ADEQ

A R K A N S A S
Department of Environmental Quality

JUL 7 2010

Lacey Ivey, Environmental Specialist
CenterPoint Energy - Mississippi River Transmission Corp. - Tuckerman Compressor Station
P.O. Box 21734
Shreveport, LA 71151

Dear Ms. Ivey:

The enclosed Permit No. 1419-AOP-R4 is issued pursuant to the Arkansas Operating Permit Program, Regulation # 26.

After considering the facts and requirements of A.C.A. §8-4-101 et seq., and implementing regulations, I have determined that Permit No. 1419-AOP-R4 for the construction, operation and maintenance of an air pollution control system for CenterPoint Energy - Mississippi River Transmission Corp. - Tuckerman Compressor Station to be issued and effective on the date specified in the permit, unless a Commission review has been properly requested under Arkansas Department of Pollution Control & Ecology Commission's Administrative Procedures, Regulation 8.603, within thirty (30) days after service of this decision.

All persons submitting written comments during the thirty (30) day, and all other persons entitled to do so, may request an adjudicatory hearing and Commission review on whether the decision of the Director should be reversed or modified. Such a request shall be in the form and manner required by Regulation 8.603, including filing a written Request for Hearing with the APC&E Commission Secretary at 101 E. Capitol Ave., Suite 205, Little Rock, Arkansas 72201. If you have any questions about filing the request, please call the Commission at 501-682-7890.

Sincerely,

Mike Bates
Chief, Air Division

ADEQ
OPERATING
AIR PERMIT

Pursuant to the Regulations of the Arkansas Operating Air Permit Program, Regulation 26:

Permit No. : 1419-AOP-R4

IS ISSUED TO:

CenterPoint Energy - Mississippi River Transmission Corp. -
Tuckerman Compressor Station
Gracelawn Street
Tuckerman, AR 72473
Jackson County
AFIN: 34-00111

THIS PERMIT AUTHORIZES THE ABOVE REFERENCED PERMITTEE TO INSTALL, OPERATE, AND MAINTAIN THE EQUIPMENT AND EMISSION UNITS DESCRIBED IN THE PERMIT APPLICATION AND ON THE FOLLOWING PAGES. THIS PERMIT IS VALID BETWEEN:

JUL 7 2010 AND JUL 6 2015

THE PERMITTEE IS SUBJECT TO ALL LIMITS AND CONDITIONS CONTAINED HEREIN.

Signed:

Mike Bates
Chief, Air Division

JUL 7 2010
Date

CenterPoint Energy - Mississippi River Transmission Corp. - Tuckerman Compressor Station
Permit #: 1419-AOP-R4
AFIN: 34-00111

Table of Contents

List of Acronyms and Abbreviations

A.C.A.	Arkansas Code Annotated
AFIN	ADEQ Facility Identification Number
CFR	Code of Federal Regulations
CO	Carbon Monoxide
HAP	Hazardous Air Pollutant
lb/hr	Pound Per Hour
MVAC	Motor Vehicle Air Conditioner
No.	Number
NO_x	Nitrogen Oxide
PM	Particulate Matter
PM_{10}	Particulate Matter Smaller Than Ten Microns
SNAP	Significant New Alternatives Program (SNAP)
SO_2	Sulfur Dioxide
SSM	Startup, Shutdown, and Malfunction Plan
Tpy	Tons Per Year
UTM	Universal Transverse Mercator
VOC	Volatile Organic Compound

SECTION I: FACILITY INFORMATION

PERMITTEE:	CenterPoint Energy - Mississippi River Transmission Corp. - Tuckerman Compressor Station
AFIN:	34-00111
PERMIT NUMBER:	1419-AOP-R4
FACILITY ADDRESS:	Gracelawn Street Tuckerman, AR 72473
MAILING ADDRESS:	P.O. Box 21734 Shreveport, LA 71151
COUNTY:	Jackson County
CONTACT NAME:	Lacey Ivey
CONTACT POSITION:	Environmental Specialist
TELEPHONE NUMBER:	318-429-3297
REVIEWING ENGINEER:	Andrea Sandage
UTM North South (Y):	Zone 15: 3953873.97 m
UTM East West (X):	Zone 15: 661059.97 m

SECTION II: INTRODUCTION

Summary of Permit Activity

CenterPoint Energy - Mississippi River Transmission Corporation (MRT) owns and operates a compressor station near Tuckerman, Arkansas. There are no changes in the method of operation at this Title V facility.

This permitting action is necessary to renew the Title 5 permit which is set to expire on July 19, 2010. Included in this renewal is the request submitted October 19, 2009 to update the insignificant activities by removing two 150-gallon diesel storage tanks and adding one 500-gallon diesel storage tank to group A-3. This request was accepted as an Administrative Amendment and will be incorporated in this permit.

Any changes in source emissions are a result of new factors or clerical/rounding errors and do not represent a change in the operating scenario. The total decrease in emissions include: 7.8 tpy NO_X, 0.60 tpy Acetaldehyde, 0.60 tpy Acrolein, 4.40 tpy formaldehyde, and 0.20 tpy Methanol. The total increase in emissions include: 7.9 tpy CO, and 0.10 tpy Toluene.

Process Description

Friction losses cause a drop in pressure in natural gas pipelines. To maintain flow, gas must be removed from the pipeline, compressed, and returned to the pipeline. Natural gas enters the station and is compressed, exiting the station at a higher pressure. Prior to compression, the gas passes through an inlet separator where entrained liquids are removed from the gas stream. Pipeline liquids are stored in the produced water tank and removed from the station via tanker truck when necessary.

This compressor station currently has four Clark HRA-8 880 HP compressor engines, one Worthington LTC-5 625 HP compressor engine, one Clark TRA-6 1,100 HP compressor engine, one Solar Taurus 5,850 HP turbine drive centrifugal compressor, one Caterpillar G-379 300 HP engine generator, and one Olympian 64 HP engine generator. Support equipment includes several tanks and an engine oil filter incinerator which are considered insignificant activities

Limits on allowable hours of operation for the Solar Taurus turbine, its associated emergency generator, and the Caterpillar generator established for PSD netting in 1419-AOP-R2 are maintained in this permit.

Regulations

The following table contains the regulations applicable to this permit.

Regulations
Arkansas Air Pollution Control Code, Regulation 18, effective January 25, 2009

Regulations
Regulations of the Arkansas Plan of Implementation for Air Pollution Control, Regulation 19, effective July 18, 2009
Regulations of the Arkansas Operating Air Permit Program, Regulation 26, effective January 25, 2009
40 CFR Part 60 Subpart GG - *Standards of Performance for Stationary Gas Turbines*
40 CFR Part 63 Subpart ZZZZ - *National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines*. However, the stationary RICEs (SN-01 thru SN-04, SN-06, and SN-08) at this facility do not have to meet the requirements of this subpart, and no initial notification is necessary pursuant to 40 CFR 63.6590(b)(3) since they are existing 2SLB engines.
40 CFR Part 63 Subpart YYYY - *National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines.* However, the stationary combustion turbine (SN-11) at this facility does not have to meet the requirements of this subpart, and no initial notification is necessary pursuant to 40 CFR 63.6090(b)(4) since it is not new or reconstructed.

Emission Summary

The following table is a summary of emissions from the facility. This table, in itself, is not an enforceable condition of the permit.

EMISSION SUMMARY				
Source Number	Description	Pollutant	Emission Rates	
			lb/hr	tpy
Total Allowable Emissions		PM/PM_{10}	1.8	4.5
		SO_2	1.1	1.4
		VOC	9.0	37.6
		CO	48.2	159.3
		NO_X	281.0	1133.4
		*Acetaldehyde**	0.55	1.80
		*Acrolein**	0.33	1.34
		*Benzene**	0.14	0.39
		*Formaldehyde**	2.36	9.80
		*Methanol**	0.13	0.45
		*Toluene**	0.09	0.21
01	Clark HRA-8 compressor engine (880 HP)	PM/PM_{10}	0.2	0.6
		SO_2	0.1	0.1
		VOC	1.6	6.8
		CO	4.2	18.1

EMISSION SUMMARY				
Source Number	Description	Pollutant	Emission Rates	
			lb/hr	tpy
	2 stroke lean burn	NO_x	45.4	198.5
		Acetaldehyde	0.05	0.22
		Acrolein	0.05	0.22
		Benzene	0.02	0.06
		Formaldehyde	0.35	1.55
		Methanol	0.02	0.07
		Toluene	0.01	0.03
02	Clark HRA-8 compressor engine (880 HP) 2 stroke lean burn	PM/PM_{10}	0.2	0.6
		SO_2	0.1	0.1
		VOC	1.6	6.8
		CO	4.2	18.1
		NO_x	45.4	198.5
		Acetaldehyde	0.05	0.22
		Acrolein	0.05	0.22
		Benzene	0.02	0.06
		Formaldehyde	0.35	1.55
		Methanol	0.02	0.07
		Toluene	0.01	0.03
03	Clark HRA-8 compressor engine (880 HP) 2 stroke lean burn	PM/PM_{10}	0.2	0.6
		SO_2	0.1	0.1
		VOC	1.6	6.8
		CO	4.2	18.1
		NO_x	45.4	198.5
		Acetaldehyde	0.05	0.22
		Acrolein	0.05	0.22
		Benzene	0.02	0.06
		Formaldehyde	0.35	1.55
		Methanol	0.02	0.07
		Toluene	0.01	0.03
04	Clark HRA-8 compressor engine (880 HP) 2 stroke lean burn	PM/PM_{10}	0.2	0.6
		SO_2	0.1	0.1
		VOC	1.6	6.8
		CO	4.2	18.1
		NO_x	45.4	198.5
		Acetaldehyde	0.05	0.22
		Acrolein	0.05	0.22
		Benzene	0.02	0.06
		Formaldehyde	0.35	1.55
		Methanol	0.02	0.07
		Toluene	0.01	0.03

EMISSION SUMMARY				
Source Number	Description	Pollutant	Emission Rates	
			lb/hr	tpy
06	Worthington LTC-5 compressor engine (625 HP) 2 stroke lean burn	PM/PM_{10}	0.1	0.4
		SO_2	0.1	0.1
		VOC	0.9	3.9
		CO	2.7	11.9
		NO_x	28.5	124.6
		Acetaldehyde	0.04	0.15
		Acrolein	0.04	0.15
		Benzene	0.01	0.04
		Formaldehyde	0.25	1.10
		Methanol	0.01	0.05
		Toluene	0.01	0.02
08	Clark TRA compressor engine (1,100 HP) 2 stroke lean burn	PM/PM_{10}	0.2	0.5
		SO_2	0.1	0.1
		VOC	1.3	5.8
		CO	9.0	39.5
		NO_x	30.6	133.7
		Acetaldehyde	0.06	0.27
		Acrolein	0.06	0.27
		Benzene	0.02	0.07
		Formaldehyde	0.44	1.93
		Methanol	0.02	0.09
		Toluene	0.01	0.03
10	Caterpillar G379 generator engine (300 HP) 4 stroke rich burn	PM/PM_{10}	0.1	0.1
		SO_2	0.1	0.1
		VOC	0.1	0.2
		CO	9.9	20.2
		NO_x	6.1	12.4
		Acetaldehyde	0.01	0.02
		Acrolein	0.01	0.02
		Benzene	0.01	0.01
		Formaldehyde	0.04	0.10
		Methanol	0.01	0.02
		Toluene	0.01	0.01
11	Solar Taurus Model 60 T7000 turbine engine (5,850 HP)	PM/PM_{10}	0.5	1.0
		SO_2	0.3	0.6
		VOC	0.2	0.4
		CO	7.0	14.6
		NO_x	32.5	68.2
		Acetaldehyde	0.23	0.47
		Acrolein	0.01	0.01

EMISSION SUMMARY				
Source Number	Description	Pollutant	Emission Rates	
			lb/hr	tpy
		Benzene	0.01	0.02
		Formaldehyde	0.22	0.46
		Toluene	0.01	0.02
12	Olympian Standby generator engine (64 HP) 4 stroke rich burn	PM/PM_{10}	0.1	0.1
		SO_2	0.1	0.1
		VOC	0.1	0.1
		CO	2.8	0.7
		NO_x	1.7	0.5
		Acetaldehyde	0.01	0.01
		Acrolein	0.01	0.01
		Benzene	0.01	0.01
		Formaldehyde	0.01	0.01
		Methanol	0.01	0.01
		Toluene	0.01	0.01

*HAPs included in the VOC totals. Italic indicates HAPs. Other HAPs are not included in any other totals unless specifically stated.

