

Facility Name: **CITGO Asphalt Refining Company**

City: Savannah

County: Chatham

AIRS #: 04-13-051-00012

Application #: TV-14951

Date SIP Application Received: January 13, 2004

Date Title V Application Received: January 13, 2004

Permit No: 2911-051-0012-V-01-2

| Program | Review Engineers | Review Managers |
|----------------|-------------------------|------------------------|
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| TOXICS | N/A | N/A |

Introduction

This narrative is being provided to assist the reader in understanding the content of the referenced SIP permit to construct and draft operating permit amendment. 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 issued pursuant to: (1) Sections 391-3-1-.03(1) and 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 following narrative is designed to accompany the draft permit and is presented in the same general order as the permit. 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 comment period and EPA review process will be described in an addendum to this narrative.

I. Facility Description**A. Existing Permits**

Table 1 below lists the current Title V permit, and all administrative amendments, minor and significant modifications to that permit, and 502(b)(10) attachments. Comments are listed in Table 2 below.

Table 1: Current Title V Permit and Amendments

| Permit/Amendment Number | Date of Issuance | Comments | |
|-------------------------|-------------------|----------|----|
| | | Yes | No |
| 2911-051-0012-V-01-0 | July 13, 1999 | X | |
| 2911-051-0012-V-01-1 | February 17, 2003 | X | |

Table 2: Comments on Specific Permits

| Permit Number | Comments |
|----------------------|--|
| 2911-051-0012-V-01-0 | Initial TV Permit |
| 2911-051-0012-V-01-1 | TV Permit Amendment for Distillation Tower D001 Replacement Project. |

B. Regulatory Status**1. PSD/NSR/RACT**

CITGO Asphalt Refining Company (hereinafter facility) is located in an attainment area. It is one of the 28 named source categories under PSD of CAA and is a major source under PSD/NSR regulations, but has never undergone a PSD review. The facility modified No. 2 Unit Heater (ID No. F002) in 1984. The facility received a PSD avoidance permit, through a PSD netting exercise. The sulfur dioxide (SO₂) and nitrogen oxides (NO_x) emissions from Heater F002 were capped by limiting the residual oil usage of Heater F002 and the sulfur content in the residual oil; the limits are now contained in Conditions 3.2.1 and 3.2.2 of TV Permit No. 2911-051-0012-V-01-0. The facility submitted Application No. TV-13891 for the replacement of crude distillation tower No. 1 (ID No. D001) in 2002. The facility received a PSD avoidance permit (TV significant modification) by accepting facility-wide emission limits of NO_x, SO₂, volatile organic compounds (VOC), and reduced sulfur (H₂S). The emission limits are contained in Conditions 2.1.2 – 2.1.5 of TV Permit Amendment No. 2911-051-0012-V-01-1.

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 | ✓ | | | ✓ |
| PM ₁₀ | ✓ | | | ✓ |
| SO ₂ | ✓ | ✓ | | |
| VOC | ✓ | ✓ | | |
| NO _x | ✓ | ✓ | | |
| CO | ✓ | | | ✓ |
| TRS | ✓ | ✓ | | |
| H ₂ S | ✓ | ✓ | | |
| Individual HAP | ✓ | | ✓ | |
| Total HAPs | ✓ | | ✓ | |

II. Proposed Modification

A. Description of Modification

CITGO is proposing to replace crude oil distillation tower No. 2 (ID No. D002). The expected maximum capacity of the new distillation column would increase from the current 14,000 barrels per day (bpd) to 17,050 bpd, thus increasing the facility's total refining capacity to 34,100 bpd. Note that the permit application indicates that this expected maximum capacity of 17,050 bpd is 10% more than the rated capacity of the existing distillation column (ID No. D002), which is 15,500 bpd. This is a 3,050 bpd or 21.8% increase in capacity over the existing unit (ID No. D002).

The proposed distillation column will operate in a similar manner to the existing unit. The unit will contain approximately the same number of fractionating trays (31), but will be equipped with a more efficient fractionation packed bed. As part of the replacement, CITGO will also install six new process heat exchangers and a new "re-boiler" exchanger to aid in system operation.

B. Emissions Change

Table 4: Emissions Change Due to Modification

| Pollutant | Is the Pollutant Emitted? | Net Actual Emissions Increase (Decrease) (tpy) | Net Potential Emissions Increase (Decrease) (tpy) |
|------------------|----------------------------------|---|--|
| PM | Yes | 11.2 | 11.2 |
| PM ₁₀ | Yes | 8.02 | 8.02 |
| SO ₂ | Yes | 39.9 | 39.9 |
| VOC | Yes | 39.9 | 39.9 |
| NO _x | Yes | 39.9 | 39.9 |
| CO | Yes | 47.9 | 47.9 |
| TRS | Yes | 9.90 | 9.90 |
| H ₂ S | Yes | 9.90 | 9.90 |
| Individual HAP | Yes | 0 | 0 |
| Total HAPs | Yes | 0 | 0 |

C. PSD/NSR Applicability

The regulations for Prevention of Significant Air Quality Deterioration (PSD) in 40 CFR 52.21 require that any new major source or modification of an existing major source be reviewed to determine the potential emissions of all pollutants subject to regulations under the Clean Air Act. The PSD review requirements apply for any modification of a major stationary source which results in a significant net emission increase of any regulated pollutant.

The installation of the new distillation column (ID No. D002) will cause an increase in total facility rated production from 31,050 bpd to 34,100 bpd. Pollutant emissions from the facility will therefore increase accordingly. The facility proposed various emission limits for the modification described in

Application No. TV-14951, in order to avoid a PSD review. Details of the PSD avoidance aspects of this modification (replacement of Distillation Tower D002) are discussed in Section III.A of this narrative.

