

Facility Name: **Tenaska Georgia Generating Station**
 City: Franklin
 County: Heard
 AIRS #: 04-13-149-00004

Application #: TV-13761
 Date Application Received: April 29, 2002
 Date Application Deemed
 Administratively Complete: June 28, 2002
 Date of Draft Permit: April 8, 2003
 Permit No: 4911-149-0004-V-02-0

Program	Review Engineers	Review Managers
SSPP/ASU	Susan Jenkins	James Capp
SSCP/ASU	Tennille Frock	James Eason
ISMP	DeAnna Oser	Larry Webber
Toxics	Not Applicable	Not Applicable

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 herein simpler terms and/or greater detail than is sometimes possible in the actual permit. This permit is being issued pursuant to: (1) Georgia Air Quality Act, O.C.G.A § 12-9-1, et seq. and (2) Georgia Rules for Air Quality Control, Chapter 391-3-1, and (3) Title V of the Clean Air Act Amendments of 1990. Section 391-3-1-.03(10) of the Georgia Rules for Air Quality Control incorporates requirements of Part 70 of Chapter I of Title 40 of the Code of Federal Regulations promulgated pursuant to the Federal Clean Air Act. The primary purpose of this permit is to consolidate and identify existing state and federal air requirements applicable to **Tenaska Georgia Generating Station** 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, the applicable requirements and their significance, and the methods for determining compliance with those applicable requirements. This narrative is intended as an adjunct for the reviewer and to provide information only. It has no legal standing. Any revisions made to the permit in response to comments received during the public participation and EPA review process will be described in an addendum to this narrative.

I. Facility Description**A. Facility Identification**

1. Facility Name: Tenaska Georgia Generating Station
2. Parent/Holding Company Name: Tenaska Georgia Partners, L.P.
3. Previous and/or Other Name(s): No previous names identified.
4. Facility Location: 2100 George Brown Road, Franklin, Heard County, Georgia 30217
5. Attainment or Non-attainment Area Location

Heard County is an attainment area for all criteria air pollutants but has been determined, by the Division, to be an area contributing to the ambient air level of ozone in the metropolitan Atlanta ozone nonattainment area.

6. Class I Area Impacts

The facility is not located within 100-km of a Class I area.

B. Site Determination

There are no other facilities which could possibly be contiguous or adjacent and under common control.

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
4911-149-0004-P-01-0	December 18, 1998	X	
4911-149-0004-P-01-1	April 21, 1999	X	

Table 2: Comments on Specific Permits

Permit Number	Comments
4911-149-0004-P-01-0	Initial PSD permit to construct and operate facility. This permit also serves as the Phase II Acid Rain Permit.
4911-149-0004-P-01-1	Amendment authorizing the construction and operation of a 165,000 barrel fuel oil storage tank.

D. Process Description

1. SIC Codes(s): 4911

The SIC Code(s) identified above were assigned by EPD's Air Protection Branch for purposes pursuant to the Georgia Air Quality Act and related administrative purposes only and are not intended to be used for any other purpose. Assignment of SIC Codes by EPD's Air Protection Branch for these purposes does not prohibit the facility from using these or different SIC Codes for other regulatory and non-regulatory purposes.

Should the reference(s) to SIC Code(s) in any narratives or narrative addendum previously issued for the Title V permit for this facility conflict with the revised language herein, the language herein shall control; provided, however, language in previously issued narratives that does not expressly reference SIC Code(s) shall not be affected.

2. Description of Product(s)

The facility produces electricity for sale.

3. Overall Facility Process Description

The facility consists of six simple cycle combustion turbines. The units fire natural gas as primary fuel and fuel oil as backup. The turbines are equipped with dry low NOx combustors and water and/or injection for control of NOx emissions. Each combustion turbine generates a base load rating of approximately 166 megawatts (for natural gas combustion) and 174 megawatts (for fuel oil combustion) at 59 deg F. Each turbine vents through its own 70 foot stack.

4. Overall Process Flow Diagram (optional)

The facility provided an overall process flow diagram in their Title V permit application.

E. Regulatory Status

1. PSD/NSR

The facility is a major source under PSD because it has potential emissions of nitrogen oxides (NOx), carbon monoxide (CO), and sulfur dioxide (SO₂) greater than 250 tons per year. Note 1: The facility is not classified as one of the 28 named source categories. The facility was permitted under the PSD regulations in 1998 and the requirements of PSD applied to emissions of NOx, CO, VOC, SO₂, PM/PM₁₀, visible emissions, and sulfuric acid.

Georgia Rule 391-3-1-.03(8)(c)15 (effective February 16, 2000) establishes the facility as a major NSR source of NOx emissions because potential NOx emissions exceed 100 tons per year.

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	Yes	X		
PM ₁₀	Yes	X		
SO ₂	Yes	X		
VOC	Yes	X		
NO _x	Yes	X		
CO	Yes	X		
TRS	No			N/A

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
H ₂ S	No			N/A
Individual HAP	Yes			X
Total HAPs	Yes			X

3. MACT Standards

The facility is not subject to a proposed or final MACT standard.

4. Program Applicability

Program Code	Applicable (y/n)
Program Code 6 - PSD	Yes
Program Code 8 – Part 61 NESHAP	No
Program Code 9 - NSPS	Yes
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: None applicable.
- C. Compliance Status: Refer to Section VII.F.
- D. Operational Flexibility: Refer to Section VII.A.
- E. Permit Conditions: None applicable.

III. Regulated Equipment Requirements

A. Brief Process Description

The facility consists of six simple cycle combustion turbines. The units fire natural gas as primary fuel and fuel oil as backup. The turbines are equipped with dry low NO_x combustors and water and/or steam injection for control of NO_x emissions. Each combustion turbine generates a base load rating of approximately 166 megawatts (for natural gas combustion) and 174 megawatts (for fuel oil combustion) at 59 deg F. Each turbine vents through its own 70 foot stack.

B. Equipment List for the Process

Emission Units		Specific Limitations/Requirements	Air Pollution Control Devices	
ID No.	Description	Applicable Requirements/Standards	ID No.	Description
CT01	Combustion Turbine	391-3-1-.02(2)(g) 391-3-1-.02(2)(b) 391-3-1-.02(2)(nnn) 40 CFR 52.21 40 CFR 60, Subpart A 40 CFR 60, Subpart GG Acid Rain Regulations	DRY1 WAT1	Dry Low NOx Combustor Water and/or Steam Injection
CT02	Combustion Turbine	391-3-1-.02(2)(g) 391-3-1-.02(2)(b) 391-3-1-.02(2)(nnn) 40 CFR 52.21 40 CFR 60, Subpart A 40 CFR 60, Subpart GG Acid Rain Regulations	DRY2 WAT2	Dry Low NOx Combustor Water and/or Steam Injection
CT03	Combustion Turbine	391-3-1-.02(2)(g) 391-3-1-.02(2)(b) 391-3-1-.02(2)(nnn) 40 CFR 52.21 40 CFR 60, Subpart A 40 CFR 60, Subpart GG Acid Rain Regulations	DRY3 WAT3	Dry Low NOx Combustor Water and/or Steam Injection
CT04	Combustion Turbine	391-3-1-.02(2)(g) 391-3-1-.02(2)(b) 391-3-1-.02(2)(nnn) 40 CFR 52.21 40 CFR 60, Subpart A 40 CFR 60, Subpart GG Acid Rain Regulations	DRY4 WAT4	Dry Low NOx Combustor Water and/or Steam Injection
CT05	Combustion Turbine	391-3-1-.02(2)(g) 391-3-1-.02(2)(b) 391-3-1-.02(2)(nnn) 40 CFR 52.21 40 CFR 60, Subpart A 40 CFR 60, Subpart GG Acid Rain Regulations	DRY5 WAT5	Dry Low NOx Combustor Water and/or Steam Injection
CT06	Combustion Turbine	391-3-1-.02(2)(g) 391-3-1-.02(2)(b) 391-3-1-.02(2)(nnn) 40 CFR 52.21 40 CFR 60, Subpart A 40 CFR 60, Subpart GG Acid Rain Regulations	DRY6 WAT6	Dry Low NOx Combustor Water and/or Steam Injection
FOST1	6.93 million gallon No. 2 fuel oil storage tank	40 CFR 52.21 40 CFR 60, Subpart Kb	NA	None

