ADEQ
ARKANSAS
Department of Environmental Quality

JAN 15 2008

Ronald Bowen
City Water & Light Plant
P.O. Box 1289
Jonesboro, AR 72401

Re: Notice of Administrative Amendment
AFIN: 16-00412, Permit No.: 1819-AOP-R5

Dear Mr. Bowen:

Enclosed is revised Permit 1819-AOP-R5 completed in accordance with the provisions of Section 26.901 of Regulation No. 26, Regulations of the Arkansas Operating Air Permit Program.

Appendix H – Acid Rain Permit has been added to the permit.

Please place the revised permit in your files.

Sincerely,

Mike Bates

Mike Bates
Chief, Air Division

jlb
Enclosure

ADEQ
OPERATING
AIR PERMIT

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

Permit No. : 1819-AOP-R5
Renewal #1
IS ISSUED TO:
City Water & Light Plant of the City of Jonesboro
1400 Hanley Drive
Jonesboro, AR 72401
Craighead County
AFIN: 16-00412

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:

April 6, 2005 AND April 5, 2010

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

Signed:

Mike Bates

Mike Bates
Chief, Air Division

JAN 15 2008

Date Amended

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:	City Water & Light Plant of the City of Jonesboro
AFIN:	16-00412
PERMIT NUMBER:	1819-AOP-R5
FACILITY ADDRESS:	1400 Hanley Drive Jonesboro, AR 72401
MAILING ADDRESS:	P.O. Box 1289 Jonesboro, AR 72403-1289
COUNTY:	Craighead
CONTACT POSITION:	Rick White, Senior Engineer
TELEPHONE NUMBER:	(870) 930-3323
REVIEWING ENGINEER:	Joseph Hurt
UTM North South (Y):	Zone 15: 3969.3 km N
UTM East West (X):	Zone 15: 705.4 km E

SECTION II: INTRODUCTION

Summary of Permit Activity

The City of Jonesboro operates a turbine powered peaking power plant located at the Northwest Substation at 1400 Hanley Drive. The facility was originally constructed in early 1999 with two GE LM2500 turbine driven generators rated 23 MW per unit and a fuel storage tank under a minor source permit. The original Title V permit was issued to allow the addition of a GE LM6000 turbine driven generator rated approximately 45 MW. A later modification was issued to allow the addition of a fourth turbine driven generator which will also be powered by a GE LM6000 rated approximately 49 MW. Emissions consist of products of combustion from the turbine exhausts, volatile organic compounds from the fuel storage tank, and particulate matter from the cooling tower drift.

This permit modification is issued to install a new GE LM6000 turbine driven generator (SN-07) rated approximately 45 MW and a new Cooling Tower (SN-05B) to cool the inlet air to SN-04, SN-06, and SN-07. The new generator is permitted to use only natural gas as a fuel, whereas the other four generators are permitted to use either natural gas or fuel oil as a fuel. The current Cooling Tower SN-05 has been renamed SN-05A. The annual plantwide limits for combustion emissions from turbines SN-02, SN-03, SN-04, and SN-06 have remained the same as the previous permit. The emissions from SN-07 have been bubbled together with the other simple-cycle combustion turbines. Permitted emission increases from the addition of SN-07 and SN-05B include 3.5 tpy of PM/PM_{10}.

Process Description

Five simple-cycle combustion turbines (which will be water injected for nitrogen oxides emissions control) will be utilized at a peaking power plant at the Northwest Substation, owned by City Water & Light in Jonesboro, Arkansas to drive electric generators to produce electricity.

The two original simple-cycle turbine units are General Electric LM2500 turbines capable of producing approximately twenty-three (23) megawatts of power each. Each of the original turbines can be fired with natural gas or fuel oil. Hot turbine exhaust gases are discharged from the power turbines through stacks designated as SN-01 for the first power turbine and SN-02 for the second power turbine. These units are permitted to fire either natural gas or diesel fuel oil.

The third and fourth simple-cycle turbine units have been added which are General Electric LM6000 turbines. The No. 3 unit is capable of producing approximately forty-five (45) megawatts of power, and the No. 4 unit is capable of producing approximately forty-nine (49) megawatts of power. Hot turbine exhaust gases are discharged from the power turbine through a stack designated as SN-04 for the No. 3 unit and SN-06 for the No. 4 unit. These units are permitted to fire either natural gas or diesel fuel oil. The No. 5 unit (SN-07) is capable of producing approximately forty-five (45) megawatts of power and is permitted to fire only natural gas.

A cooling tower is used to cool the inlet air to the LM6000 units (SN-04 and SN-06) allowing them to operate at a higher rated power level during high ambient air temperatures. The drift from the cooling tower (SN-05) will contain particulate matter.

A third emission point, identified as SN-03, is the fuel oil storage tank.

Estimations of hazardous air pollutant (HAP) emission rates are based on AP-42 – Table 3.1-3 – Emission Factors for HAPs from NG fired Stationary Gas Turbines (while fired with natural gas) and AP-42 – Table 3.1-4 and 3.1-5 – Emission Factors for HAPs from Oil Fired Stationary Gas Turbines (when fired with fuel oil). Emissions limits for criteria pollutants are also based on the current AP-42 factors and the carbon monoxide, sulfur dioxide, and oxides of nitrogen limits have been confirmed by initial stack testing.

Regulations

The following table contains the regulations applicable to this permit.

Source No.	Regulation Citations
Facility	*The Arkansas Air Pollution Control Code* (Regulation 18)
Facility	*Regulations of the Arkansas Plan of Implementation for Air Pollution Control* (Regulation 19)
Facility	*Regulations of the Arkansas Operating Air Permit Program* (Regulation 26).
SN-01, SN-02, SN-04, SN-06 and SN-07	*New Source Performance Standards (NSPS)*, 40 CFR Part 60, Subpart GG
SN-04, SN-06, and SN-07	Federal Acid Rain Program, specifically the requirements of 40 CFR Parts 72, 73, and 75
SN-03	40 CFR 60 Subpart Kb - *Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced after July 23, 1984*

This permit contains Specific Conditions limiting operating hours and fuel restrictions only for SN-04 and SN-06 such that they can be classified as peaking units as defined in 40 CFR 72.2. This permit contains additional Specific Conditions limiting operating hours and fuel restrictions for SN-07. These conditions for SN-04, SN-06, and SN-07 allows PEMS to be substituted for a CEMS for SO_2 and NO_x monitoring, no continuous opacity monitor required, and other provisions of the acid rain sections to not be applicable.

The following table is a summary of emissions from the facility. The following table contains cross-references to the pages containing specific conditions and emissions for each source. This table, in itself, is not an enforceable condition of the permit.

Emission Summary

EMISSION SUMMARY				
Source Number	Description	Pollutant	Emission Rates	
			lb/hr	tpy
Total Allowable Emissions		PM	77.6	75.2
		PM_{10}	77.6	75.2
		SO_2	241.0	221.5
		VOC	80.4	85.7
		CO	125.0	153.6
		NO_X	300.0	239.0
HAPs		Acrolein Benzene 1,3-Butadiene Formaldehyde PAH♦* Toluene Arsenic Beryllium Cadmium Lead Manganese Mercury Selenium	1.14E-02 7.34E-02 2.14E-02 1.26 5.44E-02 2.31E-01 1.47E-02 4.13E-04 6.40E-03 1.87E-02 1.06 1.60E-03 3.34E-02	3.90E-02 3.20E-01 9.30E-02 0.53 2.40E-01 9.96E-01 6.40E-02 1.80E-03 2.80E-02 8.20E-02 4.70 7.00E-03 1.50E-01
SN	Description	Pollutant		
01	General Electric LM 2500 Combustion Turbine Natural Gas Fired 228 MMBtu/Hr	PM PM_{10} SO_2 VOC CO NO_x Acrolein Formaldehyde PAH♦	8 8 8 10 25 38.9 1.46E -03 1.62E -01 5.02E -04	68.2** 68.2** 221.5** 85.4** 153.6** 239.0**

EMISSION SUMMARY				
Source Number	Description	Pollutant	Emission Rates	
			lb/hr	tpy
01	General Electric LM 2500 Combustion Turbine Fuel Oil Fired 234 MMBtu/Hr	PM	10	
		PM_{10}	10	
		SO_2	38	
		VOC	10	
		CO	25	
		NO_x	41	
		Benzene	1.25E-02	
		1,3-Butadiene	3.65E-03	
		Formaldehyde	6.38E-02	
		PAH♣	9.12E-03	
		Arsenic	2.51E-03	
		Beryllium	7.07E-05	
		Cadmium	1.09E-03	
		Lead	3.19E-03	
		Manganese	1.80E-01	
		Mercury	2.74E-04	
		Selenium	5.70E-03	
02	General Electric LM 2500 Combustion Turbine Natural Gas Fired 228 MMBtu/Hr	PM	8	
		PM_{10}	8	
		SO_2	8	
		VOC	10	
		CO	25	
		NO_x	38.9	
		Acrolein	1.46E -03	
		Formaldehyde	1.62E -01	
		PAH♣	5.02E -04	

EMISSION SUMMARY				
Source Number	Description	Pollutant	Emission Rates	
			lb/hr	tpy
02	General Electric LM 2500 Combustion Turbine Fuel Oil Fired 234 MMBtu/Hr	PM PM_{10} SO_2 VOC CO NO_x Benzene 1,3-Butadiene Formaldehyde PAH♣ Arsenic Beryllium Cadmium Lead Manganese Mercury Selenium	10 10 38 10 25 41 1.25E-02 3.65E-03 6.38E-02 9.12E-03 2.51E-03 7.07E-05 1.09E-03 3.19E-03 1.80E-01 2.74E-04 5.70E-03	
04	General Electric LM 6000 Combustion Turbine Natural Gas Fired 440 MMBtu/Hr	PM PM_{10} SO_2 VOC CO NO_x Acrolein Formaldehyde PAH♣	16 16 15 20 25 56 2.82E -03 3.12E -01 9.68E -04	

EMISSION SUMMARY				
Source Number	Description	Pollutant	Emission Rates	
			lb/hr	tpy
04	General Electric LM 6000 Combustion Turbine Fuel Oil Fired 440 MMBtu/Hr	PM	20	
		PM_{10}	20	
		SO_2	75	
		VOC	20	
		CO	25	
		NO_x	81	
		Benzene	2.42E-02	
		1,3-Butadiene	7.04E-03	
		Formaldehyde	1.23E-01	
		PAH♠	1.76E-02	
		Arsenic	4.84E-03	
		Beryllium	1.36E-04	
		Cadmium	2.11E-03	
		Lead	6.16E-03	
		Manganese	3.48E-01	
		Mercury	5.28E-04	
		Selenium	1.10E-02	
06	General Electric LM 6000 Combustion Turbine Natural Gas Fired 440 MMBtu/Hr	PM	16	
		PM_{10}	16	
		SO_2	15	
		VOC	20	
		CO	25	
		NO_x	56	
		Acrolein	2.82E -03	
		Formaldehyde	3.12E -01	
		PAH♠	9.68E -04	

EMISSION SUMMARY				
Source Number	Description	Pollutant	Emission Rates	
			lb/hr	tpy
06	General Electric	PM	20	
	LM 6000	PM_{10}	20	
	Combustion	SO_2	75	
	Turbine	VOC	20	
	Fuel Oil Fired	CO	25	
	440 MMBtu/Hr	NO_x	81	
		Benzene	2.42E-02	
		1,3-Butadiene	7.04E-03	
		Formaldehyde	1.23E-01	
		PAH♠	1.76E-02	
		Arsenic	4.84E-03	
		Beryllium	1.36E-04	
		Cadmium	2.11E-03	
		Lead	6.16E-03	
		Manganese	3.48E-01	
		Mercury	5.28E-04	
		Selenium	1.10E-02	
07	General Electric	PM	16	
	LM 6000	PM_{10}	16	
	Combustion	SO_2	15	
	Turbine	VOC	20	
	Natural Gas Fired	CO	25	
	440 MMBtu/Hr	NO_x	56	
		Acrolein	2.82E -03	
		Formaldehyde	3.12E -01	
		PAH♠	9.68E -04	
Facility	HAPs	Acrolein*		3.8E -02
–		Benzene*		3.2E -01
Turbines		1,3-Butadiene*		9.3E -02
01, 02,		Formaldehyde*		0.42
04, 06,		PAH♠*		2.4E -01
& 07		Arsenic		6.4E -02
only		Beryllium		1.8E -03
		Cadmium		2.8E -02
		Lead		8.2E -02
		Manganese		4.70
		Mercury		7.0E -03
		Selenium		1.5E -01

EMISSION SUMMARY				
Source Number	Description	Pollutant	Emission Rates	
			lb/hr	tpy
03	Vertical Fuel Oil Storage Tank 15' High x 80' Diameter (1999)	VOC	0.4	0.4
05A	Cooling Tower (2000)	PM PM_{10}	0.8 0.8	3.5 3.5
05B	Cooling Tower (2006)	PM PM_{10}	0.8 0.8	3.5 3.5

* - HAPs included in the VOC totals. Other HAPs are not included in any other totals unless specifically stated.
** - Emission limits for combustion products from the turbines are a PAL based on Specific Condition # 3.
♠ - Polycyclic Aromatic Hydrocarbons

SECTION III: PERMIT HISTORY

Permit No. 1819-A was issued on June 3, 1999 to Jonesboro - City Water and Light for the installation and operation of a peaking power plant powered by two 23 MW GE LM-2500 turbines. Permit limits were listed as PM/PM_{10} - 17.6 tpy, SO_2 - 26.8 tpy, VOC - 21.4 tpy, CO - 89.9 tpy and NO_x - 83.5 tpy.