III. Facility Wide Requirements

A. Emission and Operating Caps:

Under PSD regulations, if the proposed emission increase at a major source is by itself (i.e., without considering any decreases) less than “significant”, it does not require consideration of previous contemporaneous small (i.e. less than significant) emission increases at the source and the source can avoid PSD review. However, a deliberate decision to split an otherwise “significant” project into two or more smaller projects to avoid PSD review would be viewed as circumvention and would subject the entire project to enforcement action if construction on any of the small projects commences without a valid PSD permit. It is therefore important to consider that the facility submitted Application No. TV-13973 dated July 12, 2002, for the replacement of Distillation Tower D001; Permit Amendment No. 2911-051-0012-V-01-1 was issued on February 17, 2003, as a result. Then, eighteen months after the submittal of the D001 application, the facility submitted this application (No. TV-14951 dated January 12, 2004) for the replacement of Distillation Tower D002. A question regarding whether the two replacement projects should be considered as one single project was raised.

The facility submitted a letter on June 1, 2004, to clarify why the replacement projects for Distillation Tower D002 and Distillation Tower D001 should not be considered as a single project under PSD. First, Distillation Towers D001 and D002 are independent process units designed to operate either concurrently or individually. This operating strategy is part of the original plant design to provide operational flexibility, to optimize maintenance planning, to respond to economic or emergency situations, and for other reasons. This separate process design allows operations to turn down the processes or run both units to respond to changes or delays in crude supply, product storage/shipment, market demand, and so on. Second, the Tower D002 replacement project is a separate business decision, with a separate funding justification, and it will be a separate construction project. According to CITGO, the decision to evaluate the replacement of Tower D001 began in Year 2001 due to its poorer operation and high maintenance costs, compared to Tower D002, and to provide process improvements that would enhance unit efficiency and reliability. The Tower D001 replacement project proceeded under its own design, justification, and authorization for expenditure (AFE). The Tower D002 project will be a totally independent event with construction taking place at least two years later, with a separate engineering, design, and AFE. In fact, CITGO management has not yet approved the final Tower D002 project AFE. If approved by CITGO management, operation of the modified Tower D002 will not occur until at least February or March, 2005. As demonstrated by the separate designs, schedules, AFE’s, and so on, the two projects are each independently economically viable and are not co-dependent. EPD agrees with the facility’s statements and is processing the Tower D002 replacement project as a separate modification application.

The facility provided the last two years’ (Jan 02 – Dec 03) records of actual emissions of particulate matter (PM/PM10), NO_x, carbon monoxide (CO), SO₂, VOC, and H₂S, and proposed PSD avoidance emission limits for NO_x, SO₂, VOC, and H₂S in Application No. TV-14951. After several phone conversations with Mr. Frank White (Environmental Manager) and Steven Hawkins (consultant), it is confirmed that the data provided by the facility was not correct because the facility used outdated AP-42 emission factors to calculate the last two years’ actual emissions. The updated information and proposed PSD avoidance emission limits are listed in the following table. Detailed

calculations and a discussion follow the table. Note that the potential emission for various pollutants are calculated based upon different worst-case scenarios.

Table 5. Summary of the PSD Avoidance Determination

| Pollutant | Past-two-year Actual Annual Emissions (tpy) | Potential Emissions (tpy) | Old PSD Avoidance Limits (tpy) ¹ | New PSD Avoidance Limits (tpy) | Net Emission Increase (tpy) | PSD Significant Increase Level (tpy) |
|------------------|---|---------------------------|---|--------------------------------|-----------------------------|--------------------------------------|
| CO | 33.3 | 81.2 | -- | N/A | 47.9 | 100 |
| SO ₂ | 152.5 | 2,480 | 128.9 | 192.4 | 39.9 | 40 |
| NO _x | 59.4 | 361 | 110.6 | 99.3 | 39.9 | 40 |
| PM/PM10 | 6.87 / 4.88 | 65.7 / 46.6 | -- | N/A | < 25 / 15 | 25 / 15 |
| VOC | 122.0 | ND ² | 149.5 | 161.9 | 39.9 | 40 |
| H ₂ S | 21.2 | ND | 38.7 | 31.1 | 9.9 | 10 |

¹ Old PSD Avoidance Limits refer to the emission limits contained in Permit Conditions 2.1.2-2.1.5 of Permit Amendment No. 2911-051-0012-V-01-1.

² Not Determined.

The facility provided monthly fuel usage consumption records for the period from January 2002 to December 2003. The facility-wide average annual natural gas consumption rate for that period was 744.40 MM (million) cubic feet and the average annual No. 6 fuel oil consumption rate was 808,200 gallons.

Emissions of CO, SO₂, NO_x, and PM/PM10 are generated from the combustion of natural gas and No. 6 fuel oil in the boilers (ID Nos. B004 and B005) and the heaters (ID Nos. F001 and F002). The majority of VOC and H₂S emissions come from the process vent/condenser (ID No. REF1), naphtha marine loading, truck loading, and process tanks. The combustion of natural gas and No. 6 fuel oil also generates a small amount of VOC emissions. AP-42 emission factors are used to calculate emissions of all criteria pollutants (CO, SO₂, NO_x, PM/PM10, and VOC) from combustion devices.