SECTION III: PERMIT HISTORY

Mississippi River Transmission Corporation -Tuckerman Compressor Station began operation in 1950.

Permit No. 1419-A was issued to MRTC on December 14, 1992. This permit was for eight reciprocating engines, one engine driven generator, and one emergency engine driven generator. No blowdown or fugitive emissions were listed. Hourly and annual emissions were listed for each source. Facility wide annual emissions were listed. Permitted pollutants were sulfur dioxide, volatile organic compounds, carbon monoxide, and oxides of nitrogen.

Permit No. 1419-AR-1 was issued to MRTC on June 8, 1994. No modifications were done to the facility. The major permit change was that the maximum allowable fuel rate changed from a per unit maximum to an overall facility maximum.

Permit No. 1419-AR-2 was issued to MRTC on March 13, 1996. The facility was changed by removing two compressor engines from service (two Worthington LTC-5 625 HP Engine Compressors - SN-05 & SN-07) and one of the engine generators (SN-09), and adding a Solar Taurus 5,850 HP turbine driven compressor (SN-11) and its associated 64 HP Olympian standby engine generator (SN-12). Blowdown emissions and minor emissions from the station tanks were added. This permit involved a PSD netting to ensure that addition of the Solar Taurus turbine driven compressor (and its associated generator) resulted in a less than 40 tpy increase. This new compressor (and its associated generator) and the existing power generator were restricted in allowable hours of operation.

Permit No. 1419-AOP-R0 was the initial Title V permit. There were no physical changes to the facility.

Permit No. 1419-AOP-R1- was issued on July 12, 2000. This permit was issued as the result of an agreement upon changes in the Permit Appeal Resolution (PAR).

Permit No.1419-AOP-R2- was issued on July 20 , 2005 as a renewal. This Title V air permit renewal revises PM/PM_{10}, SO_2, VOC, and HAPs emission limits of the compressor and turbine engines by using the USEPA AP-42 and GRI-HAPCalc emission factors. NO_X emissions from SN-10 are revised using USEPA AP-42 emission factor. The stack testing schedule for the compressor engines and turbines is also being clarified. There are no physical changes or changes in the method of operation at the facility.

Permit No. 1419-AOP-R3 was issued July 3, 2006. This permit was a Minor Modification to change the requirements for fuel sulfur monitoring under 40 CFR 60 Subpart GG. This modification requests the removal of sub-sections (c) through (j) from Specific Condition 15 for the natural gas fired compressor turbine (SN-11). In accordance with 40 CFR 63.334(h)(3), MRT has elected to demonstrate that the gaseous fuel combusted in SN-11 meets the definition of natural gas by maintaining appropriate records onsite that specify the maximum sulfur content of the gaseous fuel shall not exceed 20.0 grains/100 scf as specified in 40 CFR 63.334(h)(3)(i).

SECTION IV: SPECIFIC CONDITIONS

SN-01 thru SN-04, SN-06 and SN-08
Compressor Engines

Source Description

Four 880 HP Clark HRA-8 compressor engines (SN-01, SN-02, SN-03, and SN-04) were installed/last modified in 1950; a 625 HP Worthington LTC-5 compressor engine (SN-06) and a 1,100 HP Clark TRA-6 compressor engine (SN-08) were installed/last modified in 1952. The purpose of the compressor station is to compress natural gas. The gas is removed from the pipeline, sent to the compressors (SN-01 thru SN-04, SN-06 and SN-08) to be compressed, cooled, delivered to the discharge piping system, and back to the pipeline. The reciprocating engines are capable of running at 120% of capacity and are being permitted to do so.

Specific Conditions

1. The permittee shall not exceed the emission rates set forth in the following table. The permittee shall demonstrate compliance with this condition by Plantwide Condition 7. [Regulation 19, §19.501 et seq., and 40 CFR Part 52, Subpart E]

SN	Description	Pollutant	lb/hr	tpy
01	Clark HRA-8 880 HP Installed/modified 1950	PM_{10} SO_2 VOC CO NO_X	0.2 0.1 1.6 4.2 45.4	0.6 0.1 6.8 18.1 198.5
02	Clark HRA-8 880 HP Installed/modified 1950	PM_{10} SO_2 VOC CO NO_X	0.2 0.1 1.6 4.2 45.4	0.6 0.1 6.8 18.1 198.5
03	Clark HRA-8 880 HP Installed/modified 1950	PM_{10} SO_2 VOC CO NO_X	0.2 0.1 1.6 4.2 45.4	0.6 0.1 6.8 18.1 198.5
04	Clark HRA-8 880 HP Installed/modified 1950	PM_{10} SO_2 VOC CO NO_X	0.2 0.1 1.6 4.2 45.4	0.6 0.1 6.8 18.1 198.5

SN	Description	Pollutant	lb/hr	tpy
06	Worthington LTC-5 625 HP Installed/modified 1952	PM_{10} SO_2 VOC CO NO_X	0.1 0.1 0.9 2.7 28.5	0.4 0.1 3.9 11.9 124.6
08	Clark TRA-6 1100 HP Installed/modified 1952	PM_{10} SO_2 VOC CO NO_X	0.2 0.1 1.3 9.0 30.6	0.5 0.1 5.8 39.5 133.7

2. The permittee shall not exceed the emission rates set forth in the following table. The permittee shall demonstrate compliance with the HAP emissions with the use of natural gas and operating at or below maximum capacity of the equipment. The HAP emissions listed for these sources were based upon published emission factors at the time of permit issuance. Any change in these emission factors will not constitute a violation of the HAP emission rate listed below.. [Regulation 18, §18.801, and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

SN	Description	Pollutant	lb/hr	tpy
01	Clark HRA-8 880 HP Installed/modified 1950	PM *Acetaldehyde* *Acrolein* *Benzene* *Formaldehyde* *Methanol* *Toluene*	0.2 0.05 0.05 0.02 0.35 0.02 0.01	0.6 0.22 0.22 0.06 1.55 0.07 0.03
02	Clark HRA-8 880 HP Installed/modified 1950	PM *Acetaldehyde* *Acrolein* *Benzene* *Formaldehyde* *Methanol* *Toluene*	0.2 0.05 0.05 0.02 0.35 0.02 0.01	0.6 0.22 0.22 0.06 1.55 0.07 0.03
03	Clark HRA-8 880 HP Installed/modified 1950	PM *Acetaldehyde* *Acrolein* *Benzene* *Formaldehyde* *Methanol* *Toluene*	0.2 0.05 0.05 0.02 0.35 0.02 0.01	0.6 0.22 0.22 0.06 1.55 0.07 0.03

SN	Description	Pollutant	lb/hr	tpy
04	Clark HRA-8 880 HP Installed/modified 1950	PM	0.2	0.6
		Acetaldehyde	0.05	0.22
		Acrolein	0.05	0.22
		Benzene	0.02	0.06
		Formaldehyde	0.35	1.55
		Methanol	0.02	0.07
		Toluene	0.01	0.03
06	Worthington LTC-5 625 HP Installed/modified 1952	PM	0.1	0.4
		Acetaldehyde	0.04	0.15
		Acrolein	0.04	0.15
		Benzene	0.01	0.04
		Formaldehyde	0.25	1.10
		Methanol	0.01	0.05
		Toluene	0.01	0.02
08	Clark TRA-6 1100 HP Installed/modified 1952	PM	0.2	0.5
		Acetaldehyde	0.06	0.27
		Acrolein	0.06	0.27
		Benzene	0.02	0.07
		Formaldehyde	0.44	1.93
		Methanol	0.02	0.09
		Toluene	0.01	0.03

3. The permittee shall not exceed 5% opacity from source SN-01 thru SN-04, SN-06, and SN-08 as measured by EPA Reference Method 9. Compliance with this condition shall be demonstrated by burning pipeline quality natural gas. [Regulation 18, §18.501, and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

SN-10
Natural Gas Generator Engine

Source Description

Source SN-10, a 300 HP Caterpillar G-379 Generator Engine, was last installed or modified in 1981. This engine is being permitted to run at 100% of its rated load capacity. The unit is restricted on hours of operation (per rolling 12 months period) and therefore tons emissions per year (because of the netting done in Permit No. 1419-AR-2).

Specific Conditions

4. The permittee shall not exceed the emission rates set forth in the following table. The permittee shall demonstrate compliance with this condition by the use of natural gas and a restriction on the hours of operation of the equipment. [Regulation 19, §19.501 et seq. and 40 CFR Part 52, Subpart E]

SN	Description	Pollutant	lb/hr	tpy
10	Caterpillar G-379 300HP Installed/modified 1981	PM_{10}	0.1	0.1
		SO_2	0.1	0.1
		VOC	0.1	0.2
		CO	9.9	20.2
		NO_x	6.1	12.4

5. The permittee shall not exceed the emission rates set forth in the following table. The permittee shall demonstrate compliance with this condition by the use of natural gas and a restriction on the hours of operation of the equipment. The HAP emissions listed for this source were based upon published emission factors at the time of permit issuance. Any change in these emission factors will not constitute a violation of the HAP emission rates listed below. [Regulation 18, §18.801 and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

SN	Description	Pollutant	lb/hr	tpy
10	Caterpillar G-379 300HP Installed/modified 1981	PM	0.1	0.1
		Acetaldehyde	0.01	0.02
		Acrolein	0.01	0.02
		Benzene	0.01	0.01
		Formaldehyde	0.04	0.10
		Methanol	0.01	0.02
		Toluene	0.01	0.01

6. The permittee shall not exceed 5% opacity from source SN-10 as measured by EPA Reference Method 9. Compliance with this condition shall be demonstrated by burning

pipeline quality natural gas. [Regulation 18, §18.501, and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

7. The permittee shall not operate SN-10 more than 4,086 hours in any consecutive twelve month period. [Regulation 19, §19.705, 40 CFR 70.6, and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

8. The permittee shall maintain records which demonstrate compliance with the limit set in Specific Condition #7. These records may be used by the Department for enforcement purposes. The records shall be updated on a monthly basis, shall be kept at the nearest manned location, and shall be provided to the Department personnel upon request. [Regulation 19, §19.705, and 40 CFR Part 52]

SN-11
Natural Gas Compressor Turbine

Source Description

Source SN-11, a 5850 HP Solar Taurus Model 60 - T7000 natural gas fired turbine, was last installed or modified in 1996. This turbine is being permitted at its highest emission rate for each pollutant based on operating map testing by the manufacturer. The unit is restricted on hours of operation(per rolling 12 months period) and therefore tons emissions per year (because of the netting done in Permit No. 1419-AR-2). This unit is subject to 40 CFR, Subpart GG - Standards of Performance for Stationary Gas Turbines.