Permit No. 1819-AOP-R0 was issued on March 10, 2000 to Jonesboro - City Water and Light for the addition of a third unit at the power plant which was driven by a 45 MW GE LM-6000 turbine. Hours of operation limits were taken to classify the unit as a "peaking unit" as defined in 40 CFR Part 75. Permit limits were listed as PM/PM_{10} - 75.0 tpy, SO_2 - 83.9 tpy, VOC - 89.0 tpy, CO - 239.0 tpy, NO_x - 239.0 tpy and acetaldehyde - 14.1 tpy.

Permit No. 1819-AOP-R1 was issued on May 17, 2001 to Jonesboro - City Water and Light to allow the GE LM6000 unit to also be fired for a limit amount of time on fuel oil. Permit limits were listed as PM/PM_{10} - 72.1 tpy, SO_2 - 93.6 tpy, VOC - 88.6 tpy, CO - 239.0 tpy, NO_x - 239.0 tpy and acetaldehyde - 14.1 tpy.

Permit No. 1819-AOP-R2 was issued on March 18, 2003 to Jonesboro - City Water and Light to allow the second GE LM6000 unit to be installed at the facility. Permit limits were listed as PM/PM_{10} – 75.6 tpy, SO_2 - 93.6 tpy, VOC – 89.1 tpy, CO - 239.0 tpy, NO_x - 239.0 tpy and acetaldehyde - 14.1 tpy.

Permit No. 1819-AOP-R3 was issued on January 26, 2004 to Jonesboro - City Water and Light to allow 4 minor changes to the permit. These included revising emission limits to agree with the stack testing and to revise the annual emission limits formulas. Permit limits were listed as PM/PM_{10} – 71.7 tpy, SO_2 – 221.5 tpy, VOC – 85.5 tpy, CO – 153.6 tpy, NO_x - 239.0 tpy and acetaldehyde - 14.1 tpy.

Permit No. 1819-AOP-R4 was issued on March 6, 2005 to Jonesboro – City Water and Light to renew its initial Title V permit. No changes occurred in the emission units or processes at the facility. The criteria emission limits remain unchanged for the facility. The non-criteria pollutant emission limits for the turbines were recalculated based on the latest AP-42 factors for stationary turbines (Table 3.1-3, Emission Factors for HAPs from NG Fired Stationary Gas Turbines and Table 3.1-4 and 3.1-5 – Emission Factors for HAPs from Oil Fired Stationary Gas Turbines). Based on the re-calculated emission limits, the facility was no longer a major source for HAP emissions and will not be subject to 40 CFR 63, Subpart YYYY - National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines.

SECTION IV: SPECIFIC CONDITIONS

SN-01, 02, 04, 06, & 07

General Electric Turbine Drive Generators

Source Description

The two original simple-cycle turbine units are General Electric LM2500 turbines capable of producing approximately twenty-three (23) megawatts each. Each simple cycle turbine will be fired with natural gas or fuel oil. The fuel burns in a combustor with air pressurized by the axial air compressor. Combustion products exit the combustor and drive the power turbine which powers both the electric generator and the axial air compressor. Hot turbine exhaust gases are discharged from the power turbines through stacks designated as SN-01 for the first power turbine and SN-02 for the second power turbine. These two turbines are subject to 40 CFR 60, Subpart GG - *New Source Performance Standards for Stationary Gas Turbines.* The non-criteria pollutant emission limits for the turbines have been recalculated based on the latest AP-42 factors for stationary turbines (Table 3.1-3, Emission Factors for HAPs from NG Fired Stationary Gas Turbines and Table 3.1-4 and 3.1-5 – Emission Factors for HAPs from Oil Fired Stationary Gas Turbines). Based on the newly calculated emission limits, the facility will no longer be a major emitter of HAP emissions and will not be subject to 40 CFR 63, Subpart YYYY - National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines as it is currently permitted.

The third, fourth, and fifth turbine units are General Electric LM6000 turbines. The third and fifth units are capable of producing approximately forty-five (45) megawatts and the fourth unit capable of producing approximately forty-nine (49) megawatts. The fuel burns in a combustor with air pressurized by the axial air compressor. Combustion products exit the combustor and drive the power turbine which powers both the electric generator and the axial air compressor. Hot turbine exhaust gases are discharged from the power turbine through stacks designated as SN-04, SN-06, and SN-07. These turbines are subject to 40 CFR 60, Subpart GG - *New Source Performance Standards for Stationary Gas Turbines.* They are also subject to regulation by the Federal Acid Rain Program, specifically the requirements of 40 CFR Parts 72, 73, and 75. This permit contains Specific Conditions limiting operating hours for SN-04 and SN-06 such that they can be classified as peaking units as defined in 40 CFR 72.2. This allows a PEMS to be substituted for a CEMS for SO_2 and NOx monitoring, no continuous opacity monitor required, and other provisions of the acid rain sections to not be applicable. All five turbines are water injected to control the level of nitrogen oxides emissions.

The criteria pollutant permitted pollutants in pounds per hour for SN-01, SN-02, SN-04, and SN-06 is based on maximum capacity of the equipment and the fuel utilized. The tons per year emission limits for criteria pollutants for these turbines for all pollutants are based on limiting the hours of operation by the formula included in the permit in Specific Condition No.3 to prevent exceeding the permit limits.

The criteria pollutant permitted pollutants in pounds per hour for SN-07 is based on a maximum of 700 hundred hours of operations, annually, with natural gas as its only type of fuel utilized. The tons per year emission limits for criteria pollutants for SN-07 is based on the maximum annual permitted hours of operation. All HAP emission limits are based on potential to emit. All emissions from SN-07 have been bubbled together with the existing generator bubble for SN-01, SN-02, SN-04, and SN-06.

The potential uncontrolled emissions from SN-01, SN-02, SN-04, SN-06, and SN-07 turbines fulfill the applicability criteria of the Compliance Assurance Monitoring (CAM) Rule (40 Code of Federal Regulations (CFR) Part (§) 64). Accordingly, the (CAM) Plan for the facility is provided in Appendix F. Per §64.2(a), the aforementioned sources are regulated under the CAM Rule because they meet the following criteria: (1) each unit is subject to emission limitations for NO_x, (2) each source is equipped with a control device (i.e., water injection), and (3) each unit has potential pre-control emissions of NO_x that exceed the applicable major source threshold (i.e., 100 tons per year). In accordance with §64.3, Jonesboro has developed a CAM Plan for these sources. The Plan establishes the operating parameters that will be monitored in order to demonstrate compliance with the NO_x emission limits at each source.

Specific Conditions

1. The permittee shall not exceed the emission rates set forth in the following table. The lb/hr emission limits are based on the maximum capacity of the equipment. Compliance with the ton per year limits for SN-01, SN-02, SN-04, and SN-06 will be demonstrated by completion of the formulas contained in Specific Condition # 3 for SN-01, SN-02, SN-04, and SN-06. Compliance with the ton per year limits for SN-07 will be demonstrated by Specific Condition # 4 and # 5. [Regulation 19, §19.501 et seq., effective May 28, 2006 and 40 CFR Part 52, Subpart E]

SN	Description	Pollutant	lb/hr	tpy
01	General Electric LM 2500 Combustion Turbine Natural Gas Fired 228 MMBtu/Hr	PM_{10} SO_2 VOC CO NO_x	8 8 10 25 38.9	68.2** 221.5** 85.4** 153.6** 239.0**
01	General Electric LM 2500 Combustion Turbine Fuel Oil Fired 234 MMBtu/Hr	PM_{10} SO_2 VOC CO NO_x	10 38 10 25 41	
02	General Electric LM 2500 Combustion Turbine Natural Gas Fired 228 MMBtu/Hr	PM_{10} SO_2 VOC CO NO_x	8 8 10 25 38.9	

SN	Description	Pollutant	lb/hr	tpy
02	General Electric LM 2500 Combustion Turbine Fuel Oil Fired 234 MMBtu/Hr	PM_{10} SO_2 VOC CO NO_x	10 38 10 25 41	
04	General Electric LM 6000 Combustion Turbine Natural Gas Fired 440 MMBtu/Hr	PM_{10} SO_2 VOC CO NO_x	16 15 20 25 56	
04	General Electric LM 6000 Combustion Turbine Fuel Oil Fired 440 MMBtu/Hr	PM_{10} SO_2 VOC CO NO_x	20 75 20 25 81	
06	General Electric LM 6000 Combustion Turbine Natural Gas Fired 440 MMBtu/Hr	PM_{10} SO_2 VOC CO NO_x	16 15 20 25 56	
06	General Electric LM 6000 Combustion Turbine Fuel Oil Fired 440 MMBtu/Hr	PM_{10} SO_2 VOC CO NO_x	20 75 20 25 81	
07	General Electric LM 6000 Combustion Turbine Natural Gas Fired 440 MMBtu/Hr	PM_{10} SO_2 VOC CO NO_x	16 15 20 25 56	

** - Emission limits for combustion products from the turbines are a PAL based on Specific Condition # 3.

2. The permittee shall not exceed the emission rates set forth in the following table. The lb/hr emission limits for particulate matter and hazardous air pollutants are based on capacity of the equipment. Compliance with the ton per year limits for SN-01, SN-02, SN-04, and SN-06 will be demonstrated by completion of the formulas contained in Specific Condition # 3 for SN-01, SN-02, SN-04, and SN-06. Compliance with the ton per year limits for SN-07 will be demonstrated by Specific Conditions # 3, # 4, and # 5. [Regulation 18, §18.801, effective February 15, 1999, 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, 02, 04, 06, & 07	Combustion Turbine Bubble Limits	PM Acrolein Formaldehyde PAH♣ Benzene 1,3-Butadiene Arsenic Beryllium Cadmium Lead Manganese Mercury Selenium		68.2** 3.8E -02** 4.2E +00** 2.0E -01** 3.2E -01** 9.3E -02** 6.4E -02** 1.8E -03** 2.8E -02** 8.2E -02** 4.7E +00** 7.0E -03** 1.5E -01**
01	General Electric LM 2500 Combustion Turbine Natural Gas Fired 228 MMBtu/Hr	PM Acrolein Formaldehyde PAH♣	8 1.46E-03 1.62E-01 5.02E-04	
01	General Electric LM 2500 Combustion Turbine Fuel Oil Fired 234 MMBtu/Hr	PM Benzene 1,3-Butadiene Formaldehyde PAH♣ Arsenic Beryllium Cadmium Lead Manganese Mercury Selenium	10 1.25E-02 3.65E-03 6.38E-02 9.12E-03 2.51E-03 7.07E-05 1.09E-03 3.19E-03 1.80E-01 2.74E-04 5.70E-03	
02	General Electric LM 2500 Combustion Turbine Natural Gas Fired 228 MMBtu/Hr	PM Acrolein Formaldehyde PAH♣	8 1.46E-03 1.62E-01 5.02E-04	
02	General Electric LM 2500 Combustion Turbine Fuel Oil Fired 234 MMBtu/Hr	PM Benzene 1,3-Butadiene Formaldehyde PAH♣ Arsenic Beryllium Cadmium Lead Manganese	10 1.25E-02 3.65E-03 6.38E-02 9.12E-03 2.51E-03 7.07E-05 1.09E-03 3.19E-03 1.80E-01	

SN	Description	Pollutant	lb/hr	tpy
		Mercury Selenium	2.74E-04 5.70E-03	
04	General Electric LM 6000 Combustion Turbine Natural Gas Fired 440 MMBtu/Hr	PM Acrolein Formaldehyde PAH♠	16.0 2.82E-03 3.12E-01 9.68E-04	
04	General Electric LM 6000 Combustion Turbine Fuel Oil Fired 440 MMBtu/Hr	PM Benzene 1,3-Butadiene Formaldehyde PAH♠ Arsenic Beryllium Cadmium Lead Manganese Mercury Selenium	20 2.42E-02 7.04E-03 1.23E-01 1.76E-02 4.84E-03 1.36E-04 2.11E-03 6.16E-03 3.48E-01 5.28E-04 1.10E-02	
06	General Electric LM 6000 Combustion Turbine Natural Gas Fired 440 MMBtu/Hr	PM Acrolein Formaldehyde PAH♠	16.0 2.82E-03 3.12E-01 9.68E-04	
06	General Electric LM 6000 Combustion Turbine Fuel Oil Fired 440 MMBtu/Hr	PM Benzene 1,3-Butadiene Formaldehyde PAH♠ Arsenic Beryllium Cadmium Lead Manganese Mercury Selenium	20 2.42E-02 7.04E-03 1.23E-01 1.76E-02 4.84E-03 1.36E-04 2.11E-03 6.16E-03 3.48E-01 5.28E-04 1.10E-02	
07	General Electric LM 6000 Combustion Turbine Natural Gas Fired 440 MMBtu/Hr	PM Acrolein Formaldehyde PAH♠	16.0 2.82E-03 3.12E-01 9.68E-04	

** - Emission limits for combustion products from the turbines are a PAL based on Specific Condition # 3.
♠ - Polycyclic Aromatic Hydrocarbons

3. The permittee shall calculate the tons per previous 12 months emissions based on the following formulas during each month facility is operated. [§19.705 or regulation 19, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, 40 CFR 70.6]

CO (tpy) = [(25 lb/hr x DF12) + (25 lb/hr x NG12) + (25 lb/hr x DF46) + (25 lb/hr x NG467)] / 2000

NOx (tpy) = [(41 lb/hr x DF12) + (38.9 lb/hr x NG12) + (81 lb/hr x DF46) + (56 lb/hr x NG467)] / 2000

SO_2 (tpy) = [(38 lb/hr x DF12) + (8 lb/hr x NG12) + (75 lb/hr x DF46) + (15 lb/hr x NG467)] / 2000

VOC (tpy) = [(10 lb/hr x DF12) + (10 lb/hr x NG12) + (20 lb/hr x DF46) + (20lb/hr x NG467)] / 2000

PM_{10} (tpy) = [10 lb/hr x DF12) + (8 lb/hr x NG12) + (20 lb/hr x DF46) + (16 lb/hr x NG467)] / 2000

PM (tpy) = [10 lb/hr x DF12) + (8 lb/hr x NG12) + (20 lb/hr x DF46) + (16 lb/hr x NG467)] / 2000

Where:

DF12 = total operating hours of SN-01 and SN-02 when firing diesel fuel previous 12 months

NG12 = total operating hours of SN-01 and SN-02 when firing natural gas previous 12 months

DF46 = total operating hours of SN-04 and SN-06 when firing diesel fuel previous 12 months

NG467 = total operating hours of SN-04, SN-06, and SN-07 when firing natural gas previous 12 months

A resultant from the above formulas of greater than the limits listed in Specific Conditions # 1 & 2, for SN-01, SN-02, SN-04, SN-06, and SN-07, shall be considered a violation of this permit. The results of these calculations shall be completed by the 15^{th} of the month for the previous month, kept on site, and made available to Department personnel upon request. A copy of the results of these calculations for each month operated shall be submitted in accordance with General Provision # 7.