Capacity of Boiler B004 = 52.83 MM Btu/hr
 Capacity of Boiler B005 = 59.40 MM Btu/hr
 Capacity of Heater F001 = 56.40 MM Btu/hr
 Capacity of Heater F002 = 56.40 MM Btu/hr
 Heat Content of Natural Gas = 0.00102 MM Btu/ft³
 Heat Content of Residual Fuel Oil = 0.150 MM Btu/gal

Carbon Monoxide (CO) Emissions

Emission Factor (natural gas, Table 1.4-1) = 84 lbs/10⁶ scf (0.0824 lb/MM Btu)
 Emission Factor (No. 6 fuel oil, Table 1.3-1) = 5 lbs/10³ gal (0.0333 lb/MM Btu)

Average, Actual, Annual CO Emissions During Years 2002 and 2003
 = [(84 lbs / 10⁶ scf) * (744.40 * 10⁶ ft³ / yr) + (5 lbs / 10³ gal) * (808,200 gallons / yr)] *
 (1 ton / 2,000 lbs)
 = 33.3 tpy CO

The worst case scenario when most CO emissions occur is when all fuel burning equipment fires natural gas 8,760 hours per year.

PTE of CO from CITGO

$$= [(52.83 \text{ MM Btu / hr }) + (59.40 \text{ MM Btu / hr }) + (56.40 \text{ MM Btu / hr }) + (56.40 \text{ MM Btu / hr })] * (1 \text{ ft}^3 / 0.00102 \text{ MM Btu }) * (84 \text{ lbs / } 10^6 \text{ scf }) * (8,760 \text{ hrs / yr }) * (1 \text{ ton / } 2,000 \text{ lbs })$$

$$= 81.2 \text{ tpy CO}$$

Since the difference (47.9 tpy) between the potential to emit (PTE) and the past-two-year annual actual emissions is below the PSD significant increase level for CO (100 tpy), **the facility is not required to have a CO limit to avoid a PSD review.**

Sulfur Dioxide (SO₂) Emissions

| | |
|---|----------------------|
| Emission Factor (natural gas, Table 1.4-2) = 0.6 lb/10 ⁶ scf | (0.000588 lb/MM Btu) |
| No. 6 Fuel Oil Sulfur Content Permit Limit = 2.4 percent | |
| Emission Factor (No. 6 fuel oil, Table 1.3-1) | |
| = 157 * 2.4 lbs/10 ³ gal = 376.8 lbs/10 ³ gal | (2.512 lbs/MM Btu) |

Average, Actual, Annual SO₂ Emissions During Years 2002 and 2003

$$= [(0.6 \text{ lbs / } 10^6 \text{ scf }) * (744.40 * 10^6 \text{ ft}^3 / \text{yr}) + (376.8 \text{ lbs / } 10^3 \text{ gal }) * (808,200 \text{ gallons / yr })] * (1 \text{ ton / } 2,000 \text{ lbs })$$

$$= 152.5 \text{ tpy SO}_2$$

The worst case scenario when most SO₂ emissions occur is when all fuel burning equipment fires No. 6 fuel oil 8,760 hours per year.

PTE of SO₂ from CITGO

$$= [(52.83 \text{ MM Btu / hr }) + (59.40 \text{ MM Btu / hr }) + (56.40 \text{ MM Btu / hr }) + (56.40 \text{ MM Btu / hr })] * (1 \text{ gal / } 0.150 \text{ MM Btu }) * (376.8 \text{ lbs / } 10^3 \text{ gal }) * (8,760 \text{ hrs / yr }) * (1 \text{ ton / } 2,000 \text{ lbs })$$

$$= 2,480 \text{ tpy SO}_2$$

Although the average annual actual SO₂ emissions during Years 2002 and 2003 (152.5 tpy) exceeds the SO₂ emission cap (128.9 tpy) that is contained in Permit Condition 2.1.2 of Permit Amendment No. 2911-051-0012-V-01-1, the facility did not violate any permit limit. Permit Amendment No. 2911-051-0012-V-01-1 did not become effective until April 16, 2003. The past-two-year actual emissions are based on records for the period from January 2002 to December 2003. Considering the period after Permit Amendment No. 2911-051-0012-V-01-1 became effective, the facility consumed 524,400 gallons of No. 6 fuel oil, from May 2003 to December 2003, that resulted in 98.8 tons per year of SO₂ emissions (SO₂ emissions from firing natural gas is negligible). Therefore, the facility complied with the PSD avoidance limit contained in Condition 2.1.2 of Permit Amendment No. 2911-051-0012-V-01-1. Therefore, EPD agrees with the facility that the new SO₂ emission limit should be 192.4 tpy (152.5 + 39.9 tpy).

If Boilers B004/B005 and Heaters F001/F002 fire natural gas year round, the maximum SO₂ emissions from Boilers B004/B005 and Heaters F001 and F002 will be 0.580 tons per year.

$$[(52.83 \text{ MM Btu / hr }) + (59.40 \text{ MM Btu / hr }) + (56.40 \text{ MM Btu / hr }) + (56.40 \text{ MM Btu / hr })] * (1 \text{ ft}^3 / 0.00102 \text{ MM Btu }) * (0.6 \text{ lb} / 10^6 \text{ scf }) * (8,760 \text{ hrs / yr }) * (1 \text{ ton / 2,000 lbs }) = 0.580 \text{ tpy SO}_2$$

Thus, the facility is allowed by revised Condition 2.1.2 to have a 1,018,000-gallon facility-wide residual fuel consumption limit in order to avoid PSD review.

$$192.4 \text{ tpy SO}_2 - 0.580 \text{ tpy SO}_2 = 191.8 \text{ tpy SO}_2$$

$$(191.8 \text{ tons SO}_2 / \text{yr}) * (2000 \text{ lbs / ton }) * (10^3 \text{ gal / 376.8 lbs SO}_2) = 1,018,000 \text{ gallons No. 6 fuel oil / yr}$$

Nitrogen Oxides (NOx) Emissions

| | |
|--|--------------------|
| Emission Factor (natural gas, Table 1.4-1) = 100 lbs/10 ⁶ scf | (0.0980 lb/MM Btu) |
| Emission Factor (No. 6 fuel oil, Table 1.3-1) = 55 lbs/10 ³ gal | (0.367 lb/MM Btu) |

Average, Actual, Annual NOx Emissions During Years 2002 and 2003

$$= [(100 \text{ lbs / 10}^6 \text{ scf }) * (744.40 * 10^6 \text{ ft}^3 / \text{yr}) + (55 \text{ lbs / 10}^3 \text{ gal }) * (808,200 \text{ gallons / yr })] * (1 \text{ ton / 2,000 lbs }) = 59.4 \text{ tpy NOx}$$

The worst case scenario when most NOx emissions occur is when all fuel burning equipment fires No. 6 fuel oil 8,760 hours per year.

