chapter I of Title 40 of the Code of Federal Regulations, and (3) Title V of the Clean Air Act Amendments of 1990. The primary purpose of this permit is to consolidate and identify existing state and federal air requirements applicable to Shaw Industries, Inc., Plant No. 4 and to provide practical methods for determining compliance with these requirements. The following narrative is designed to accompany the draft permit and is presented in the same general order as the permit. It initially describes the facility receiving the permit, then the applicable requirements and their significance, and finally the methods for determining compliance with those applicable requirements. This narrative is intended only as an adjunct for the reviewer and has no legal standing. Any revisions made to the permit in response to comments received during the public participation process will be described in an addendum to this narrative.

I. Facility Description

A. Facility Identification

1. Facility Name

Shaw Industries, Inc., Plant #4

2. Parent/Holding Company Name

Shaw Industries, Inc.

3. Previous and/or Other Name(s)

Star Finishing Company, Division of Shaw Industries, Inc.

4. Facility Location

2225 Hamilton Street Ext, Dalton, Georgia

5. Attainment or Non-attainment Area Location

This facility is located in Whitfield County, is in an attainment area for all criteria pollutants.

6. Class I Area Impacts

This facility is located within 100 Km of the Cohutta Class I area.

B. Site Determination

Shaw Industries, Inc., has fifteen manufacturing plants in Whitfield County, Dalton, with nine of them classified as Title V major sources. Three applications are being submitted together (Plant Nos. 2, 4 and 80) as a package because the site determination as detailed in subsequent paragraphs has led the Division to conclude that these three facilities meet the definition of a Part 70 Single Site. The original applications were submitted because potential emissions of SO₂, NO_x, PM, and VOC from the entire site exceed the 100 tpy threshold for criteria pollutants.

Shaw Plant #2 is located at 2207 South Hamilton Street Extension, Dalton, GA. This plant was purchased by Shaw Industries, Inc., in early 1987 from Unique Processing Co. On June 6, 1988, an Air Quality permit was issued to Shaw for the operation of Plant #2 and construction of two (2) 73.7 million Btu per hour boilers. Shaw Plant #2 is located directly north of Plant #4, on contiguous property.

Shaw Plant #4 is located at 2225 South Hamilton Street Extension, on contiguous property with Plant #2; it is also adjacent to Shaw plant #80 which is separated by a public road (South Hamilton Extension). There is also a small chemical blending operation at Plant #4 that supplies auxiliary chemicals to other Shaw plants within and beyond Whitfield County. Shaw Plant #4 is the oldest Shaw property at this site dating back to the early 1970's. On December 10, 1979 an Air Quality permit was issued to Shaw for the operation of Shaw Plant #4 and associated process equipment including boilers. In 1984, a second permit was issued for the construction and operation of

three (3) coal fired boilers.

Shaw plant #80 is located at 2230 South Hamilton Street Extension, adjacent to Plant #4. This plant was purchased by Shaw Industries, Inc., in late 1987 from West Point Pepperell, Inc. On April 27, 1988, an Air Quality permit was issued to Shaw for the operation of plant #80.

Plants 2, 4, and 80 are all one Part 70 source because they are under common control, located on contiguous and/or adjacent property, and have the same 2-digit SIC code.

For administrative purposes, Shaw requested separate Title V permits be issued for each facility. AIRS No. 313-00061 currently belong to plant #2 will be used for the Title V permit for plant #2, AIRS No. 313-00084 currently belong to plant #4 will be used for the Title V permit for plant #4 and 313-00003 currently belong to plant #80 will be used for the Title V permit for plant #80.

C. Existing Permits

Table 1: List of Current Permits, as Amended

Permit Number and/or Purpose of Issuance	Date of Issuance and Date of Amendments (if any)	Comments	
		Yes	No
2272-155-7209-0	November 30, 1979, and amended on June 7, 1984	X	
2275-155-8840	June 7, 1984, and Amended on April 3, 1987	X	
2273-313-0084-E-01-0	September 30, 1999	X	

Table 2: Comments on Specific Permits

Permit Number	Comments
2272-155-7209-0	Issued to Star Finishing, Division of Shaw Industries, Inc., for operation of three boilers.
2272-155-8840	Issued to Shaw Industries Inc., for construction and operation of three coal fired boilers, and amended to allow the facility to burn coal with sulfur content not to exceed 0.8 percent by weight in a calendar year with no individual fuel shipment sulfur content exceeds 1.0 percent sulfur, and limiting the total coal fired in all three boilers to 22,115 tons per year.
2273-313-0084-E-01-0	Issued to Shaw Industries Inc., for construction and operation of 41 MMBtu/hr latex coater (source code LC03), and limiting the LC03 to 123,000,000 square yards of carpet.

D. Process Description

1. SIC Code(s)

Major - 2273
Other - None

2. Description of Product(s)

The final product of the facility broadloom tufted carpet.

3. Overall Facility Process Description

Processed yarn is tufted into greige goods. These greige goods are then dyed in a continuous process. Once the greige goods have been dyed, they are then coated with an SBR latex adhesive backing that adds durability. During this process, the yarn fibers are sheared for consistent length. At the end of this process the finished carpet is inspected and cut to consumer specified lengths. The steam produced by five boilers (source codes BL04, BL05, BL06, BL07 and BL08) is mainly used to power the continuous dye operation and coating processes.

4. Overall Process Flow Diagram (optional)

There is one attached to the application.

E. Regulatory Status

1. PSD/NSR

Plants 2, 4, and 80 are a major source under PSD because they have potential to emit (PTE) of PSD regulated pollutants over 250 tpy (they are not one of the 28 named source categories under PSD).

Site History

On November 30, 1979 Air Quality Permit No. 2272-155-7209-O was issued to Shaw Industries Inc., (Shaw) for the operation of Shaw Plant No. 4. The permit was for the operation of two 59 MMBtu per hour boilers and one 25 MMBtu per hour boiler firing natural gas or fuel oil. On June 7, 1984; the Division issued Air Quality Permit No. 2272-155-8840 to Shaw for the construction and operation of three coal-fired boilers, each with a rated capacity of 37.5 MMBtu per hour heat input, to be located at Shaw Plant No. 4. Annual coal consumption was limited to 22,115 tons with an average sulfur content of 0.8 percent by weight to limit SO₂ emission from the coal-fired boilers to less than 345 tons per year.

At the time the coal-fired boilers were installed at Shaw Plant No. 4, Shaw Plant No. 4 was not considered a major source under the PSD regulations and, therefore, the use of reduction credits or netting was not allowed by the regulations. The Division has determined that the permit issued for the three coal-fired boilers at Shaw Plant No. 4 should have limited the SO₂ emissions to less than 250 tons SO₂ per year to prevent the installation of the boilers from being a major source as defined by the PSD regulations.

On April 27, 1988, the Division issued Air Quality Permit No. 2273-155-9888 to Shaw for the operation of a carpet finishing facility formally known as the Westcott Plant and a name change to Shaw Industries, Incorporated Plant No. 80. Shaw Plant No. 80 included boilers rated at 90 MMBtu per hour heat input, 65 MMBtu per hour heat input and 69 MMBtu per hour heat input, burning natural gas or No. 6 fuel oil.

On June 9, 1988, the Division issued Air Quality Permit No. 2272-155-9902 to Shaw for the construction and operation of two 73.7 MMBtu per hour heat input boilers to be located at Shaw Plant No. 2. Annual fuel oil consumption in the two boilers was limited so that the SO₂ emission from the two boilers would not exceed than 371 tons per year. At the time Shaw installed the two 73.7 MMBtu per hour boilers, Shaw Plant No. 2, Shaw Plant No. 4 and Shaw Plant No. 80 should have been considered one source and a major source as defined by the PSD regulations because they were located on contiguous property, were under common ownership and belonged to the same industrial grouping as identified by the same two-digit SIC code. The Division has determined that the permit for two 73.7 MMBtu per hour boilers at Shaw Plant No. 2 should have limited the emissions increase from the two boilers to less than the significant emissions levels of 40 tons per year of SO₂ and NO_x to prevent the installation of the boilers from being a major modification as defined by the PSD regulations.