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

C. Equipment & Rule Applicability

NOx emissions from each combustion turbine are regulated by 40 CFR 52.21 [PSD-BACT], 40 CFR 60 Subpart GG [NSPS GG], and Georgia Rule 391-3-1-.02(2)(nnn). Georgia Rule (nnn) is an applicable requirement during the ozone season beginning in 2003. The following table illustrates the allowable NOx emission limits established by these regulations:

Regulation	NOx Emission Limit ppmvd at 15% oxygen	Averaging Period
<u>PSD Regulation – 40 CFR 52.21</u> Emission limit is referred to as BACT emission limit.	<u>For Natural Gas Combustion</u> 15 <u>For Fuel Oil Combustion</u> 42	Based on Method 20 (i.e., 1-hr) Based on Method 20 (i.e., 1-hr)
<u>NSPS GG</u>	<u>For Natural Gas and Fuel Oil Combustion</u> 75-100	Based on Method 20 (i.e., 1-hr)
<u>Georgia Rule 391-3-1-.02(2)(nnn)</u>	<u>For Natural Gas and Fuel Oil Combustion</u> 30	Based on Method 7E (i.e., 3-hrs)

As illustrated in this table, the most stringent NOx emission rate during natural gas combustion is established by 40 CFR 52.21 which subsumes the requirements of NSPS GG and Georgia Rule (nnn). Up until May 1, 2003, the most stringent NOx emission rate during fuel oil combustion is established by 40 CFR 52.21 which subsumes the requirements of NSPS GG and Georgia Rule (nnn). Beginning May 1, 2003 and up until September 30, 2003 (and each subsequent May 1-September 30 time period), the most stringent NOx emission rate during fuel oil combustion is established by Georgia Rule (nnn).

The existing PSD NOx emissions limit for the turbines on a combined basis (1,788 tons per year) is transferred to the Title V permit.

Fuel oil usage for the turbines on a combined basis is limited to 57 million gallons during any twelve consecutive months. [Equivalent to 720 hours per year of fuel oil combustion per turbine.] The existing PSD operational limit of 3,066 average hour per year per turbine is carried over to the Title V permit.

Georgia Rule (nnn) limits the short term NOx emissions during the ozone season beginning in 2003. This limit applies during periods which include startup and shutdown in accordance with Georgia Rule 391-3-1.

Carbon monoxide emissions from each combustion turbine are regulated by 40 CFR 52.21. The BACT CO emission limit for each turbine is 15 ppmvd, at 15% oxygen, for natural gas combustion. The BACT CO emission limit, during fuel oil combustion, is 20 ppmvd, at 15% oxygen, at or above 123 MW (gross output) and 33 ppmvd, at 15% oxygen, below 123 MW (gross output). These BACT emission limits apply during startup and shutdown.

Particulate matter emissions from each combustion turbine are regulated by 40 CFR 52.21. The BACT PM/PM10 emission limit for each turbine is 0.010 pound per million Btu (lb/MMBtu) for natural gas combustion. Alternatively, the PM/PM10 limit for each turbine, during fuel oil combustion is 0.013

lb/MMBtu at or above 123 MW (gross output) and 0.017 lb/MMBtu below 123 MW (gross output). These BACT emission limits apply during startup and shutdown.

Volatile organic compound emissions from each combustion turbine are regulated by 40 CFR 52.21. The BACT VOC emission limit for each turbine is 0.003 lb/MMBtu (natural gas combustion) and 0.005 lb/MMBtu (fuel oil combustion), as methane. These BACT emission limits apply during startup and shutdown.

Sulfur dioxide emissions from the combustion of fuel oil are regulated by 40 CFR 52.21, 40 CFR 60.333(b) [NSPS GG], and Georgia Rules 391-3-1-.02(2)(g)1 and (g)2. The requirements of 40 CFR 52.21, in this case, require a maximum fuel oil sulfur content of 0.05 weight percent. According to the PSD application for this site, such a fuel oil sulfur content limit equates to a sulfur dioxide emission rate of approximately 0.053 lb/MMBtu. NSPS [40 CFR 60.333(b)] limits fuel sulfur content to 0.8 percent by weight. Georgia Rule (g)1 applies because each turbine was constructed after January 1, 1972 and has a maximum heat input capacity greater than 250 MMBtu/hr. Georgia Rule (g)1 limits sulfur dioxide emissions to 0.8 lb/MMBtu. Georgia Rule (g)2 limits the fuel sulfur content to 3 percent sulfur by weight since each combustion turbine has a maximum heat input greater than 100 MMBtu/hr. Of these various limits, the requirements of 40 CFR 52.21 are the most stringent and as such subsume the requirements of NSPS GG and Georgia Rules (g)1 and (g)2.

Sulfur dioxide emissions from the combustion of natural gas are regulated by 40 CFR 52.21, 40 CFR 60.333(b) [NSPS GG], and Georgia Rules 391-3-1-.02(2)(g)2. In this case, 40 CFR 52.21 imposes no requirements on the sulfur content of the natural gas. Note: Georgia Rule (g)1 does not apply for natural gas fired fuel sources. Georgia Rule (g)2 limits the fuel sulfur content to 3 percent sulfur by weight since each combustion turbine has a maximum heat input greater than 100 MMBtu/hr. NSPS GG [40 CFR 60.333(b)] limits the fuel sulfur content to 0.8 percent by weight. In this case, the requirements of NSPS GG are more stringent than the requirements of Georgia Rule (g)2 and thus subsume Georgia Rule (g)2.

Visible emissions from each combustion turbine are regulated by 40 CFR 52.21 and Georgia Rule 391-3-1-.02(2)(b). The requirements of 40 CFR 52.21 subsume the requirements of Georgia Rule (b). The BACT limits for visible emissions are as follows: (1) For Natural Gas Combustion: 10 percent; and (2) For Fuel Oil Combustion: 20 percent.

Storage tank FOST1 is subject to 40 CFR 60, Subpart Kb because (1) it was constructed after July 23, 1984 and (2) it has a capacity greater than 40 m³ (~10,586 gallons). The tank is not subject to an emission standard under NSPS Kb because the material stored has a true vapor pressure less than 3.5 kPa (~0.51 psia).

- D. Compliance Status: Refer to Section VII.F.
- E. Operational Flexibility: Refer to Section VII.A.
- F. Permit Conditions

Condition 3.3.1 specifies the total NO_x emission limit per combustion turbine.

Condition 3.3.2 specifies the annual average hours of operation for each combustion turbine.

Condition 3.3.3 specifies the combustion modification/control technology for minimizing NO_x emissions under PSD.

Condition 3.3.4 notes that 40 CFR 60, Subpart A is an applicable requirement for the turbines.

Condition 3.3.5 specifies the NSPS GG fuel sulfur limit for natural gas fired in the combustion turbines.

Condition 3.3.6 specify the BACT emission limits for each combustion turbine during natural gas combustion.

Condition 3.3.7 specifies the annual total fuel oil consumption limit.