PTE of NOx from CITGO

$$= [(52.83 \text{ MM Btu / hr }) + (59.40 \text{ MM Btu / hr }) + (56.40 \text{ MM Btu / hr }) + (56.40 \text{ MM Btu / hr })] * (1 \text{ gal / 0.150 MM Btu }) * (55 \text{ lbs / 10}^3 \text{ gal }) * (8,760 \text{ hrs / yr }) * (1 \text{ ton / 2,000 lbs }) = 361 \text{ tpy NOx}$$

$$59.4 \text{ tpy} + 39.9 \text{ tpy} = 99.3 \text{ tpy NOx allowable for avoiding PSD review}$$

Since the difference between the potential to emit (PTE) and the past-two-year annual actual emissions is above the PSD significant increase level for NOx (40 tpy), the facility is required to have a NOx limit (99.3 tpy) to avoid a PSD review. Although the facility-wide annual No. 6 fuel oil consumption is limited at 1,018,000 gallons, PTE for NOx from Boilers B004/B005 and Heaters F001/F002 is still above the required PSD avoidance limit (99.3 tpy).

NOx emissions from firing 1,018,000 gallons per yr of No. 6 fuel oil

$$= (55 \text{ lbs / 10}^3 \text{ gal }) * (1,018,000 \text{ gallons / yr }) * (1 \text{ ton / 2,000 lbs }) = 28.0 \text{ tpy NOx}$$

$$\begin{aligned} & \text{Average operating hours per year per boiler/heater resulting from No. 6 fuel oil consumption limit} \\ & = (1,018,000 \text{ gal / yr}) * (0.150 \text{ MM Btu / gal}) / [(52.83 \text{ MM Btu / hr}) + (59.40 \text{ MM Btu / hr}) + \\ & \quad (56.40 \text{ MM Btu / hr}) + (56.40 \text{ MM Btu / hr})] \\ & = 679 \text{ hours / year} \end{aligned}$$

The Maximum Operating hours per year that each boiler/heater would fire on natural gas for the rest of the year (if firing No. 6 fuel oil)

$$\begin{aligned} & = 8,760 \text{ hrs / yr} - 679 \text{ hrs / yr} \\ & = 8,081 \text{ hrs / yr} \end{aligned}$$

NOx emissions from firing natural gas for the rest of the year (if firing No. 6 fuel oil)

$$\begin{aligned} & = [(52.83 \text{ MM Btu / hr}) + (59.40 \text{ MM Btu / hr}) + (56.40 \text{ MM Btu / hr}) + (56.40 \text{ MM Btu / hr})] * \\ & \quad (1 \text{ ft}^3 / 0.00102 \text{ MM Btu}) * (100 \text{ lb}/10^6 \text{ scf}) * (8,081 \text{ hrs / yr}) * (1 \text{ ton} / 2,000 \text{ lbs}) \\ & = 89.1 \text{ tpy NOx} \end{aligned}$$

PTE of NOx with the No. 6 fuel oil consumption limit

$$\begin{aligned} & = 28.0 + 89.1 \\ & = 117.1 \text{ tpy NOx} > 99.3 \text{ tpy NOx} \end{aligned}$$

Thus, **Condition 2.1.3 limits the facility-wide NOx emission rate to 99.3 tons per year in order to avoid a PSD review.**

Particulate Matter (PM/PM10) Emissions

| | | |
|--|-------------------------------|---------------------|
| Emission Factor (natural gas, Table 1.4-2) | = 7.6 lbs/10 ⁶ scf | (0.00745 lb/MM Btu) |
| Emission Factor (No. 6 fuel oil, Table 1.3-1) | = 10 lbs/10 ³ gal | (0.0667 lb/MM Btu) |
| Cumulative Mass % of Particulate Matter with a size less than 10 μm (Table 1.3-4) = 71 percent | | |

Average, Actual, Annual PM Emissions During Years 2002 and 2003

$$\begin{aligned} & = [(7.6 \text{ lbs} / 10^6 \text{ scf}) * (744.40 * 10^6 \text{ ft}^3 / \text{yr}) + (10 \text{ lbs} / 10^3 \text{ gal}) * (808,200 \text{ gallons} / \text{yr})] * \\ & \quad (1 \text{ ton} / 2,000 \text{ lbs}) \\ & = 6.87 \text{ tpy PM} \end{aligned}$$

Assuming that the exhaust from the combustion of natural gas has the same particulate distribution characterization as the exhaust from the combustion of No. 6 fuel oil,

Average, Actual, and Annual PM10 Emissions During Years 2002 and 2003

$$\begin{aligned} & = (6.87 \text{ tpy}) * (71\%) \\ & = 4.88 \text{ tpy PM10} \end{aligned}$$

The worst case scenario when most PM/PM10 emissions occur is when all fuel burning equipment fires No. 6 fuel oil 8,760 hours per year.