Shaw recently agreed to a Consent Order that would, among other things, limit SO₂ and NO_x emissions from the two 73.7 MMBtu/hr boilers at Plant No. 2 to 40 tpy and limit **SO₂ emissions from the three coal-fired boilers at plant No. 4 to 250 tpy**. Compliance with each of these limits must be achieved by March 31, 2002. In addition, the company is agreeing to burn residual fuel oil at Plant No. 2 and 80 that contains no more than 1.80% sulfur.

2. Title V Major Source Status by Pollutant

Table 3: Title V Major Source Status

Pollutant	Is the Pollutant Emitted?	If emitted, what is the facility=s Title V status for the Pollutant?		
		Major Source Status	Major Source Requesting SM Status	Non-Major Source Status
PM	T	T		
PM ₁₀	T	T		
SO ₂	T	T		
VOC	T	T		
NO _x	T	T		
CO	T	T		
TRS	T			T
H ₂ S	T			T
Individual	T			T
Total HAPs	T			T

3. MACT Standards

None applicable

4. Program Applicability

Program Code	Applicable (Yes/No)
Program Code 6 - PSD	No
Program Code 8 - Part 61 NESHAP	No
Program Code 9 - NSPS	No
Program Code M - Part 63 NESHAP	No
Program Code V - Title V	Yes

Regulatory Analysis

II. Facility Wide Requirements

A. Emission and Operating Caps

None applicable

B. Applicable Rules and Regulations

! Rules and Regulations Assessment

Georgia Rule 391-3-1-.02(2)(a)1 applies to the entire facility.

! Emission and Operating Standards

None applicable

C. Compliance Status

As described in site history, the company has recently agreed to a Consent Order for excess SO₂ and NO_x emissions. An appropriate compliance schedule has been included in this permit.

D. Operational Flexibility

None

E. Permit Conditions

None

III. Regulated Equipment Requirements

A. Brief Process Description

Plant #4 manufactures tufted carpet by tufting nylon, polyester or polypropylene yarn through a polypropylene primary backing, dyeing the carpet, applying a coating to the primary backing, applying a secondary backing when called for and shearing the finished carpet. Yarn is not produced at Plant 4. It is delivered to the plant, stored in the plant and used when required. Plant 4 has 11 atmospheric dye becks which are used on a limited basis (listed in application as a insignificant sources based on emission levels), two Kuster continuous dye ranges (**source codes CD03 and CD04**) for polyester and nylon carpets and one continuous dye range for scouring polypropylene carpets. After the carpet is dyed, a stain blocker is applied, then a scotch guard is applied. Finally, a latex backing is applied to the carpet, the carpet is sheared, rolled up and marked for storage or delivery. The latex backing contains styrene and 1,3 butadiene. Lint from the shearing process is controlled by exhausting part of the lint laden air stream through a multiclone collector located outside and the other part of the line through a bag filter located inside the building. Steam required for the processes is provided by the five boilers, two natural gas/No. 2 fuel oil fired boilers (**source codes BL07 and BL08**) and three coal fired boilers (**source codes BL04, BL05 and BL06**) which are equipped with multiclone ash collection with 94.% collection efficiency (source codes PC01-03).

B. Equipment List for the Process

Emission Units		Specific Limitations/Requirements		Air Pollution Control Devices	
ID No.	Description	Applicable Requirements / Standards	Corresponding Permit Conditions	ID No.	Description
BL04	Coal boiler #1	Rule 391-3-1-.02(2)(d)2(ii) Rule 391-3-1-.02(2)(d)3 Rule 391-3-1-.02(2)(g)2	3.2.2, 3.2.4, 3.2.7, 3.4.1, 3.4.2	PC01	Multicolone
BL05	Coal boiler #2	Rule 391-3-1-.02(2)(d)2(ii) Rule 391-3-1-.02(2)(d)3 Rule 391-3-1-.02(2)(g)2	3.2.2, 3.2.4, 3.2.7, 3.4.1, 3.4.2	PC02	Multicolone
BL06	Coal boiler #3	Rule 391-3-1-.02(2)(d)2(ii) Rule 391-3-1-.02(2)(d)3 Rule 391-3-1-.02(2)(g)2	3.2.2, 3.2.4, 3.2.7, 3.4.1, 3.4.2	PC03	Multicolone
BL07	Gas boiler #1	Rule 391-3-1-.02(2)(d)2(ii) Rule 391-3-1-.02(2)(d)3 Rule 391-3-1-.02(2)(g)2	3.2.3, 3.2.5, 3.2.6, 3.4.1, 3.4.2	none	none
BL08	Gas boiler #2	Rule 391-3-1-.02(2)(d)2(ii) Rule 391-3-1-.02(2)(d)3 Rule 391-3-1-.02(2)(g)2	3.2.3, 3.2.5, 3.2.6, 3.4.1, 3.4.2	none	none
CD03	Kuster continuous dye line	Rule 391-3-1-.02(2)(b)1 Rule 391-3-1-.02(2)(e)1(ii) Rule 391-3-1-.02(2)(g)2	3.2.8, 3.4.3, 3.4.4, 3.4.5	none	none
CD04	Multi-tech continuous dye line	Rule 391-3-1-.02(2)(b)1 Rule 391-3-1-.02(2)(e)1(ii) Rule 391-3-1-.02(2)(g)2	3.2.8, 3.4.3, 3.4.4, 3.4.5	none	none
DR01	Beck dryer	Rule 391-3-1-.02(2)(b)1 Rule 391-3-1-.02(2)(e)1(ii) Rule 391-3-1-.02(2)(g)2	3.2.8, 3.4.3, 3.4.4, 3.4.5	none	none
LC02	Latex coater	Rule 391-3-1-.02(2)(b)1 Rule 391-3-1-.02(2)(e)1(ii) Rule 391-3-1-.02(2)(g)2	3.2.8, 3.4.3, 3.4.4, 3.4.5	none	none
LC03	Latex coater	Rule 391-3-1-.02(2)(b)1 Rule 391-3-1-.02(2)(e)1(ii) Rule 391-3-1-.02(2)(g)2	3.2.1, 3.2.8, 3.4.3, 3.4.4, 3.4.5	none	none

* Generally Applicable Requirements contained in this permit may apply also to emission units listed above.

C. Equipment & Rule Applicability

! Emission and Operating Caps

Latex Coater #2 (source code LC03): To avoid PSD permitting and review, the facility agreed to limit the LC03 production rate to 123,000,000 square yards coated carpet which equates or less than 38 tons per year of VOC.

VOC emissions

$[(280 \text{ mg/sq. yard of carpet}) \times (1 \text{ gram}/1000 \text{ mg}) \times (1\text{b}/454 \text{ gram})(123,000,000 \text{ sq. yard of carpet})] = 37.92 \text{ tpy}$

Coal fired Boilers (source codes BL04, BL05 and BL06): As a part of the **Consent Order**, the facility agreed to limit the potential of SO₂ emissions from coal fired boilers BL04, BL05 and BL06 below 250 tpy (to avoid PSD review) commencing with the twelve consecutive month period ending March 31, 2002.

Potential SO₂ emissions = $[(\text{tons of coal})(\text{emission factor})(\%S)/(\text{ton}/2000 \text{ lb})]$

Potential SO₂ emissions = $[(16,320 \text{ t/yr})(0.8) (38 \text{ lb/t})/(\text{ton}/2000 \text{ lb})] = \underline{248.1 \text{ tpy}}$

Potential NO_x emissions = $[(\text{tons of coal})(\text{emission factor})/(\text{ton}/2000 \text{ lb})]$

Potential NO_x emissions = $[(16,320 \text{ t/yr})(9 \text{ lbs NO}_x / 1 \text{ ton coal})/(\text{ton}/2000 \text{ lb})] = \underline{74 \text{ tpy}}$

Natural gas/ NO. 2 fuel oil fired Boilers (source codes BL07, and BL08)**No. 2 fuel oil**

BL07 and BL08 are limited to 450,000 gallons of No. 2 fuel oil during any twelve consecutive months.