Condition 3.3.8 specifies the maximum fuel oil sulfur content.

Condition 3.3.9 specify the BACT emission limits for each combustion turbine during fuel oil combustion.

Condition 3.4.1 specifies the NO_x emission limit for each combustion turbine, during each ozone season, beginning in 2003 in accordance with Georgia Rule (nnn).

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

A. General Testing Requirements

A condition specifying that the Division can require emissions testing on any emissions unit is included. The test methods to be used to determine compliance with the limitations in Part 3 are listed and a general condition requiring notification of any test and submission of a test plan are also provided.

Condition 4.1.3 allows for the Director or his designee to make minor changes in methodology, which are sometimes necessitated by process variables, changes in facility design, or improvements or corrections that render those methods or procedures more reliable.

B. Specific Testing Requirements

The applicant has completed all of the performance testing required by Condition 4.3 of their PSD Permit. No new testing requirements are imposed by this Title V permit.

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

A. General Monitoring Requirements

Condition 5.1.1 requires that all monitors be operated continuously except during breakdowns and repairs. Any repairs or maintenance should be completed in an expeditious manner so downtime is minimized. All data should be recorded during any calibration activity to help verify that the calibration was performed and completed properly.

B. Specific Monitoring Requirements

Combustion Turbines CT01, CT02, CT03, CT04, CT05, and CT06 are subject to the requirements of 40 CFR 52.21 [PSD] for NO_x, CO, PM/PM10, VOC, SO₂ emissions and visible emissions; 40 CFR 60 Subpart GG [NSPS GG] for NO_x and SO₂ emissions; and Georgia Rules 391-3-1-.02(2)(b), (g), and (nnn) for visible emissions, fuel sulfur content, and NO_x emissions. Verification of the requirements for SO₂ emissions (i.e., fuel sulfur content) is via record keeping which is discussed in Section VI of this narrative.

The monitoring provisions of NSPS GG [40 CFR 60.334(c)(1)] specify the use of water-to-fuel rates and fuel nitrogen content to identify periods of NO_x excess emissions. The combustion turbines are equipped to utilize water and/or steam injection only during periods of fuel oil combustion. To reasonably assure compliance with the requirements of 40 CFR 52.21, the Continuous Emissions Monitoring Systems (CEMS), required by the Acid Rain regulations, are used to monitor NO_x emissions. The NO_x CEMS provides an indicator of compliance regarding each combustion turbine's compliance status on a continuous basis following the initial tests. With this in mind, the Division believes there is enough justification to not require monitoring of the water-to-fuel ratio and fuel nitrogen content as required in 40 CFR 60.334(c)(1). The values reported by the NO_x CEMS will be used to assess the existence of an excess emission or exceedance as noted in the following table:

Fuel Type	Allowable Emission Limit ppmvd at 15% oxygen	Legal Authority for Allowable Emissions Limit	Classification for Condition Nos. 6.1.4 and 6.1.7
Natural Gas	15 on a 1-hour average	40 CFR 52.21(j)(2)	Excess Emissions as defined by PSD Permit
Fuel Oil	42 on a 1-hour average	40 CFR 52.21(j)(2)	Excess Emissions as defined by PSD Permit
Natural Gas and Fuel Oil	30 on a 3-hour average	Georgia Rule 391-3-1-.02(2)(nnn) during ozone season beginning in 2003	Exceedance

Verification of compliance with the rolling annual NO_x emission limit per turbine is discussed in Part VI of this narrative.

Carbon monoxide and volatile organic compound emissions from each combustion turbine are regulated by 40 CFR 52.21. The applicant conducted performance testing for CO and VOC emissions during natural gas and fuel oil combustion. The results of these tests show that the CO and VOC emissions comply with the BACT emission limits. The applicant tested the CO and VOC emission rates at base load and at approximately 90 megawatts (i.e., 50 % load) for natural gas and 99 megawatts (i.e., 50% load) for fuel oil combustion. The likelihood of violation of the CO and VOC BACT emission limits is minimal during periods of lean pre-mix combustion (e.g., 50% load and greater). The Title V permit imposes a new monitoring requirement in order to provide a reasonable assurance of compliance with the CO and VOC BACT emission limits. The Permittee shall continuously monitor the megawatts (MWs) of each combustion turbine and record the hourly average value. An excursion is defined as any one-hour period of operation in which the average electrical output generated by the combustion turbine is less than 90 MWs for natural gas and 99 MWs for fuel oil combustion, excluding periods of startup and shutdown.

Particulate matter and visible emissions from each combustion turbine are regulated by 40 CFR 52.21. Initial compliance with the short term PM/PM₁₀ and visible emission limits were verified through initial performance tests. Natural gas and very low sulfur distillate fuel oil are clean burning fuels and the likelihood of violating the established said BACT limits is minimal. Thus no additional periodic monitoring is prescribed for PM/PM₁₀ and visible emissions.

The turbines are subject to an operational limit 3,066 hours as a rolling annual average. The Permittee operates an hour meter on each turbine and records the data on a monthly basis. This type of monitoring provides for a reasonable assurance of compliance with this operational limit.

The turbines on a combined basis are limited to a PSD fuel oil usage limit. NSPS GG [40 CFR 60.334(a)] requires the Permittee to install and operate continuous monitoring systems for fuel consumption. This type of monitoring provides for a reasonable assurance of compliance with the fuel oil usage limit.

Storage Tank FOST1 is subject to NSPS Kb which imposes no emission standards, in this case. No periodic monitoring is prescribed for this storage tank.

40 CFR Part 64-Compliance Assurance Monitoring: This review analyzes the applicability of 40 CFR Part 64 – “Compliance Assurance Monitoring.” The requirements of Part 64 do not apply to the fuel gas heaters or fuel oil storage tanks because these units are not equipped with a *control device* as defined in Part 64.1. The requirements of Part 64 do not apply to each combustion turbine during natural gas combustion because the dry low NOx combustion systems do not meet the definition of *control device* as defined in Part 64.1. The requirements of Part 64 do not apply to each combustion turbine for CO, VOC, and PM emissions, during natural gas and fuel oil combustion, because there is no *control device* for these air pollutants.

The requirements of Part 64 apply to each combustion turbine during fuel oil combustion because (1) water injection is used to minimize NOx emissions and water injection meets the definition of *control device* in §64.1; (2) pre-controlled NOx emissions exceed the Part 70 major source threshold for NOx; and (3) the NOx CEMS does not meet the definition of *continuous compliance determination method* in §64.1. Note: The regulatory exemption found in Part 64.2(b)(vi) does not apply, in this case, because the existing NOx CEMS does not meet the definition of *continuous compliance determination* found in Part 64.1. This is because the existing PSD permit and Georgia Rule (nnn) do not stipulate that the NOx CEMS is to be a *continuous compliance determination method* and was not intended to do so. The applicable reference method for determining compliance with the applicable NOx limit for fuel oil combustion is Method 20.

Tenaska submitted a CAM plan on October 8, 2002, and they propose to use the NOx CEMS to satisfy the requirements of Part 64. The applicable elements of the applicant’s CAM plan are included in Attachment D of the Title V permit for this facility.

VI. Other 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 information related to deviations from the applicable equipment. 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 semiannual basis.

B. Specific Record Keeping and Reporting Requirements

Verification of Compliance with the NOx Emission Limit

Verification of compliance with the individual turbine twelve month rolling total NOx emission rate is determined using the NOx CEMS data to compute the NOx mass emission rate. The Permittee is required to maintain monthly records which specify the individual turbine twelve consecutive month total NOx emissions (in tons). Failure to maintain NOx emissions from the combustion turbines on a combined basis equal to or less than 1,788 tons during any twelve consecutive months must be reported as an exceedance.