PTE of PM from CITGO

$$\begin{aligned} & = [(52.83 \text{ MM Btu / hr}) + (59.40 \text{ MM Btu / hr}) + (56.40 \text{ MM Btu / hr}) + (56.40 \text{ MM Btu / hr})] * \\ & \quad (1 \text{ gal} / 0.150 \text{ MM Btu}) * (10 \text{ lbs} / 10^3 \text{ gal}) * (8,760 \text{ hrs / yr}) * (1 \text{ ton} / 2,000 \text{ lbs}) \\ & = 65.7 \text{ tpy PM} \end{aligned}$$

$$\begin{aligned} & \text{PTE of PM}_{10} \text{ from CITGO} \\ & = (65.7 \text{ tpy}) * (71\%) \\ & = 46.6 \text{ tpy PM}_{10} \end{aligned}$$

$$6.87 \text{ tpy} + 24.9 \text{ tpy} = 31.77 \text{ tpy PM allowable for avoiding PSD review}$$

$$4.88 \text{ tpy} + 14.9 \text{ tpy} = 19.78 \text{ tpy PM}_{10} \text{ allowable for avoiding PSD review}$$

Since the difference between the potential to emit (PTE) and the past-two-year annual actual emissions is above the PSD significant increase levels for PM/PM₁₀ (25 tpy/15 tpy), the facility is required to have PM/PM₁₀ limits (31.77 tpy / 19.78 tpy) to avoid a PSD review. However, if the facility always complies with the 99.3 tpy NO_x PSD avoidance limit, it is impossible that the facility would emit PM/PM₁₀ equal to or greater than the proposed limits (31.77 tpy / 19.78 tpy).

$$\begin{aligned} & \text{The maximum amount of No. 6 fuel oil that the facility can fire and reach the NO}_x \text{ limit} \\ & = (99.3 \text{ tons NO}_x / \text{yr}) * (2,000 \text{ lbs / ton}) * (10^3 \text{ gal / 55 lbs NO}_x) \\ & = 3,610,000 \text{ gallons / yr} \end{aligned}$$

$$\begin{aligned} & \text{The maximum amount of PM emissions from firing the maximum amount of No. 6 fuel oil that the} \\ & \text{facility can reach the NO}_x \text{ limit} \\ & = (10 \text{ lbs / } 10^3 \text{ gal}) * (3,610,000 \text{ gallons / yr}) * (1 \text{ ton / 2,000 lbs}) \\ & = 18.1 \text{ tpy PM} \end{aligned}$$

$$\begin{aligned} & \text{The maximum amount of PM}_{10} \text{ emissions from firing the maximum amount of No. 6 fuel oil that} \\ & \text{the facility can reach the NO}_x \text{ limit} \\ & = (18.1 \text{ tpy}) * (71\%) \\ & = 12.9 \text{ tpy PM}_{10} \end{aligned}$$

$$\begin{aligned} & \text{The maximum amount of natural gas that the facility can fire and reach the NO}_x \text{ limit} \\ & = (99.3 \text{ tons NO}_x / \text{yr}) * (2,000 \text{ lbs / ton}) * (10^6 \text{ ft}^3 / 100 \text{ lbs NO}_x) \\ & = 1.99 * 10^9 \text{ ft}^3 / \text{yr} \end{aligned}$$

$$\begin{aligned} & \text{The maximum amount of PM emissions from firing the maximum amount of natural gas that the} \\ & \text{facility can reach the NO}_x \text{ limit} \\ & = (7.6 \text{ lbs / } 10^6 \text{ scf}) * (1.99 * 10^9 \text{ ft}^3 / \text{yr}) * (1 \text{ ton / 2,000 lbs}) \\ & = 7.56 \text{ tpy PM} \end{aligned}$$

$$\begin{aligned} & \text{The maximum amount of PM}_{10} \text{ emissions from firing the maximum amount of No. 6 fuel oil that} \\ & \text{the facility can reach the NO}_x \text{ limit} \\ & = (7.56 \text{ tpy}) * (71\%) \\ & = 5.37 \text{ tpy PM}_{10} \end{aligned}$$

The more No. 6 fuel oil the facility fires, the more PM/PM10 emissions would be generated (closer to 18.1 tpy / 12.9 tpy); the more natural gas the facility fires, the less PM/PM10 emissions would be generated (closer to 7.56 tpy / 5.37 tpy). It can be concluded that, if the facility always complies with the 99.3 NOx PSD avoidance limit, potential PM/PM10 emissions will never exceed 18.1 and 12.9 tpy. Note that the facility is actually limited to 1,018,000 gallons per year of No. 6 fuel oil consumption for limiting SO₂ (instead of 3,610,000 gallons per year) and past actual emission are not taken into consideration; yet, the maximum expected PM/PM10 emission rates are already lower than the PSD significant emission levels for PM/PM10 (25 tpy / 15 tpy). Thus, **the facility is not required to have any PM/PM10 limits in order to avoid a PSD review. The SO₂ and NOx emission limits are sufficient to ensure that the emission increases of PM/PM10 caused by this modification are below the PSD significant emission levels for PM/PM10.**

Volatile Organic Compounds (VOC) Emissions

CITGO submitted a letter dated May 28, 2004, to supply additional information regarding VOC and H₂S emission calculations. The facility attached several spreadsheet tables containing the most updated fuel usage/product storage/transfer records and demonstrating the calculation of the past actual VOC and H₂S emissions. These tables are carefully examined and summaries of discussions are included in the following paragraphs.