Specific Conditions

9. The permittee shall not exceed the emission rates set forth in the following table. The permittee shall demonstrate compliance with this condition by the use of natural gas and a restriction on the hours of operation of the equipment. [Regulation 19, §19.501 et seq. and 40 CFR Part 52, Subpart E]

SN	Description	Pollutant	lb/hr	tpy
11	Solar Taurus Model 60-T7000 5850HP Installed/modified 1996	PM_{10}	0.5	1.0
		SO_2	0.3	0.6
		VOC	0.2	0.4
		CO	7.0	14.6
		NO_x	32.5	68.2

10. The permittee shall not exceed the emission rates set forth in the following table. The permittee shall demonstrate compliance with this condition by the use of natural gas and a restriction on the hours of operation of the equipment. The HAP emissions listed for this source were based upon published emission factors at the time of permit issuance. Any change in these emission factors will not constitute a violation of the HAP emission rates listed below. [Regulation 18, §18.801 and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

SN	Description	Pollutant	lb/hr	tpy
11	Solar Taurus Model 60-T7000 5850HP Installed/modified 1996	PM	0.5	1.0
		Acetaldehyde	0.23	0.47
		Acrolein	0.01	0.01
		Benzene	0.01	0.02
		Formaldehyde	0.22	0.46
		Toluene	0.01	0.02

11. The permittee shall not exceed 5% opacity from source SN-11 as measured by EPA Reference Method 9. Compliance with this condition shall be demonstrated by burning pipeline quality natural gas. [Regulation 18, §18.501, and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

12. The permittee shall not operate SN-11 more than 4,200 hours in any consecutive twelve month period. [Regulation 19, §19.705, 40 CFR 70.6, and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

13. The permittee shall maintain records which demonstrate compliance with the limit set in Specific Condition #12. These records may be used by the Department for enforcement purposes. The records shall be updated on a monthly basis, shall be kept at the nearest manned location, and shall be provided to the Department personnel upon request. [Regulation 19, §19.705, and 40 CFR Part 52]

14. The permittee shall not cause to be discharge into the atmosphere from SN-11, any gases which contain NO_x in excess of the following equation:

$$STD = 0.0075\ (14.4/Y) + F$$

where:
STD = allowable ISO corrected (if required as given in §60.334(b)(1)) NOx emissions concentration (percent by volume at 15% oxygen and on a dry basis),
Y = manufacturer's rated heat rate at manufacturer's rated load (kilojoules per watt hour) or, actual measured heat rate based on lower heating value of fuel as measured at actual peak load for the facility. The value of Y shall not exceed 14.4 kilojoules per watt hour.
F = NOx emission allowance for fuel-bound nitrogen as defined in paragraph 60.332(a)(3) of Subpart GG.

[Regulation 19, §19.304, 40 CFR 60.332, and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

15. SN-11 (Solar Taurus Model 60) is subject to 40 CFR, Part 60, Subpart 60, Subpart A, General Provisions and 40 CFR, Part 60, Subpart GG, Standards of Performance for Stationary Gas Turbines due to being a stationary gas turbine greater than 10.7 gigajoules per hour installed after October 3, 1977. A copy of Subpart GG is provided in Appendix A. The NSPS requirements, as listed in the November 2, 1999 letter from EPA regarding the *Request for Broad Approval of Custom Fuel Monitoring Schedule for NSPS Subpart GG,* are summarized as follows:

a. The permittee shall conduct an initial compliance test for NO_x from all sources for which an initial performance test has not been previously performed. These test results shall be kept on site and shall be provided to Department personnel upon request.

b. Monitoring of fuel nitrogen content shall not be required while natural gas is the only fuel fired in the gas turbine.

c. The permittee shall demonstrate that the gaseous fuel combusted in SN-11 meets the definition of natural gas as noted below. The permittee has elected not to monitor the total sulfur content of the gaseous fuel combusted in SN-11 according to 40 CFR 60.334(h)(3). Compliance shall be demonstrated by complying with Condition #15d. [§19.705 of Regulation 19, 40 CFR 60.331(u), 40 CFR 60.334(h)(3)(i) and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

Natural gas means a naturally occurring fluid mixture of hydrocarbons (*e.g.*, methane, ethane, or propane) produced in geological formations beneath the Earth's surface that maintains a gaseous state at standard atmospheric temperature and pressure under ordinary conditions. Natural gas contains 20.0 grains or less of total sulfur per 100 standard cubic feet. Equivalents of this in other units are as follows: 0.068 weight percent total sulfur, 680 parts per million by weight (ppmw) total sulfur, and 338 parts per million by volume (ppmv) at 20 degrees Celsius total sulfur. Additionally, natural gas must either be composed of at least 70 percent methane by volume or have a gross calorific value between 950 and 1100 British thermal units (Btu) per standard cubic foot. Natural gas does not include the following gaseous fuels: landfill gas, digester gas, refinery gas, sour gas, blast furnace gas, coal-derived gas, producer gas, coke oven gas, or any gaseous fuel produced in a process which might result in highly variable sulfur content or heating value.

d. The permittee shall maintain adequate records by maintaining onsite a copy of the gas quality characteristics in a current, valid purchase contract, tariff sheet or transportation contract for the gaseous fuel, specifying that the maximum total sulfur content of the fuel is 20.0 grains/100 scf or less to demonstrate compliance with Specific Condition #15c. Records shall be made available to Department personnel upon request. The permittee shall update the records within 30 days of approval, by the Federal Energy Regulatory Commission in the case of tariff sheets, or within 30 days of execution by all parties in the case of any purchase or transportation contracts. A copy of the current tariff shall be maintained on the permittee's intranet at all times so an electronic copy is readily available to Department personnel upon request. [§19.304, of Regulation 19, 40 CFR, Part 60, Subpart GG, and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

SN-12
Natural Gas Generator Engine

Source Description

Source SN-12, a 64 HP Olympian standby generator engine, was last installed or modified in 1996. This engine is being permitted at 100% of its rated load capacity. The unit is restricted on hours of operation (per rolling 12 months period) and therefore tons emissions per year (because of the netting done in Permit No. 1419-AR-2).

Specific Conditions

16. The permittee shall not exceed the emission rates set forth in the following table. The permittee shall demonstrate compliance with this condition by the use of natural gas and a restriction on the hours of operation of the equipment. [Regulation 19, §19.501 et seq. and 40 CFR Part 52, Subpart E]

SN	Description	Pollutant	lb/hr	tpy
12	Olympian 64HP Installed/modified 1996	PM_{10}	0.1	0.1
		SO_2	0.1	0.1
		VOC	0.1	0.1
		CO	2.8	0.7
		NO_x	1.7	0.5

17. The permittee shall not exceed the emission rates set forth in the following table. The permittee shall demonstrate compliance with this condition by the use of natural gas and a restriction on the hours of operation of the equipment. The HAP emissions listed for this source were based upon published emission factors at the time of permit issuance. Any change in these emission factors will not constitute a violation of the HAP emission rates listed below. [Regulation 18, §18.801 and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

SN	Description	Pollutant	lb/hr	tpy
12	Olympian 64HP Installed/modified 1996	PM	0.1	0.1
		Acetaldehyde	0.01	0.01
		Acrolein	0.01	0.01
		Benzene	0.01	0.01
		Formaldehyde	0.01	0.01
		Methanol	0.01	0.01
		Toluene	0.01	0.01

18. The permittee shall not exceed 5% opacity from source SN-10 as measured by EPA Reference Method 9. Compliance with this condition shall be demonstrated by burning

pipeline quality natural gas. [Regulation 18, §18.501, and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

19. The permittee shall not operate SN-12 more than 500 hours in any consecutive twelve month period. [Regulation 19, §19.705, 40 CFR 70.6, and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

20. The permittee shall maintain records which demonstrate compliance with the limit set in Specific Condition #19. These records may be used by the Department for enforcement purposes. The records shall be updated on a monthly basis, shall be kept at the nearest manned location, and shall be provided to the Department personnel upon request. [Regulation 19, §19.705, and 40 CFR Part 52]

SECTION V: COMPLIANCE PLAN AND SCHEDULE

CenterPoint Energy - Mississippi River Transmission Corp. - Tuckerman Compressor Station will continue to operate in compliance with those identified regulatory provisions. The facility will examine and analyze future regulations that may apply and determine their applicability with any necessary action taken on a timely basis.

SECTION VI: PLANTWIDE CONDITIONS

1. The permittee shall notify the Director in writing within thirty (30) days after commencing construction, completing construction, first placing the equipment and/or facility in operation, and reaching the equipment and/or facility target production rate. [Regulation 19, §19.704, 40 CFR Part 52, Subpart E, and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

2. If the permittee fails to start construction within eighteen months or suspends construction for eighteen months or more, the Director may cancel all or part of this permit. [Regulation 19, §19.410(B) and 40 CFR Part 52, Subpart E]

3. The permittee must test any equipment scheduled for testing, unless otherwise stated in the Specific Conditions of this permit or by any federally regulated requirements, within the following time frames: (1) new equipment or newly modified equipment within sixty (60) days of achieving the maximum production rate, but no later than 180 days after initial start up of the permitted source or (2) operating equipment according to the time frames set forth by the Department or within 180 days of permit issuance if no date is specified. The permittee must notify the Department of the scheduled date of compliance testing at least fifteen (15) days in advance of such test. The permittee shall submit the compliance test results to the Department within thirty (30) days after completing the testing. [Regulation 19, §19.702 and/or Regulation 18 §18.1002 and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

4. The permittee must provide:

    a. Sampling ports adequate for applicable test methods;
    b. Safe sampling platforms;
    c. Safe access to sampling platforms; and
    d. Utilities for sampling and testing equipment.

    [Regulation 19, §19.702 and/or Regulation 18, §18.1002 and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

5. The permittee must operate the equipment, control apparatus and emission monitoring equipment within the design limitations. The permittee shall maintain the equipment in good condition at all times. [Regulation 19, §19.303 and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

6. This permit subsumes and incorporates all previously issued air permits for this facility. [Regulation 26 and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

7. Pipeline quality natural gas shall be the only fuel used to fire the compressor at this facility. [Regulation 19, §19.705, A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311, and 40 CFR 70.6]

8. The permittee shall simultaneously conduct tests for CO and NOx on one-half of each type of compressor engine every 5 years in accordance with Plantwide Condition 3 and every five years thereafter. For reciprocating engines, EPA Reference Method 10 and 7E shall be used for CO and NOx, respectively. For turbine, EPA Reference Method 10 and 20 shall be used for CO and NOx, respectively. The permittee shall test the engine within 90% of its rated capacity. If the engine is not tested within this range, the permittee shall be limited to operating within 10% above the tested rate. The Department reserves the right to select the engine(s) to be tested. The engine(s) tested shall be rotated so that no engine(s) is tested twice before another similar (make and model) engine of equal horsepower is test once. If the tested emission rate for any pollutant is in excess of the permitted emission rate, all similar engines (make and model) shall be tested for that pollutant. [Regulation No.19 §19.702, and 40 CFR Part 52, Subpart E]

9. The permittee may replace any existing engines or turbine on a temporary or permanent basis with an engine(s) or turbine(s) that has the same or lower emission rates on a pound per hour basis; has the same or lower horsepower; and which replacement does not result in a significant emissions increase as defined and applied pursuant to 40 CFR 52.21, and as set out below:

    a. The permittee shall notify ADEQ of the replacement within 30 days after the replacement is made, which notification shall identify the previous and replacement engines or turbine, and provide the reason why the replacement was necessary. If applicable, the notification shall also provide a permit application and, when required, a CAM plan under 40 CFR Part 64. [Regulation No.19 §19.705, A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311, §19.705 and 40 CFR Part 64]

    b. The permittee shall conduct NO_x and CO emission testing within 90 days of the date of replacement to verify the emissions from the newly installed engine(s) or turbine(s). The testing shall be conducted in accordance with EPA Reference Method 7E for NO_x(reciprocating engine), EPA Reference Method 20 for NO_x (turbine)and EPA Reference Method 10 for CO.

    c. Notwithstanding the above, as provided by Regulation 26, in the event an emergency occurs, the permittee shall have an affirmative defense of emergency to an action brought for non-compliance with technology-based limitations if the conditions of Regulation 26, §26.707 are met.