Verification of Compliance with the Operational Limits on the Turbines

The Permit specifies record keeping for the monthly and rolling annual fuel oil usage for the combustion turbines on a combined basis. An exceedance is defined as any rolling twelve consecutive month total fuel oil usage which exceeds 57 million gallons.

The Permit specifies record keeping for the monthly (or net) and average rolling annual hours of operation per turbine. An exceedance is defined as any rolling annual average hours of operation which exceeds 3,066 hours.

Verification of Compliance with the Fuel Sulfur Content Limits on the Turbines

The fuel oil sulfur content limit for the fuel consumed by the turbines is 0.05 weight percent. The natural gas fuel sulfur content limit is 0.8 percent by weight. NSPS GG [see 40 CFR 60.334(b)(2)] requires daily monitoring of the sulfur and nitrogen content of the fuels supplied without intermediate bulk storage [i.e., in this case natural gas]. The Division believes that a waiver of the nitrogen monitoring requirement for natural gas is acceptable based upon the fact that NO_x emissions are measured by a continuous emissions monitoring system (CEMS) and because pipeline natural gas does not contain fuel-bound nitrogen that would generate NO_x emissions. The Division has approved such a waiver in the past. [See August 14, 1987 Memo-EPA Custom Fuel Monitoring Policy].

The Permittee receives its pipeline natural gas from TRANSCO. Historically, the Division has allowed a semiannual analysis of the sulfur content of the TRANSCO natural gas pipeline instead of daily sampling even though the Division has not received a waiver from EPA to reduce the frequency of monitoring from daily to semiannual for this pipeline. The Division has been receiving semiannual reports from TRANSCO which shows the sulfur content of its gas to be much less than 0.1 percent. The Division did not, and does not, believe that there is anything to be gained by requiring a sulfur analysis on a schedule more frequent than semiannual. Thus, the existing semiannual monitoring and reporting requirements for natural gas content are carried over to their Title V permit. An exceedance is defined as any semi-annual analysis of the sulfur content of the natural gas whose value exceeds 0.8 weight percent.

PSD Permit No. 4911-149-0004-P-01-0 requires the Permittee to monitor the sulfur content and nitrogen content of each fuel shipment to the plant. NSPS GG [see 40 CFR 60.334(b)(1)] requires monitoring of the sulfur and nitrogen content of the fuel supplied from a bulk storage tank [i.e., in this case distillate fuel oil] on each occasion that fuel is transferred to the storage tank from any other source. As an approved monitoring alternative for NSPS GG, EPA Region 4 has allowed owners/operators that receive fuel oil in tanker trucks to use vendor analyses to satisfy the fuel oil nitrogen and sulfur monitoring requirements under NSPS GG [40 CFR 60.334(b)(1)]. [EPA Region 4 Memo May 26, 2000– “Approval of Routine Alternative Testing and Monitoring Procedures for Combustion Turbines Regulated Under New Source Performance Standards]. The Title V permit will allow Tenaska to monitor the sulfur content using “as-delivered” samples instead of samples collected from their own storage tank. The Division believes that this method of compliance is acceptable if the sulfur content of all the fuel oil delivered meets the applicable limits since the average sulfur content of the fuel oil in the storage tank would meet the applicable limits by default under this scenario. EPA has provided a waiver to owners and operators of the requirements to determine the nitrogen content of the fuel oil burned in a combustion turbine in cases where NO_x excess emissions are monitored using a CEMS. Thus, the Title V permit will not require the Permittee to monitor the nitrogen content of the fuel oil. The PSD Permit also defines an excess emission at any fuel oil shipment whose sulfur content exceeds 0.05 percent by weight. For purposes of this Title V permit, the definition will be carried over.

NSPS Kb Requirements

As noted earlier in the narrative, the fuel oil storage tank with emission unit ID No. FOST1 is subject to the NSPS Kb requirements specified in 40 CFR 60.116b. The requirements of 40 CFR 60.116b are specified in Part 6 of the Permittee's Title V permit.

Reporting Requirements

Condition 6.1.4 outlines the semiannual reporting requirements. Condition 6.2.12 specifies additional parameters which must be included in these semiannual reports. The additional parameters are:

*The twelve consecutive month total fuel oil consumption from the combustion turbines on a combined basis.

*The twelve consecutive month average total hours of operation for the combustion turbines on a combined basis.

* The twelve consecutive month total NOx emissions per turbine.

*The fuel oil supplier certifications for each shipment of fuel oil received during the reporting period and a statement signed by a responsible official that the records of fuel supplier certifications submitted represent all of the fuel oil received during the semiannual reporting period. If no fuel oil has been received during the reporting period, the report should so state.

VII. Specific Requirements**A. Operational Flexibility**

This permit includes the standard conditions allowing section 502(b)(10) changes and off-permit changes. Additional operational flexibility provisions do not need to be incorporated into this Title V permit as their permit already provides sufficient flexibility for the facility. The applicant did not include any alternative operating scenarios in their Title V permit application.

B. Alternative Requirements

There are no alternative requirements that need to be incorporated into the Title V permit.

C. Insignificant Activities

A list of insignificant activities is attached at the end of the Title V permit. These insignificant emission units may also be seen in Section 4.10 and 4.50 of the Title V permit application.

D. Temporary Sources

This section is not applicable to this facility. 40 CFR 70.6(e) requires the Division to provide for the permitting of certain types of temporary sources. This facility currently has no such sources and is unlikely to have such sources in the future. However, they may add temporary sources provided that the facility follows any necessary regulatory procedures for the operation of such sources. This may include amending the Title V permit, if necessary.

E. Short-Term Activities

The applicant did not indicate the existence of short term activities.

F. Compliance Schedule/Progress Reports

The facility is in compliance with all Air Quality Regulations. Therefore, no compliance schedule or progress reports are necessary.

G. Emissions Trading

The facility is not involved in any emissions trading programs.

H. Acid Rain Requirements

The facility is subject to requirements in Title IV of the Clean Air Act. They are subject to 40 CFR 72 (permits), 73 (sulfur dioxide), and 75 (monitoring). They are not subject to the NOx provisions (40 CFR 76) of the Acid Rain regulations because the turbines do not have the capability to burn coal. Each of the turbines is an affected unit under the Acid Rain regulations.

Tenaska was issued a Phase II Acid Rain permit by the Division on December 18, 1998. The facility is required under 40 CFR 75 to monitor certain pollutants and parameters, including NOx emissions, SO₂ emissions, CO₂ emissions, and heat input. These pollutants and parameters are reported directly to EPA, electronically, on a quarterly basis.

I. Prevention of Accidental Releases

This facility is not subject to the requirements of 40 CFR 68.

J. Stratospheric Ozone Protection Requirements

The facility is not subject to the requirements of 40 CFR Part 82.

K. Pollution Prevention

Not applicable.

L. Specific Conditions

None

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.

Narrative Addendum

The Georgia EPD issued draft Title V Permit No. 4911-149-0004-V-02-0 on April 8, 2003 to Tenaska Georgia Generating Station located in Franklin, Heard County, Georgia. Due to the nature of the comments submitted by the Permittee on April 29, 2003, EPD revised portions of the draft permit. EPD issued the second draft version of the permit to the applicant on May 15, 2003. Tenaska published the Title V notice in The News and Banner (legal organ for Heard County) on May 28, 2003. The comment period expired on June 27, 2003. Comments were received from the applicant on May 5, 2003 (dated May 1, 2003), June 13, 2003 (dated June 12, 2003) and July 1, 2003 (dated June 27, 2003) and from members of the public on June 26, 2003 and July 3, 2003.