VOC emissions come from the crude oil distillation process, product transfer/storage, and combustion processes. Condition 6.2.4 of TV Permit No. 2911-051-0012-V-01-0 contains VOC emission tracking equations listed as follows:

a. Process vent from REF1:

VOC emissions = $0.01 * (0.42183 * 10^{0.10322(T/10)})$ lb VOC/bbl crude)*(total bbls crude charged/month)*(1 ton/2000 lbs)
where T= average REF1 vent gas temperature for that particular month.

b. Marine vessel loading racks (for naphtha only):

VOC emissions = (3.9 lbs VOC/1000 gallons transferred)*(gallons transferred/month)*(1 ton/2000 lbs)

c. Truck loading racks (for naphtha only):

VOC emissions = (4.07 lbs VOC/1000 gallons transferred)*(gallons transferred/month)*(1 ton/2000 lbs)

d. All storage tanks

VOC emissions shall be computed using approved emission factors such as those listed in the most recent AP-42 or the most recent US EPA TANKS program.

In addition to the above equations, VOC emissions generated from the combustion of fuel in Boilers B004/B005 and Heaters F001/F002 must also be considered. Below is a sample calculation of VOC emissions during the month of December 2003.

T = Average REF1 vent gas temperature during the month of December 2003 = 42.1°F

Total barrels of crude run during December 2003 = 698,771 bbls (dry)

Total barrels of marine Naphtha loadings during December 2003 = 57,687 barrels

Total barrels of truck Naphtha loadings during December 2003 = 0 barrels

1 Barrels = 42 gallons

Total quantity of No. 6 fuel oil fired in the refinery during December 2003 = 263,756.38 gallons

Total quantity of natural gas fired in the refinery during December 2003 = 38,679,000 ft³

Emission Factor (natural gas, Table 1.4-2) = 5.5 lbs/10⁶ scf

Emission Factor (No. 6 fuel oil, Table 1.3-3) = 0.28 lbs/10³ gal

a. Process vent from REF1:

VOC emissions during December 2003

$$= 0.01 * (0.42183 * 10^{0.10322(42.1/10)} \text{ lb VOC/bbl crude}) * (698,771 \text{ bbls crude}) * (1 \text{ ton}/2000 \text{ lbs})$$

$$= 4.01 \text{ tons}$$

b. Marine vessel loading racks (for naphtha only):

VOC emissions during December 2003

$$= (3.9 \text{ lbs VOC}/1000 \text{ gallons}) * (57,687 \text{ bbls}) * (42 \text{ gallons/bbl}) * (1 \text{ ton}/2000 \text{ lbs})$$

$$= 4.72 \text{ tons}$$

c. Truck loading racks (for naphtha only):

VOC emissions during December 2003

$$= (4.07 \text{ lbs VOC}/1000 \text{ gallons}) * (0 \text{ gallons}) * (1 \text{ ton}/2000 \text{ lbs})$$

$$= 0 \text{ ton}$$

d. All storage tanks

EPA's Tanks 4.0 has been run for all listed tanks; emissions equations, where appropriate, are inserted into the spreadsheet cells and are used to calculate monthly VOC emissions from storage tanks.

VOC emissions from storage tanks during December 2003

$$= 0.20 + 0.19 + 0.20 + 0.40 + 0.20 + 0.12 + 0.21 + 0.42 + 0.07 + 0.01 + 0.01 + 2.28$$

$$= 4.31 \text{ tons}$$

e. Combustion of Fuel

VOC emissions from firing natural gas and No. 6 fuel oil during December 2003

$$= [(5.5 \text{ lbs}/10^6 \text{ ft}^3) * (38,679,000 \text{ ft}^3) + (0.28 \text{ lbs}/10^3 \text{ gal}) * (263,756.38 \text{ gallons})] * (1 \text{ ton}/2,000 \text{ lbs})$$

$$= 0.143 \text{ tons}$$

Therefore,

$$\text{Total VOC Emissions during December 2003} = 4.01 + 4.72 + 0 + 4.31 + 0.143 = \mathbf{13.2 \text{ tons}}$$

The following table includes past actual VOC emission data.

Table 6. CITGO's Past VOC emissions (ton)

| Month | VOC from Combustion of Fuel | VOC from All Other Activities | Month | VOC from Combustion of Fuel | VOC from All Other Activities |
|-----------------|-----------------------------|-------------------------------|-----------------|-----------------------------|-------------------------------|
| Jan-02 | 0.08 | 1.55 | Jan-03 | 0.07 | 2.00 |
| Feb-02 | 0.17 | 6.73 | Feb-03 | 0.18 | 7.19 |
| Mar-02 | 0.22 | 8.78 | Mar-03 | 0.08 | 11.60 |
| Apr-02 | 0.23 | 11.72 | Apr-03 | 0.12 | 10.50 |
| May-02 | 0.23 | 15.61 | May-03 | 0.16 | 10.94 |
| Jun-02 | 0.24 | 10.68 | Jun-03 | 0.22 | 10.04 |
| Jul-02 | 0.22 | 11.10 | Jul-03 | 0.24 | 14.65 |
| Aug-02 | 0.23 | 11.79 | Aug-03 | 0.15 | 6.05 |
| Sep-02 | 0.23 | 11.94 | Sep-03 | 0.23 | 13.34 |
| Oct-02 | 0.21 | 10.44 | Oct-03 | 0.19 | 11.69 |
| Nov-02 | 0.23 | 8.65 | Nov-03 | 0.19 | 11.98 |
| Dec-02 | 0.10 | 7.55 | Dec-03 | 0.15 | 13.03 |
| Year 2002 Total | 118.9 | | Year 2003 Total | 125.0 | |

Average, Actual, and Annual VOC Emissions During Years 2002 and 2003

$$= (118.9 + 125.0) / 2$$

$$= 122.0 \text{ tpy VOC}$$

In order to avoid a PSD review, the facility is required to have a facility-wide VOC emission cap. When the facility prepared Application No. 14951 in late Year 2003, they calculated past VOC emissions using the fuel usage and product storage/transfer rate for December 2003. With the updated data provided in the letter dated May 28, 2004, and with data from 2002/2003, the average is 122.0 tpy. Therefore, **the facility-wide VOC emission limit contained in Condition 2.1.4 is changed to 161.9 tpy** (122.0 + 39.9 tpy).