    [Regulation No. 19, §19.705, §19-304, ACA 8-4-203 as referenced by ACA 8-4-304 and 8-4-311, and 40 CFR Part 64.]

10. The permittee shall use good maintenance practices to control emissions from valves, fittings, flanges, seals and other associated equipment. [Regulation 19, §19.303 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

Title VI Provisions

11. The permittee must comply with the standards for labeling of products using ozone-depleting substances. [40 CFR Part 82, Subpart E]

    a. All containers containing a class I or class II substance stored or transported, all products containing a class I substance, and all products directly manufactured with a class I substance must bear the required warning statement if it is being introduced to interstate commerce pursuant to §82.106.

    b. The placement of the required warning statement must comply with the requirements pursuant to §82.108.

    c. The form of the label bearing the required warning must comply with the requirements pursuant to §82.110.

    d. No person may modify, remove, or interfere with the required warning statement except as described in §82.112.

12. The permittee must comply with the standards for recycling and emissions reduction, except as provided for MVACs in Subpart B. [40 CFR Part 82, Subpart F]

    a. Persons opening appliances for maintenance, service, repair, or disposal must comply with the required practices pursuant to §82.156.

    b. Equipment used during the maintenance, service, repair, or disposal of appliances must comply with the standards for recycling and recovery equipment pursuant to §82.158.

    c. Persons performing maintenance, service repair, or disposal of appliances must be certified by an approved technician certification program pursuant to §82.161.

    d. Persons disposing of small appliances, MVACs, and MVAC-like appliances must comply with record keeping requirements pursuant to §82.166. ("MVAC-like appliance" as defined at §82.152.)

    e. Persons owning commercial or industrial process refrigeration equipment must comply with leak repair requirements pursuant to §82.156.

    f. Owners/operators of appliances normally containing 50 or more pounds of refrigerant must keep records of refrigerant purchased and added to such appliances pursuant to §82.166.

13. If the permittee manufactures, transforms, destroys, imports, or exports a class I or class II substance, the permittee is subject to all requirements as specified in 40 CFR Part 82, Subpart A, Production and Consumption Controls.

14. If the permittee performs a service on motor (fleet) vehicles when this service involves ozone-depleting substance refrigerant (or regulated substitute substance) in the motor vehicle air conditioner (MVAC), the permittee is subject to all the applicable requirements as specified in 40 CFR part 82, Subpart B, Servicing of Motor Vehicle Air Conditioners.

The term "motor vehicle" as used in Subpart B does not include a vehicle in which final assembly of the vehicle has not been completed. The term "MVAC" as used in Subpart B does not include the air-tight sealed refrigeration system used as refrigerated cargo, or the system used on passenger buses using HCFC-22 refrigerant.

15. The permittee can switch from any ozone-depleting substance to any alternative listed in the Significant New Alternatives Program (SNAP) promulgated pursuant to 40 CFR Part 82, Subpart G, "Significant New Alternatives Policy Program".

Permit Shield

16. Compliance with the conditions of this permit shall be deemed compliance with all applicable requirements, as of the date of permit issuance, included in and specifically identified in the following table of this condition. The permit specifically identifies the following as applicable requirements based upon the information submitted by the permittee in an application dated November 16, 2009.

Applicable Regulations

Source No.	Regulation	Description
Facility Wide	*Arkansas Plan of Implementation for Air Pollution Control* (Regulation 19)	SIP
Facility Wide	*Regulations of the Arkansas Operating Air Permit Program* (Regulation 26).	Title V
SN-11	40 CFR Part 60 Subpart GG – *Standards of Performance for Stationary Gas Turbines*	NSPS
SN-01 thru SN-04, SN-06, and SN-08	*40 CFR Part 63 Subpart ZZZZ - *National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines.*	NESHAP
SN-11	**40 CFR Part 63 Subpart YYYY - *National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines.*	NESHAP

* The stationary RICEs at this facility do not have to meet the requirements of this subpart, and no initial notification is necessary pursuant to 40 CFR 63.6590(b)(3).
** The stationary combustion turbine at this facility does not have to meet the requirements of this subpart, and no initial notification is necessary pursuant to 40 CFR 63.6090(b)(4).

SECTION VII: INSIGNIFICANT ACTIVITIES

The following sources are insignificant activities. Any activity that has a state or federal applicable requirement shall be considered a significant activity even if this activity meets the criteria of §26.304 of Regulation 26 or listed in the table below. Insignificant activity determinations rely upon the information submitted by the permittee in an application dated November 16, 2009.

Description	Category
0.1 MMBtu/hr Boiler	Group A 1
Smart Ash Incinerator	Group A 13
Produced Water Tank (8,700 gal)	Group A 3
Lube Oil Tank (11,300 gal)	Group A 13
Lube Oil Tank (1,120 gal)	Group A 3
Diesel Tank (500 gal)	Group A 3
Antifreeze Mix Tank (7,954 gal)	Group A 3
Antifreeze Tank (5,500 gal)	Group A 3
Truck Loading	Group A 13
Station Blowdowns	Group A 13
Fugitive Emissions	Group A 13

SECTION VIII: GENERAL PROVISIONS

1. Any terms or conditions included in this permit which specify and reference Arkansas Pollution Control & Ecology Commission Regulation 18 or the Arkansas Water and Air Pollution Control Act (A.C.A. §8-4-101 et seq.) as the sole origin of and authority for the terms or conditions are not required under the Clean Air Act or any of its applicable requirements, and are not federally enforceable under the Clean Air Act. Arkansas Pollution Control & Ecology Commission Regulation 18 was adopted pursuant to the Arkansas Water and Air Pollution Control Act (A.C.A. §8-4-101 et seq.). Any terms or conditions included in this permit which specify and reference Arkansas Pollution Control & Ecology Commission Regulation 18 or the Arkansas Water and Air Pollution Control Act (A.C.A. §8-4-101 et seq.) as the origin of and authority for the terms or conditions are enforceable under this Arkansas statute. [40 CFR 70.6(b)(2)]

2. This permit shall be valid for a period of five (5) years beginning on the date this permit becomes effective and ending five (5) years later. [40 CFR 70.6(a)(2) and §26.701(B) of the Regulations of the Arkansas Operating Air Permit Program (Regulation 26)]

3. The permittee must submit a complete application for permit renewal at least six (6) months before permit expiration. Permit expiration terminates the permittee's right to operate unless the permittee submitted a complete renewal application at least six (6) months before permit expiration. If the permittee submits a complete application, the existing permit will remain in effect until the Department takes final action on the renewal application. The Department will not necessarily notify the permittee when the permit renewal application is due. [Regulation 26, §26.406]

4. Where an applicable requirement of the Clean Air Act, as amended, 42 U.S.C. 7401, et seq. (Act) is more stringent than an applicable requirement of regulations promulgated under Title IV of the Act, the permit incorporates both provisions into the permit, and the Director or the Administrator can enforce both provisions. [40 CFR 70.6(a)(1)(ii) and Regulation 26, §26.701(A)(2)]

5. The permittee must maintain the following records of monitoring information as required by this permit.

    a. The date, place as defined in this permit, and time of sampling or measurements;
    b. The date(s) analyses performed;
    c. The company or entity performing the analyses;
    d. The analytical techniques or methods used;
    e. The results of such analyses; and
    f. The operating conditions existing at the time of sampling or measurement.

    [40 CFR 70.6(a)(3)(ii)(A) and Regulation 26, §26.701(C)(2)]

6. The permittee must retain the records of all required monitoring data and support information for at least five (5) years from the date of the monitoring sample, measurement, report, or application. Support information includes all calibration and maintenance records and all original strip chart recordings for continuous monitoring instrumentation, and copies of all reports required by this permit. [40 CFR 70.6(a)(3)(ii)(B) and Regulation 26, §26.701(C)(2)(b)]

7. The permittee must submit reports of all required monitoring every six (6) months. If permit establishes no other reporting period, the reporting period shall end on the last day of the anniversary month of the initial Title V permit. The report is due within thirty (30) days of the end of the reporting period. Although the reports are due every six months, each report shall contain a full year of data. The report must clearly identify all instances of deviations from permit requirements. A responsible official as defined in Regulation No. 26, §26.2 must certify all required reports. The permittee will send the reports to the address below:

    Arkansas Department of Environmental Quality
    Air Division
    ATTN: Compliance Inspector Supervisor
    5301 Northshore Drive
    North Little Rock, AR 72118-5317

    [40 C.F.R. 70.6(a)(3)(iii)(A) and Regulation 26, §26.701(C)(3)(a)]

8. The permittee shall report to the Department all deviations from permit requirements, including those attributable to upset conditions as defined in the permit.

    a. For all upset conditions (as defined in Regulation19, § 19.601), the permittee will make an initial report to the Department by the next business day after the discovery of the occurrence. The initial report may be made by telephone and shall include:

        i. The facility name and location;
        ii. The process unit or emission source deviating from the permit limit;
        iii. The permit limit, including the identification of pollutants, from which deviation occurs;
        iv. The date and time the deviation started;
        v. The duration of the deviation;
        vi. The average emissions during the deviation;
        vii. The probable cause of such deviations;
        viii. Any corrective actions or preventive measures taken or being taken to prevent such deviations in the future; and
        ix. The name of the person submitting the report.

The permittee shall make a full report in writing to the Department within five (5) business days of discovery of the occurrence. The report must include, in addition to the information required by the initial report, a schedule of actions taken or planned to eliminate future occurrences and/or to minimize the amount the permit's limits were exceeded and to reduce the length of time the limits were exceeded. The permittee may submit a full report in writing (by facsimile, overnight courier, or other means) by the next business day after discovery of the occurrence, and the report will serve as both the initial report and full report.

b. For all deviations, the permittee shall report such events in semi-annual reporting and annual certifications required in this permit. This includes all upset conditions reported in 8a above. The semi-annual report must include all the information as required by the initial and full reports required in 8a.