Potential SO₂ emissions = $(142 \times 0.5) \times 450,000 \text{ gal/yr} / (2 \times 10^6) = \underline{16 \text{ tpy}}$

Potential NO_x emissions from No. 2 fuel oil

$(450,000 \text{ gal/yr})(20 \text{ lb}/1000 \text{ gal}) = 9,000 \text{ lb/year of NO}_x$

$(9,000 \text{ lb/year}) / 1 \text{ ton}/2000 \text{ lbs} = \underline{4.5 \text{ tons per year}}$

Natural gas**Potential NO_x Emissions**

Maximum rated input for two boilers (Btu/hr) = $[59 + 59] \text{ MMBtu/hr} = 118 \text{ MMBtu/hr}$

Heating value of fuel (Btu/ft³), natural gas = 1000 Btu/ ft³

Emission factor (lb/10⁶ ft³) = 140 lb. NO_x/ MMft³ natural gas

Maximum operating time (hr/day) = 24 hours

$118 \text{ MM Btu/hr}/1000 \text{ Btu/ft}^3 = 118,000 \text{ ft}^3/\text{hr}$

Maximum natural gas usage

$(118,000 \text{ ft}^3/\text{hr})(8760 \text{ hrs/year}) = 1,033,680,000 \text{ ft}^3/\text{year}$

Potential To Emit (PTE) of NO_x

$(1,033 \text{ MMCF/year})(140 \text{ lb/MMCF}) = 144,620 \text{ lb/year of NO}_x$

$(144,620 \text{ lb/year}) / 1 \text{ ton}/2000 \text{ lbs} = \underline{72 \text{ tons per year}}$

Potential NOx Emissions from natural gas for DR01, CD03, CD04, LC02 and LC03

Maximum rated input in Btu/hr = [14+ 16+ 29 + 42.5 + 41] MMBtu/hr = 142.5 MMBtu/hr

Heating value of fuel (Btu/ft³), natural gas = 1000 Btu/ ft³

Emission factor (lb/10⁶ ft³) = 140 lb. NOx/ MMft³ natural gas

Maximum operating time (hr/day) = 24 hours

142.5 MM Btu/hr/1000 Btu/ft³ = 142,500 ft³/hr

Maximum natural gas usage

(142,500 ft³/hr)(8760 hrs/year) = 1,248,300,000 ft³/ year

Potential To Emit (PTE) of NO_x

(1,248.3 MMCF/year)(140 lb/MMCF) = 174,762 lb/year of NO_x

(174,762 lb/year)/ 1 ton/2000 lbs = **88 tons per year**

! Applicable Rules and Regulations

Boilers: Currently there are five boilers in operation (source codes BL04, BL05, BL06, BL07 and BL08). BL04, BL05 and BL06 (37.5 MMBtu/hr each) are coal fired boilers and were constructed prior to 1984 and installed in 1984. Since these units were constructed after January 1, 1972, the allowable PM emission rate from each boiler is specified by Georgia Rule 391-3-1-.02(2)(d)2(ii), which is stated as follows: $P = 0.5 \cdot (10/R)^{0.5}$, where P equals the allowable PM emission rate in pounds per million Btu and R equals the heat input in million Btus per hour.

Boiler BL07 and BL08 (59 MMBtu/hr each) are natural gas/No. 2 fuel oil fired boilers and were constructed prior to 1973 and installed in 1973. Since these units were constructed after January 1, 1972, the allowable PM emission rate from each boiler is specified by Georgia Rule 391-3-1-.02(2)(d)2(ii), which is stated as follows:

$P = 0.5 \cdot (10/R)^{0.5}$ where P equals the allowable PM emission rate in pounds per million Btu and R equals the heat input in million Btus per hour.

Boilers BL04, BL05, BL06, BL07, and BL08 are also subject to Georgia Rule for Air Quality Control 391-3-1-.02(2)(d)3 because they were constructed after January 1, 1972. Georgia Rule 391-3-1-.02(2)(d)3 limits the opacity to 20 percent except for one six minute period per hour of not more than 27 percent opacity.

Since boilers BL04, BL05, and BL06 are capable of firing on coal, Georgia Rule 391-3-1-.02(2)(g)2 limited sulfur content to 2.5 weight percent. However, the facility agreed to limit the sulfur content of coal to 0.8%.

Since boilers BL07, and BL08 are capable of firing on natural gas or No. 2 fuel oil, Georgia Rule 391-3-1-.02(2)(g)2 limited sulfur content to 2.5 weight percent. However, the facility agreed to limit the sulfur content of No. 2 fuel to 0.50%.

For the 16 MMBtu/hr natural gas fired **Kuster continuous dye line** (source code CD03, constructed prior to 1970 and installed in 1970), 29 MMBtu/hr natural gas fired **Multi-tech continuous dye line** (source code CD04, constructed prior to 1977 and installed in 1977), 14 MMBtu/hr natural gas fired **Beck dryer** (source code DR01, constructed prior to 1981 and installed in 1981), 42.5 MMBtu/hr natural gas fired **Latex coater** (source code LC02, constructed prior to 1978 and installed in 1978), and natural gas fired **Latex coater** (source code LC03, constructed in 1999 and installed in 2000), the fuel sulfur content is limited to 2.5 weight percent, in accordance with Georgia Rule 391-3-1-.02(2)(g)2.

DR01, CD03, CD04, LC02, and LC03 are used for latex adhesive to carpet and are capable of firing on natural gas only. Each unit is treated as a separate process, and the allowable PM emission rate from this range is expressed by Georgia Rule 391-3-1-.02(2)(e)1. which is stated as follows:

For process weight input rates up to 30 tons per hour: $E = 4.1P^{0.67}$, where E equals the allowable PM emission rate in pounds per hour and P equals the maximum process input weight rate in tons per hour.

DR01

Note I: TV Application indicated that the DR01 processes approximately 16,875 lbs per hour (8.5 tph) tufted greige goods.

$$E = 4.1P^{0.67} = (4.1)(8.5)^{0.67} = 17.20 \text{ lbs per hour allowable PM emission}$$

Note II: Applicant estimated in Section 7.10 of the application that maximum anticipated actual emissions for DR01 is approximately 1 lb/hr (based on best available data). Since the maximum anticipated actual emissions is less than allowable emissions, compliance with Rule (e) is expected.

Note III: Applicant estimated in Section 7.10 of the application that maximum anticipated actual emissions of VOC for DR01 is approximately 6 tpy (based on industry emissions factor).

CD03

Note I: TV application indicated that the CD03 processes approximately 12,430 lbs per hour (6.22 tph) tufted greige goods.

$$E = 4.1P^{0.67} = (4.1)(6.22)^{0.67} = 14 \text{ lbs per hour allowable PM emission.}$$

Note II: Applicant estimated in Section 7.10 of the application that maximum anticipated actual emissions for CD03 is approximately 1 lbs/hr (based on best available data). Since the maximum anticipated actual emissions is less than allowable emissions, compliance with Rule (e) is expected.

Note III: Applicant estimated in Section 7.10 of the application that maximum anticipated actual emissions of VOC for CD03 is approximately 8.5 tpy (based on industry emissions factor).

CD04

Note I: TV Application indicated that the CD04 processes approximately 12,375 lbs per hour (6.2 tph) tufted greige goods.

$$E = 4.1P^{0.67} = (4.1)(6.2)^{0.67} = 14 \text{ lbs per hour allowable PM emission}$$

Note II: Applicant estimated in Section 7.10 of the application that maximum anticipated actual emissions for CD04 is approximately 1 lbs/hr (based on best available data). Since the maximum anticipated actual emissions is less than allowable emissions, compliance with Rule (e) is expected.