Comment from Tenaska Georgia Generating Station**1. Section 3.1 and Draft Condition No. 3.3.3**

Comment: Tenaska requests that the reference to “steam injection” be removed from these portions of the permit as the applicant only utilizes water injection.

Response: EPD has updated these conditions as requested.

2. Draft Condition Nos. 3.3.6 and 3.3.9

Comment: Draft Condition Nos. 3.3.6 and 3.3.9 specify the short term BACT emission limits for each combustion turbine. The applicant asserts that these limits do not apply during periods of startup and shutdown and as such the conditions should be revised accordingly.

Secondly, the applicant requests that the phrase “Note: Equivalent to 21.5 lb/hr at full load” found in Draft Condition 3.3.6.c should be removed as such language is not found in the PSD PM emissions limit.

Response: EPD disagrees with the commenter that the short term BACT emission limits for each combustion turbine do not apply during periods of startup and shutdown. The existing PSD permit does not contain such language. The commenter is reminded that the BACT requirements cannot be waived or otherwise ignored during periods of startup and shutdown. The commenter is also reminded that BACT applies during normal source operation and normal source operation does include periods of startup and shutdown. This is reiterated in *In re Tallmadge Generating Station, PSD Appeal No. 02-12 (EAB May 22, 2003)* decision. In addition the Memorandum from Kathleen M. Bennett, Assistant Administrator for Air, Noise, and Radiation, U.S. EPA, to Region Administrators, Regions I-X (September 28, 1982) support EPD’s stance on this issue.

EPD agrees to revise Draft Condition 3.3.6.c as requested.

3. Georgia Rule 391-3-1-.02(2)(nnn) Applicability and Inclusion in the Draft Permit

Comment: Draft Condition Nos. 3.4.1, 5.2.5, 6.1.7.b.i, and Attachment D – Compliance Assurance Monitoring relate to the interpretation of and implementation of Georgia Rule 391-3-1-.02(2)(nnn). As the primary concern is Georgia Rule (nnn) applicability, the comment deals primarily with Draft Condition No. 3.4.1 which specifies the requirements of Georgia Rule 391-3-1-.02(2)(nnn).

Tenaska strongly objects to EPD’s decision that the combustion turbines are subject to the Georgia Rule 391-3-1-.02(2)(nnn)1.(i) NOx emission limit of 30 ppm, corrected to 15% oxygen, rather than the Georgia Rule(nnn)1.(ii) emission standard during periods of fuel oil combustion. Tenaska notes that they were made aware of EPD’s interpretation of Georgia Rule (nnn) which suggested a definition of the phrase “with natural gas” as equivalent to “equipped with a connection to a natural gas pipeline” in an April 8, 2003 letter from Ronald C. Methier to Greg Kunkel prior to issuance of the draft Title V permit. Tenaska asserts that EPD’s interpretation of the rule far exceeds the literal and legal meaning of the regulation, is arbitrary and capricious, violates Georgia’s Constitution, and constitutes a circumvention of the notice and comment requirements of the Georgia Administrative Procedures Act.

Tenaska proceeded to petition EPD to withdraw the draft Title V operating permit until EPD renders a final decision on a May 1, 2003 petition to seek relief from EPD's interpretation. Tenaska's June 27, 2003 comments reiterate this request as well as reiterate the applicant's claim that EPD's Georgia Rule (nnn) rule applicability determination conclusion violates the Georgia Constitution. Tenaska's May 1, 2003 petition seeks relief two different ways. First the applicant is seeking relief by requesting the Director to modify Georgia Rule (nnn)1.(i) as it relates to fuel oil combustion in light of the fact that such a limit is not "technically achievable taking into account the cost and feasibility of available control options." As an alternative, the applicant is seeking relief by petitioning the EPD Director for a Regulatory Exception pursuant to Georgia Rule 391-3-1-.05.

Response: Tenaska has requested a regulatory exemption in accordance with Georgia Rule 391-3-1-.05. EPD is evaluating this request outside of the Title V permitting process, and therefore EPD will not comment on this request in this narrative addendum. In addition, Tenaska has requested a revision to Georgia Rule (nnn)5. EPD is evaluating this request outside of the Title V permitting process. EPD will not comment on this request in this narrative addendum.

Tenaska asserts that the proper Georgia Rule (nnn) NOx emission standard during fuel oil combustion is Georgia Rule (nnn)1.(ii) rather than Georgia Rule (nnn)1.(i) based on the phrase "with no natural gas" found in Georgia Rule (nnn)1.(ii). Tenaska claims that EPD has inappropriately interpreted the Rules of Air Quality Control in determining that a facility is "without natural gas" only if it has no physical connection to the natural gas service network. Tenaska claims that this interpretation is arbitrary and capricious, without notice and in appropriate rule-making. EPD disagrees and strongly believes that the rule went through the proper notice and comment period and no comments were received on the issue now raised. EPD has not, since the creation of Georgia Rule (nnn) through the rulemaking process, changed its interpretation of the rule now in question. The rule did not intend to put EPD in the position of determining when, on a day to day basis, a facility received natural gas through its pipes. Rather, the bright-line rule establishes that "with" or "without" natural gas relates to connectivity to the natural gas service system. EPD still supports its earlier decision on this matter as documented in EPD's April 8, 2003 to the applicant.

Tenaska also asserts that not burning fuel oil during the ozone season provides no environmental benefit. The applicant looks at the history of the industry and claims that the industries prior practices of not burning fuel oil during the ozone season, shows that there is no environmental benefit to the current rule. This argument runs counter to the company's stated desire to emit higher levels of air pollution in the future. Only through the implementation of a limit on emissions from fuel oil combustion is EPD able to ensure continued improvement of the environment. Indeed, the changes in practice contemplated by the applicant to be realized through this request for a more lenient NOx emission standard, leads directly to the conclusion that the applicant intends to emit more NOx. Tenaska is seeking approval to increase their NOx emissions during the ozone season from 15 ppm while firing natural gas to 42 ppm while burning fuel oil. This change in emissions will negatively impact Georgia's Air Quality, is contrary to the State Implementation Plan and is in appropriate under the Clean Air Act and Rules of Air Quality Control.

Tenaska claims that the imposition of new terms and conditions in the Title V permit are being done without due process. This claim is flatly untrue. The permit has been crafted with input from the company, is subject to public notice and comment is based on regulations that were themselves subject to public participation at both the State and Federal Level.

Tenaska claims that the distinction made between facilities "with" and "without natural gas" is an arbitrary classification between identical businesses bearing no relation to purpose of the Air Quality Act. EPD argues that this claim fails, in that the purpose of the Air Quality Act is to provide for cleaner air through reasonable regulations. Facilities with natural gas are able to continue to operate, at a profit, through the burning of natural

gas. This has been the standard practice for the industry. The distinction for facilities that are without natural gas is that these facilities have no operational alternative than to burn fuel oil. In the case of a facility without natural gas, the facility would have to shut down. Clearly, the cessation of all operations was not the intention of the Act.

4. **Draft Condition No. 4.1.3**

Comment: Tenaska objects to the test method stipulated for VOC emissions from the combustion turbines. Tenaska requests that the Title V permit require method 25A for VOC emissions. The PSD Permit listed Method 25A and the proposed Title V permit lists Method 25.3 of the South Coast Air Quality Management District.

Response: The Division agrees that the test methods specified in Air Quality Permit No. 4911-149-0004-P-01-0, for measuring emissions of volatile organic compounds, should be in the Condition 4.1.3. This condition is revised as requested.

5. **Draft Condition Nos. 5.2.5**

Comment: Draft Condition 5.2.5 requires the Permittee to compute a three-hour average NOx emission rate for purposes of verifying compliance with Georgia Rule (nnn). Tenaska states that the applicable averaging period is 30-days in accordance with Section 2.121 of EPD's **Procedures for Testing and Monitoring Sources of Air Pollutants**.