4. The permittee shall use only natural gas as a fuel for the combustion turbine (SN-07). [§19.705 of Regulation 19 and A.C.A.§8-4-203 as referenced by §8-4-304 and §8-4-311]

5. The permittee shall not exceed 700 hours of operations per consecutive 12-month period for the combustion turbine (SN-07). [§19.705 of Regulation 19 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

6. The permittee shall maintain monthly records which demonstrate compliance with Specific Conditions # 4 and # 5. Records shall be updated by the fifteenth day of the month following the month for which the records pertain. These records shall be kept on site, and shall be made available to Department personnel upon request. [§19.705 of Regulation 19 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311

7. Visible emissions shall not exceed the limits specified in the following table of this permit as measured by EPA Reference Method No. 9. [A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

SN	Limit	Regulatory Citation
SN-01, SN-02, SN-04, SN-06, & SN-07 (gas fired)	5 %	§18.501

SN	Limit	Regulatory Citation
SN-01, SN-02, SN-04, SN-06 (oil fired)	20 %	§19.503

8. One observation of the opacity from either SN-01 or SN-02 and one observation of the opacity from either SN-04 or SN-06 (while they are being fired with fuel oil) shall be measured during each calendar year using personnel trained in EPA Reference Method 9. Should visible emissions appear in excess of the permitted opacity, the permittee shall immediately take action to identify the cause of the visible emissions, implement corrective action, and document that visible emissions did not appear to be in excess of the permitted opacity following the corrective action. The permittee shall maintain records which contain the records of the visible emissions while firing with fuel oil in order to demonstrate compliance with Specific Condition # 7. These records shall be updated yearly, kept on site, and made available to Department personnel upon request. [§18.1004 of Regulation 18 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

9. The facility shall use only fuel oil with a sulfur content of less than 0.16 weight percent when firing on fuel oil. [§19.705 of Regulation 19 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

10. The permittee shall maintain monthly records which demonstrate compliance with Specific Condition # 9. Records shall be updated by the fifteenth day of the month following the month for which the records pertain. These records shall be kept on site, and shall be made available to Department personnel upon request. [§19.705 of Regulation 19 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

11. The permittee shall not exceed the NO_x average hourly emission concentration, in ppmvd, corrected to 15% O_2 at ISO conditions in the following table. Compliance shall be demonstrated by NSPS monitoring requirements and Specific Condition #20. [§19. 304, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 CFR Part 64]

SN	Fuel	NO_x Concentration
SN-01 & SN-02	Natural Gas	100 ppm
SN-01 & SN-02	Fuel Oil	102 ppm
SN-04 & SN-06	Natural Gas	75 ppm
SN-04 & SN-06	Fuel Oil	77 ppm
SN-07	Natural Gas	To be determined during performance testing

12. The five (5) simple-cycle turbines, SN-01, SN-02, SN-04, SN-06, and SN-07, are subject to the provisions of NSPS Subpart GG. The permittee shall demonstrate compliance with NSPS Subpart GG by compliance with Specific Conditions # 13 through # 28. [§19.705 of Regulation 19 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

NSPS Requirements

13. The natural gas fired at the facility shall be only pipeline quality natural gas. Pipeline quality natural gas contains less than 20.0 grains or less of total sulfur per hundred standard cubic feet, and either composed of at least 70% methane by volume or has a gross calorific value between 950 and 1100 BTU per standard cubic foot. [§19.304 of Regulation 19 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 CFR Part 60 Subpart GG §60.331(u)]

14. The permittee is not required to operate the water injection equipment when ice fog is deemed a traffic hazard by the owner or operator of the gas turbine. [§19.304 of Regulation 19 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 CFR Part 60 Subpart GG §60.332(f)]

15. The permittee shall conduct an initial performance test for NO_x and SO_2 emissions from the LM-6000 Combustion Turbine (SN-07) as required by 40 CFR Part 60 Subpart A §60.8. [§19. 304, A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311, and 40 CFR Part 60 Subpart A §60.8]

16. On and after the date on which the performance test required to be conducted by §60.8 is completed, the permittee shall not cause to be discharged into the atmosphere from any stationary gas turbine, any gases which contain nitrogen oxides in excess of:

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

where:

a. STD = allowable ISO corrected NO_x emission concentration (percent by volume at 15 percent oxygen and on a dry basis).

b. 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 measure at actual peak load for the facility. The value of Y shall not exceed 14.4 kilojoules per watt hour; and

c. F = NO_x emission allowance for fuel-bound nitrogen as defined in Specific Condition # 17.

[§19. 304, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 CFR Part 60 Subpart GG §60.332(a)(1)]

17. The value of 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 (% by weight)	F (NO_x percent by volume)
$N \leq 0.015$	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

[§19. 304, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 CFR Part 60 Subpart GG §60.332(a)(4)]

18. On and after the date on which the performance test required to be conducted by §60.8 is completed, the permittee shall not cause to be discharged into the atmosphere from any stationary gas turbine, any gases which contain sulfur dioxide in excess of:

    a. 0.015 percent by volume at 15 percent oxygen and on a dry basis; or

    b. 0.8 percent by weight (8000 ppmw).

    [§19. 304, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 CFR Part 60 Subpart GG §60.333(a) and (b)]

19. The permittee shall comply with the monitoring of operations requirements of 40 CFR 60.334 for the stationary gas turbine (SN-07). These requirements include, but are not limited to, the following:

    a. The permittee 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; or

    b. The permittee shall install, certify, maintain, operate, and quality-assure a continuous monitoring system (CEMS) consisting of NO_x and O_2 monitors.

    [§19. 304, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 CFR Part 60 Subpart GG §60.334(a) and (b)]

20. The steam or water to fuel ratio or other parameters that are continuously monitored as described in Specific Condition # 19.a shall be monitored during the performance test required under §60.8, to establish acceptable values and ranges, or as outlined in 40 CFR 60.334(g). [§19. 304, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 CFR Part 60 Subpart GG §60.334(g)]

21. The owner or operator of any stationary gas turbine shall monitor the total sulfur content of the fuel being fired in the turbine. The sulfur content of the fuel must be determined using one of the following:

a. The sulfur content of the fuel must be determined using total sulfur methods described in §60.335(b)(10); or

b. 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 D 4084-82, 94, D 5504-01, D 6228-98, or Gas Processors Association Standard 23777-86 (all of which are incorporated by reference-see §60.17), which measure the major sulfur compounds may be used; or

c. 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 as provided by §60.331(u), as referenced by Specific Condition # 13. The owner or operator shall use on 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.

[§19. 304, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, 40 CFR Part 60 Subpart GG §60.334(h)(1), Subpart GG §60.334(h)(3)(i), and Subpart GG §60.334(h)(3)(ii)]

22. The owner or operator of any stationary gas turbine 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. [§19. 304, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 CFR Part 60 Subpart GG §60.334(h)]

23. The frequency of determining the sulfur and nitrogen content of the gaseous fuel shall be as follows:

a. Any applicable nitrogen content value of the gaseous fuel shall be determined and recorded once per unit operating day; and

b. For owners and operators that elect not to demonstrate sulfur content using §60.334(h)(3), as referenced by Specific Condition # 21.c, 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; or

c. Notwithstanding the requirements of Specific Condition # 23.b, 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.

[§19. 304, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 CFR Part 60 Subpart GG §60.334(i)(2)]

24. 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 as defined in §60.334(j) and its subparts. [§19. 304, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 CFR Part 60 Subpart GG §60.334(j)]

25. The permittee shall determine compliance with the nitrogen oxides standards in Specific Condition # 16, and conduct the performance tests required in §60.8 using one of the following:

a. EPA Method 20; or

b. ASTM D6522-00 (incorporated by reference, see §60.17); or

c. EPA Method 7E and either EPA Method 3 or 3A in appendix A of 40 CFR Part 60 to determine NO_x and diluent concentration.

[§19. 304, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 CFR Part 60 Subpart GG §60.335(a)(1) through (3)]

26. The sampling traverse points are to be selected and sampled for equal time intervals as defined below:

a. Sampling traverse points are to be selected following Method 20 or Method 1, (non-particulate procedures). 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.; or

b. 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. The owner or operator may perform a stratification test for NO_x and diluent pursuant to:

1. 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:

1. If each of the individual traverse point NO_x concentrations, 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

2. 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.; or

c. 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.

[§19. 304, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 CFR Part 60 Subpart GG §60.335(a)(4) through (6), Subpart GG §60.335(c)(1)]

27. 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:

a. For each run of the performance test, the mean nitrogen oxides emission concentration (NO_{xo}) 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:

$NOx = (NOxo)(Pr/Po)^{0.5}[e^{19(Ho-0.00633)}](288/Ta)^{1.53}$
Where:
NOx = emission rate at 15% O_2 and ISO standard ambient conditions, ppm by volume
NOxo = observed NOx concentration, ppm by volume at 15%
Pf = reference combustor inlet absolute pressure at 101.3 kilopascals ambient pressure, mm Hg
Po = observed combustor inlet absolute pressure at test, mm Hg
Ho = specific humidity of ambient air, gram H_2O per gram air
e = transcendental constant, 2.718
Ta = ambient temperature, °K.Ta = ambient temperature, °K.

b. 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).

[§19. 304, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 CFR Part 60 Subpart GG §60.335(b)(1) & (2)]

28. The permittee shall measure the emissions of both of the General Electric LM2500 simple-cycle combustion turbines, SN-01 and SN-02, while using fuel oil and while using natural gas (2 separate tests), and all three of the General Electric LM6000 simple-cycle combustion turbines, SN-04, SN-06, and SN-07, while using natural gas, and SN-04 and SN06 General Electric LM6000 simple-cycle combustion turbines while using fuel oil. Periodic performance testing shall be performed every five (5) years on one of each model of engines installed with each LM2500 unit being tested alternated every five (5) years and with each LM6000 unit being tested alternated every five (5) years. The turbine shall be tested for NO_x and SO_2 using EPA Method 20, and CO using EPA Method 10. These three pollutant tests shall be done simultaneously. The turbine shall be tested in accordance with the New Source Performance Standard, Subpart GG, Sections 60.335 (a) and (b). The water to fuel ratio used during each test point (30, 50, 75, and 100 percent of peak load or at four points in the normal operating range of the gas turbine) shall be submitted in the report. The test results shall be submitted to the Department (Compliance Section Manager) within 30 days after the completion of the testing. [§19. 304, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 CFR Part 60 Subpart GG]

CAM Requirements

29. The permittee shall monitor the water to fuel ratio fired in the turbines. The permittee shall demonstrate compliance for the water to fuel ratio fired by maintaining ratios below the ratio for compliance as stated in the table provided in Appendix G for the existing turbines (SN-01, SN-02, SN-04, and SN-06). The permittee shall determine, and comply with, the indicator range for the water to fuel ratio for the new turbine (SN-07) established during the performance test. [§19. 304, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 CFR Part 64]

30. The permittee shall maintain daily records which demonstrate compliance with Specific Condition # 29. Records shall be updated by the fifteenth day of the month following the month for which the records pertain. These records shall be kept on site, and shall be made available to Department personnel upon request. [§19.705 of Regulation 19 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

Acid Rain Requirements

31. The General Electric LM6000 units (SN-04, SN-06, and SN-07) are subject to and shall comply with all applicable provisions of the Acid Rain Program (40 CFR Parts 72, 73, and 75).

    a. Pursuant to 40 CFR Part 75 .14 (c) - Continuous Opacity Monitoring - SN-04, SN-06, and SN-07 are exempt from the requirement for a continuous opacity monitor based on using only natural gas fuel and low sulfur diesel fuel.

    b. Pursuant to 40 CFR Part 75 - SN-04, SN-06, and SN-07 are new "peaking units" as defined :

        i. An average capacity factor of 10.0 percent during any 3 consecutive calendar years.

        ii. A capacity factor of no more than 20.0 percent during any of those years.

32. The hours of operation for the General Electric LM6000 Combustion Turbines (SN-04 and SN-06) shall not exceed 1,752 rated hours full load equivalent each as calculated in 40 CFR Part 75 during any single calendar year and shall not exceed 2,628 rated hours full load equivalent each as calculated in 40 CFR Part 75 for any consecutive 3 calendar year period. [§19.304 of Regulation 19 and 40 CFR 75]

33. The permittee shall maintain monthly records which demonstrate compliance with Specific Condition #32. Records shall be updated by the fifteenth day of the month following the month for which the records pertain. These records shall be kept on site, and shall be made available to Department personnel upon request. [§19.705 of Regulation 19 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

SN-03
Fuel Oil Storage Tank

Source Description

A fuel storage tank is utilized for storing the fuel oil for the turbines. The tank has a shell height of fifteen feet (15') and a diameter of eighty feet (80'). This tank has a storage capacity of 564,076 gallons. The net emissions are calculated based on throughput of 1,128,000 gallons per year. The fuel oil storage tank is subject to 40 CFR 60 Subpart Kb - *Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced after July 23, 1984* which is attached as Appendix F. Since the tank has a capacity greater than 151 cubic meters and stores a liquid with a true maximum vapor pressure of less than 3.5 kPa, this equipment is probably only subject to the provisions of §60.110b(c), §60.116b(a), and §60.116b(b).