Note III: Applicant estimated in Section 7.10 of the application that maximum anticipated actual emissions of VOC for CD04 is approximately 6.7 tpy (based on industry emissions factor).

LC02

Note I: TV application indicated that the LC02 processes approximately 18,750 lbs per hour (9.40 tph) tufted greige goods.

$$E = 4.1P^{0.67} = (4.1)(9.40)^{0.67} = 18.40 \text{ lbs per hour allowable PM emission}$$

Note II: Applicant estimated in Section 7.10 of the application that maximum anticipated actual emissions for LC02 is approximately 1 lbs/hr (based on best available data). Since the maximum anticipated actual emissions is less than allowable emissions, compliance with Rule (e) is expected.

Note III: Applicant estimated in Section 7.10 of the application that maximum anticipated actual emissions of VOC for LC02 is approximately 23 tpy (based on industry emissions factor).

LC03

Note I: TV Application indicated that the LC03 processes approximately 24,500 lbs per hour (12.30 tph) tufted greige goods.

$$E = 4.1P^{0.67} = (4.1)(12.30)^{0.67} = 22 \text{ lbs per hour allowable PM emission.}$$

Note II: Applicant estimated in Section 7.10 of the application that maximum anticipated actual emissions for LC03 is approximately 1 lbs/hr (based on best available data). Since the maximum anticipated actual emissions is less than allowable emissions, compliance with Rule (e) is expected.

Note III: Applicant estimated in Section 7.10 of the application that maximum anticipated actual emissions of VOC for LC03 is approximately 29 tpy (based on industry emissions factor).

CD03, CD04, DR01, LC02, and LC03 are subject to Georgia Rule 391-3-1-.02(2)(b)1. Georgia Rule 391-3-1-.02(2)(b)1 limits the opacity to forty percent.

D. Compliance Status

As described in site history, there has been some noncompliance that is being resolved through a Consent Order and this permit.

E. Operational Flexibility

None applicable

F. Permit Conditions

The permit conditions are described above in the Equipment & Rule Applicability section. There are no unusual conditions that need to be highlighted in this section.

IV. Testing Requirements (with Associated Record Keeping and Reporting)General Testing Requirements

A requirement for performance testing on any specified emissions unit, when directed by the Division, is included. Requirements for a 30 day notification of testing and the submission of a test plan are also included. Test methods and procedures to be used are specified.

Specific Testing Requirements

The Permit contains condition that require performance test for Particulate Matter (PM) emissions on each coal fired boiler within 90 days following the date of issue of this permit, and at 12 month intervals.

V. Monitoring Requirements (with Associated Record Keeping and Reporting)

A. General Monitoring Requirements

Condition 5.1.1 requires that all continuous monitoring system required by the Division and installed by the Permittee shall be in continuous operation. All data recorded during all periods of operation of the affected facility except for continuous monitoring system breakdowns and repairs. Data shall be recorded during calibration checks and zero and span adjustments. Maintenance or repair shall be conducted in the most expedient manner to minimize the period during which the system is out of service.

B. Specific Monitoring Requirements

Boilers BL04, BL05 and BL06 are subject to Georgia Rules 391-3-1-.02(2)(d) for opacity and Particulate Matter (PM) and 391-3-1-.02(2)(g) for Sulfur Dioxide. Each boiler is controlled for PM emissions using a separate multiclone. Proper operation and maintenance of the PM control equipment will ensure that emissions are low and within allowable limits. To ensure that the cyclones are operating properly, weekly inspections of the multiclones are required to be conducted. Excursions, to be reported quarterly, are specified. All boilers are fired with coal and daily readings of visible emissions (opacity) are required to ensure compliance with Rule (d) PM limitations. For each boiler, twenty percent opacity was chosen as the trigger level at which corrective action is required to be taken. Occurrences of opacity greater than or equal to the trigger level that are not corrected within 24 hours and are required to be reported. Rule (g) limits the sulfur content of each fuel to 2.5 percent sulfur, by weight. *Condition 3.2.4* of the permit further limits the sulfur content of the coal to be 0.8 percent. Monitoring for these sulfur limits are through sampling and analysis using appropriate ASTM Methods. In this Title V permit, the sulfur limit has been changed from 0.8% annual basis (from SIP Permit) to a maximum of 0.8% on every shipment. Periodic monitoring is based on a sulfur analysis of each shipment. We could allow the sulfur limit to be 0.8% on a 12 month rolling average. However, periodic monitoring would have to be much more stringent to verify compliance with such a limit, possibly including Aas-fired@sulfur monitoring similar to the coal-fired electric utility plants. As part of the Consent Order, boilers BL04, BL05 and BL06 are subject to PSD avoidance limits for amount of coal burn to 16,320 tons during any twelve consecutive months (the limit is equal to 250 tpy of SO₂ emissions for all boilers) commencing with the twelve consecutive month ending March 31, 2002. Compliance will be determined using coal usage records and sulfur content.

Boilers BL07 and BL08 are subject to Georgia Rules 391-3-1-.02(2)(d) for opacity and Particulate Matter (PM) and 391-3-1-.02(2)(g) for Sulphur Dioxide. The boilers are natural gas fired with number 2 fuel oil as the backup fuel. No monitoring is required when the boilers are fired with natural gas, and or No. 2 fuel oil because it is very unlikely that emissions would exceed opacity and PM limitations. However, for each shipment of distillate fuel oil (Numbers 1 or 2) received for combustion, Shaw Industries Inc., Plant No. 4 shall obtain from the fuel supplier a statement that the fuel oil complies with the specifications for No. 2 fuel oil, as defined in ASTM D396 - Standard Specifications for Fuel Oil to ensure compliance with the 0.5 weight percent fuel sulfur content limit. The fuel supplier certifications serves as the monitoring to assure compliance with the fuel sulfur limit. Compliance with the Rule (g) fuel sulfur limit is determined using fuel supplier certifications for distillate fuel oil (Numbers 1 or 2). BL07 and BL08 are subject to a fuel oil usage limit of 450,000 gal/yr. Compliance will be determined using fuel oil records.

DR01, CD03, CD04, LC02 and LC03 are subject to Georgia Rules 391-3-1-.02(2)(b) for opacity and (e) for Particulate Matter (PM) emissions. No control equipment is present on any of the units; however, PM emissions from these units are very low and it is very unlikely that Particulate Matter and opacity limitations will be exceeded. Therefore, no monitoring is required.

DR01, CD03, CD04, LC02 and LC03 are capable of firing on natural gas only and subject to Georgia Rule 391-3-1-.02(2)(g)2 for Sulphur Dioxide. No control equipment is present on each unit. It is very unlikely that Rule (g) will be exceeded due to low sulfur content of natural gas. Therefore, no monitoring is required.

LC03 is subject to a throughput limit of 123 million square yards per year. Compliance will be determined using material usage records.

Condition 5.3.1 requires the Permittee to maintain records of all data and information required by Conditions No. 5.2.1 and 5.2.2 and submit a report quarterly in accordance with Condition No. 6.1.4.

VI. Other Record Keeping and Reporting Requirements

General Record Keeping and Reporting Requirements

A. General Record Keeping and Reporting Requirements

The Permit contains general requirements for the maintenance of all records for a period of five years following the date of entry and requires the prompt reporting of all related information to deviations from applicable requirements. Records, including identification of any excess emissions, exceedances, or excursions from the applicable monitoring triggers, the cause of such occurrence, and the corrective action taken, are required to be kept by the Permittee and reporting is required on a quarterly basis.

B. Specific Record Keeping and Reporting Requirements

Condition Nos. 6.2.2 and 6.2.4 define the coal analysis as well as the reporting requirements for the laboratory analysis for sulfur content of each shipment and the quantity of each shipment.