Response: EPD disagrees with the commenter. The commenter appears to be basing its decision on the provisions of Section 2.121 that apply to combustion turbines permitted after January 1, 2000. The combustion turbines at Tenaska were permitted before January 1, 2000 and as such the provisions of Section 2.121.2 of EPD's **Procedures for Testing and Monitoring Sources of Air Pollutants** applies. The provisions of Section 2.121.2 of said procedures states that Method 7E shall be used to determine the NOx concentration. In addition, the sampling time for each test run shall be at least 60 minutes. The provisions of Section 1.2(h) state, "Unless otherwise specified in the applicable source category, test method, or otherwise specified by the Director, each performance test shall consist of three separate runs using the applicable test method." With this in mind, the applicable averaging period for the NOx emission standard specified by Georgia Rule (nnn)1.(i) is based on Method 7E and Method 7E concentration is based on a three-hour average. It should be noted that, for turbines permitted after April 1, 2000, the NOx Continuous Emission Monitoring System (CEMS) is the compliance determination method (i.e., each 30-day NOx average is a performance test to determine compliance with the emission limitation) and the CEMS is required to comply with the quarterly accuracy determinations and calibration drift assessments contained in Appendix F of the Division's **Procedures for Testing and Monitoring Sources of Air Pollutants**.

6. **Draft Condition No. 6.1.7.c**

Comment: The applicant requests that the basis of the excursions should be 50% of rated capacity (as found in PSD Permit Condition 10.2) rather than based on 90 MW (natural gas combustion) and 99 MW (fuel oil combustion).

Response: EPD examined the relationship between the requirements of PSD Condition 10.2 and PSD Condition Nos.4.3.d and 4.3.e. PSD Condition Nos. 4.3.d and 4.3.e require performance tests for CO emissions at base load and at outputs less than 116 MW (for natural gas combustion) and 123 MW (for fuel oil combustion). The applicant tested for CO emissions, in part, at 90 MW (for natural gas combustion) and 99 MW (for fuel oil combustion) in order to satisfy the requirements of PSD Condition Nos. 4.3.d and 4.3.e. Based on these test results the applicant showed compliance with the applicable CO BACT emissions limit.

PSD Condition 10.2 was not transferred to the Title V Permit because the applicant has not demonstrated that the operation of the combustion turbines would comply with the applicable short term BACT emission limits below 50% capacity. The applicant has only showed compliance with the applicable short term NOx and CO BACT emission limits at or above 58% load (i.e., 90 MW for natural gas and fuel oil combustion). Thus, PSD Condition

10.2 is not carried over to the Title V Permit. EPD is willing to revisit the excursion values upon demonstration of compliance by the Permittee.

EPD does agree, however, to reduce the excursion parameter for fuel oil combustion from 99 MW to 90 MW because the applicant has demonstrated compliance with the short term NO_x and CO BACT emission limits at the lower output. Note: Testing was not conducted at lower loads for PM emissions.

7. **Draft Condition No. 6.2.1**

Comment: Draft Condition 6.2.1 requires a semiannual analysis of the natural gas sulfur content. The applicant requests deletion of this condition based on an EPA Direct Final Rule for 40 CFR 60 Subpart GG published in the Federal Register on April 14, 2003.

Response: EPA withdrew the cited Direct Final Rule on May 28, 2003. The permit is not changed based on this comment.

8. **Draft Condition No. 6.2.3**

Comment: Tenaska requests that EPD strike the current text and replace it with “*The Permittee shall use one of the total sulfur sampling options for fuel oil and the associated sampling frequency described in sections 2.2.3, 2.2.4.1, 2.2.4.2, and 2.2.4.3 of Appendix D to 40 CFR Part 75 (i.e., flow proportioned sampling, daily sampling, sampling from the unit’s storage tank after each addition of fuel to the tank, or sampling each delivery prior to combining it with fuel oil already in the intended storage tank.*” The company has no reason as to why draft Condition 6.2.3 should be replaced with the requested condition.

Response: Draft Condition 6.2.3 requires the Permittee to verify that each shipment of fuel oil received complies with the specifications for Low Sulfur No. 1-D or Low Sulfur No. 2-D as defined by the American Society for Testing and Materials (ASTM) in ASTM D975-01-“Standard Specifications for Diesel Fuel Oils.” The Permittee is required to obtain a fuel supplier certifications for verification that the oil complies with the specifications for Low Sulfur No. 1-D or Low Sulfur No. 2-D diesel fuel oil.

The Division is requiring Title V facilities, which use diesel fuel oil and fuel oil (i.e., Number 1, Number 2, etc), to obtain fuel oil supplier certifications to verify that the fuel sulfur content meets applicable sulfur limitations. Fuel supplier certifications represent adequate and acceptable means of monitoring fuel sulfur for Title V periodic monitoring requirements. The company’s proposal is unacceptable because it is not specific in regard to a monitoring protocol for fuel sulfur. The proposal would allow the monitoring protocol to be changed at the discretion of the company and that is unacceptable for Title V periodic monitoring purposes. The Division notes, although the Acid Rain Rule (Part 75) has several monitoring options for determining fuel oil sulfur content, the facility must select one protocol. Under the Acid Rain Rule, the facility is required to submit to U.S. Environmental Protection Agency a monitoring plan which contains the selected protocol (i.e., the monitoring plan does not include multiple protocols).

9. **Draft Condition 6.2.5**

Comment: In the first line, reference should be made to Condition 6.2.4, rather than Condition 6.2.5.

Response: EPD agrees to this change.

10. **Attachment B, Insignificant Activities Checklist**

Comment: Tenaska requests revision to the quantities specified for item numbers 3 and 8 under the storage tanks and equipment category.

Response: EPD agrees to these changes.

11. **Draft Condition Nos. 6.2.5, 6.2.6, 6.2.10, and 6.2.11**

Comment: These conditions refer to a “rolling twelve consecutive month period” and Draft Condition 6.2.6 defines this phrase. The applicant expressed confusion regarding the definition citing that the definition implies that a rolling twelve consecutive month total be calculated on a daily or continuous basis.

Response: The applicant did not propose new language even though they found the proposed language confusing. With that in mind, EPD believes that the applicant is reading more into the condition language than necessary. The rolling twelve consecutive month total only needs to be computed once on a monthly basis and not continually or on a daily basis.

EPD does believe that the definition of a “rolling twelve month period” needs to be added to Draft Conditions 6.2.5.b.

12. **Draft Condition No. 6.2.11 (Comment letter identifies as Condition 6.2.12)**

Comment: The applicant requests deletion of the reporting conditions specified in this condition as these reporting requirements are not required by their PSD Permit.

Response: The reporting requirements are added for Part 70 purposes. EPD has removed PSD as a legal authority for this condition.

13. **Draft Condition No. 7.10**

Comment: This condition refers to the Prevention of Accidental Releases (Section 112(r) of the 1990 CAAA) that is not applicable to this facility. The applicant requests that the condition include a statement that this regulation is not an applicable requirement.

Response: EPD reminds the applicant that the opening sentence of this condition states, “When and if the requirements of 40 CFR Part 68 become applicable, ...” EPD does not believe that a statement, as proposed by the applicant, is necessary. The permit is not changed based on this comment.

14. **Draft Condition No. 7.11**

Comment: This condition refers to the Stratospheric Ozone Protection Requirements that is not applicable to this facility. The applicant requests that the condition include a statement that this regulation is not an applicable requirement.

Response: EPD does not believe that a statement, as proposed by the applicant, is necessary. The permit is not changed based on this comment.