Specific Conditions

34. The permittee shall not exceed the emission rates set forth in the following table. The emission limits are based on the maximum capacity of the equipment. [Regulation 19, §19.501 et seq. and 40 CFR Part 52, Subpart E]

SN	Description	Pollutant	lb/hr	tpy
03	Fuel Storage Tank - 15' x 80'	VOC	0.4	0.4

NSPS Requirement

35. The facility shall keep readily accessible records showing the dimensions of the fuel oil storage tank and an analysis showing the capacity of the storage tank for the life of the facility. All volatile organic liquids stored in the fuel oil storage tank must have a true vapor pressure of less than 3.5 kPa (0.5 psia). [§19.304 of Regulation 19 and 40 CFR, Part 60, Subpart Kb]

SN-05A and SN-05B
Cooling Towers

Source Description

A cooling tower will circulate water which will be used on hot days to cool the inlet air to the turbine. This will allow the turbines to maintain rated power on high ambient temperature days. The cooling tower drift will contain water with total dissolved solids. The total dissolved solids are considered to be particulate emissions. The cooling tower will be equipped with drift eliminators to control these particulate emissions.

Specific Conditions

36. The permittee shall not exceed the emission rates set forth in the following table. The lb/hr and tons per year emission limits are based on the maximum capacity of the equipment. The permittee shall demonstrate compliance with this condition by Specific Condition # 38. [Regulation 19, §19.501 et seq. and 40 CFR Part 52, Subpart E]

SN	Description	Pollutant	lb/hr	tpy
05A	Cooling Tower A	PM_{10}	0.8	3.5
05B	Cooling Tower B	PM_{10}	0.8	3.5

37. The permittee shall not exceed the emission rates set forth in the following table. The permittee shall demonstrate compliance with this condition by Specific Condition # 38. [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
05A	Cooling Tower A	PM	0.8	3.5
05B	Cooling Tower B	PM	0.8	3.5

38. The permittee shall test and record the total dissolved solids of the cooling water on a weekly basis when SN-05A or SN-05B is operating. Results less than 1,500 ppm total dissolved solids will assure compliance with Specific Conditions # 36 and # 37 of this permit. The results shall be kept on site and made available to Department personnel upon request. [§19.705 of Regulation #19, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 CFR Part 52, Subpart E]

SECTION V: COMPLIANCE PLAN AND SCHEDULE

City Water & Light Plant of the City of Jonesboro 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 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: [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]

   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.

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. The permittee must prepare and implement a Startup, Shutdown, and Malfunction Plan (SSM). If the Department requests a review of the SSM, the permittee will make the SSM available for review. The permittee must keep a copy of the SSM at the source's location and retain all previous versions of the SSM plan for five years. [Regulation 19, §19.304 and 40 CFR 63.6(e)(3)]

Acid Rain (Title IV)

8. The Director prohibits the permittee to cause any emissions exceeding any allowances the source lawfully holds under Title IV of the Act or the regulations promulgated under the Act. No permit revision is required for increases in emissions allowed by allowances acquired pursuant to the acid rain program, if such increases do not require a permit revision under any other applicable requirement. This permit establishes no limit on the number of allowances held by the permittee. However, the source may not use allowances as a defense for noncompliance with any other applicable requirement of this permit or the Act. The permittee will account for any such allowance according to the procedures established in regulations promulgated under Title IV of the Act. A copy of the facility's Acid Rain Permit is attached in an appendix to this Title V permit. [Regulation No. 26 §26.701 and 40 CFR 70.6(a)(4)]

Title VI Provisions

9. 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.

10. 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.

11. 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.

12. 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.

13. 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

14. 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 Table 4 – Applicable Regulations of this condition. The permit specifically identifies the following as applicable requirements based upon the information submitted by the permittee in an application dated August 25, 2004.

Table 4 – Applicable Regulations

Source No.	Regulation	Description
Facility	Regulation 18	Arkansas Air Pollution Code
Facility	Regulation 19	Regulations of the Arkansas Plan of Implementation for Air Pollution Control

Facility	Regulation 26	Regulations of the Arkansas Operating Air Permit Program
SN-04, SN-06, SN-07	40 CFR Parts 72, 73, and 75	Title IV Federal Clean Air Act Amendments
Facility	40 CFR Part 50	National Ambient Air Quality Standards
SN-01, SN-02, SN-04, SN-06, SN-07	40 CFR 60 – Subpart GG	Standards of Performance for Stationary Gas Turbines
SN-03	40 CFR 60 – Subpart Kb	Standards of Performance for Volatile Organic Liquid Storage Vessels
SN-01, SN-02, SN-04, SN-06, SN-07	40 CFR Part 64	Compliance Assurance Monitoring

The permit specifically identifies the following as inapplicable based upon information submitted by the permittee in an application dated August 25, 2004.

Table 5 – Inapplicable Regulations

Source No.	Regulation	Description
SN-01, SN-02, SN-04, SN-06	40 CFR 63, Subpart YYYY	National Emission Standards for Hazardous Air Pollutants: Combustion Turbines
SN-01, SN-02, SN-04, SN-06	40 CFR 63, Subpart ZZZZ	National Emission Standards for Hazardous Air Pollutants: Internal Combustion Engines
SN-07	40 CFR 60, Subpart KKKK	Standards of Performance for Stationary Combustion Turbines
Facility	40 CFR 52.21	Prevention of Significant Deterioration

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 August 25, 2004. No insignificant activities were listed.

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), effective September 26, 2002]

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

   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.

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

   Arkansas Department of Environmental Quality
   Air Division
   ATTN: Compliance Inspector Supervisor
   Post Office Box 8913
   Little Rock, AR 72219

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;
e. and 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]

APPENDIX A

ADEQ CEMS Condition

Arkansas Department of Environmental Quality

CONTINUOUS EMISSION MONITORING SYSTEMS CONDITIONS

Revised August 2004

PREAMBLE

These conditions are intended to outline the requirements for facilities required to operate Continuous Emission Monitoring Systems/Continuous Opacity Monitoring Systems (CEMS/COMS). Generally there are three types of sources required to operate CEMS/COMS:

1. CEMS/COMS required by 40 CFR Part 60 or 63,
2. CEMS required by 40 CFR Part 75,
3. CEMS/COMS required by ADEQ permit for reasons other that Part 60, 63 or 75.

These CEMS/COMS conditions are not intended to supercede Part 60, 63 or 75 requirements.

- Only CEMS/COMS in the third category (those required by ADEQ permit for reasons other than Part 60, 63, or 75) shall comply with SECTION II, MONITORING REQUIREMENTS and SECTION IV, QUALITY ASSURANCE/QUALITY CONTROL.

- All CEMS/COMS shall comply with Section III, NOTIFICATION AND RECORDKEEPING.

SECTION I

DEFINITIONS

Continuous Emission Monitoring System (CEMS) - The total equipment required for the determination of a gas concentration and/or emission rate so as to include sampling, analysis and recording of emission data.

Continuous Opacity Monitoring System (COMS) - The total equipment required for the determination of opacity as to include sampling, analysis and recording of emission data.

Calibration Drift (CD) - The difference in the CEMS output reading from the established reference value after a stated period of operation during which no unscheduled maintenance, repair, or adjustments took place.

Back-up CEMS (Secondary CEMS) - A CEMS with the ability to sample, analyze and record stack pollutant to determine gas concentration and/or emission rate. This CEMS is to serve as a back-up to the primary CEMS to minimize monitor downtime.

Excess Emissions - Any period in which the emissions exceed the permit limits.

Monitor Downtime - Any period during which the CEMS/COMS is unable to sample, analyze and record a minimum of four evenly spaced data points over an hour, except during one daily zero-span check during which two data points per hour are sufficient.

Out-of-Control Period - Begins with the time corresponding to the completion of the fifth, consecutive, daily CD check with a CD in excess of two times the allowable limit, or the time corresponding to the completion of the daily CD check preceding the daily CD check that results in a CD in excess of four times the allowable limit and the time corresponding to the completion of the sampling for the RATA, RAA, or CGA which exceeds the limits outlined in Section IV. Out-of-Control Period ends with the time corresponding to the completion of the CD check following corrective action with the results being within the allowable CD limit or the completion of the sampling of the subsequent successful RATA, RAA, or CGA.

Primary CEMS - The main reporting CEMS with the ability to sample, analyze, and record stack pollutant to determine gas concentration and/or emission rate.

Relative Accuracy (RA) - The absolute mean difference between the gas concentration or emission rate determined by the CEMS and the value determined by the reference method plus the 2.5 percent error confidence coefficient of a series of tests divided by the mean of the reference method tests of the applicable emission limit.

Span Value – The upper limit of a gas concentration measurement range.

SECTION II

MONITORING REQUIREMENTS

A. For new sources, the installation date for the CEMS/COMS shall be no later than thirty (30) days from the date of start-up of the source.

B. For existing sources, the installation date for the CEMS/COMS shall be no later than sixty (60) days from the issuance of the permit unless the permit requires a specific date.

C. Within sixty (60) days of installation of a CEMS/COMS, a performance specification test (PST) must be completed. PST's are defined in 40 CFR, Part 60, Appendix B, PS 1-9. The Department may accept alternate PST's for pollutants not covered by Appendix B on a case-by-case basis. Alternate PST's shall be approved, in writing, by the ADEQ CEM Coordinator prior to testing.

D. Each CEMS/COMS shall have, as a minimum, a daily zero-span check. The zero-span shall be adjusted whenever the 24-hour zero or 24-hour span drift exceeds two times the limits in the applicable performance specification in 40 CFR, Part 60, Appendix B. Before any adjustments are made to either the zero or span drifts measured at the 24-hour interval the excess zero and span drifts measured must be quantified and recorded.

E. All CEMS/COMS shall be in continuous operation and shall meet minimum frequency of operation requirements of 95% up-time for each quarter for each pollutant measured. Percent of monitor down-time is calculated by dividing the total minutes the monitor is not in operation by the total time in the calendar quarter and multiplying by one hundred. Failure to maintain operation time shall constitute a violation of the CEMS conditions.

F. Percent of excess emissions are calculated by dividing the total minutes of excess emissions by the total time the source operated and multiplying by one hundred. Failure to maintain compliance may constitute a violation of the CEMS conditions.

G. All CEMS measuring emissions shall complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive fifteen minute period unless more cycles are required by the permit. For each CEMS, one-hour averages shall be computed from four or more data points equally spaced over each one hour period unless more data points are required by the permit.

H. All COMS shall complete a minimum of one cycle of sampling and analyzing for each successive 10-second period and one cycle of data recording for each successive 6-minute period.

I. When the pollutant from a single affected facility is released through more than one point, a CEMS/COMS shall be installed on each point unless installation of fewer systems is approved, in writing, by the ADEQ CEM Coordinator. When more than one CEM/COM is used to monitor emissions from one affected facility the owner or operator shall report the results as required from each CEMS/COMS.

SECTION III

NOTIFICATION AND RECORD KEEPING

A. When requested to do so by an owner or operator, the ADEQ CEM Coordinator will review plans for installation or modification for the purpose of providing technical advice to the owner or operator.

B. Each facility which operates a CEMS/COMS shall notify the ADEQ CEM Coordinator of the date for which the demonstration of the CEMS/COMS performance will commence (i.e. PST, RATA, RAA, CGA). Notification shall be received in writing no less than 15 days prior to testing. Performance test results shall be submitted to the Department within thirty days after completion of testing.

C. Each facility which operates a CEMS/COMS shall maintain records of the occurrence and duration of start up/shut down, cleaning/soot blowing, process problems, fuel problems, or other malfunction in the operation of the affected facility which causes excess emissions. This includes any malfunction of the air pollution control equipment or any period during which a continuous monitoring device/system is inoperative.

D. Except for Part 75 CEMs, each facility required to install a CEMS/COMS shall submit an excess emission and monitoring system performance report to the Department (Attention: Air Division, CEM Coordinator) at least quarterly, unless more frequent submittals are warranted to assess the compliance status of the facility. Quarterly reports shall be postmarked no later than the 30th day of the month following the end of each calendar quarter. Part 75 CEMs shall submit this information semi-annually and as part of Title V six (6) month reporting requirement if the facility is a Title V facility.

E. All excess emissions shall be reported in terms of the applicable standard. Each report shall be submitted on ADEQ Quarterly Excess Emission Report Forms. Alternate forms may be used with prior written approval from the Department.

F. Each facility which operates a CEMS/COMS must maintain on site a file of CEMS/COMS data including all raw data, corrected and adjusted, repair logs, calibration checks, adjustments, and test audits. This file must be retained for a period of at least five years, and is required to be maintained in such a condition that it can easily be audited by an inspector.

G. Except for Part 75 CEMs, quarterly reports shall be used by the Department to determine compliance with the permit. For Part 75 CEMs, the semi-annual report shall be used.

SECTION IV

QUALITY ASSURANCE/QUALITY CONTROL

A. For each CEMS/COMS a Quality Assurance/Quality Control (QA/QC) plan shall be submitted to the Department (Attn.: Air Division, CEM Coordinator). CEMS quality assurance procedures are defined in 40 CFR, Part 60, Appendix F. This plan shall be submitted within 180 days of the CEMS/COMS installation. A QA/QC plan shall consist of procedure and practices which assures acceptable level of monitor data accuracy, precision, representativeness, and availability.

B. The submitted QA/QC plan for each CEMS/COMS shall not be considered as accepted until the facility receives a written notification of acceptance from the Department.