[Regulation 19, §19.601 and §19.602, Regulation 26, §26.701(C)(3)(b), and 40 CFR 70.6(a)(3)(iii)(B)]

9. If any provision of the permit or the application thereof to any person or circumstance is held invalid, such invalidity will not affect other provisions or applications hereof which can be given effect without the invalid provision or application, and to this end, provisions of this Regulation are declared to be separable and severable. [40 CFR 70.6(a)(5), Regulation 26, §26.701(E), and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

10. The permittee must comply with all conditions of this Part 70 permit. Any permit noncompliance with applicable requirements as defined in Regulation 26 constitutes a violation of the Clean Air Act, as amended, 42 U.S.C. §7401, et seq. and is grounds for enforcement action; for permit termination, revocation and reissuance, for permit modification; or for denial of a permit renewal application. [40 CFR 70.6(a)(6)(i) and Regulation 26, §26.701(F)(1)]

11. It shall not be a defense for a permittee in an enforcement action that it would have been necessary to halt or reduce the permitted activity to maintain compliance with the conditions of this permit. [40 CFR 70.6(a)(6)(ii) and Regulation 26, §26.701(F)(2)]

12. The Department may modify, revoke, reopen and reissue the permit or terminate the permit for cause. The filing of a request by the permittee for a permit modification, revocation and reissuance, termination, or of a notification of planned changes or anticipated noncompliance does not stay any permit condition. [40 CFR 70.6(a)(6)(iii) and Regulation 26, §26.701(F)(3)]

13. This permit does not convey any property rights of any sort, or any exclusive privilege. [40 CFR 70.6(a)(6)(iv) and Regulation 26, §26.701(F)(4)]

14. The permittee must furnish to the Director, within the time specified by the Director, any information that the Director may request in writing to determine whether cause exists for modifying, revoking and reissuing, or terminating the permit or to determine compliance with the permit. Upon request, the permittee must also furnish to the Director copies of records required by the permit. For information the permittee claims confidentiality, the Department may require the permittee to furnish such records directly to the Director along with a claim of confidentiality. [40 CFR 70.6(a)(6)(v) and Regulation 26, §26.701(F)(5)]

15. The permittee must pay all permit fees in accordance with the procedures established in Regulation 9. [40 CFR 70.6(a)(7) and Regulation 26, §26.701(G)]

16. No permit revision shall be required, under any approved economic incentives, marketable permits, emissions trading and other similar programs or processes for changes provided for elsewhere in this permit. [40 CFR 70.6(a)(8) and Regulation 26, §26.701(H)]

17. If the permit allows different operating scenarios, the permittee shall, contemporaneously with making a change from one operating scenario to another, record in a log at the permitted facility a record of the operational scenario. [40 CFR 70.6(a)(9)(i) and Regulation 26, §26.701(I)(1)]

18. The Administrator and citizens may enforce under the Act all terms and conditions in this permit, including any provisions designed to limit a source's potential to emit, unless the Department specifically designates terms and conditions of the permit as being federally unenforceable under the Act or under any of its applicable requirements. [40 CFR 70.6(b) and Regulation 26, §26.702(A) and (B)]

19. Any document (including reports) required by this permit must contain a certification by a responsible official as defined in Regulation 26, §26.2. [40 CFR 70.6(c)(1) and Regulation 26, §26.703(A)]

20. The permittee must allow an authorized representative of the Department, upon presentation of credentials, to perform the following: [40 CFR 70.6(c)(2) and Regulation 26, §26.703(B)]

    a. Enter upon the permittee's premises where the permitted source is located or emissions related activity is conducted, or where records must be kept under the conditions of this permit;
    b. Have access to and copy, at reasonable times, any records required under the conditions of this permit;
    c. Inspect at reasonable times any facilities, equipment (including monitoring and air pollution control equipment), practices, or operations regulated or required under this permit; and

d. As authorized by the Act, sample or monitor at reasonable times substances or parameters for assuring compliance with this permit or applicable requirements.

21. The permittee shall submit a compliance certification with the terms and conditions contained in the permit, including emission limitations, standards, or work practices. The permittee must submit the compliance certification annually within 30 days following the last day of the anniversary month of the initial Title V permit. The permittee must also submit the compliance certification to the Administrator as well as to the Department. All compliance certifications required by this permit must include the following: [40 CFR 70.6(c)(5) and Regulation 26, §26.703(E)(3)]

a. The identification of each term or condition of the permit that is the basis of the certification;
b. The compliance status;
c. Whether compliance was continuous or intermittent;
d. The method(s) used for determining the compliance status of the source, currently and over the reporting period established by the monitoring requirements of this permit; and
e. Such other facts as the Department may require elsewhere in this permit or by §114(a)(3) and §504(b) of the Act.

22. Nothing in this permit will alter or affect the following: [Regulation 26, §26.704(C)]

a. The provisions of Section 303 of the Act (emergency orders), including the authority of the Administrator under that section;
b. The liability of the permittee for any violation of applicable requirements prior to or at the time of permit issuance;
c. The applicable requirements of the acid rain program, consistent with §408(a) of the Act; or
d. The ability of EPA to obtain information from a source pursuant to §114 of the Act.

23. This permit authorizes only those pollutant emitting activities addressed in this permit. [A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

24. The permittee may request in writing and at least 15 days in advance of the deadline, an extension to any testing, compliance or other dates in this permit. No such extensions are authorized until the permittee receives written Department approval. The Department may grant such a request, at its discretion in the following circumstances:

a. Such an extension does not violate a federal requirement;
b. The permittee demonstrates the need for the extension; and
c. The permittee documents that all reasonable measures have been taken to meet the current deadline and documents reasons it cannot be met.

[Regulation 18, §18.314(A), Regulation 19, §19.416(A), Regulation 26, §26.1013(A), A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311, and 40 CFR Part 52, Subpart E]

25. The permittee may request in writing and at least 30 days in advance, temporary emissions and/or testing that would otherwise exceed an emission rate, throughput requirement, or other limit in this permit. No such activities are authorized until the permittee receives written Department approval. Any such emissions shall be included in the facility's total emissions and reported as such. The Department may grant such a request, at its discretion under the following conditions:

    a. Such a request does not violate a federal requirement;
    b. Such a request is temporary in nature;
    c. Such a request will not result in a condition of air pollution;
    d. The request contains such information necessary for the Department to evaluate the request, including but not limited to, quantification of such emissions and the date/time such emission will occur;
    e. Such a request will result in increased emissions less than five tons of any individual criteria pollutant, one ton of any single HAP and 2.5 tons of total HAPs; and
    f. The permittee maintains records of the dates and results of such temporary emissions/testing.

[Regulation 18, §18.314(B), Regulation 19, §19.416(B), Regulation 26, §26.1013(B), A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311, and 40 CFR Part 52, Subpart E]

26. The permittee may request in writing and at least 30 days in advance, an alternative to the specified monitoring in this permit. No such alternatives are authorized until the permittee receives written Department approval. The Department may grant such a request, at its discretion under the following conditions:

    a. The request does not violate a federal requirement;
    b. The request provides an equivalent or greater degree of actual monitoring to the current requirements; and
    c. Any such request, if approved, is incorporated in the next permit modification application by the permittee.

[Regulation 18, §18.314(C), Regulation 19, §19.416(C), Regulation 26, §26.1013(C), A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311, and 40 CFR Part 52, Subpart E]

Appendix A
40 CFR Part 60 Subpart GG –
Standards of Performance for Stationary Gas Turbines

Title 40: Protection of Environment

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Browse Previous | Browse Next

Subpart GG—Standards of Performance for Stationary Gas Turbines

§ 60.330 Applicability and designation of affected facility.

(a) The provisions of this subpart are applicable to the following affected facilities: All stationary gas turbines with a heat input at peak load equal to or greater than 10.7 gigajoules (10 million Btu) per hour, based on the lower heating value of the fuel fired.

(b) Any facility under paragraph (a) of this section which commences construction, modification, or reconstruction after October 3, 1977, is subject to the requirements of this part except as provided in paragraphs (e) and (j) of §60.332.

[44 FR 52798, Sept. 10, 1979, as amended at 52 FR 42434, Nov. 5, 1987; 65 FR 61759, Oct. 17, 2000]

§ 60.331 Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act and in subpart A of this part.

(a) *Stationary gas turbine* means any simple cycle gas turbine, regenerative cycle gas turbine or any gas turbine portion of a combined cycle steam/electric generating system that is not self propelled. It may, however, be mounted on a vehicle for portability.

(b) *Simple cycle gas turbine* means any stationary gas turbine which does not recover heat from the gas turbine exhaust gases to preheat the inlet combustion air to the gas turbine, or which does not recover heat from the gas turbine exhaust gases to heat water or generate steam.

(c) *Regenerative cycle gas turbine* means any stationary gas turbine which recovers heat from the gas turbine exhaust gases to preheat the inlet combustion air to the gas turbine.

(d) *Combined cycle gas turbine* means any stationary gas turbine which recovers heat from the gas turbine exhaust gases to heat water or generate steam.

(e) *Emergency gas turbine* means any stationary gas turbine which operates as a mechanical or electrical power source only when the primary power source for a facility has been rendered inoperable by an emergency situation.

(f) *Ice fog* means an atmospheric suspension of highly reflective ice crystals.

(g) *ISO standard day conditions* means 288 degrees Kelvin, 60 percent relative humidity and 101.3 kilopascals pressure.

(h) *Efficiency* means the gas turbine manufacturer's rated heat rate at peak load in terms of heat input per unit of power output based on the lower heating value of the fuel.

(i) *Peak load* means 100 percent of the manufacturer's design capacity of the gas turbine at ISO standard day conditions.

(j) *Base load* means the load level at which a gas turbine is normally operated.

(k) *Fire-fighting turbine* means any stationary gas turbine that is used solely to pump water for extinguishing fires.

(l) *Turbines employed in oil/gas production or oil/gas transportation* means any stationary gas turbine used to provide power to extract crude oil/natural gas from the earth or to move crude oil/natural gas, or products refined from these substances through pipelines.

(m) A *Metropolitan Statistical Area* or *MSA* as defined by the Department of Commerce.

(n) *Offshore platform gas turbines* means any stationary gas turbine located on a platform in an ocean.

(o) *Garrison facility* means any permanent military installation.

(p) *Gas turbine model* means a group of gas turbines having the same nominal air flow, combuster inlet pressure, combuster inlet temperature, firing temperature, turbine inlet temperature and turbine inlet pressure.

(q) *Electric utility stationary gas turbine* means any stationary gas turbine constructed for the purpose of supplying more than one-third of its potential electric output capacity to any utility power distribution system for sale.

(r) *Emergency fuel* is a fuel fired by a gas turbine only during circumstances, such as natural gas supply curtailment or breakdown of delivery system, that make it impossible to fire natural gas in the gas turbine.

(s) *Unit operating hour* means a clock hour during which any fuel is combusted in the affected unit. If the unit combusts fuel for the entire clock hour, it is considered to be a full unit operating hour. If the unit combusts fuel for only part of the clock hour, it is considered to be a partial unit operating hour.

(t) *Excess emissions* means a specified averaging period over which either:

(1) The NO_x emissions are higher than the applicable emission limit in §60.332;

(2) The total sulfur content of the fuel being combusted in the affected facility exceeds the limit specified in §60.333; or

(3) The recorded value of a particular monitored parameter is outside the acceptable range specified in the parameter monitoring plan for the affected unit.

(u) *Natural gas* means a naturally occurring fluid mixture of hydrocarbons (*e.g.* , methane, ethane, or propane) produced in geological formations beneath the Earth's surface that maintains a gaseous state at standard atmospheric temperature and pressure under ordinary conditions. Natural gas contains 20.0 grains or less of total sulfur per 100 standard cubic feet. Equivalents of this in other units are as follows: 0.068 weight percent total sulfur, 680 parts per million by weight (ppmw) total sulfur, and 338 parts per million by volume (ppmv) at 20 degrees Celsius total sulfur. Additionally, natural gas must either be composed of at least 70 percent methane by volume or have a gross calorific value between 950 and 1100 British thermal units (Btu) per standard cubic foot. Natural gas does not include the following gaseous fuels: landfill gas, digester gas, refinery gas, sour gas, blast furnace gas, coal-derived gas, producer gas, coke oven gas, or any gaseous fuel produced in a process which might result in highly variable sulfur content or heating value.

(v) *Duct burner* means a device that combusts fuel and that is placed in the exhaust duct from another source, such as a stationary gas turbine, internal combustion engine, kiln, etc., to allow the firing of additional fuel to heat the exhaust gases before the exhaust gases enter a heat recovery steam generating unit.

(w) *Lean premix stationary combustion turbine* means any stationary combustion turbine where the air and fuel are thoroughly mixed to form a lean mixture for combustion in the combustor. Mixing may occur before or in the combustion chamber. A unit which is capable of operating in both lean premix and diffusion flame modes is considered a lean premix stationary combustion turbine when it is in the lean premix mode, and it is considered a diffusion flame stationary combustion turbine when it is in the diffusion flame mode.

(x) *Diffusion flame stationary combustion turbine* means any stationary combustion turbine where fuel and air are injected at the combustor and are mixed only by diffusion prior to ignition. A unit which is capable of operating in both lean premix and diffusion flame modes is considered a lean premix stationary combustion turbine when it is in the lean premix mode, and it is considered a diffusion flame stationary combustion turbine when it is in the diffusion flame mode.