Records for the amount of fuel combusted in each boiler each calendar month are also specified. For each month, a 12-consecutive month total for the amount of coal (tons) combusted in boilers BL04, BL05, BL06 and amount

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of No. 2 fuel oil (gallons) burned in boiler BL07, and BL08. A 12-consecutive month total for each month in the reporting period is to be submitted with the quarterly reports. Also to be submitted are the fuel supplier certifications with the fuel sulfur limits.

Condition Nos. 6.2.1 and 6.2.3 define the content of the fuel oil certifications as well as the reporting requirements for these certifications. The fuel supplier certifications serve as the monitoring to assure compliance with the fuel sulfur limit. Compliance with the Rule (g) fuel sulfur limit is determined using fuel supplier certifications for distillate fuel oil (Numbers 1 or 2).

Records for the amount coated carpet process in Latex Coater (LC03) for each month of operation are also specified. Condition No. 6.2.5 requires the facility to keep the records. A 12-consecutive month total for each month in the reporting period is to be submitted with the quarterly reports.

VII. Specific Requirements

A. Operational Flexibility

None applicable

B. Alternative Requirements

None applicable

C. Insignificant Activities

None applicable

D. Temporary Sources

None applicable

E. Short-Term Activities

None applicable

F. Compliance Schedule/Progress Reports

The compliance schedule for SO₂ emissions has been incorporated into Conditions 3.2.2 by limiting amount of coal burned in BL04, BL05 and BL06. Progress reports have been incorporated into Condition 6.2.7.

G. Emissions Trading

None applicable

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H. Acid Rain Requirements

None applicable

I. Prevention of Accidental Releases

This facility is not subject to 40 CFR 68.

J. Stratospheric Ozone Protection Requirements

The standard permit condition pursuant to 40 CFR 82 Subpart F has been included in the Title V Permit. The facility operates equipment that is subject to Title VI of the 1990 Clean Air Act Amendments.

K. Pollution Prevention

None applicable

L. Specific Conditions

None applicable

VIII. General Provisions

Generic provisions have been included in this permit to address the requirements in 40 CFR Part 70 that apply to all Title V sources, and the requirements in Chapter 391-3-1 of the Georgia Rules for Air Quality Control that apply to all stationary sources of air pollution.

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Addendum to Narrative

The announced comment deadline for the draft permit was August 6, 2001. Written comments dated August 6, 2001, were received on August 8, 2001 from the Georgia Center for Law in the Public Interest. The initial paragraph of the comments states that the comments were submitted "On behalf of the Georgia ForestWatch and the Sierra Club..."

Written comments dated July 12, 2001, were also received from Shaw Industries, Inc., Plant No. 4.

Comments from the Georgia Center for Law in the Public Interest

Comment 1

A comment was made that "EPD'S PUBLIC NOTICE PROCEDURES ARE NOT ADEQUATE."

As explained below in detail, the Environmental Protection Division (EPD) did not undertake the required public participation activities for this draft permit. Therefore, EPD may not issue the final permit. 40 CFR ' 70.7(a)(1)(ii). Rather, EPD must re-notice the draft permit for a new public comment period that follows, at a minimum, the public participation processes specified in the law.

For example, 40 CFR ' 70.7(h)(2) states that the public notice will explain where the public can review all relevant supporting documents. EPD's public notice states that all relevant information is available at the Air Protection Branch in Suite 120. This may not be accurate. For example, relevant information may be located in an EPD regional office. In addition, information relevant to accidental releases under Clean Air Act ' 112(r) may be located at other agencies. EPD has stated intent to provide the public with a list of where all of the information is available. However, we are unaware that such information has been made available.

EPD has recently changed the public notice so that the public notice for this facility states that "[t]his permit will be enforceable by the Georgia EPD, the U.S. Environmental Protection Agency, and other persons as otherwise authorized by law." The inclusion of the "and other persons as otherwise authorized by law," is a small step in the right direction. However, this language seems excessively legalistic for a public notice. We would recommend just saying "and the public."

The public notice states that "[a]fter the comment period has expired, the EPD will consider all comments, make any necessary changes and issue the Title V operating permit." This statement is inaccurate. Specifically, the statement suggests that, while changes may be made, in the end, the permit will be issued. However, under certain circumstances, EPD is required to deny a Title V permit. 40 CFR ' 70.7(a). As such, this statement could be interpreted as an indication of EPD's predisposition to issue Title V permits regardless of whether the permit complies with the law. See *American Wildlands v. Forest Service*, CV 97-160-M-DWM (D.Mont. Apr. 16, 1999)(Denying government deference because of evidence of predisposition towards a predetermined outcome). Therefore, we suggest that EPD include in the public notice an additional statement that it will make a determination of whether to issue or deny the permit.

Response: The commenter correctly noted that the permit, when issued, would be enforceable by the public. EPD has determined that the language in the public notice meets the Public Notification requirements of 40 CFR 70.7(h)(2). EPD has not received any information to indicate that a Part 70 operating permit should be denied for this facility.

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Comment 2

A comment was made that "THE PERMIT IMPERMISSIBLY LIMITS ENFORCMENT TO "CITIZENS OF THE UNITED STATES."

Section 8.2.1. of the draft permit claims to limit enforcement to citizens of the United States. However, the Clean Air Act states that any person can take an enforcement action. 42 U.S.C. ' 7604(a). Therefore, the permit must be changed to state that any person can enforce this permit. Furthermore, the permit is misleading by including mention of the public's right to sue under a section entitled "EPA Authority." We recommend that EPD create a separate section, which discusses the public's right to sue under a heading such as "Public's Enforcement Authority."

Sierra Club has raised this issue in prior comments on other Title V proposed permits. Nevertheless, no changes have been made to the permit template. This may be an indication that EPD needs to establish or improve a system to capture and implement lessons learned. It may also be an indication that EPD does not have the ability to maintain a fully delegated Title V program.

Response: The language of Condition 8.2.1 was derived from 40 CFR ' 70.6(b)(1), which states that Part 70 permits "are enforceable by the Administrator and citizens under the Act." The language in Condition 8.2.1 of the permit had read, in part, "all terms and conditions contained herein shall be enforceable by the EPA and citizens of the United States." The phrase "of the United States" has been deleted from Condition 8.2.1 to reflect the exact language in the Act contained in the phrase, "are enforceable by the Administrator and citizens under the Act."

Comment 3

A comment was made that "THE PERMIT MUST REQUIRE THE PERMITTEE TO SUBMIT ALL MONITORING INFORMATION TO EPD."

40 CFR ' 70.6(a)(3)(iii)(A) and 42 U.S.C. ' 7661(c)(a) require that permits issued by state agencies include a requirement for submittal of reports of any required monitoring at least every 6 months. The permit does not contain any such requirement.

EPD may claim that condition 6.1.4 of the permit satisfies the requirements of ' 70.6(a)(3)(iii)(A). However, condition 6.1.4 requires reporting of excess emissions, exceedances and/or excursions. The reporting of these deviations is required by ' 70.6(a)(iii)(B). However, ' 70.6(a)(iii)(A) requires reporting of all monitoring. It is a cardinal rule of statutory and regulatory interpretation that a regulation should be interpreted in such a manner as to not render any provision of the regulation meaningless. However, EPD's claim that reporting of deviations constitutes reporting of any required monitoring renders ' 70.6(a)(iii)(A) meaningless as it would be redundant to ' 70.6(a)(iii)(B).

It is true that Condition 6.1.4b does require bi-annual reporting of total process operating time during each reporting period. While this certainly is a small step towards compliance with ' 70.6(a)(iii)(A), that subsection requires reporting of all monitoring. Total processing time is just one monitoring requirement. However, there are many other monitoring requirements that must be reported. For example, Condition 5.2.2 requires the permittee to maintain a log of maintenance checks. This is exactly the type of monitoring that ' 70.6(a)(iii)(A) requires to be reported at least bi-annually and that the Facility's permit does not require.