Reduced Sulfur (H₂S) Emissions

In the letter dated May 28, 2004, the facility explained that they conducted an emission test in Year 1997. Six vent gas samples were sent to CITGO's analytical laboratory in Corpus Christi, Texas, for analysis; the facility obtained an H₂S/hexane concentration ratio (8.4692/1.0436) and has calculated past H₂S emissions with the H₂S/hexane ratio. CITGO claimed that no H₂S emissions are expected from the naphtha storage and bading operations because they treat naphtha with aqueous sodium hydroxide (10%_w) prior to storage, thereby reducing its liquid phase H₂S content to below 1 ppm. Thus, the facility now calculates H₂S emissions by first calculating hexane emissions from Process Vent REF1 with the equation contained in Condition 6.2.5 of Permit No. 2911-051-0012-V-01-0, and then multiplying the result by the H₂S/hexane ratio.

Below shows a sample calculation H₂S of emissions during the month of December 2003.

Hexane emissions from Process Vent REF1 during December 2003
 = (0.23648*10^{0.10214(42.1/10)} lb hexane / 1,000 bbls crude) * (698,771 bbls crude) *
 (1 ton/2000 lbs)
 = 0.222 tons

H₂S emissions from Process Vent REF1 during December 2003
 = (0.222 tons) * (8.4692/1.0436)
 = 1.80 tons

The following table includes past actual H₂S emission data.

Table 7. CITGO's Past H₂S emissions (ton)

| Month | H ₂ S from Process Vent REF1 | Month | H ₂ S from Process Vent REF1 |
|-----------------|---|-----------------|---|
| Jan-02 | 0.31 | Jan-03 | 0.31 |
| Feb-02 | 1.34 | Feb-03 | 1.47 |
| Mar-02 | 1.50 | Mar-03 | 2.00 |
| Apr-02 | 2.12 | Apr-03 | 1.72 |
| May-02 | 2.34 | May-03 | 1.65 |
| Jun-02 | 1.96 | Jun-03 | 2.33 |
| Jul-02 | 1.86 | Jul-03 | 2.47 |
| Aug-02 | 2.28 | Aug-03 | 1.35 |
| Sep-02 | 1.86 | Sep-03 | 2.28 |
| Oct-02 | 1.74 | Oct-03 | 1.97 |
| Nov-02 | 1.85 | Nov-03 | 3.21 |
| Dec-02 | 0.65 | Dec-03 | 1.80 |
| Year 2002 Total | 19.81 | Year 2003 Total | 22.56 |

Average, Actual, and Annual H₂S Emissions During Years 2002 and 2003
 = (19.81 + 22.56) / 2
 = 21.2 tpy H₂S

In order to avoid a PSD review, the facility is required to have a facility-wide H₂S emission cap. According to the information provided by CITGO, **the facility-wide H₂S emission limit contained in Condition 2.1.5 is changed to 31.1 tpy (21.2 + 9.9 tpy).**

B. Applicable Rules and Regulations

The modification would be subject to 40 CFR 52.21, Prevention of Significant Deterioration (PSD) regulations and its mirror rule in Georgia Air Quality Rule 391-3-1-.02(7); however, conditions are included in the permit to avoid the regulations as explained above.

C. Compliance Status

None applicable.

D. Operational Flexibility

None applicable.

E. Permit Conditions

As described above, Conditions 2.1.2 – 2.1.5 have been modified accordingly.

IV. Regulated Equipment Requirements

A. Brief Process Description

CITGO is proposing to replace crude oil distillation tower No. 2 (ID No. D002). The expected maximum capacity of the new distillation column would increase from the current 14,000 barrels per day (bpd) to 17,050 bpd. Please note that the permit application indicates that this expected maximum capacity of 17,050 bpd is 10% more than the rated capacity of the distillation column (ID No. D002), which is 15,500 bpd. This is a 3,050 bpd (21.8%) increase in capacity over the existing unit (ID No. D002).

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 |
| D002** | Distillation Tower | PSD Avoidance | 2.1.1, 2.1.2, 2.1.3, 2.1.4, 2.1.5 | REF1 | Refrigeration/condenser system |

* Generally applicable requirements contained in this permit may also apply to emission units listed above.

** Replacement of original Tower D002.

C. Equipment & Rule Applicability

Emission and Operating Caps –

Condition 3.2.1 of Title V Permit No. 2911-051-0012-V-01-0 limits the facility to firing no fuel oil containing more than 2.4 percent sulfur, by weight. The facility indicated in Application No. TV-14951 that the facility fires natural gas and No. 6 fuel oil in combustion devices F001, F002, B004, and B005. Past actual SO₂ emissions are calculated based on the actual natural gas and No. 6 fuel oil consumption data, and future SO₂ emissions are limited by the annual residual fuel oil limit contained in Condition 2.1.2 in order to avoid a PSD review. There is no condition in Title V Permit No. 2911-051-0012-V-01-0 and its amendment that limits the use of any fuel oils other than residual fuel oil. Therefore, Condition 3.2.1 is modified so that the facility is allowed to fire only natural gas and/or residual fuel oil in combustion devices F001, F002, B004, and B005 and the residual fuel oil shall not contain more than 2.4 percent sulfur, by weight. This modified condition helps ensure that future SO₂ emissions will always stay below 192.4 tons during any twelve consecutive months and the Distillation Tower D002 Replacement Project does not require a PSD review.