(y) *Unit operating day* means a 24-hour period between 12:00 midnight and the following midnight during which any fuel is combusted at any time in the unit. It is not necessary for fuel to be combusted continuously for the entire 24-hour period.

[44 FR 52798, Sept. 10, 1979, as amended at 47 FR 3770, Jan. 27, 1982; 65 FR 61759, Oct. 17, 2000; 69 FR 41359, July 8, 2004]

§ 60.332 Standard for nitrogen oxides.

(a) On and after the date on which the performance test required by §60.8 is completed, every owner or operator subject to the provisions of this subpart as specified in paragraphs (b), (c), and (d) of this section shall comply with one of the following, except as provided in paragraphs (e), (f), (g), (h), (i), (j), (k), and (l) of this section.

(1) No owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any stationary gas turbine, any gases which contain nitrogen oxides in excess of:

$$STD = 0.0075\frac{(14.4)}{Y} + F$$

where:

STD = allowable ISO corrected (if required as given in §60.335(b)(1)) NO_X emission concentration (percent by volume at 15 percent oxygen and on a dry basis),

Y = manufacturer's rated heat rate at manufacturer's rated load (kilojoules per watt hour) or, actual measured heat rate based on lower heating value of fuel as measured at actual peak load for the facility. The value of Y shall not exceed 14.4 kilojoules per watt hour, and

F = NO_X emission allowance for fuel-bound nitrogen as defined in paragraph (a)(4) of this section.

(2) No owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any stationary gas turbine, any gases which contain nitrogen oxides in excess of:

$$STD = 0.0150\frac{(14.4)}{Y} + F$$

where:

STD = allowable ISO corrected (if required as given in §60.335(b)(1)) NO_X emission concentration (percent by volume at 15 percent oxygen and on a dry basis),

Y = manufacturer's rated heat rate at manufacturer's rated peak load (kilojoules per watt hour), or actual measured heat rate based on lower heating value of fuel as measured at actual peak load for the facility. The value of Y shall not exceed 14.4 kilojoules per watt hour, and

F = NO_X emission allowance for fuel-bound nitrogen as defined in paragraph (a)(4) of this section.

(3) The use of F in paragraphs (a)(1) and (2) of this section is optional. That is, the owner or operator may choose to apply a NO_X allowance for fuel-bound nitrogen and determine the appropriate F-value in accordance with paragraph (a)(4) of this section or may accept an F-value of zero.

(4) If the owner or operator elects to apply a NO_X emission allowance for fuel-bound nitrogen, F shall be defined according to the nitrogen content of the fuel during the most recent performance test required under §60.8 as follows:

Fuel-bound nitrogen (percent by weight)	F (NO_X percent by volume)
$N \leq .015$	0
$0.015 < N \leq 0.1$	0.04 (N)
$0.1 < N \leq 0.25$	0.004+0.0067(N–0.1)
$N > 0.25$	0.005

Where:

N = the nitrogen content of the fuel (percent by weight).

or:

Manufacturers may develop and submit to EPA custom fuel-bound nitrogen allowances for each gas turbine model they manufacture. These fuel-bound nitrogen allowances shall be substantiated with data and must be approved for use by the Administrator before the initial performance test required by §60.8. Notices of approval of custom fuel-bound nitrogen allowances will be published in theFederal Register.

(b) Electric utility stationary gas turbines with a heat input at peak load greater than 107.2 gigajoules per hour (100 million Btu/hour) based on the lower heating value of the fuel fired shall comply with the provisions of paragraph (a)(1) of this section.

(c) Stationary gas turbines with a heat input at peak load equal to or greater than 10.7 gigajoules per hour (10 million Btu/hour) but less than or equal to 107.2 gigajoules per hour (100 million Btu/hour) based on the lower heating value of the fuel fired, shall comply with the provisions of paragraph (a)(2) of this section.

(d) Stationary gas turbines with a manufacturer's rated base load at ISO conditions of 30 megawatts or less except as provided in §60.332(b) shall comply with paragraph (a)(2) of this section.

(e) Stationary gas turbines with a heat input at peak load equal to or greater than 10.7 gigajoules per hour (10 million Btu/hour) but less than or equal to 107.2 gigajoules per hour (100 million Btu/hour) based on the lower heating value of the fuel fired and that have commenced construction prior to October 3, 1982 are exempt from paragraph (a) of this section.

(f) Stationary gas turbines using water or steam injection for control of NO_X emissions are exempt from paragraph (a) when ice fog is deemed a traffic hazard by the owner or operator of the gas turbine.

(g) Emergency gas turbines, military gas turbines for use in other than a garrison facility, military gas turbines installed for use as military training facilities, and fire fighting gas turbines are exempt from paragraph (a) of this section.

(h) Stationary gas turbines engaged by manufacturers in research and development of equipment for both gas turbine emission control techniques and gas turbine efficiency improvements are exempt from paragraph (a) on a case-by-case basis as determined by the Administrator.

(i) Exemptions from the requirements of paragraph (a) of this section will be granted on a case-by-case basis as determined by the Administrator in specific geographical areas where mandatory water restrictions are required by governmental agencies because of drought conditions. These exemptions will be allowed only while the mandatory water restrictions are in effect.

(j) Stationary gas turbines with a heat input at peak load greater than 107.2 gigajoules per hour that commenced construction, modification, or reconstruction between the dates of October 3, 1977, and January 27, 1982, and were required in the September 10, 1979,Federal Register(44 FR 52792) to comply with paragraph (a)(1) of this section, except electric utility stationary gas turbines, are exempt from paragraph (a) of this section.

(k) Stationary gas turbines with a heat input greater than or equal to 10.7 gigajoules per hour (10 million Btu/hour) when fired with natural gas are exempt from paragraph (a)(2) of this section when being fired with an emergency fuel.

(l) Regenerative cycle gas turbines with a heat input less than or equal to 107.2 gigajoules per hour (100 million Btu/hour) are exempt from paragraph (a) of this section.

[44 FR 52798, Sept. 10, 1979, as amended at 47 FR 3770, Jan. 27, 1982; 65 FR 61759, Oct. 17, 2000; 69 FR 41359, July 8, 2004]

§ 60.333 Standard for sulfur dioxide.

On and after the date on which the performance test required to be conducted by §60.8 is completed, every owner or operator subject to the provision of this subpart shall comply with one or the other of the following conditions:

(a) No owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any stationary gas turbine any gases which contain sulfur dioxide in excess of 0.015 percent by volume at 15 percent oxygen and on a dry basis.

(b) No owner or operator subject to the provisions of this subpart shall burn in any stationary gas turbine any fuel which contains total sulfur in excess of 0.8 percent by weight (8000 ppmw).

[44 FR 52798, Sept. 10, 1979, as amended at 69 FR 41360, July 8, 2004]

§ 60.334 Monitoring of operations.

(a) Except as provided in paragraph (b) of this section, the owner or operator of any stationary gas turbine subject to the provisions of this subpart and using water or steam injection to control NO_Xemissions shall install, calibrate, maintain and operate a continuous monitoring system to monitor and record the fuel consumption and the ratio of water or steam to fuel being fired in the turbine.

(b) The owner or operator of any stationary gas turbine that commenced construction, reconstruction or modification after October 3, 1977, but before July 8, 2004, and which uses water or steam injection to control NO_Xemissions may, as an alternative to operating the continuous monitoring system described in paragraph (a) of this section, install, certify, maintain, operate, and quality-assure a continuous emission monitoring system (CEMS) consisting of $NO_X$and O_2monitors. As an alternative, a CO_2monitor may be used to adjust the measured NO_Xconcentrations to 15 percent $O_2$by either converting the CO_2hourly averages to

equivalent O_2concentrations using Equation F–14a or F–14b in appendix F to part 75 of this chapter and making the adjustments to 15 percent O_2, or by using the CO_2readings directly to make the adjustments, as described in Method 20. If the option to use a CEMS is chosen, the CEMS shall be installed, certified, maintained and operated as follows:

(1) Each CEMS must be installed and certified according to PS 2 and 3 (for diluent) of 40 CFR part 60, appendix B, except the 7-day calibration drift is based on unit operating days, not calendar days. Appendix F, Procedure 1 is not required. The relative accuracy test audit (RATA) of the $NO_X$and diluent monitors may be performed individually or on a combined basis, *i.e.* , the relative accuracy tests of the CEMS may be performed either:

(i) On a ppm basis (for NO_X) and a percent O_2basis for oxygen; or

(ii) On a ppm at 15 percent O_2basis; or

(iii) On a ppm basis (for NO_X) and a percent CO_2basis (for a CO_2monitor that uses the procedures in Method 20 to correct the NO_Xdata to 15 percent O_2).

(2) As specified in §60.13(e)(2), during each full unit operating hour, each monitor must complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each 15-minute quadrant of the hour, to validate the hour. For partial unit operating hours, at least one valid data point must be obtained for each quadrant of the hour in which the unit operates. For unit operating hours in which required quality assurance and maintenance activities are performed on the CEMS, a minimum of two valid data points (one in each of two quadrants) are required to validate the hour.

(3) For purposes of identifying excess emissions, CEMS data must be reduced to hourly averages as specified in §60.13(h).

(i) For each unit operating hour in which a valid hourly average, as described in paragraph (b)(2) of this section, is obtained for both $NO_X$and diluent, the data acquisition and handling system must calculate and record the hourly NO_Xemissions in the units of the applicable NO_Xemission standard under §60.332(a), *i.e.* , percent $NO_X$by volume, dry basis, corrected to 15 percent $O_2$and International Organization for Standardization (ISO) standard conditions (if required as given in §60.335(b)(1)). For any hour in which the hourly average O_2concentration exceeds 19.0 percent O_2, a diluent cap value of 19.0 percent O_2may be used in the emission calculations.

(ii) A worst case ISO correction factor may be calculated and applied using historical ambient data. For the purpose of this calculation, substitute the maximum humidity of ambient air (Ho), minimum ambient temperature (T_a), and minimum combustor inlet absolute pressure (P_o) into the ISO correction equation.

(iii) If the owner or operator has installed a NO_XCEMS to meet the requirements of part 75 of this chapter, and is continuing to meet the ongoing requirements of part 75 of this chapter, the CEMS may be used to meet the requirements of this section, except that the missing data substitution methodology provided for at 40 CFR part 75, subpart D, is not required for purposes of identifying excess emissions. Instead, periods of missing CEMS data are to be reported as monitor downtime in the excess emissions and monitoring performance report required in §60.7(c).

(c) For any turbine that commenced construction, reconstruction or modification after October 3, 1977, but before July 8, 2004, and which does not use steam or water injection to control NO_Xemissions, the owner or operator may, but is not required to, for purposes of determining excess emissions, use a CEMS that meets the requirements of paragraph (b) of this section. Also, if the owner or operator has previously submitted and received EPA, State, or local permitting authority approval of a procedure for monitoring compliance with the applicable NO_Xemission limit under §60.332, that approved procedure may continue to be used.

(d) The owner or operator of any new turbine constructed after July 8, 2004, and which uses water or steam injection to control NO_Xemissions may elect to use either the requirements in paragraph (a) of this section for continuous water or steam to fuel ratio monitoring or may use a NO_XCEMS installed, certified, operated, maintained, and quality-assured as described in paragraph (b) of this section.

(e) The owner or operator of any new turbine that commences construction after July 8, 2004, and which does not use water or steam injection to control NO_X emissions, may, but is not required to, elect to use a NO_X CEMS installed, certified, operated, maintained, and quality-assured as described in paragraph (b) of this section. Other acceptable monitoring approaches include periodic testing approved by EPA or the State or local permitting authority or continuous parameter monitoring as described in paragraph (f) of this section.