C. Facilities responsible for one, or more, CEMS/COMS used for compliance monitoring shall meet these minimum requirements and are encouraged to develop and implement a more extensive QA/QC program, or to continue such programs where they already exist. Each QA/QC program must include written procedures which should describe in detail, complete, step-by-step procedures and operations for each of the following activities:

1. Calibration of CEMS/COMS
    a. Daily calibrations (including the approximate time(s) that the daily zero and span drifts will be checked and the time required to perform these checks and return to stable operation)
2. Calibration drift determination and adjustment of CEMS/COMS
    a. Out-of-control period determination
    b. Steps of corrective action
3. Preventive maintenance of CEMS/COMS
    a. CEMS/COMS information
        1) Manufacture
        2) Model number
        3) Serial number
    b. Scheduled activities (check list)
    c. Spare part inventory
4. Data recording, calculations, and reporting
5. Accuracy audit procedures including sampling and analysis methods
6. Program of corrective action for malfunctioning CEMS/COMS

D. A Relative Accuracy Test Audit (RATA), shall be conducted at least once every four calendar quarters. A Relative Accuracy Audit (RAA), or a Cylinder Gas Audit (CGA), may be conducted in the other three quarters but in no more than three quarters in succession. The RATA should be conducted in accordance with the applicable test procedure in 40 CFR Part 60 Appendix A and calculated in accordance with the applicable performance specification in 40 CFR Part 60 Appendix B. CGA's and RAA's should be conducted and the data calculated in accordance with the procedures outlined on 40 CFR Part 60 Appendix F.

If alternative testing procedures or methods of calculation are to be used in the RATA, RAA or CGA audits prior authorization must be obtained from the ADEQ CEM Coordinator.

E. Criteria for excessive audit inaccuracy.

RATA

All Pollutants except Carbon Monoxide	> 20% Relative Accuracy
Carbon Monoxide	> 10% Relative Accuracy
All Pollutants except Carbon Monoxide	> 10% of the Applicable Standard
Carbon Monoxide	> 5% of the Applicable Standard
Diluent (O_2 & CO_2)	> 1.0 % O2 or CO2
Flow	> 20% Relative Accuracy

CGA

Pollutant	> 15% of average audit value or 5 ppm difference
Diluent (O_2 & CO_2)	> 15% of average audit value or 5 ppm difference

RAA

Pollutant	> 15% of the three run average or > 7.5 % of the applicable standard
Diluent (O_2 & CO_2)	> 15% of the three run average or > 7.5 % of the applicable standard

F. If either the zero or span drift results exceed two times the applicable drift specification in 40 CFR, Part 60, Appendix B for five consecutive, daily periods, the CEMS is out-of-control. If either the zero or span drift results exceed four times the applicable drift specification in Appendix B during a calibration drift check, the CEMS is out-of-control. If the CEMS exceeds the audit inaccuracies listed above, the CEMS is out-of-control. If a CEMS is out-of-control, the data from that out-of-control period is not counted towards meeting the minimum data availability as required and described in the applicable subpart. The end of the out-of-control period is the time corresponding to the completion of the successful daily zero or span drift or completion of the successful CGA, RAA or RATA.

G. A back-up monitor may be placed on an emission source to minimize monitor downtime. This back-up CEMS is subject to the same QA/QC procedure and practices as the primary CEMS. The back-up CEMS shall be certified by a PST. Daily zero-span checks must be performed and recorded in accordance with standard practices. When the primary CEMS goes down, the back-up CEMS may then be engaged to sample, analyze and record the emission source pollutant until repairs are made and the primary unit is placed back in service. Records must be maintained on site when the back-up CEMS is placed in service, these records shall include at a minimum the reason the primary CEMS is out of service, the date and time the primary CEMS was out of service and the date and time the primary CEMS was placed back in service.

APPENDIX B

Compliance Assurance Monitoring Plan

COMPLIANCE ASSURANCE MONITORING (CAM) PLAN

APPLICABILITY OF CAM RULE

The City Water & Light Plant of the City of Jonesboro (Jonesboro) facility uses control devices intended to achieve compliance with emission limitations for NO_x from the five turbines (SN-01, 02, 04, 06, 07). The uncontrolled emissions from SN-01, SN-02, SN-04, SN-06, and SN-07 turbines fulfill the applicability criteria of the Compliance Assurance Monitoring (CAM) Rule (40 Code of Federal Regulations (CFR) Part (§) 64). Accordingly, the (CAM) Plan for the facility is provided in this section of the permit application. The production units affected by the CAM Plan are listed below:

Source Description	Source No.	Controlled NOx Emission Rate (TPY)	Uncontrolled NOx Emission Rate (TPY)
LM-2500 Combustion Turbine	SN-01	119.5	>119.5
LM-2500 Combustion Turbine	SN-02	119.5	>119.5
LM-6000 Combustion Turbine	SN-04	119.5	>119.5
LM-6000 Combustion Turbine	SN-06	119.5	>119.5
LM-6000 Combustion Turbine	SN-07	119.5	>119.5

Per §64.2(a), the aforementioned sources are regulated under the CAM Rule because they meet the following criteria: (1) each unit is subject to emission limitations for NO_x, (2) each source is equipped with a control device (i.e., water injection), and (3) each unit has potential pre-control emissions of NO_x that exceed the applicable major source threshold (i.e., 100 tons per year).

In accordance with §64.3, Jonesboro has developed a CAM Plan for the aforementioned sources. The Plan establishes the operating parameters that will be monitored in order to demonstrate compliance with the NO_x emission limits at each source.

GENERAL CRITERIA FOR CAM PLAN [PER §64.3(A)]

Criteria	Description
Emission Sources:	SN-01, SN-02, SN-04, SN-06 and SN-07
Pollutants:	NO_x
Applicable Permit Requirements:	NO_x Limits
Control Technology:	Water Injection
Control Efficiency:	72.7% (estimated)
General Monitoring Approach:	Predictive Emission Monitoring System (PEMS) for NOx and Continuous Emission Monitoring Systems (CEMS) of fuel consumption and ratio of scrubber water to fuel as required by Subpart GG NSPS for Stationary Gas Turbines.
Rationale for Monitoring Approach:	Per NSPS Requirements
Indicator Monitored:	Gaseous and Oil Fuel Bound Nitrogen (ppm) Fuel Consumption (Gas or Oil) Water to Fuel Ratio
Indicator Range:	See Appendix G

PERFORMANCE CRITERIA FOR CAM PLAN [PER §64.3(B)]

Criteria	Description
Specifications for Obtaining Representative Data:	Fuel Consumption (Gas or Oil) – Continuous Water to Fuel Ratio - Continuous Gaseous and Oil Fuel Bound Nitrogen (ppm) Oil fuel monitored each time fuel is transferred to tank and Gaseous fuel monitoring is completed per Appendix C of the current permit.
Monitoring Frequency:	Fuel Consumption (Gas or Oil) - Continuous Water to Fuel Ratio - Continuous Gaseous and Oil Fuel Bound Nitrogen (ppm) Oil fuel monitored each time fuel is transferred to tank and Gaseous fuel monitoring is completed per Appendix C of the current permit.

PERFORMANCE CRITERIA FOR CAM PLAN [PER §64.3(B)] - CONTINUED

Data Collection Procedures:	Fuel Consumption (Gas or Oil) – Flow Meter Water to Fuel Ratio – Flow Meters Gaseous and Oil Fuel Bound Nitrogen (ppm) Trained plant operators or their elected representative will perform sample collection using generally accepted procedures. PEMS calculations will be performed by a qualified plant employee or their elected representative.
Data Averaging Period:	Fuel Consumption (Gas or Oil) – Continuous Water to Fuel Ratio – Hourly Fuel Bound Nitrogen (ppm) - Any Period
Recordkeeping:	Records will be kept of all emission readings.
Verification Procedures to Confirm Oper. Status:	Maintenance and repair of systems will be performed in accordance with the manufacturer's specifications.
QA/QC Practices:	Plant operators and maintenance personnel will be adequately trained. Maintenance and repair of systems will be performed in accordance with the manufacturer's specifications.

REGULATORY REFERENCES

- Compliance Assurance Monitoring Regulations (40 CFR §64)
- Draft CAM Technical Guidance Document (EPA – August 1998)
- Title V Monitoring Reference Document (EPA – April 2001)

APPENDIX C

Custom Fuel Monitoring Schedule (Natural Gas)

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 6
1445 ROSS AVENUE, SUITE 1200
DALLAS, TX 75202-2733

JUN 1 2 2003

Mr. Guy Bell
Gas Turbine Power Plant
Jonesboro City Water and Light
1400 Hanley Dr.
Jonesboro, AR 72401

Re: Request for Approval - Custom Fuel Monitoring Schedule,
New Source Performance Standards (NSPS)
40 CFR Part 60, Subpart GG

Dear Mr. Bell:

This letter is in response to your request for approval of a custom fuel monitoring schedule (CFMS), dated November 27, 2002. You stated in your CFMS request that you are seeking approval of the use of certain recordkeeping and reporting requirements as an alternative to the monitoring in NSPS Part 60, Subpart GG. You indicated that the CFMS approval request is for gas turbines located at the Jonesboro, Arkansas facility, owned and operated by Jonesboro City Water and Light ("JCWL").

Your CFMS request letter, dated November 27, 2002,indicated that you have the following gas turbines that fire pipeline quality natural gas:

- Source No. 1 LM2500 Gas Turbine
- Source No. 2 LM2500 Gas Turbine
- Source No. 4 LM6000 Gas Turbine
- Source No. 5 LM6000 Gas Turbine

You stated that these turbines are peaking units that are rarely used and during the past three years, turbines 1,2, and 4 have averaged less than four hundred hours per year. You also stated that historically, JCWL has not operated these turbines for a continuous two week period and therefore the daily monitoring of sulfur and nitrogen content is overly burdensome.

You propose that monitoring of the fuel nitrogen content shall not be required while natural gas is the only fuel fired in the gas turbine. You propose to determine the sulfur content of the fuel using an approved alternative test method, GPA Standard 2377-86, "Test for Hydrogen Sulfide and Carbon Dioxide in Natural Gas Using Length of Stain Tube", and that JCWL will sample the sulfur content of the natural gas once per quarter during the first two quarters of the year. During the third quarter of the year, JCWL will sample the sulfur content of the natural gas for five consecutive days. If after the above required monitoring, the sulfur content of the fuel shows little variability and, calculated as sulfur dioxide emissions, represents consistent compliance with the sulfur dioxide emissions limits under 40 CFR 60.333, sample analysis shall be conducted twice per annum, during the second and third quarters of each calendar year. At EPA's request, you also submitted additional data on June 9, 2003 for the fuel sulfur content.

Based upon the data submitted by JCWL and previous determinations, EPA makes the following determinations regarding the gas turbines at your Jonesboro facility.

EPA approves JCWL custom fuel monitoring schedule, as detailed in this letter, in accordance with 40 CFR 60.334(b)(2) and 60.13(i).

JCWL can use the following custom fuel monitoring schedule for fuel nitrogen content and fuel sulfur content when the fuel being fired is pipeline qaulity natural gas as defined in 40 CFR 72.2. When fuel other than pipeline quality natural gas is fired in the turbines, monitoring is required in accordance with 40 CFR 60.334. This decision is consistent with EPA's guidance provided in a policy memorandum dated August 14, 1987.

1. Monitoring of fuel nitrogen content shall not be required while pipeline quality natural gas, as defined in 40 CFR 72.2, is the only fuel fired in the gas turbine.

2. Sulfur Monitoring

a. Analysis for fuel sulfur content of the natural gas shall be conducted using one of the approved ASTM reference methods for the measurement of sulfur in gaseous fuels, or an approved alternative method. The reference methods are: ASTM D1072-80; ASTM D3031-81; ASTM D3246-81; and ASTM D4084-82 as referenced in 40 CFR 60.335(d).

b. Effective the date of this custom schedule, sulfur monitoring shall be conducted once per quarter for six consecutive quarters.

c. If, after the monitoring required in 2(b) above, or herein, the sulfur content of the fuel shows little variability, and calculated as sulfur dioxide, represents consistent compliance with the sulfur dioxide emission limits specified under 40 CFR 60.333, sample analysis shall be conducted twice per annum. This monitoring shall be conducted during the second and third quarters of each calendar year.

d. Should any sulfur analysis as required in items 2(b) or 2(c) above indicate noncompliance with 40 CFR 60.333, the owner or operator shall notify ADEQ of such excess emissions and the custom schedule shall be re-examined by the EPA. Sulfur monitoring shall be conducted weekly during the interim period when this custom schedule is being re-examined.

3. If there is a change in fuel supply, the owner or operator must notify ADEQ of such change for re-examination of this custom schedule. A substantial change in fuel quality shall be considered a change in fuel supply. Sulfur monitoring shall be conducted weekly during the interim period when this custom schedule is being re-examined.

4. Records of sample analysis and fuel supply pertinent to this custom schedule shall be retained for a period of three years, and be available for inspection by personnel of federal, state, and local air pollution control agencies.

This approval of a CFMS is based on the information submitted to EPA Region 6 on November 27, 2002 and on June 9, 2003. If any information is found that would reverse this determination, then it would become invalid and a new determination would be needed. If any fuel other than natural gas is fired in the unit, then this approval would become invalid and the facility would be required to keep records per 40 CFR 60.334.

If you have any questions concerning this determination, please contact Ms. Anupa Ahuja of my staff, at (214) 665-2701.

Sincerely yours,

William K. Honker, P.E.
Chief
Air/Toxics and Inspection
Coordination Branch

cc: Keith Michaels (ADEQ)
Paul Osmon (ADEQ

APPENDIX D

Custom Fuel Monitoring Schedule (Diesel Fuel)

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 6
1445 ROSS AVENUE, SUITE 1200
DALLAS, TX 75202-2733

[illegible]

Mr. Guy Bell
Gas Turbine Power Plant
Jonesboro City Water and Light
1400 Hanley Dr.
Jonesboro, AR 72401

Re: Request for Approval -
Alternative Monitoring Plan
New Source Performance Standards (NSPS)
40 CFR Part 60, Subpart GG

Dear Mr. Bell:

This letter is in response to your request for approval of an alternative monitoring plan (AMP), dated November 17, 2003. You stated in your AMP request that you are seeking approval of the use of certain monitoring, recordkeeping and reporting requirements as an alternative to the monitoring in NSPS Part 60, Subpart GG. You indicated that the AMP approval request is for gas turbines located at the Jonesboro, Arkansas facility, owned and operated by Jonesboro City Water and Light ("JCWL").