Comments by Stack & Associates, P.C. on Behalf of Specified Members of the Public**1. Formaldehyde Emissions**

Comment: Much like the original PSD permit for this facility, there does not appear to have been any testing or consideration given to formaldehyde emissions from this facility. The draft permit does not provide for any monitoring for such emissions. At a minimum, the permit should require testing for potential formaldehyde emissions with further provisions to address such emissions as needed.

Response: The applicant noted in Section 2.10 that the facility's potential total hazardous air pollutant (HAP) emissions was less than 10 tons per year. The applicant's PSD and Title V permit applications specify the following formaldehyde emissions from natural gas combustion:

Source	Emissions lb/hr/turbine	PTE (TPY)*	Reference	Combustion Mode
PSD Application	6.1	56.1	NA	NA
Title V Application Table B1a	5.69	52.3	AP-42 (1998)	Diffusion Flame
Title V Application Table B2a	0.259	2.4	AP-42 (2000)	Dry Low NOx Combustor

*At 3,066 hrs/yr

EPD believes that the dry low NOx combustors on each turbine impact the generation of formaldehyde emissions much the same way that catalytic oxidation controls formaldehyde emissions. Namely, formaldehyde emissions from dry low NOx combustors (AP-42, 2000) are lower than from diffusion flame combustion (AP-42, 1998). EPD expects the facility-wide formaldehyde emissions, generated from natural gas combustion, are less than 10 tons per year. Nonetheless, EPD will require a formaldehyde emissions performance test on one combustion turbine to verify this belief. The testing requirement is incorporated into the final Title V permit as New Condition 4.2.1. The results of the performance tests will be used to determine if the facility is a major source of formaldehyde emissions and whether additional requirements apply.

2. Reference to Georgia Rule (nnn)

Comment: Draft Condition Nos. 3.3.6.a and 3.3.9.a specify the short term PSD BACT NOx emission limits. Draft Condition No. 3.4.1 specifies the short term NOx RACT requirement in accordance with Georgia Rule (nnn). The commenter asserts that the permit must include language which clarifies which short term emission limit applies during the ozone season. They base this assertion on the fact that Draft Condition No. 3.4.1 specifies an emission limit which is more stringent than Draft Condition 3.3.9.a.

Secondly, the commenter encourages EPD to deny the applicant's request for a revision to Georgia Rule (nnn).

Response: The following legal authority is added to Draft Condition Nos. 3.3.6.a and 3.3.9.a: [40 CFR 52.21(j)(2) and 391-3-1-.02(2)(nnn)(subsumed)].

EPD has determined that no additional language needs to be incorporated in Draft Condition 3.4.1 which identifies when the prescribed short term limit applies. EPD believes that by adding the updated legal authority to Draft Condition 3.3.9.a, that the permit as written clearly states the applicable requirements.

EPD will consider the commenter's assertion regarding the need, or lack thereof, for revising Georgia Rule (nnn) outside of the Title V process.

3. Draft Condition 8.2.1

Comment: As currently written this paragraph states that the terms and conditions of the permit are enforceable by “. . . the EPA and citizens under the Clean Air Act” However, in order to remain consistent with the actual language of the Clean Air Act, 42 U.S.C. §7406(a), this section must state that the permit may be enforced by “any person.”

Response: EPD disagrees with the commenter that the word “citizen” is not supported by the legal record. EPD believes that the word “citizen” is correct and EPD basis its decision on the following:

“Section 304 of the Clean Air Act (Act) entitled “Citizen suits” provides that “any person may commence a civil action “for, among other things, violations of an emission standard or limitation in a Title V permit, provided certain notice requirements are met. 42 U.S.C. §7604. U.S. EPA’s regulations implementing this provision require all Title V permits to contain a condition stating that “[a]ll [federally-enforceable] terms and condition in a part 70 permit, including any provisions designed to limit the source’s potential to emit, are enforceable by the Administrator [of U.S. EPA] and citizens under the Act.” (Emphasis added.) See 40 C.F.R. §70.6(b)(1).”
[See letter from Diane L. DeShazo, Assistant Attorney General for the State of Georgia, to Stanley Meiburg, Acting Regional Administrator, EPA Region 4, (Sept. 6, 2001)]

Draft Condition No. 8.2.1 contains this same requirement as 40 CFR 70.6(b)(1). Draft Condition No. 8.2.1 reads as follows:

“Except as identified as ‘State-only enforceable’ requirements in this Permit, all terms and conditions contained herein shall be enforceable by the EPA and citizens under the Clean Air Act, as amended, 42 U.S.C. 7401, et seq. [40 CFR 70.6(b)(1)]”

Thus this condition is not revised based on this request.

Comments by Exelon Generation**1. Georgia Rule (nnn) Applicability**

Comment: Exelon objected to EPD’s interpretation of the phrase “with no natural gas” found in Georgia Rule (nnn)I.(ii) stating that such an interpretation will prevent the facility from generating electricity under fuel oil operation during the summer season. Exelon notes that such a prohibition is not in the best interests of the consumers and citizens of Georgia.

Response: EPD will consider the commenter’s assertion regarding the need, or lack thereof, for revising Georgia Rule (nnn) outside of the Title V process.

MODIFIED CONDITIONS FOR
PERMIT NO. 4911-149-0049-V-02-0

1.3 Overall Facility Process Description

The facility consists of six simple cycle combustion turbines. The units fire natural gas as primary fuel and fuel oil as backup. Each turbine is equipped with dry low NO_x combustors and water ~~and/or steam~~ injection for control of NO_x emissions. Each combustion turbine generates a base load rating of approximately 166 megawatts (for natural gas combustion) and 174 megawatts (for fuel oil combustion) at 59 deg. F. Each turbine vents through its own 70 foot stack.

3.1 Emission Units

Emission Units		Specific Limitations/Requirements		Air Pollution Control Devices	
ID No.	Description	Applicable Requirements/Standards	Corresponding Permit Conditions	ID No.	Description
CT01	Combustion Turbine	391-3-1-.02(2)(g) 391-3-1-.02(2)(b) 391-3-1-.02(2)(nnn) 40 CFR 52.21 40 CFR 60, Subpart A 40 CFR 60, Subpart GG Acid Rain Regulations	3.3.1 through 3.3.9 3.4.1, 5.2.1 through 5.2.5, 6.2.1 through 6.2.7, 6.2.9 through 6.2.12	DRY1 WAT1	Dry Low NO _x Combustor Water and/or Steam Injection
CT02	Combustion Turbine	391-3-1-.02(2)(g) 391-3-1-.02(2)(b) 391-3-1-.02(2)(nnn) 40 CFR 52.21 40 CFR 60, Subpart A 40 CFR 60, Subpart GG Acid Rain Regulations	See CT01	DRY2 WAT2	Dry Low NO _x Combustor Water and/or Steam Injection
CT03	Combustion Turbine	391-3-1-.02(2)(g) 391-3-1-.02(2)(b) 391-3-1-.02(2)(nnn) 40 CFR 52.21 40 CFR 60, Subpart A 40 CFR 60, Subpart GG Acid Rain Regulations	See CT01	DRY3 WAT3	Dry Low NO _x Combustor Water and/or Steam Injection
CT04	Combustion Turbine	391-3-1-.02(2)(g) 391-3-1-.02(2)(b) 391-3-1-.02(2)(nnn) 40 CFR 52.21 40 CFR 60, Subpart A 40 CFR 60, Subpart GG Acid Rain Regulations	See CT01	DRY4 WAT4	Dry Low NO _x Combustor Water and/or Steam Injection
CT05	Combustion Turbine	391-3-1-.02(2)(g) 391-3-1-.02(2)(b) 391-3-1-.02(2)(nnn) 40 CFR 52.21 40 CFR 60, Subpart A 40 CFR 60, Subpart GG Acid Rain Regulations	See CT01	DRY5 WAT5	Dry Low NO _x Combustor Water and/or Steam Injection
CT06	Combustion Turbine	391-3-1-.02(2)(g) 391-3-1-.02(2)(b) 391-3-1-.02(2)(nnn) 40 CFR 52.21 40 CFR 60, Subpart A 40 CFR 60, Subpart GG Acid Rain Regulations	See CT01	DRY6 WAT6	Dry Low NO _x Combustor Water and/or Steam Injection