(f) The owner or operator of a new turbine that commences construction after July 8, 2004, which does not use water or steam injection to control NO_X emissions may, but is not required to, perform continuous parameter monitoring as follows:

(1) For a diffusion flame turbine without add-on selective catalytic reduction controls (SCR), the owner or operator shall define at least four parameters indicative of the unit's NO_X formation characteristics and shall monitor these parameters continuously.

(2) For any lean premix stationary combustion turbine, the owner or operator shall continuously monitor the appropriate parameters to determine whether the unit is operating in low-NO_X mode.

(3) For any turbine that uses SCR to reduce NO_X emissions, the owner or operator shall continuously monitor appropriate parameters to verify the proper operation of the emission controls.

(4) For affected units that are also regulated under part 75 of this chapter, if the owner or operator elects to monitor NO_X emission rate using the methodology in appendix E to part 75 of this chapter, or the low mass emissions methodology in §75.19 of this chapter, the requirements of this paragraph (f) may be met by performing the parametric monitoring described in section 2.3 of appendix E or in §75.19(c)(1)(iv)(H) of this chapter.

(g) The steam or water to fuel ratio or other parameters that are continuously monitored as described in paragraphs (a), (d) or (f) of this section shall be monitored during the performance test required under §60.8, to establish acceptable values and ranges. The owner or operator may supplement the performance test data with engineering analyses, design specifications, manufacturer's recommendations and other relevant information to define the acceptable parametric ranges more precisely. The owner or operator shall develop and keep on-site a parameter monitoring plan which explains the procedures used to document proper operation of the NO_X emission controls. The plan shall include the parameter(s) monitored and the acceptable range(s) of the parameter(s) as well as the basis for designating the parameter(s) and acceptable range(s). Any supplemental data such as engineering analyses, design specifications, manufacturer's recommendations and other relevant information shall be included in the monitoring plan. For affected units that are also subject to part 75 of this chapter and that use the low mass emissions methodology in §75.19 of this chapter or the NO_X emission measurement methodology in appendix E to part 75, the owner or operator may meet the requirements of this paragraph by developing and keeping on-site (or at a central location for unmanned facilities) a quality-assurance plan, as described in §75.19 (e)(5) or in section 2.3 of appendix E and section 1.3.6 of appendix B to part 75 of this chapter.

(h) The owner or operator of any stationary gas turbine subject to the provisions of this subpart:

(1) Shall monitor the total sulfur content of the fuel being fired in the turbine, except as provided in paragraph (h)(3) of this section. The sulfur content of the fuel must be determined using total sulfur methods described in §60.335(b)(10). Alternatively, if the total sulfur content of the gaseous fuel during the most recent performance test was less than 0.4 weight percent (4000 ppmw), ASTM D4084–82, 94, D5504–01, D6228–98, or Gas Processors Association Standard 2377–86 (all of which are incorporated by reference-see §60.17), which measure the major sulfur compounds may be used; and

(2) Shall monitor the nitrogen content of the fuel combusted in the turbine, if the owner or operator claims an allowance for fuel bound nitrogen (*i.e.* , if an F-value greater than zero is being or will be used by the owner or operator to calculate STD in §60.332). The nitrogen content of the fuel shall be determined using methods described in §60.335(b)(9) or an approved alternative.

(3) Notwithstanding the provisions of paragraph (h)(1) of this section, the owner or operator may elect not to monitor the total sulfur content of the gaseous fuel combusted in the turbine, if the gaseous fuel is demonstrated to meet the definition of natural gas in §60.331(u), regardless of whether an existing custom

schedule approved by the administrator for subpart GG requires such monitoring. The owner or operator shall use one of the following sources of information to make the required demonstration:

(i) The gas quality characteristics in a current, valid purchase contract, tariff sheet or transportation contract for the gaseous fuel, specifying that the maximum total sulfur content of the fuel is 20.0 grains/100 scf or less; or

(ii) Representative fuel sampling data which show that the sulfur content of the gaseous fuel does not exceed 20 grains/100 scf. At a minimum, the amount of fuel sampling data specified in section 2.3.1.4 or 2.3.2.4 of appendix D to part 75 of this chapter is required.

(4) For any turbine that commenced construction, reconstruction or modification after October 3, 1977, but before July 8, 2004, and for which a custom fuel monitoring schedule has previously been approved, the owner or operator may, without submitting a special petition to the Administrator, continue monitoring on this schedule.

(i) The frequency of determining the sulfur and nitrogen content of the fuel shall be as follows:

(1) *Fuel oil.* For fuel oil, use one of the total sulfur sampling options 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 part 75 of this chapter (*i.e.* , flow proportional 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). If an emission allowance is being claimed for fuel-bound nitrogen, the nitrogen content of the oil shall be determined and recorded once per unit operating day.

(2) *Gaseous fuel.* Any applicable nitrogen content value of the gaseous fuel shall be determined and recorded once per unit operating day. For owners and operators that elect not to demonstrate sulfur content using options in paragraph (h)(3) of this section, and for which the fuel is supplied without intermediate bulk storage, the sulfur content value of the gaseous fuel shall be determined and recorded once per unit operating day.

(3) *Custom schedules.* Notwithstanding the requirements of paragraph (i)(2) of this section, operators or fuel vendors may develop custom schedules for determination of the total sulfur content of gaseous fuels, based on the design and operation of the affected facility and the characteristics of the fuel supply. Except as provided in paragraphs (i)(3)(i) and (i)(3)(ii) of this section, custom schedules shall be substantiated with data and shall be approved by the Administrator before they can be used to comply with the standard in §60.333.

(i) The two custom sulfur monitoring schedules set forth in paragraphs (i)(3)(i)(A) through (D) and in paragraph (i)(3)(ii) of this section are acceptable, without prior Administrative approval:

(A) The owner or operator shall obtain daily total sulfur content measurements for 30 consecutive unit operating days, using the applicable methods specified in this subpart. Based on the results of the 30 daily samples, the required frequency for subsequent monitoring of the fuel's total sulfur content shall be as specified in paragraph (i)(3)(i)(B), (C), or (D) of this section, as applicable.

(B) If none of the 30 daily measurements of the fuel's total sulfur content exceeds 0.4 weight percent (4000 ppmw), subsequent sulfur content monitoring may be performed at 12 month intervals. If any of the samples taken at 12-month intervals has a total sulfur content between 0.4 and 0.8 weight percent (4000 and 8000 ppmw), follow the procedures in paragraph (i)(3)(i)(C) of this section. If any measurement exceeds 0.8 weight percent (8000 ppmw), follow the procedures in paragraph (i)(3)(i)(D) of this section.

(C) If at least one of the 30 daily measurements of the fuel's total sulfur content is between 0.4 and 0.8 weight percent (4000 and 8000 ppmw), but none exceeds 0.8 weight percent (8000 ppmw), then:

(*1*) Collect and analyze a sample every 30 days for three months. If any sulfur content measurement exceeds 0.8 weight percent (8000 ppmw), follow the procedures in paragraph (i)(3)(i)(D) of this section. Otherwise, follow the procedures in paragraph (i)(3)(i)(C)(2) of this section.

(2) Begin monitoring at 6-month intervals for 12 months. If any sulfur content measurement exceeds 0.8 weight percent (8000 ppmw), follow the procedures in paragraph (i)(3)(i)(D) of this section. Otherwise, follow the procedures in paragraph (i)(3)(i)(C)(3) of this section.

(3) Begin monitoring at 12-month intervals. If any sulfur content measurement exceeds 0.8 weight percent (8000 ppmw), follow the procedures in paragraph (i)(3)(i)(D) of this section. Otherwise, continue to monitor at this frequency.

(D) If a sulfur content measurement exceeds 0.8 weight percent (8000 ppmw), immediately begin daily monitoring according to paragraph (i)(3)(i)(A) of this section. Daily monitoring shall continue until 30 consecutive daily samples, each having a sulfur content no greater than 0.8 weight percent (8000 ppmw), are obtained. At that point, the applicable procedures of paragraph (i)(3)(i)(B) or (C) of this section shall be followed.

(ii) The owner or operator may use the data collected from the 720-hour sulfur sampling demonstration described in section 2.3.6 of appendix D to part 75 of this chapter to determine a custom sulfur sampling schedule, as follows:

(A) If the maximum fuel sulfur content obtained from the 720 hourly samples does not exceed 20 grains/100 scf (*i.e.* , the maximum total sulfur content of natural gas as defined in §60.331(u)), no additional monitoring of the sulfur content of the gas is required, for the purposes of this subpart.

(B) If the maximum fuel sulfur content obtained from any of the 720 hourly samples exceeds 20 grains/100 scf, but none of the sulfur content values (when converted to weight percent sulfur) exceeds 0.4 weight percent (4000 ppmw), then the minimum required sampling frequency shall be one sample at 12 month intervals.

(C) If any sample result exceeds 0.4 weight percent sulfur (4000 ppmw), but none exceeds 0.8 weight percent sulfur (8000 ppmw), follow the provisions of paragraph (i)(3)(i)(C) of this section.

(D) If the sulfur content of any of the 720 hourly samples exceeds 0.8 weight percent (8000 ppmw), follow the provisions of paragraph (i)(3)(i)(D) of this section.

(j) For each affected unit that elects to continuously monitor parameters or emissions, or to periodically determine the fuel sulfur content or fuel nitrogen content under this subpart, the owner or operator shall submit reports of excess emissions and monitor downtime, in accordance with §60.7(c). Excess emissions shall be reported for all periods of unit operation, including startup, shutdown and malfunction. For the purpose of reports required under §60.7(c), periods of excess emissions and monitor downtime that shall be reported are defined as follows:

(1) Nitrogen oxides.

(i) For turbines using water or steam to fuel ratio monitoring:

(A) An excess emission shall be any unit operating hour for which the average steam or water to fuel ratio, as measured by the continuous monitoring system, falls below the acceptable steam or water to fuel ratio needed to demonstrate compliance with §60.332, as established during the performance test required in §60.8. Any unit operating hour in which no water or steam is injected into the turbine shall also be considered an excess emission.

(B) A period of monitor downtime shall be any unit operating hour in which water or steam is injected into the turbine, but the essential parametric data needed to determine the steam or water to fuel ratio are unavailable or invalid.

(C) Each report shall include the average steam or water to fuel ratio, average fuel consumption, ambient conditions (temperature, pressure, and humidity), gas turbine load, and (if applicable) the nitrogen content of the fuel during each excess emission. You do not have to report ambient conditions if you opt to use the

worst case ISO correction factor as specified in §60.334(b)(3)(ii), or if you are not using the ISO correction equation under the provisions of §60.335(b)(1).

(ii) If the owner or operator elects to take an emission allowance for fuel bound nitrogen, then excess emissions and periods of monitor downtime are as described in paragraphs (j)(1)(ii)(A) and (B) of this section.

(A) An excess emission shall be the period of time during which the fuel-bound nitrogen (N) is greater than the value measured during the performance test required in §60.8 and used to determine the allowance. The excess emission begins on the date and hour of the sample which shows that N is greater than the performance test value, and ends with the date and hour of a subsequent sample which shows a fuel nitrogen content less than or equal to the performance test value.

(B) A period of monitor downtime begins when a required sample is not taken by its due date. A period of monitor downtime also begins on the date and hour that a required sample is taken, if invalid results are obtained. The period of monitor downtime ends on the date and hour of the next valid sample.

(iii) For turbines using $NO_X$and diluent CEMS:

(A) An hour of excess emissions shall be any unit operating hour in which the 4-hour rolling average NO_Xconcentration exceeds the applicable emission limit in §60.332(a)(1) or (2). For the purposes of this subpart, a "4-hour rolling average NO_Xconcentration" is the arithmetic average of the average NO_Xconcentration measured by the CEMS for a given hour (corrected to 15 percent $O_2$and, if required under §60.335(b)(1), to ISO standard conditions) and the three unit operating hour average NO_Xconcentrations immediately preceding that unit operating hour.