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Response: The section of the United States Code cited by the commenter requires that the Permittee submit, no less than every six months, the results of any required monitoring. 40 CFR 40 ' 70.6(a)(3)(iii) and Georgia Rule 391-3-1-.03(10)(d)1.(i), which incorporates the federal requirements by reference, require the submittal, at least every six months, of reports of any required monitoring. These citations do not require the submittal of copies of all monitoring data recorded by the Permittee; rather, they require submittal of reports on the results of this monitoring. In fact, in one of the Title V workshops organized by the EPA, the question was asked if sources were required to submit raw data on monitoring/testing as part of its monitoring report. The answer from the EPA was an emphatic "No."

Comment 4

A comment was made that "THE PERMIT CANNOT LIMIT CREDIBLE EVIDENCE FROM BEING USED IN AN ENFORCEMENT ACTION."

As emphasized by the United States Environmental Protection Agency's (EPA) Credible Evidence Rule, 62 FR 8314 (Feb. 24, 1997), the Clean Air Act (CAA) allows the public, EPD, EPA, and the regulated facility to rely upon any credible evidence to demonstrate violations of or compliance with the terms and conditions of a Title V operating permit. Specifically, EPA revised 40 CFR ' 51.212, 51.12. 52.30, 60.11 and 61.12 to "make clear that enforcement authorities can prosecute actions based exclusively on any credible evidence, without the need to rely on any data from a particular reference test." 62 FR at 8316. EPD must ensure that no permit purports to limit the use of credible evidence. Moreover, the permit should include standard language stating that all credible evidence may be used.

A. EPD Must Remove Language that Purports to Limit Credible Evidence.

EPD must ensure that its Title V permits contain no language that could be interpreted to limit credible evidence. For example, condition 4.1.3. in the permit states that "[t]he methods for the determination of compliance with emissions limits listed under Sections 3.2, 3.3 and 3.4 which pertains to the emission units listed in Section 3.1 are as follows:" One could read this provision to stand for the proposition that when a government agency or member of the public takes an enforcement action for a permittee violating its permit, the enforcer can only rely on information from the methods of determination listed in the permit. This position is directly contrary to the Clean Air Act requirements in CAA ' ' 113(a), 113(e)(1) and 40 CFR ' 51.212, 51.12. 52.30, 60.11 and 61.12 which allow anyone taking an enforcement action to rely on any credible evidence. Therefore, the aforementioned sentence in Section 4.1.3 should be stricken.

Another example of the permit's attempt to limit credible evidence is found in the second sentence of condition 8.17.1. This condition claims to limit usable evidence to information that is available to EPD. Of course, the public or EPA may obtain information about a facility from sources other EPD such as information from a "whistleblower" or from people that live near the facility. As such, it is inappropriate to limit credible evidence to exclude such information. Therefore, the aforementioned provision must be removed from the permit. Of course, the preferred option is to simply remove the sentence. A less desirable option is to re-write it to state that "EPD may determine . . ."

Similarly, Condition 6.1.3 of the permit, which states that "failures shall be determined through observation, data from any monitoring protocol, or by any other monitoring which is required by the permit," could be considered to limit the use of credible evidence. To correct the problem, this Condition should include an additional clause requiring reporting of any failure based on any credible evidence, credible evidence, as well as observation, data from monitoring protocols and other monitoring required by the permit.

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B. EPD Should Include Standard Language in the Permit that Explicitly States that Anyone Can Use Any Credible Evidence

The permit does not affirmatively state that any credible evidence may be used in an enforcement action. EPA supports the inclusion of credible evidence language in all Title V permits. As explained by the Acting Chief of US EPA's Air Programs branch:

It is the United States Environmental Protection Agency's position that the general language addressing the use of credible evidence is necessary to make it clear that despite any other language contained in the permit, credible evidence can be used to show compliance or noncompliance with applicable requirements. . . . [A] regulated entity could construe the language to mean that the methods for demonstrating compliance specified in the permit are the only methods admissible to demonstrate violation of the permit terms. It is important that Title V permits not lend themselves to this improper construction.

Letter from Cheryl L. Newton, Acting Chief, Air Programs Branch, EPA, to Robert F. Hodanbosi, Chief, Division of Air Pollution Control, Ohio Environmental Protection Agency, dated October 30, 1998. In fact, EPA apparently sent a letter in May 1998 specifically directing EPD to amend its SIP to include language clarifying that any credible evidence may be used. Nevertheless, while three years have elapsed since EPA's request, the permit does not contain the necessary language.

While anyone may rely on all credible evidence regardless of whether this condition appears in the permit, EPD should include credible evidence language in the permits and permit template to make the point clear. Specifically, EPA has recommended that the following language be included in all Title V permits:

Notwithstanding the conditions of this permit that state specific methods that may be used to assess compliance or noncompliance with applicable requirements, other credible evidence may be used to demonstrate compliance or noncompliance.

Letter from Stephen Rothblatt, Acting Director, Air and Radiation Division, US EPA, to Paul Deubenetzky, Indiana Department of Environmental Management, dated July 28, 1998. We request that EPD include this provision in the permit to clarify the availability of any credible evidence to demonstrate noncompliance with permit requirements.

Response: The prescribed performance test methods and procedures, which are incorporated in the Georgia Rules for Air Quality Control, contain clear provisions that, by prescribing such procedures, nothing would preclude the additional use of other credible evidence, either for compliance certifications or for establishing whether or not a source is in violation of any emissions limitation or standard. [See Rule 391-3-1.02(3)(a) and the referenced Procedures for Testing and Monitoring Sources of Air Pollutants at Section 1.3(g).] Even without this direct inclusion, the Rules themselves are cited in all permits issued by the Division.

Furthermore, the Division believes that adequate provisions for consideration of credible evidence have been included in Condition 8.17.1, which states, in part, that "Determination of whether acceptable operating and maintenance procedures are being used will be based on any information available to the Division which may include, but is not limited to, monitoring results, observations of the opacity or other characteristics of emissions, review of operating and maintenance procedures or records, and inspection or surveillance of the source."

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The Division has elected not to include any additional language beyond the Rules cited above because it is our belief that any attempt to clarify the rule or define credible evidence will generally produce an impression of limiting of the scope of the rule. This we do not wish to do. The Division believes that any challenge to the authority of the U.S. EPA, State of Georgia, or any citizen with standing to use any credible evidence would easily be turned away. On the other hand, if limiting language such as that offered in the referenced EPA text were to be used, arguments to use such statements to "whither away" at the general principle could and most probably would be made. For instance, petitioners might suggest that the statement was only meant to apply to stated test methods and not work practice or other parts of the applicable standards, including the general provisions to the rules. Therefore, for the benefit of the enforceability of the standards by using any credible evidence available, the permit need not and is not being modified.

Comment 5

A comment was made that "THE PERMIT MUST REQUIRE THE PERMITTEE TO REPORT ALL EXCEEDANCES, EXCURSIONS AND EXCESS EMISSIONS."

Condition 6.1.7. limits the exceedances, excursions and excess emissions that the facility must report. This needs to be removed because 40 C.F.R. ' 70.6(a)(3)(iii)(B) and (6)(i) mandates that the permit require the permittee to report all exceedances, excesses and excursions.

Response: The Division agrees that all exceedances, excursions and excesses be reported and therefore Condition 6.1.4 of the proposed permit states "The Permittee shall submit a written report containing any excess emissions, exceedances, and/or excursionsY" Condition 6.1.7, by listing explicitly what constitutes an excess emission, exceedance, and excursion, makes this requirement practically enforceable.

Comment 6

A comment was made that "THE PERMIT DOES NOT FULLY INCLUDE THE ACCIDENTAL RELEASE REQUIREMENTS."

Section 112(r) of the Clean Air Act sets out the requirements for stationary sources to avoid and address the accidental release of hazardous substances. 42 U.S.C. ' 7412(r). Section 112(r) is an applicable requirement under Title V and therefore must be included in Title V permits. 40 C.F.R. ' 70.2(Applicable Requirements (4)).