Condition 3.2.2 of Title V Permit No. 2911-051-0012-V-01-0 limits the consumption of residual fuel oil in combustion device F002 to not exceed 2,715,000 gallons during any twelve consecutive months. New Condition 2.1.2 of the proposed Title V Permit Amendment No. 2911-051-0012-V-01-2 limits the consumption of residual fuel oil at the entire facility to not exceed 1,018,000 gallons during any twelve consecutive months. Since the new facility-wide residual fuel oil consumption limit is more stringent than the existing residual fuel oil consumption limit, Condition 3.2.2 is deleted in the proposed Title V Permit Amendment No. 2911-051-0012-V-01-2.

Applicable Rules and Regulations – None applicable.

D. Compliance Status

None applicable.

E. Operational Flexibility

None applicable.

F. Permit Conditions

As described above, Condition 3.2.1 has been modified and Condition 3.2.2 has been deleted.

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

Condition 4.1.3 has been modified to include Reference Methods 18 for the determination of hexane emissions and 25/25A for the determination of volatile organic compound emissions.

A. Individual Equipment: None applicable.

B. Equipment Groups (all subject to the same test requirements): None applicable.

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

A. Individual Equipment: None applicable.

B. Equipment Groups (all subject to the same monitoring requirements): Item x has been added at the end of Condition 5.2.5.j. Any gases released as a result of a safety or pressure relief opening should be considered and reported as an excess emission because the released gas is not controlled.

VII. Other Record Keeping and Reporting Requirements**A. General Record Keeping and Reporting Requirements**

Condition 6.1.4.b is modified to correspond to the changes of facility wide emission caps and operating limits in Conditions 2.1.2 to 2.1.5.

B. Specific Record Keeping and Reporting Requirements

Section 6.2 is significantly modified due to the Distillation Tower D002 Replacement project. Permit Amendment No. 2911-051-0012-V-01-1 was the result of the Distillation Tower D001 Replacement application and five conditions (Condition 6.2.9-6.2.13) were added. Since the facility wide emission caps and operating limits in Section 2.1 of existing Permit Amendment No. 2911-051-0012-V-01-1 are all modified, all existing recordkeeping requirements contained in Permit Amendment No. 2911-051-0012-V-01-1 must also be modified. The proposed Permit Amendment No. 2911-051-0012-V-01-2 modifies Conditions 6.2.4 and 6.2.7 and deletes Condition 6.2.8 of the initial TV Permit No. 2911-051-0012-V-01-0. The proposed TV Permit Amendment No. 2911-051-0012-V-01-2 deletes Conditions 6.2.9 and 6.2.13, modifies Conditions 6.2.10, 6.2.11, and 6.2.12 of Permit Amendment No. 2911-051-0012-V-01-1, and re-numbers them to 6.2.8-6.2.10. Conditions 6.2.10 and 6.2.11 are the new recordkeeping and reporting requirements that help to ensure that the facility will not exceed the facility wide emission caps and operating limits contained in Section 2.1 of the proposed TV permit amendment.

Conditions 2.1.2 limits the annual facility wide residual fuel oil usage so that SO₂ emissions are limited below 192.4 tpy and Conditions 2.1.3-2.1.4 contains various emission caps so that the facility can avoid a PSD review for this modification. Modified Conditions 6.2.4, 6.2.7, 6.2.8, and 6.2.9 require the facility to record monthly fuel usage and calculate VOC, NO_x, and H₂S emission with the attached equations. Item e is added to Condition 6.2.4 so that the facility has to include VOC emissions from the combustion devices in the facility wide VOC emission data computation. Condition 6.2.7 requires the facility to record monthly fuel usage; the data recorded in accordance with Condition 6.2.7.a can be used in Condition 6.2.10 and verify the compliance to Condition 2.1.2. Fuel usage recordkeeping requirement for combustion device F002 is no longer necessary because Condition 3.2.2 of the initial TV Permit No. 2911-051-0012-V-01-0 is deleted by this permit amendment for the reason discussed in Section IV.C of this narrative.

New equations are given in Conditions 6.2.8 and 6.2.9 to calculate monthly NO_x and H₂S emissions. The equation in Condition 6.2.8 utilizes AP-42 emission factors for combustions devices. The equation in Condition 6.2.9 references the additional information provided by the facility in a letter dated May 28, 2004. Monthly H₂S emissions are calculated by multiplying monthly hexane emissions from Process Vent REF1 and the average H₂S/hexane concentration ratio (8.4692/1.0436). Please refer to Section III.A of this narrative for the detailed discussion.

Conditions 6.2.10 and 6.2.11 are new conditions. Condition 6.2.10 requires the facility to calculate the twelve-month totals of residual fuel oil usage, NO_x, VOC, and H₂S emissions for each twelve-month period ending at each calendar month in the semiannual reporting period. Then, Condition 6.2.11 requires the facility to submit the data obtained in accordance with Condition 6.2.10 within their semiannual reports.

VIII. 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

None applicable.

G. Emissions Trading

None applicable.

H. Acid Rain Requirements

None applicable.

I. Prevention of Accidental Releases

None applicable.

J. Stratospheric Ozone Protection Requirements

None applicable.

K. Pollution Prevention

None applicable.

L. Specific Conditions

None applicable.

Addendum to Narrative

The 30-day public review started on September 17, 2004, and ended on October 18, 2004. Comments were not received by the Division. Therefore, a notification letter is being issued and Permit Amendment No. 2911-051-0012-V-01-2 is now final.