Emission Units		Specific Limitations/Requirements		Air Pollution Control Devices	
ID No.	Description	Applicable Requirements/Standards	Corresponding Permit Conditions	ID No.	Description
FOST1	6.93 million gallon No. 2 fuel oil storage tank	40 CFR 52.21 40 CFR 60 Subpart Kb	6.2.8	NA	None

3.3.3 The Permittee shall install and operate, as Best Available Control Technology (BACT), for nitrogen oxides on each combustion turbine, (Emission Unit ID Nos. CT01, CT02, CT03, CT04, CT05, and CT06) dry low NOx combustors for natural gas combustion and water ~~and/or steam~~ injection for fuel oil combustion. [40 CFR 52.21(j)(2)]

3.3.6 The Permittee shall not discharge, or cause the discharge, into the atmosphere, from each combustion turbine (Emission Unit ID Nos. CT01, CT02, CT03, CT04, CT05, and CT06), when the combustion turbine is fired with natural gas, any gases which:

- a. Contain nitrogen oxides in excess of 15 ppmvd, corrected to 15% oxygen.
- b. Contain carbon monoxide in excess of 15 ppmvd, corrected to 15% oxygen.
[40 CFR 52.21(j)(2)]
- c. Contain particulate matter in excess of 0.010 pounds per million Btu heat input, HHV basis. [~~Note: Equivalent to 21.5 lb/hr at full load~~]
[40 CFR 52.21(j)(2)]
- d. Contain volatile organic compounds in excess of 0.003 pounds per million Btu heat input, as methane, HHV. [40 CFR 52.21(j)(2)]
- e. Exhibit greater than 10 percent opacity.
[40 CFR 52.21(j)(2) and 391-3-1-.02(2)(b) (subsumed)]

4.3.1

~~l. Method 25.3 [South Coast Air Quality Management District (Los Angeles, CA) — Determination of Low Concentration Non Methane Non Ethane Organic Compound Emissions from Cleans Fueled Combustion Sources] shall be used for the determination of concentrations of volatile organic compounds. The sampling time for each run shall be for one hour.~~

l. Method 25A for the determination of concentration of volatile organic compounds. The minimum sampling time shall be one hour.

m. Test method results in New Condition 4.1.3.n which reads as follows: Method 0011 for the determination of concentration of formaldehyde.

4.2.1 Within 180 days of the Effective Date of this Permit, the Permittee shall conduct a formaldehyde emissions test on one of the combustion turbines (emission unit ID Nos. CT01, CT02, CT03, CT04, CT05, and CT06) at base load and fifty (50) percent load while firing natural gas. The Permittee shall furnish to the Division a written report of the results of such performance tests. The results of

the performance tests will be used to determine if the facility is a major source of formaldehyde emissions and whether additional requirements apply. [391-3-1-.02(6)(b)1(i)]

- 6.1.7 For the purpose of reporting excess emissions, exceedances or excursions in the report required in Condition 6.1.4, the following excess emissions, exceedances, and excursions shall be reported: [391-3-1-.02(6)(b)1 and 40 CFR 70.6(a)(3)(i)]
- c. Excursions: (means for the purpose of this Condition and Condition 6.1.4, any departure from an indicator range or value established for monitoring consistent with any averaging period specified for averaging the results of the monitoring)
 - ii. Any one-hour period, excluding periods of startup, shutdown, and malfunction, during which the average megawatt output of a combustion turbine (Emission Unit ID Nos. CT01, CT02, CT03, CT04, CT05, and CT06), firing fuel oil, is less than ~~99~~ **90** megawatts.
- 6.2.5 The Permittee shall use the fuel oil usage data required by Condition ~~6.2.5~~ **6.2.4** to determine and record the following, as it relates to the combustion turbines (Emission Unit ID Nos. CT01, CT02, CT03, CT04, CT05, and CT06), on a monthly basis: [391-3-1-.02(6)(b)1., 40 CFR 52.21, and 40 CFR 70.6(a)(3)(i)]
- a. The total monthly fuel oil usage (gallons) for the combustion turbines on a combined basis.
 - b. The rolling twelve month total fuel oil usage (gallons) for the combustion turbines on a combined basis. **A twelve consecutive month total shall be the total for a month in the reporting period plus the totals of the previous eleven consecutive months. These records (including calculations) shall be maintained as part of the monthly record suitable for inspection or submittal.**
- 6.2.11 The Permittee shall submit a report of the following information for each semiannual period ending June 30 and December 31 of each year. The reports shall be postmarked by the 30th day following the end of the semiannual period (July 30 and January 30, respectively). [391-3-1-.02(6)(b)1., ~~40 CFR 52.21~~, and 40 CFR 70.6(a)(3)(i)]
- a. The rolling twelve consecutive month total NO_x emissions (in tons) from all combustion turbines (Emission Unit ID Nos.: CT01, CT02, CT03, CT04, CT05, and CT06), on a combined basis, for each month in the reporting period.
 - b. The rolling twelve consecutive month fuel oil usage (in gallons) for the combustion turbines (Emission Unit ID Nos.: CT01, CT02, CT03, CT04, CT05, and CT06), on a combined basis, for each month in the reporting period;
 - c. The rolling twelve consecutive month average hours of operation for each combustion turbine (Emission Unit ID Nos.: CT01, CT02, CT03, CT04, CT05, and CT06), for each month in the reporting period;
 - d. A copy of the fuel oil supplier certifications for each shipment of fuel oil received during the reporting period and a statement signed by a responsible official that the records of fuel supplier certifications submitted represent all of the fuel oil

received during the semiannual reporting period. If no fuel oil has been received during the reporting period, the report should so state.

INSIGNIFICANT ACTIVITIES CHECKLIST

Category	Description of Insignificant Activity/Unit	Quantity
Storage Tanks and Equipment	1. All petroleum liquid storage tanks storing a liquid with a true vapor pressure of equal to or less than 0.50 psia as stored.	1
	2. All petroleum liquid storage tanks with a capacity of less than 40,000 gallons storing a liquid with a true vapor pressure of equal to or less than 2.0 psia as stored that are not subject to any standard, limitation or other requirement under Section 111 or 112 (excluding 112(r)) of the Federal Act.	0
	3. All petroleum liquid storage tanks with a capacity of less than 10,000 gallons storing a petroleum liquid.	1 8
	4. All pressurized vessels designed to operate in excess of 30 psig storing petroleum fuels that are not subject to any standard, limitation or other requirement under Section 111 or 112 (excluding 112(r)) of the Federal Act.	0
	5. Gasoline storage and handling equipment at loading facilities handling less than 20,000 gallons per day or at vehicle dispensing facilities that are not subject to any standard, limitation or other requirement under Section 111 or 112 (excluding 112(r)) of the Federal Act.	0
	6. Portable drums, barrels, and totes provided that the volume of each container does not exceed 550 gallons.	8 Varies
	7. All chemical storage tanks used to store a chemical with a true vapor pressure of less than or equal to 10 millimeters of mercury (0.19 psia).	0