However, the permit does not contain this requirement in its entirety. While the Permit does state that "the Permittee shall submit a Risk Management Plan (RMP) in accordance with the 40 CFR Part 68, when and if, such requirement becomes applicable," Section 7.10.1, it fails to require that the permit comply with its Risk Management Plan or with any other requirement under Part 68 or Section 112(r). For example, 42 U.S.C. ' 7412(r)(7)(E) requires that the operator of a source subject to Part 68 operate its facility in compliance with Part 68. Therefore, EPD needs to completely incorporate Section 112(r) and Part 68 into Section 7.10 of the permit.

Response: As indicated in the text of the comment, EPD includes the 112(r) requirements in Condition 7.10.1 of Title V permits. EPD reviewed the language of Condition 7.10.1 for adequacy and modified this template condition. This Title V permit has been modified to reflect this change.

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Comment 7

A comment was made that "REQUIREMENTS WERE ALTERED FROM THE SIP PERMITS."

The Part 70 regulations mandate that all requirements in a facility's SIP permit be included in its Title V permit. Conditions 3.B and 3.C of Permit 2272-155-7209-0 are not in the Title V permit and should be. In addition, Conditions 6 and 9 of SIP permit 2273-313-0084-E-01-0 are not in the Title V permit and should be.

Response: Condition 3 of Permit 2272-155-7209-0 was originally added in the 1979 permit (as condition #1), based on three boilers burning #6 oil and natural gas. These boilers were not limited by fuel use on an annual basis; the permit was issued based on parameters of steam generation limits to restrict the SO₂ emissions from these boilers. Emissions reduction 'credits' by switching these boilers from #6 to #2 oil were erroneously used and incorporated into the permit revision in 1984. In addition, a hard cap on annual use of #2 oil (450,00 gallons) was placed on these boilers. The revised permit was based on the annual #2 fuel oil limit and the old steam limit should have been stricken as redundant, but was not removed. No changes were made to final permit.

Condition 6 of SIP Permit 2273-313-0084-E-01-0 was to ensure Permittee to perform routine maintenance on control equipment. However, Title V application indicated that Boiler Nos. 4, 5 and 6 (source codes BL04, BL05 and BL06) have air pollution control devices "multiclone" (source codes PC01, PC02 and PC03). Condition 6 of SIP permit 2273-313-0084-E-01-0 was incorporated into Draft Title V permit as Condition 5.2.2. Condition 9 of SIP permit 2273-313-0084-E-01-0 was to ensure that Permittee take all reasonable precautions with any operation, process, handling, transportation, or storage facilities to prevent fugitive emissions of air contaminants. Condition 9 of SIP permit 2273-313-0084-E-01-0 was incorporated into Draft Title V permit as Condition 8.22.1. No changes were made to final permit.

Comment 8

A comment was made that "ONE PERMIT MUST BE ISSUED FOR PLANTS 2, 4, AND 80 THAT INCLUDES THE REQUIREMENT FOR THE FACILITIES TO GO THROUGH NEW SOURCE REVIEW."

The draft permit acknowledges that "Plants # 2,4, and 80 are all one Part 70 source[.]" Draft Permit at 1. However, EPD states that it is going to issue three separate permits for "administrative purposes." Id. EPD does not have the authority to issue three separate permits for one Title V facility. Therefore, EPD needs to re-notice this draft permit and issue one permit for all three plants. This combined permit should require that all three plants go through New Source Review.

Response: The Division disagrees with the commenter's assertion that one permit must be issued for Shaw Industries Inc., Plant Nos. 2, 4 and 80 located in Dalton, Georgia. While it is true that Part 70 does not explicitly state that more than one Title V permit can be issued for a single Title V source, there are federal documents that indicate that this was the intent of Congress and the U.S. EPA. Section 502, paragraph (c) of the Clean Air Act Amendment of 1990 states: "a single permit may be issued for a facility with multiple sources." If Congress intended to mandate that a Title V site to be issued only one permit, the word "must" would have been used instead of "may". We also note that the EPA guidance document dated August 2, 1996, with the title: "Major Source Determination for Military Installations under the Air Toxics, New Source Review, and Title V Operating Permit Programs of the Clean Air Act (Act)", gave permitting authorities the discretion, with regard to military bases, to issue more than one Title V permit to each major source at that installation, so long as the collection of permits assures that all applicable requirements would be met that otherwise would have been required under a single permit for each major source. While it is true that this guidance applies specifically to military installations, the Division

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believes that the underlying principle extends to any major Part 70 site that is composed of functionally distinct operating units or facilities. Furthermore, EPD has verified with U.S. EPA that it is acceptable to issue multiple Title V permits to a single Title V source.

In regard to the comment that the facility needs to go through PSD review, page 4 of the Title V Application Review details the history of this site as it relates to the PSD regulations. EPD believes that these regulations have been applied correctly.

Comment 8

A comment was made that "VISUAL OPACITY INSPECTION IS INSUFFICIENT."

Condition 5.2.1 requires visual inspections for opacity. This primitive and sporadic monitoring method is not adequate to assure compliance. Condition 5.2.1 should be changed to require a continuous opacity monitor systems (COMS).

Response: The Division affirms its decision to require daily visible emissions (VE) checks for these boilers to assess compliance with the PM10 emission and opacity standards. The Division maintains that daily VE checks for the coal fired boilers in conjunction with the APCD inspection required by Condition 5.2.2 yield reliable data from the relevant time period that is representative of the boiler's compliance with the PM10 emission and opacity standards. No changes were made to final permit. The Division has determined that the prescribed monitoring contained in conditions 5.2.1 and 5.2.2 is sufficient for providing a reasonable assurance of compliance with the Georgia Rule (d) limits.

Comments from Shaw Industries Inc., Plant No. 4

Condition 3.2.2 restricts boilers BL04, BL05, and BL06 to burning no more than 16,320 tons of coal during any twelve-month period. Together with Condition 3.2.4 that restricts the sulfur content of the coal to no more than 0.8%, these limits are for PSD avoidance. As written in the original SIP permit, the limit on coal burning was weighted based on the actual sulfur content - i.e. $0.8/S \times \text{Tons Coal}$, where S = twelve consecutive month average percentage of sulfur in the coal. Shaw proposes that Condition 3.2.2 be revised to reinstate this fuel flexibility and provide an incentive for burning lower sulfur fuels, or be stricken entirely and replaced with the following language.

"The permittee shall not discharge or cause the discharge into the atmosphere from coal boilers (source codes BL04, BL05, BL06), SO₂ emissions in amount equal to or greater than 250 tons during any twelve consecutive months commencing with the twelve consecutive month period ending March 31, 2002. SO₂ emissions shall be calculated in accordance with Condition 6.x.x."

(The Condition 6.x.x above refers to a new condition that would be added in conjunction with the above referenced change to Condition 3.2.2, and would prescribe the method for calculating SO₂ emissions from coal with variable sulfur content). If the Division agrees to the changes to Condition 3.2.2, then Conditions 6.1.7(iv), and 6.2.7a will also need to be amended.

Condition 3.2.4 prohibits the burning of any coal in the coal boilers with sulfur content greater than 0.8%, by weight. This represents a change from the maximum sulfur content of 1.0% that was allowable in the SIP permit for these boilers (2272-155-8840, amended 04/03/87). Shaw requests that the maximum sulfur content of the coal be reinstated as 1.0%, to allow for the inherent variability in the sulfur content of coal, and to avoid having to report a permit exceedance for a single coal sample that might spike above 0.8%. It is in our best interest to burn low sulfur coal in order to maximize the Btu input available from coal, but we wish to avoid unnecessarily reporting permit exceedances where we have not violated the

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underlying emissions limit. We would also ask that the annual average sulfur content of 1.0% either be reinstated to be consistent with the existing SIP permit, or be stricken entirely and refer to the 250 tons SO₂. Making this change does not increase the SO₂ emissions from these boilers above their PSD avoidance limit, nor would it be in excess of Rule (g)2. As stated in the previous bullet item, Shaw is requesting that the SO₂ PSD avoidance limit be explicitly based on the 250 tons SO₂ limit and not the amount of coal burned. Therefore, if the 2-month average sulfur percentage increases then the amount of allowable tons of coal will be reduced, whereas more tons can be burned if lower sulfur coal is burned. If the Division agrees to this change, then Conditions 6.1.7(i) will also have to be amended.