Your request letter, dated November 21, 2003, indicated that you have a fuel oil storage tank that is filled once or twice per year. The filling of this tank may involve as many as 24 truckloads over 1 to 3 days. NSPS Subpart GG requires that sulfur and nitrogen be tested "on each occasion that the fuel is transferred to the storage tank from any other source". You request that each purchase of diesel fuel be considered as one "fuel lot". You propose to take a sample from each truckload in the "fuel lot". These samples would then be combined to obtain a representative sample of the entire lot. This representative sample would then be tested for nitrogen and sulfur content. You stated that sampling every truckload would be burdensome and that JCWL has always purchased low sulfur fuel that tests lower than 0.05 wt%.

EPA approves your request for alternative monitoring as outlined below in accordance with 40 CFR 60.13(i).

1. A fuel lot is considered to be the amount of oil purchased from one supplier under one invoice and intended as one shipment or delivery.

2. No other fuels shall be blended with the fuel oil from the trucks in one shipment in the storage tank.

3. A sample will be taken from each truck comprising the single shipment from a single supplier.

4. Samples from all trucks in a single shipment from a single supplier will be mixed to obtain a combined representative sample.

5. This sample shall be tested for fuel nitrogen and sulfur content by an approved ASTM method or approved alternative method.

6. Records of the number of trucks comprising a single shipment from a single supplier shall be kept, along with records of the number of individual samples taken per shipment, and the results of the analysis for nitrogen and sulfur. These records will kept for a period of three years and be available at the request of any federal, state, or local agency.

7. Should any sulfur analysis indicate non compliance, or the nitrogen analysis indicate a change in the fuel bound nitrogen content, the owner or operator will notify ADEQ and this alternative monitoring method approval is revoked.

This approval of an alternative monitoring plan is based on the information submitted to EPA Region 6 on November 17, 2003. If any information is found that would reverse this determination, then it would become invalid and a new determination would be needed.

If you have any questions concerning this determination, please contact Ms. Anupa Ahuja of my staff at (214) 665-2701.

Sincerely yours,

FOR

William K. Honker, P.E.
Chief
Air/Toxics and Inspection
Coordination Branch

cc: Keith Michaels (ADEQ)

APPENDIX E

40 CFR 60 Subpart GG

Standards of Performance for Stationary Gas Turbines

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)
$N \leq 0.015$	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_xemissions 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_Xemissions, may, but is not required to, elect to use a NO_XCEMS 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_Xemissions 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_Xformation 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_Xmode.

(3) For any turbine that uses SCR to reduce NO_Xemissions, 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_Xemission 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_Xemission 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_Xemission 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_xconcentration during the stratification test; or

(B) If each of the individual traverse point NO_xconcentrations, 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_{Xo}) 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:

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

Where:

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

NO_{Xo}= 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_X emission 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_X CEMS 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_X emission 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_x emission 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]

APPENDIX F

40 CFR 60 Subpart Kb

Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984

Title 40: Protection of Environment
PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

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Subpart Kb—Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984

Source: 52 FR 11429, Apr. 8, 1987, unless otherwise noted.

§ 60.110b Applicability and designation of affected facility.

(a) Except as provided in paragraph (b) of this section, the affected facility to which this subpart applies is each storage vessel with a capacity greater than or equal to 75 cubic meters (m^3) that is used to store volatile organic liquids (VOL) for which construction, reconstruction, or modification is commenced after July 23, 1984.

(b) This subpart does not apply to storage vessels with a capacity greater than or equal to 151 m^3 storing a liquid with a maximum true vapor pressure less than 3.5 kilopascals (kPa) or with a capacity greater than or equal to 75 m^3 but less than 151 m^3 storing a liquid with a maximum true vapor pressure less than 15.0 kPa.

(c) [Reserved]

(d) This subpart does not apply to the following:

(1) Vessels at coke oven by-product plants.

(2) Pressure vessels designed to operate in excess of 204.9 kPa and without emissions to the atmosphere.

(3) Vessels permanently attached to mobile vehicles such as trucks, railcars, barges, or ships.

(4) Vessels with a design capacity less than or equal to 1,589.874 m^3 used for petroleum or condensate stored, processed, or treated prior to custody transfer.

(5) Vessels located at bulk gasoline plants.

(6) Storage vessels located at gasoline service stations.

(7) Vessels used to store beverage alcohol.

(8) Vessels subject to subpart GGGG of 40 CFR part 63.

(e) *Alternative means of compliance* —(1) *Option to comply with part 65.* Owners or operators may choose to comply with 40 CFR part 65, subpart C, to satisfy the requirements of §§60.112b through 60.117b for storage vessels that are subject to this subpart that meet the specifications in paragraphs (e)(1)(i) and (ii) of this section. When choosing to comply with 40 CFR part 65, subpart C, the monitoring requirements of §60.116b(c), (e), (f)(1), and (g) still apply. Other provisions applying to owners or operators who choose to comply with 40 CFR part 65 are provided in 40 CFR 65.1.

(i) A storage vessel with a design capacity greater than or equal to 151 m^3 containing a VOL that, as stored, has a maximum true vapor pressure equal to or greater than 5.2 kPa; or

(ii) A storage vessel with a design capacity greater than 75 m^3 but less than 151 m^3 containing a VOL that, as stored, has a maximum true vapor pressure equal to or greater than 27.6 kPa.

(2) *Part 60, subpart A.* Owners or operators who choose to comply with 40 CFR part 65, subpart C, must also comply with §§60.1, 60.2, 60.5, 60.6, 60.7(a)(1) and (4), 60.14, 60.15, and 60.16 for those storage vessels. All sections and paragraphs of subpart A of this part that are not mentioned in this paragraph (e)(2) do not apply to owners or operators of storage vessels complying with 40 CFR part 65, subpart C, except that provisions required to be met prior to implementing 40 CFR part 65 still apply. Owners and operators who choose to comply with 40 CFR part 65, subpart C, must comply with 40 CFR part 65, subpart A.

(3) *Internal floating roof report.* If an owner or operator installs an internal floating roof and, at initial startup, chooses to comply with 40 CFR part 65, subpart C, a report shall be furnished to the Administrator stating that the control equipment meets the specifications of 40 CFR 65.43. This report shall be an attachment to the notification required by 40 CFR 65.5(b).

(4) *External floating roof report.* If an owner or operator installs an external floating roof and, at initial startup, chooses to comply with 40 CFR part 65, subpart C, a report shall be furnished to the Administrator stating that the control equipment meets the specifications of 40 CFR 65.44. This report shall be an attachment to the notification required by 40 CFR 65.5(b).

[52 FR 11429, Apr. 8, 1987, as amended at 54 FR 32973, Aug. 11, 1989; 65 FR 78275, Dec. 14, 2000; 68 FR 59332, Oct. 15, 2003]

§ 60.111b Definitions.

Terms used in this subpart are defined in the Act, in subpart A of this part, or in this subpart as follows:

Bulk gasoline plant means any gasoline distribution facility that has a gasoline throughput less than or equal to 75,700 liters per day. Gasoline throughput shall be the maximum calculated design throughput as may be limited by compliance with an enforceable condition under Federal requirement or Federal, State or local law, and discoverable by the Administrator and any other person.

Condensate means hydrocarbon liquid separated from natural gas that condenses due to changes in the temperature or pressure, or both, and remains liquid at standard conditions.

Custody transfer means the transfer of produced petroleum and/or condensate, after processing and/or treatment in the producing operations, from storage vessels or automatic transfer facilities to pipelines or any other forms of transportation.

Fill means the introduction of VOL into a storage vessel but not necessarily to complete capacity.

Gasoline service station means any site where gasoline is dispensed to motor vehicle fuel tanks from stationary storage tanks.

Maximum true vapor pressure means the equilibrium partial pressure exerted by the volatile organic compounds (as defined in 40 CFR 51.100) in the stored VOL at the temperature equal to the highest calendar-month average of the VOL storage temperature for VOL's stored above or below the ambient temperature or at the local maximum monthly average temperature as reported by the National Weather Service for VOL's stored at the ambient temperature, as determined:

(1) In accordance with methods described in American Petroleum institute Bulletin 2517, Evaporation Loss From External Floating Roof Tanks, (incorporated by reference—see §60.17); or

(2) As obtained from standard reference texts; or

(3) As determined by ASTM D2879–83, 96, or 97 (incorporated by reference—see §60.17);

(4) Any other method approved by the Administrator.

Petroleum means the crude oil removed from the earth and the oils derived from tar sands, shale, and coal.

Petroleum liquids means petroleum, condensate, and any finished or intermediate products manufactured in a petroleum refinery.

Process tank means a tank that is used within a process (including a solvent or raw material recovery process) to collect material discharged from a feedstock storage vessel or equipment within the process before the material is transferred to other equipment within the process, to a product or by-product storage vessel, or to a vessel used to store recovered solvent or raw material. In many process tanks, unit operations such as reactions and blending are conducted. Other process tanks, such as surge control vessels and bottoms receivers, however, may not involve unit operations.

Reid vapor pressure means the absolute vapor pressure of volatile crude oil and volatile nonviscous petroleum liquids except liquified petroleum gases, as determined by ASTM D323–82 or 94 (incorporated by reference—see §60.17).

Storage vessel means each tank, reservoir, or container used for the storage of volatile organic liquids but does not include:

(1) Frames, housing, auxiliary supports, or other components that are not directly involved in the containment of liquids or vapors;

(2) Subsurface caverns or porous rock reservoirs; or

(3) Process tanks.

Volatile organic liquid (VOL) means any organic liquid which can emit volatile organic compounds (as defined in 40 CFR 51.100) into the atmosphere.

Waste means any liquid resulting from industrial, commercial, mining or agricultural operations, or from community activities that is discarded or is being accumulated, stored, or physically, chemically, or biologically treated prior to being discarded or recycled.

[52 FR 11429, Apr. 8, 1987, as amended at 54 FR 32973, Aug. 11, 1989; 65 FR 61756, Oct. 17, 2000; 68 FR 59333, Oct. 15, 2003]

§ 60.112b Standard for volatile organic compounds (VOC).

(a) The owner or operator of each storage vessel either with a design capacity greater than or equal to 151 m^3 containing a VOL that, as stored, has a maximum true vapor pressure equal to or greater than 5.2 kPa but less than 76.6 kPa or with a design capacity greater than or equal to 75 m^3 but less than 151 m^3 containing a VOL that, as stored, has a maximum true vapor pressure equal to or greater than 27.6 kPa but less than 76.6 kPa, shall equip each storage vessel with one of the following:

(1) A fixed roof in combination with an internal floating roof meeting the following specifications:

(i) The internal floating roof shall rest or float on the liquid surface (but not necessarily in complete contact with it) inside a storage vessel that has a fixed roof. The internal floating roof shall be floating on the liquid surface at all times, except during initial fill and during those intervals when the storage vessel is completely emptied or subsequently emptied and refilled. When the roof is resting on the leg supports, the process of filling, emptying, or refilling shall be continuous and shall be accomplished as rapidly as possible.

(ii) Each internal floating roof shall be equipped with one of the following closure devices between the wall of the storage vessel and the edge of the internal floating roof:

(A) A foam- or liquid-filled seal mounted in contact with the liquid (liquid-mounted seal). A liquid-mounted seal means a foam- or liquid-filled seal mounted in contact with the liquid between the wall of the storage vessel and the floating roof continuously around the circumference of the tank.

(B) Two seals mounted one above the other so that each forms a continuous closure that completely covers the space between the wall of the storage vessel and the edge of the internal floating roof. The lower seal may be vapor-mounted, but both must be continuous.

(C) A mechanical shoe seal. A mechanical shoe seal is a metal sheet held vertically against the wall of the storage vessel by springs or weighted levers and is connected by braces to the floating roof. A flexible coated fabric (envelope) spans the annular space between the metal sheet and the floating roof.

(iii) Each opening in a noncontact internal floating roof except for automatic bleeder vents (vacuum breaker vents) and the rim space vents is to provide a projection below the liquid surface.

(iv) Each opening in the internal floating roof except for leg sleeves, automatic bleeder vents, rim space vents, column wells, ladder wells, sample wells, and stub drains is to be equipped with a cover or lid which is to be maintained in a closed position at all times (i.e., no visible gap) except when the device is in actual use. The cover or lid shall be equipped with a gasket. Covers on each access hatch and automatic gauge float well shall be bolted except when they are in use.

(v) Automatic bleeder vents shall be equipped with a gasket and are to be closed at all times when the roof is floating except when the roof is being floated off or is being landed on the roof leg supports.

(vi) Rim space vents shall be equipped with a gasket and are to be set to open only when the internal floating roof is not floating or at the manufacturer's recommended setting.

(vii) Each penetration of the internal floating roof for the purpose of sampling shall be a sample well. The sample well shall have a slit fabric cover that covers at least 90 percent of the opening.

(viii) Each penetration of the internal floating roof that allows for passage of a column supporting the fixed roof shall have a flexible fabric sleeve seal or a gasketed sliding cover.

(ix) Each penetration of the internal floating roof that allows for passage of a ladder shall have a gasketed sliding cover.

(2) An external floating roof. An external floating roof means a pontoon-type or double-deck type cover that rests on the liquid surface in a vessel with no fixed roof. Each external floating roof must meet the following specifications:

(i) Each external floating roof shall be equipped with a closure device between the wall of the storage vessel and the roof edge. The closure device is to consist of two seals, one above the other. The lower seal is referred to as the primary seal, and the upper seal is referred to as the secondary seal.