(B) A period of monitor downtime shall be any unit operating hour in which sufficient data are not obtained to validate the hour, for either NO_Xconcentration or diluent (or both).

(C) Each report shall include the ambient conditions (temperature, pressure, and humidity) at the time of the excess emission period and (if the owner or operator has claimed an emission allowance for fuel bound nitrogen) the nitrogen content of the fuel during the period of excess emissions. You do not have to report ambient conditions if you opt to use the worst case ISO correction factor as specified in §60.334(b)(3)(ii), or if you are not using the ISO correction equation under the provisions of §60.335(b)(1).

(iv) For owners or operators that elect, under paragraph (f) of this section, to monitor combustion parameters or parameters that document proper operation of the NO_Xemission controls:

(A) An excess emission shall be a 4-hour rolling unit operating hour average in which any monitored parameter does not achieve the target value or is outside the acceptable range defined in the parameter monitoring plan for the unit.

(B) A period of monitor downtime shall be a unit operating hour in which any of the required parametric data are either not recorded or are invalid.

(2) Sulfur dioxide. If the owner or operator is required to monitor the sulfur content of the fuel under paragraph (h) of this section:

(i) For samples of gaseous fuel and for oil samples obtained using daily sampling, flow proportional sampling, or sampling from the unit's storage tank, an excess emission occurs each unit operating hour included in the period beginning on the date and hour of any sample for which the sulfur content of the fuel being fired in the gas turbine exceeds 0.8 weight percent and ending on the date and hour that a subsequent sample is taken that demonstrates compliance with the sulfur limit.

(ii) If the option to sample each delivery of fuel oil has been selected, the owner or operator shall immediately switch to one of the other oil sampling options (*i.e.* , daily sampling, flow proportional sampling, or sampling from the unit's storage tank) if the sulfur content of a delivery exceeds 0.8 weight percent. The owner or operator shall continue to use one of the other sampling options until all of the oil from the delivery

has been combusted, and shall evaluate excess emissions according to paragraph (j)(2)(i) of this section. When all of the fuel from the delivery has been burned, the owner or operator may resume using the as-delivered sampling option.

(iii) A period of monitor downtime begins when a required sample is not taken by its due date. A period of monitor downtime also begins on the date and hour of a required sample, if invalid results are obtained. The period of monitor downtime shall include only unit operating hours, and ends on the date and hour of the next valid sample.

(3) *Ice fog.* Each period during which an exemption provided in §60.332(f) is in effect shall be reported in writing to the Administrator quarterly. For each period the ambient conditions existing during the period, the date and time the air pollution control system was deactivated, and the date and time the air pollution control system was reactivated shall be reported. All quarterly reports shall be postmarked by the 30th day following the end of each calendar quarter.

(4) *Emergency fuel.* Each period during which an exemption provided in §60.332(k) is in effect shall be included in the report required in §60.7(c). For each period, the type, reasons, and duration of the firing of the emergency fuel shall be reported.

(5) All reports required under §60.7(c) shall be postmarked by the 30th day following the end of each 6-month period.

[44 FR 52798, Sept. 10, 1979, as amended at 47 FR 3770, Jan. 27, 1982; 65 FR 61759, Oct. 17, 2000; 69 FR 41360, July 8, 2004; 71 FR 9457, Feb. 24, 2006]

§ 60.335 Test methods and procedures.

(a) The owner or operator shall conduct the performance tests required in §60.8, using either

(1) EPA Method 20,

(2) ASTM D6522–00 (incorporated by reference, see §60.17), or

(3) EPA Method 7E and either EPA Method 3 or 3A in appendix A to this part, to determine $NO_X$and diluent concentration.

(4) Sampling traverse points are to be selected following Method 20 or Method 1, (non-particulate procedures) and sampled for equal time intervals. The sampling shall be performed with a traversing single-hole probe or, if feasible, with a stationary multi-hole probe that samples each of the points sequentially. Alternatively, a multi-hole probe designed and documented to sample equal volumes from each hole may be used to sample simultaneously at the required points.

(5) Notwithstanding paragraph (a)(4) of this section, the owner or operator may test at few points than are specified in Method 1 or Method 20 if the following conditions are met:

(i) You may perform a stratification test for $NO_X$and diluent pursuant to

(A) [Reserved]

(B) The procedures specified in section 6.5.6.1(a) through (e) appendix A to part 75 of this chapter.

(ii) Once the stratification sampling is completed, the owner or operator may use the following alternative sample point selection criteria for the performance test:

(A) If each of the individual traverse point NO_Xconcentrations, normalized to 15 percent O_2, is within ±10 percent of the mean normalized concentration for all traverse points, then you may use 3 points (located

either 16.7, 50.0, and 83.3 percent of the way across the stack or duct, or, for circular stacks or ducts greater than 2.4 meters (7.8 feet) in diameter, at 0.4, 1.2, and 2.0 meters from the wall). The 3 points shall be located along the measurement line that exhibited the highest average normalized NO_X concentration during the stratification test; or

(B) If each of the individual traverse point NO_X concentrations, normalized to 15 percent O_2, is within ±5 percent of the mean normalized concentration for all traverse points, then you may sample at a single point, located at least 1 meter from the stack wall or at the stack centroid.

(6) Other acceptable alternative reference methods and procedures are given in paragraph (c) of this section.

(b) The owner or operator shall determine compliance with the applicable nitrogen oxides emission limitation in §60.332 and shall meet the performance test requirements of §60.8 as follows:

(1) For each run of the performance test, the mean nitrogen oxides emission concentration (NO_{X_o}) corrected to 15 percent O_2 shall be corrected to ISO standard conditions using the following equation. Notwithstanding this requirement, use of the ISO correction equation is optional for: Lean premix stationary combustion turbines; units used in association with heat recovery steam generators (HRSG) equipped with duct burners; and units equipped with add-on emission control devices:

$$NO_X=(NO_{X_o})(P_r/P_o)^{0.5}\ e19\ (Ho-0.00633)(288°K/T_a)^{1.53}$$

Where:

NO_X= emission concentration of NO_X at 15 percent O_2 and ISO standard ambient conditions, ppm by volume, dry basis,

NO_{X_o}= mean observed NO_X concentration, ppm by volume, dry basis, at 15 percent O_2,

P_r= reference combustor inlet absolute pressure at 101.3 kilopascals ambient pressure, mm Hg,

P_o= observed combustor inlet absolute pressure at test, mm Hg,

H_o= observed humidity of ambient air, g H_2O/g air,

e = transcendental constant, 2.718, and

T_a= ambient temperature, °K.

(2) The 3-run performance test required by §60.8 must be performed within ±5 percent at 30, 50, 75, and 90-to-100 percent of peak load or at four evenly-spaced load points in the normal operating range of the gas turbine, including the minimum point in the operating range and 90-to-100 percent of peak load, or at the highest achievable load point if 90-to-100 percent of peak load cannot be physically achieved in practice. If the turbine combusts both oil and gas as primary or backup fuels, separate performance testing is required for each fuel. Notwithstanding these requirements, performance testing is not required for any emergency fuel (as defined in §60.331).

(3) For a combined cycle turbine system with supplemental heat (duct burner), the owner or operator may elect to measure the turbine NO_X emissions after the duct burner rather than directly after the turbine. If the owner or operator elects to use this alternative sampling location, the applicable NO_X emission limit in §60.332 for the combustion turbine must still be met.

(4) If water or steam injection is used to control NO_X with no additional post-combustion NO_X control and the owner or operator chooses to monitor the steam or water to fuel ratio in accordance with §60.334(a), then

that monitoring system must be operated concurrently with each EPA Method 20, ASTM D6522–00 (incorporated by reference, see §60.17), or EPA Method 7E run and shall be used to determine the fuel consumption and the steam or water to fuel ratio necessary to comply with the applicable §60.332 NO_Xemission limit.

(5) If the owner operator elects to claim an emission allowance for fuel bound nitrogen as described in §60.332, then concurrently with each reference method run, a representative sample of the fuel used shall be collected and analyzed, following the applicable procedures described in §60.335(b)(9). These data shall be used to determine the maximum fuel nitrogen content for which the established water (or steam) to fuel ratio will be valid.

(6) If the owner or operator elects to install a CEMS, the performance evaluation of the CEMS may either be conducted separately (as described in paragraph (b)(7) of this section) or as part of the initial performance test of the affected unit.

(7) If the owner or operator elects to install and certify a NO_XCEMS under §60.334(e), then the initial performance test required under §60.8 may be done in the following alternative manner:

(i) Perform a minimum of 9 reference method runs, with a minimum time per run of 21 minutes, at a single load level, between 90 and 100 percent of peak (or the highest physically achievable) load.

(ii) Use the test data both to demonstrate compliance with the applicable NO_Xemission limit under §60.332 and to provide the required reference method data for the RATA of the CEMS described under §60.334(b).

(iii) The requirement to test at three additional load levels is waived.

(8) If the owner or operator elects under §60.334(f) to monitor combustion parameters or parameters indicative of proper operation of NO_Xemission controls, the appropriate parameters shall be continuously monitored and recorded during each run of the initial performance test, to establish acceptable operating ranges, for purposes of the parameter monitoring plan for the affected unit, as specified in §60.334(g).

(9) To determine the fuel bound nitrogen content of fuel being fired (if an emission allowance is claimed for fuel bound nitrogen), the owner or operator may use equipment and procedures meeting the requirements of:

(i) For liquid fuels, ASTM D2597–94 (Reapproved 1999), D6366–99, D4629–02, D5762–02 (all of which are incorporated by reference, *see* §60.17); or

(ii) For gaseous fuels, shall use analytical methods and procedures that are accurate to within 5 percent of the instrument range and are approved by the Administrator.

(10) If the owner or operator is required under §60.334(i)(1) or (3) to periodically determine the sulfur content of the fuel combusted in the turbine, a minimum of three fuel samples shall be collected during the performance test. Analyze the samples for the total sulfur content of the fuel using:

(i) For liquid fuels, ASTM D129–00, D2622–98, D4294–02, D1266–98, D5453–00 or D1552–01 (all of which are incorporated by reference, *see* §60.17); or

(ii) For gaseous fuels, ASTM D1072–80, 90 (Reapproved 1994); D3246–81, 92, 96; D4468–85 (Reapproved 2000); or D6667–01 (all of which are incorporated by reference, see §60.17). The applicable ranges of some ASTM methods mentioned above are not adequate to measure the levels of sulfur in some fuel gases. Dilution of samples before analysis (with verification of the dilution ratio) may be used, subject to the prior approval of the Administrator.

(11) The fuel analyses required under paragraphs (b)(9) and (b)(10) of this section may be performed by the owner or operator, a service contractor retained by the owner or operator, the fuel vendor, or any other qualified agency.

(c) The owner or operator may use the following as alternatives to the reference methods and procedures specified in this section:

(1) Instead of using the equation in paragraph (b)(1) of this section, manufacturers may develop ambient condition correction factors to adjust the nitrogen oxides emission level measured by the performance test as provided in §60.8 to ISO standard day conditions.

[69 FR 41363, July 8, 2004, as amended at 71 FR 9458, Feb. 24, 2006]

CERTIFICATE OF SERVICE

I, Cynthia Hook, hereby certify that a copy of this permit has been mailed by first class mail to CenterPoint Energy - Mississippi River Transmission Corp. - Tuckerman Compressor Station, P.O. Box 21734, Shreveport, LA, 71151, on this 7th day of July, 2010.

C Hook

Cynthia Hook, AAII, Air Division