On September 28, 2001, the facility proposed permit conditions for the coal fired boilers that limits boilers SO₂ emissions below 250 tons, and adding a formula for calculating SO₂ emissions based on 1% sulfur content of coal in the loads received so long as the average remains at or below 0.8%. The facility requested to incorporate Condition Nos. 5 and 7 into final permit.

Response: In the draft permit, the potential of SO₂ emissions from coal fired boilers BL04, BL05 and BL06 is limited below 250 tpy (to avoid PSD review) by limiting the maximum sulfur content to 0.80% and by limiting the amount of coal burned to 16,320 tons per year commencing with the twelve consecutive month period ending March 31, 2002.

Potential SO₂ emissions = [(tons of coal)(emission factor)(%S)/(ton/2000 lb)]

Potential SO₂ emissions = [(16,320 t/yr)(0.8) (38 lb/t)/(ton/2000 lb)] = 248.1 tpy

The facility is aware that the potential SO₂ emissions must be limited below 250 tpy from the coal-fired boilers. And they are requesting more flexibility to comply with this requirement. EPD is open to concepts that allow the company more flexibility while still accomplishing the regulatory objective. However, in this case, Shaw's proposal to use "as received" sulfur reports to verify compliance with an "as burned" sulfur dioxide limit does not satisfy the requirement for periodic monitoring. Therefore, no changes were made to the final permit based on this comment except that Shaw was given three additional months (from March 31 until June 30) to get into compliance with this limit.

Condition No. 3.2.8, restricting fuel usage in all process fuel burning equipment (CD03, CD04, DR01, LC02, and LC03) to only natural gas, is proposed to be amended to allow for the use of propane as a backup fuel. All of this equipment is currently capable of burning propane; amending this Condition will not significantly change the PTE or actual emissions from the affected units.

Response: Based on following calculation, allowing facility to use propane as a backup fuel significantly change the potential to emit of NO_x or actual emissions from the affected units.

Note: Emissions factor for natural gas has been changed from 140 lb. NO_x/MMft³ natural gas to 100 lb/MMBtu.

Potential NO_x Emissions from natural gas for DR01, CD03, CD04, LC02 and LC03

Maximum rated input in Btu/hr=[14+ 16+ 29 + 42.5 + 41] MMBtu/hr = 142.5 MMBtu/hr

Heating value of fuel (Btu/ft³), natural gas = 1000 Btu/ ft³

Emission factor (lb/106 ft³) = 100 lb. NO_x/ MMft³ natural gas

Maximum operating time (hr/day) = 24 hours

142.5 MM Btu/hr/1000 Btu/ft³ = 142,500 ft³/hr

TITLE V APPLICATION REVIEW

Maximum natural gas usage

$$(142,500 \text{ ft}^3/\text{hr})(8760 \text{ hrs}/\text{year}) = 1,248,300,000 \text{ ft}^3/\text{year}$$

Potential To Emit (PTE) of NO_x

$$(1,248.3 \text{ MMCF}/\text{year})(100 \text{ lb}/\text{MMCF}) = 124,830 \text{ lb}/\text{year of NO}_x$$

$$(124,830 \text{ lb}/\text{year})/ 1 \text{ ton}/2000 \text{ lbs} = 63 \text{ tpy of NO}_x \text{ emission.}$$

Potential NO_x Emissions from propane for DR01, CD03, CD04, LC02 and LC03

Propane has a higher NO_x emission factor compared to natural gas, therefore, comparing the firing of natural gas and propane, the worst case is firing 100% propane for all fuel burning equipments, so NO_x potential for propane, using AP-42 emission factor, NO_x emission is 19 lb/1000 gal, and propane heating value is 91,500 Btu/gal.

Max. rated input for DR01, CD03, CD04, LC02 and LC03 (Btu/hr)= 142.5 MMBtu/hr.

$$142.5 \text{ MMBtu}/\text{hr}/91,500 \text{ Btu}/\text{gal}=1,558 \text{ gal}/\text{hr, for 8760 hours, propane usage is 13,642,623 gal}/\text{yr.}$$

$$13,642,623 \text{ gal}/\text{yr} * 19 \text{ lb}/1000 \text{ gal (1 ton / 2000 lb)} = 130 \text{ tpy of NO}_x \text{ emission.}$$

Potential NO_x Emissions from Natural gas fired Boilers (source codes BL07, and BL08)

Natural gas

Potential NO_x Emissions

$$\text{Maximum rated input for two boilers (Btu/hr)} = [59 + 59] \text{ MMBtu}/\text{hr} = 118 \text{ MMBtu}/\text{hr}$$

$$\text{Heating value of fuel (Btu}/\text{ft}^3), \text{ natural gas} = 1000 \text{ Btu}/\text{ft}^3$$

$$\text{Emission factor (lb}/106 \text{ ft}^3) = 100 \text{ lb. NO}_x/\text{MMft}^3 \text{ natural gas}$$

$$\text{Maximum operating time (hr}/\text{day}) = 24 \text{ hours}$$

$$118 \text{ MM Btu}/\text{hr}/1000 \text{ Btu}/\text{ft}^3 = 118,000 \text{ ft}^3/\text{hr}$$

Maximum natural gas usage

$$(118,000 \text{ ft}^3/\text{hr})(8760 \text{ hrs}/\text{year}) = 1,033,680,000 \text{ ft}^3/\text{year}$$

Potential To Emit (PTE) of NO_x

$$(1,033 \text{ MMCF}/\text{year})(100 \text{ lb}/\text{MMCF}) = 103,300 \text{ lb}/\text{year of NO}_x$$

$$(103,300 \text{ lb}/\text{year})/ 1 \text{ ton}/2000 \text{ lbs} = 52 \text{ tons per year.}$$

Total NO_x emissions from facility

Prior to proposal

$$[\text{PTE from (natural gas for DR01, CD03, CD04, LC02 and LC03)+ Boilers burning coal+ Boilers burning No. 2 fuel oil + Boilers burning natural gas}] = (63 + 74 + 4.5 + 52) \text{ tpy} = 194 \text{ tpy}$$

TITLE V APPLICATION REVIEW

After proposal

[PTE from (propane for DR01, CD03, CD04, LC02 and LC03)+ Boilers burning coal+ Boilers burning No. 2 fuel oil + Boilers burning natural gas)]

$(130 + 74 + 4.5 + 52) \text{ tpy} = 261 \text{ tpy}$, $261 \text{ tpy} - 194 \text{ tpy} = 67 \text{ tpy}$ increase in emissions.

Plants 2, 4, and 80 are a major source under PSD because they have potential to emit (PTE) of PSD regulated pollutants over 250 tpy (they are not one of the 28 named source categories under PSD) and increase in emissions as result of adding propane as a backup fuel for DR01, CD03, CD04, LC02 and LC03 is more than 40 tpy, PSD review requires. However, on Friday September 28, 2001, the facility proposed a site wide limit of 4,000,000 gallons of propane, which would results in 38 tons NOx PTE increase for propane.

Max. rated input for DR01, CD03, CD04, LC02 and LC03 (Btu/hr)= 142.5 MMBtu/hr.

Proposed propane usage= 4,000,000 gal/yr.

$[(4,000,000 \text{ gal/yr}) * (19 \text{ lb/1000 gal}) * (1 \text{ ton} / 2000 \text{ lb})] = 38 \text{ tpy}$ of NOx emission

Since adding propane as a backup fuel for DR01, CD03, CD04, LC02 and LC03 results in 38 tpy of NOx emission increase, the facility must submit an Air Quality Application for TV modification after the permit is issued. No change was made to final TV permit.