(A) The primary seal shall be either a mechanical shoe seal or a liquid-mounted seal. Except as provided in §60.113b(b)(4), the seal shall completely cover the annular space between the edge of the floating roof and tank wall.

(B) The secondary seal shall completely cover the annular space between the external floating roof and the wall of the storage vessel in a continuous fashion except as allowed in §60.113b(b)(4).

(ii) Except for automatic bleeder vents and rim space vents, each opening in a noncontact external floating roof shall provide a projection below the liquid surface. Except for automatic bleeder vents, rim space vents, roof drains, and leg sleeves, each opening in the roof is to be equipped with a gasketed cover, seal, or lid that is to be maintained in a closed position at all times (i.e., no visible gap) except when the device is in actual use. Automatic bleeder vents are to be closed at all times when the roof is floating except when the roof is being floated off or is being landed on the roof leg supports. Rim vents are to be set to open when the roof is being floated off the roof legs supports or at the manufacturer's recommended setting. Automatic bleeder vents and rim space vents are to be gasketed. Each emergency roof drain is to be provided with a slotted membrane fabric cover that covers at least 90 percent of the area of the opening.

(iii) The roof shall be floating on the liquid at all times (i.e., off the roof leg supports) except during initial fill until the roof is lifted off leg supports and when the tank is completely emptied and subsequently refilled. The process of filling, emptying, or refilling when the roof is resting on the leg supports shall be continuous and shall be accomplished as rapidly as possible.

(3) A closed vent system and control device meeting the following specifications:

(i) The closed vent system shall be designed to collect all VOC vapors and gases discharged from the storage vessel and operated with no detectable emissions as indicated by an instrument reading of less than 500 ppm above background and visual inspections, as determined in part 60, subpart VV, §60.485(b).

(ii) The control device shall be designed and operated to reduce inlet VOC emissions by 95 percent or greater. If a flare is used as the control device, it shall meet the specifications described in the general control device requirements (§60.18) of the General Provisions.

(4) A system equivalent to those described in paragraphs (a)(1), (a)(2), or (a)(3) of this section as provided in §60.114b of this subpart.

(b) The owner or operator of each storage vessel with a design capacity greater than or equal to 75 m^3 which contains a VOL that, as stored, has a maximum true vapor pressure greater than or equal to 76.6 kPa shall equip each storage vessel with one of the following:

(1) A closed vent system and control device as specified in §60.112b(a)(3).

(2) A system equivalent to that described in paragraph (b)(1) as provided in §60.114b of this subpart.

(c) *Site-specific standard for Merck & Co., Inc.'s Stonewall Plant in Elkton, Virginia.* This paragraph applies only to the pharmaceutical manufacturing facility, commonly referred to as the Stonewall Plant, located at Route 340 South, in Elkton, Virginia ("site").

(1) For any storage vessel that otherwise would be subject to the control technology requirements of paragraphs (a) or (b) of this section, the site shall have the option of either complying directly with the requirements of this subpart, or reducing the site-wide total criteria pollutant emissions cap (total emissions cap) in accordance with the procedures set forth in a permit issued pursuant to 40 CFR 52.2454. If the site chooses the option of reducing the total emissions cap in accordance with the procedures set forth in such permit, the requirements of such permit shall apply in lieu of the otherwise applicable requirements of this subpart for such storage vessel.

(2) For any storage vessel at the site not subject to the requirements of 40 CFR 60.112b (a) or (b), the requirements of 40 CFR 60.116b (b) and (c) and the General Provisions (subpart A of this part) shall not apply.

[52 FR 11429, Apr. 8, 1987, as amended at 62 FR 52641, Oct. 8, 1997]

§ 60.113b Testing and procedures.

The owner or operator of each storage vessel as specified in §60.112b(a) shall meet the requirements of paragraph (a), (b), or (c) of this section. The applicable paragraph for a particular storage vessel depends on the control equipment installed to meet the requirements of §60.112b.

(a) After installing the control equipment required to meet §60.112b(a)(1) (permanently affixed roof and internal floating roof), each owner or operator shall:

(1) Visually inspect the internal floating roof, the primary seal, and the secondary seal (if one is in service), prior to filling the storage vessel with VOL. If there are holes, tears, or other openings in the primary seal, the secondary seal, or the seal fabric or defects in the internal floating roof, or both, the owner or operator shall repair the items before filling the storage vessel.

(2) For Vessels equipped with a liquid-mounted or mechanical shoe primary seal, visually inspect the internal floating roof and the primary seal or the secondary seal (if one is in service) through manholes and roof hatches on the fixed roof at least once every 12 months after initial fill. If the internal floating roof is not resting on the surface of the VOL inside the storage vessel, or there is liquid accumulated on the roof, or the seal is detached, or there are holes or tears in the seal fabric, the owner or operator shall repair the items or empty and remove the storage vessel from service within 45 days. If a failure that is detected during inspections required in this paragraph cannot be repaired within 45 days and if the vessel cannot be emptied within 45 days, a 30-day extension may be requested from the Administrator in the inspection report required in §60.115b(a)(3). Such a request for an extension must document that alternate storage capacity is unavailable and specify a schedule of actions the company will take that will assure that the control equipment will be repaired or the vessel will be emptied as soon as possible.

(3) For vessels equipped with a double-seal system as specified in §60.112b(a)(1)(ii)(B):

(i) Visually inspect the vessel as specified in paragraph (a)(4) of this section at least every 5 years; or

(ii) Visually inspect the vessel as specified in paragraph (a)(2) of this section.

(4) Visually inspect the internal floating roof, the primary seal, the secondary seal (if one is in service), gaskets, slotted membranes and sleeve seals (if any) each time the storage vessel is emptied and degassed. If the internal floating roof has defects, the primary seal has holes, tears, or other openings in the seal or the seal fabric, or the secondary seal has holes, tears, or other openings in the seal or the seal fabric, or the gaskets no longer close off the liquid surfaces from the atmosphere, or the slotted membrane has more than 10 percent open area, the owner or operator shall repair the items as necessary so that none of the conditions specified in this paragraph exist before refilling the storage vessel with VOL. In no event shall inspections conducted in accordance with this provision occur at intervals greater than 10 years in the case of vessels conducting the annual visual inspection as specified in paragraphs (a)(2) and (a)(3)(ii) of this section and at intervals no greater than 5 years in the case of vessels specified in paragraph (a)(3)(i) of this section.

(5) Notify the Administrator in writing at least 30 days prior to the filling or refilling of each storage vessel for which an inspection is required by paragraphs (a)(1) and (a)(4) of this section to afford the Administrator the opportunity to have an observer present. If the inspection required by paragraph (a)(4) of this section is not planned and the owner or operator could not have known about the inspection 30 days in advance or refilling the tank, the owner or operator shall notify the Administrator at least 7 days prior to the refilling of the storage vessel. Notification shall be made by telephone immediately followed by written documentation demonstrating why the inspection was unplanned. Alternatively, this notification including the written documentation may be made in writing and sent by express mail so that it is received by the Administrator at least 7 days prior to the refilling.

(b) After installing the control equipment required to meet §60.112b(a)(2) (external floating roof), the owner or operator shall:

(1) Determine the gap areas and maximum gap widths, between the primary seal and the wall of the storage vessel and between the secondary seal and the wall of the storage vessel according to the following frequency.

(i) Measurements of gaps between the tank wall and the primary seal (seal gaps) shall be performed during the hydrostatic testing of the vessel or within 60 days of the initial fill with VOL and at least once every 5 years thereafter.

(ii) Measurements of gaps between the tank wall and the secondary seal shall be performed within 60 days of the initial fill with VOL and at least once per year thereafter.

(iii) If any source ceases to store VOL for a period of 1 year or more, subsequent introduction of VOL into the vessel shall be considered an initial fill for the purposes of paragraphs (b)(1)(i) and (b)(1)(ii) of this section.

(2) Determine gap widths and areas in the primary and secondary seals individually by the following procedures:

(i) Measure seal gaps, if any, at one or more floating roof levels when the roof is floating off the roof leg supports.

(ii) Measure seal gaps around the entire circumference of the tank in each place where a 0.32-cm diameter uniform probe passes freely (without forcing or binding against seal) between the seal and the wall of the storage vessel and measure the circumferential distance of each such location.

(iii) The total surface area of each gap described in paragraph (b)(2)(ii) of this section shall be determined by using probes of various widths to measure accurately the actual distance from the tank wall to the seal and multiplying each such width by its respective circumferential distance.

(3) Add the gap surface area of each gap location for the primary seal and the secondary seal individually and divide the sum for each seal by the nominal diameter of the tank and compare each ratio to the respective standards in paragraph (b)(4) of this section.

(4) Make necessary repairs or empty the storage vessel within 45 days of identification in any inspection for seals not meeting the requirements listed in (b)(4) (i) and (ii) of this section:

(i) The accumulated area of gaps between the tank wall and the mechanical shoe or liquid-mounted primary seal shall not exceed 212 Cm^2 per meter of tank diameter, and the width of any portion of any gap shall not exceed 3.81 cm.

(A) One end of the mechanical shoe is to extend into the stored liquid, and the other end is to extend a minimum vertical distance of 61 cm above the stored liquid surface.

(B) There are to be no holes, tears, or other openings in the shoe, seal fabric, or seal envelope.

(ii) The secondary seal is to meet the following requirements:

(A) The secondary seal is to be installed above the primary seal so that it completely covers the space between the roof edge and the tank wall except as provided in paragraph (b)(2)(iii) of this section.

(B) The accumulated area of gaps between the tank wall and the secondary seal shall not exceed 21.2 cm^2 per meter of tank diameter, and the width of any portion of any gap shall not exceed 1.27 cm.

(C) There are to be no holes, tears, or other openings in the seal or seal fabric.

(iii) If a failure that is detected during inspections required in paragraph (b)(1) of §60.113b(b) cannot be repaired within 45 days and if the vessel cannot be emptied within 45 days, a 30-day extension may be requested from the Administrator in the inspection report required in §60.115b(b)(4). Such extension request must include a demonstration of unavailability of alternate storage capacity and a specification of a schedule that will assure that the control equipment will be repaired or the vessel will be emptied as soon as possible.

(5) Notify the Administrator 30 days in advance of any gap measurements required by paragraph (b)(1) of this section to afford the Administrator the opportunity to have an observer present.

(6) Visually inspect the external floating roof, the primary seal, secondary seal, and fittings each time the vessel is emptied and degassed.

(i) If the external floating roof has defects, the primary seal has holes, tears, or other openings in the seal or the seal fabric, or the secondary seal has holes, tears, or other openings in the seal or the seal fabric, the owner or operator shall repair the items as necessary so that none of the conditions specified in this paragraph exist before filling or refilling the storage vessel with VOL.

(ii) For all the inspections required by paragraph (b)(6) of this section, the owner or operator shall notify the Administrator in writing at least 30 days prior to the filling or refilling of each storage vessel to afford the Administrator the opportunity to inspect the storage vessel prior to refilling. If the inspection required by paragraph (b)(6) of this section is not planned and the owner or operator could not have known about the inspection 30 days in advance of refilling the tank, the owner or operator shall notify the Administrator at least 7 days prior to the refilling of the storage vessel. Notification shall be made by telephone immediately followed by written documentation demonstrating why the inspection was unplanned. Alternatively, this notification including the written documentation may be made in writing and sent by express mail so that it is received by the Administrator at least 7 days prior to the refilling.

(c) The owner or operator of each source that is equipped with a closed vent system and control device as required in §60.112b (a)(3) or (b)(2) (other than a flare) is exempt from §60.8 of the General Provisions and shall meet the following requirements.

(1) Submit for approval by the Administrator as an attachment to the notification required by §60.7(a)(1) or, if the facility is exempt from §60.7(a)(1), as an attachment to the notification required by §60.7(a)(2), an operating plan containing the information listed below.

(i) Documentation demonstrating that the control device will achieve the required control efficiency during maximum loading conditions. This documentation is to include a description of the gas stream which enters the control device, including flow and VOC content under varying liquid level conditions (dynamic and static) and manufacturer's design specifications for the control device. If the control device or the closed vent capture system receives vapors, gases, or liquids other than fuels from sources that are not designated sources under this subpart, the efficiency demonstration is to include consideration of all vapors, gases, and liquids received by the closed vent capture system and control device. If an enclosed combustion device with a minimum residence time of 0.75 seconds and a minimum temperature of 816 °C is used to meet the 95 percent requirement, documentation that those conditions will exist is sufficient to meet the requirements of this paragraph.

(ii) A description of the parameter or parameters to be monitored to ensure that the control device will be operated in conformance with its design and an explanation of the criteria used for selection of that parameter (or parameters).

(2) Operate the closed vent system and control device and monitor the parameters of the closed vent system and control device in accordance with the operating plan submitted to the Administrator in accordance with paragraph (c)(1) of this section, unless the plan was modified by the Administrator during the review process. In this case, the modified plan applies.

(d) The owner or operator of each source that is equipped with a closed vent system and a flare to meet the requirements in §60.112b (a)(3) or (b)(2) shall meet the requirements as specified in the general control device requirements, §60.18 (e) and (f).

[52 FR 11429, Apr. 8, 1987, as amended at 54 FR 32973, Aug. 11, 1989]

§ 60.114b Alternative means of emission limitation.

(a) If, in the Administrator's judgment, an alternative means of emission limitation will achieve a reduction in emissions at least equivalent to the reduction in emissions achieved by any requirement in §60.112b, the Administrator will publish in theFederal Registera notice permitting the use of the alternative means for purposes of compliance with that requirement.

(b) Any notice under paragraph (a) of this section will be published only after notice and an opportunity for a hearing.

(c) Any person seeking permission under this section shall submit to the Administrator a written application including:

(1) An actual emissions test that uses a full-sized or scale-model storage vessel that accurately collects and measures all VOC emissions from a given control device and that accurately simulates wind and accounts for other emission variables such as temperature and barometric pressure.

(2) An engineering evaluation that the Administrator determines is an accurate method of determining equivalence.

(d) The Administrator may condition the permission on requirements that may be necessary to ensure operation and maintenance to achieve the same emissions reduction as specified in §60.112b.

§ 60.115b Reporting and recordkeeping requirements.

The owner or operator of each storage vessel as specified in §60.112b(a) shall keep records and furnish reports as required by paragraphs (a), (b), or (c) of this section depending upon the control equipment installed to meet the requirements of §60.112b. The owner or operator shall keep copies of all reports and records required by this section, except for the record required by (c)(1), for at least 2 years. The record required by (c)(1) will be kept for the life of the control equipment.

(a) After installing control equipment in accordance with §60.112b(a)(1) (fixed roof and internal floating roof), the owner or operator shall meet the following requirements.

(1) Furnish the Administrator with a report that describes the control equipment and certifies that the control equipment meets the specifications of §60.112b(a)(1) and §60.113b(a)(1). This report shall be an attachment to the notification required by §60.7(a)(3).

(2) Keep a record of each inspection performed as required by §60.113b (a)(1), (a)(2), (a)(3), and (a)(4). Each record shall identify the storage vessel on which the inspection was performed and shall contain the date the vessel was inspected and the observed condition of each component of the control equipment (seals, internal floating roof, and fittings).

(3) If any of the conditions described in §60.113b(a)(2) are detected during the annual visual inspection required by §60.113b(a)(2), a report shall be furnished to the Administrator within 30 days of the inspection. Each report shall identify the storage vessel, the nature of the defects, and the date the storage vessel was emptied or the nature of and date the repair was made.

(4) After each inspection required by §60.113b(a)(3) that finds holes or tears in the seal or seal fabric, or defects in the internal floating roof, or other control equipment defects listed in §60.113b(a)(3)(ii), a report shall be furnished to the

Administrator within 30 days of the inspection. The report shall identify the storage vessel and the reason it did not meet the specifications of §61.112b(a)(1) or §60.113b(a)(3) and list each repair made.

(b) After installing control equipment in accordance with §61.112b(a)(2) (external floating roof), the owner or operator shall meet the following requirements.

(1) Furnish the Administrator with a report that describes the control equipment and certifies that the control equipment meets the specifications of §60.112b(a)(2) and §60.113b(b)(2), (b)(3), and (b)(4). This report shall be an attachment to the notification required by §60.7(a)(3).

(2) Within 60 days of performing the seal gap measurements required by §60.113b(b)(1), furnish the Administrator with a report that contains:

(i) The date of measurement.

(ii) The raw data obtained in the measurement.

(iii) The calculations described in §60.113b (b)(2) and (b)(3).

(3) Keep a record of each gap measurement performed as required by §60.113b(b). Each record shall identify the storage vessel in which the measurement was performed and shall contain:

(i) The date of measurement.

(ii) The raw data obtained in the measurement.

(iii) The calculations described in §60.113b (b)(2) and (b)(3).

(4) After each seal gap measurement that detects gaps exceeding the limitations specified by §60.113b(b)(4), submit a report to the Administrator within 30 days of the inspection. The report will identify the vessel and contain the information specified in paragraph (b)(2) of this section and the date the vessel was emptied or the repairs made and date of repair.

(c) After installing control equipment in accordance with §60.112b (a)(3) or (b)(1) (closed vent system and control device other than a flare), the owner or operator shall keep the following records.

(1) A copy of the operating plan.

(2) A record of the measured values of the parameters monitored in accordance with §60.113b(c)(2).

(d) After installing a closed vent system and flare to comply with §60.112b, the owner or operator shall meet the following requirements.

(1) A report containing the measurements required by §60.18(f) (1), (2), (3), (4), (5), and (6) shall be furnished to the Administrator as required by §60.8 of the General Provisions. This report shall be submitted within 6 months of the initial start-up date.

(2) Records shall be kept of all periods of operation during which the flare pilot flame is absent.

(3) Semiannual reports of all periods recorded under §60.115b(d)(2) in which the pilot flame was absent shall be furnished to the Administrator.

§ 60.116b Monitoring of operations.

(a) The owner or operator shall keep copies of all records required by this section, except for the record required by paragraph (b) of this section, for at least 2 years. The record required by paragraph (b) of this section will be kept for the life of the source.

(b) The owner or operator of each storage vessel as specified in §60.110b(a) shall keep readily accessible records showing the dimension of the storage vessel and an analysis showing the capacity of the storage vessel.

(c) Except as provided in paragraphs (f) and (g) of this section, the owner or operator of each storage vessel either with a design capacity greater than or equal to 151 m^3 storing a liquid with a maximum true vapor pressure greater than or equal to 3.5 kPa or with a design capacity greater than or equal to 75 m^3 but less than 151 m^3 storing a liquid with a maximum true vapor pressure greater than or equal to 15.0 kPa shall maintain a record of the VOL stored, the period of storage, and the maximum true vapor pressure of that VOL during the respective storage period.

(d) Except as provided in paragraph (g) of this section, the owner or operator of each storage vessel either with a design capacity greater than or equal to 151 m^3 storing a liquid with a maximum true vapor pressure that is normally less than 5.2 kPa or with a design capacity greater than or equal to 75 m^3 but less than 151 m^3 storing a liquid with a maximum true vapor pressure that is normally less than 27.6 kPa shall notify the Administrator within 30 days when the maximum true vapor pressure of the liquid exceeds the respective maximum true vapor vapor pressure values for each volume range.

(e) Available data on the storage temperature may be used to determine the maximum true vapor pressure as determined below.

(1) For vessels operated above or below ambient temperatures, the maximum true vapor pressure is calculated based upon the highest expected calendar-month average of the storage temperature. For vessels operated at ambient temperatures, the maximum true vapor pressure is calculated based upon the maximum local monthly average ambient temperature as reported by the National Weather Service.

(2) For crude oil or refined petroleum products the vapor pressure may be obtained by the following:

(i) Available data on the Reid vapor pressure and the maximum expected storage temperature based on the highest expected calendar-month average temperature of the stored product may be used to determine the maximum true vapor pressure from nomographs contained in API Bulletin 2517 (incorporated by reference—see §60.17), unless the Administrator specifically requests that the liquid be sampled, the actual storage temperature determined, and the Reid vapor pressure determined from the sample(s).

(ii) The true vapor pressure of each type of crude oil with a Reid vapor pressure less than 13.8 kPa or with physical properties that preclude determination by the recommended method is to be determined from available data and recorded if the estimated maximum true vapor pressure is greater than 3.5 kPa.

(3) For other liquids, the vapor pressure:

(i) May be obtained from standard reference texts, or

(ii) Determined by ASTM D2879–83, 96, or 97 (incorporated by reference—see §60.17); or

(iii) Measured by an appropriate method approved by the Administrator; or

(iv) Calculated by an appropriate method approved by the Administrator.

(f) The owner or operator of each vessel storing a waste mixture of indeterminate or variable composition shall be subject to the following requirements.

(1) Prior to the initial filling of the vessel, the highest maximum true vapor pressure for the range of anticipated liquid compositions to be stored will be determined using the methods described in paragraph (e) of this section.

(2) For vessels in which the vapor pressure of the anticipated liquid composition is above the cutoff for monitoring but below the cutoff for controls as defined in §60.112b(a), an initial physical test of the vapor pressure is required; and a physical test at least once every 6 months thereafter is required as determined by the following methods:

(i) ASTM D2879–83, 96, or 97 (incorporated by reference—see §60.17); or

(ii) ASTM D323–82 or 94 (incorporated by reference—see §60.17); or

(iii) As measured by an appropriate method as approved by the Administrator.

(g) The owner or operator of each vessel equipped with a closed vent system and control device meeting the specification of §60.112b or with emissions reductions equipment as specified in 40 CFR 65.42(b)(4), (b)(5), (b)(6), or (c) is exempt from the requirements of paragraphs (c) and (d) of this section.

[52 FR 11429, Apr. 8, 1987, as amended at 65 FR 61756, Oct. 17, 2000; 65 FR 78276, Dec. 14, 2000; 68 FR 59333, Oct. 15, 2003]

§ 60.117b Delegation of authority.

(a) In delegating implementation and enforcement authority to a State under section 111(c) of the Act, the authorities contained in paragraph (b) of this section shall be retained by the Administrator and not transferred to a State.

(b) Authorities which will not be delegated to States: §§60.111b(f)(4), 60.114b, 60.116b(e)(3)(iii), 60.116b(e)(3)(iv), and 60.116b(f)(2)(iii).

[52 FR 11429, Apr. 8, 1987, as amended at 52 FR 22780, June 16, 1987]

APPENDIX G

Water to fuel ratio for NO_x Compliance

JONESBORO CITY WATER & LIGHT
Specific Condition #28
NOx Water to Fuel Ratios for Compliance

	Power	Water Flow gpm	Fuel Flow gpm or scfm	Ratio for Compliance lbs/lbs
Unit "A" Natural Gas	10 MW	5.6	2432	0.419
	15 MW	7.7	3169	0.442
	20 MW	11.8	4007	0.536
Diesel	10 MW	9.1	15.9	0.680
	15 MW	12.7	21	0.720
	20 MW	15.9	25.2	0.750
Unit "B" Natural Gas	5 MW	0	1488	0.000
	10 MW	4.8	2255	0.390
	15 MW	8.5	2972	0.530
	20 MW	12.6	3823	0.610
Diesel	5 MW	0	10.5	0
	10 MW	10	16	0.720
	15 MW	12.6	20.8	0.720
	20 MW	20.3	26.6	0.900
Unit "C" Natural Gas	12 MW	9.0	2910	0.480
	24 MW	11.0	4212	0.480
	36 MW	22.0	5760	0.710
	47 MW	36.0	7285	0.910
Diesel	12 MW	8.0	21.6	0.440
	24 MW	18.0	31.5	0.680
	36 MW	32.0	42.2	0.900
	47 MW	44.0	52.0	1.000
Unit "D" Natural Gas	12 MW	3	3019	0.180
	24 MW	6	4367	0.250
	36 MW	15	5906	0.470
	48 MW	31	7414	0.770
Diesel	12 MW	6	22	0.320
	24 MW	12	31	0.460
	36 MW	24	41	0.790
	48 MW	42	49	1.010

Operator: ____________________

Date ____________________

APPENDIX H

EPA Acid Rain Permit

United States
Environmental Protection Agency
Acid Rain Program

OMB No. 2060-0258

Acid Rain Permit Application

For more information, see instructions and refer to 40 CFR 72.30 and 72.31

This submission is: [X] New [ ] Revised

STEP 1

Identify the source by plant name, State, and ORIS code.

Plant Name City Water & Light Plant of the City of Jonesboro State AR ORIS Code 56505

STEP 2

Enter the unit ID# for every affected unit at the affected source in column "a." For new units, enter the requested information in columns "c" and "d."

a	b	c	d
Unit ID#	Unit Will Hold Allowances in Accordance with 40 CFR 72.9(c)(1)	New Units Commence Operation Date	New Units Monitor Certification Deadline
	Yes		
SN04	Yes	05/16/2000	11/16/2000
SN06	Yes	05/13/2003	11/13/2003
SN07	Yes	05/01/2007	11/01/2007
	Yes		
	Yes		
	Yes		
	Yes		
	Yes		
	Yes		
	Yes		
	Yes		
	Yes		
	Yes		
	Yes		
	Yes		
	Yes		
	Yes		

City Water & Light Plant of the City of Jonesboro, AR
Plant Name (from Step 1)

STEP 3

Read the standard requirements

Permit Requirements

(1) The designated representative of each affected source and each affected unit at the source shall:
(i) Submit a complete Acid Rain permit application (including a compliance plan) under 40 CFR part 72 in accordance with the deadlines specified in 40 CFR 72.30; and
(ii) Submit in a timely manner any supplemental information that the permitting authority determines is necessary in order to review an Acid Rain permit application and issue or deny an Acid Rain permit;
(2) The owners and operators of each affected source and each affected unit at the source shall:
(i) Operate the unit in compliance with a complete Acid Rain permit application or a superseding Acid Rain permit issued by the permitting authority; and
(ii) Have an Acid Rain Permit.

Monitoring Requirements

(1) The owners and operators and, to the extent applicable, designated representative of each affected source and each affected unit at the source shall comply with the monitoring requirements as provided in 40 CFR part 75.
(2) The emissions measurements recorded and reported in accordance with 40 CFR part 75 shall be used to determine compliance by the unit with the Acid Rain emissions limitations and emissions reduction requirements for sulfur dioxide and nitrogen oxides under the Acid Rain Program.
(3) The requirements of 40 CFR part 75 shall not affect the responsibility of the owners and operators to monitor emissions of other pollutants or other emissions characteristics at the unit under other applicable requirements of the Act and other provisions of the operating permit for the source.

Sulfur Dioxide Requirements

(1) The owners and operators of each source and each affected unit at the source shall:
(i) Hold allowances, as of the allowance transfer deadline, in the unit's compliance subaccount (after deductions under 40 CFR 73.34(c)), or in the compliance subaccount of another affected unit at the same source to the extent provided in 40 CFR 73.35(b)(3), not less than the total annual emissions of sulfur dioxide for the previous calendar year from the unit; and
(ii) Comply with the applicable Acid Rain emissions limitations for sulfur dioxide.
(2) Each ton of sulfur dioxide emitted in excess of the Acid Rain emissions limitations for sulfur dioxide shall constitute a separate violation of the Act.
(3) An affected unit shall be subject to the requirements under paragraph (1) of the sulfur dioxide requirements as follows:
(i) Starting January 1, 2000, an affected unit under 40 CFR 72.6(a)(2); or
(ii) Starting on the later of January 1, 2000 or the deadline for monitor certification under 40 CFR part 75, an affected unit under 40 CFR 72.6(a)(3).
(4) Allowances shall be held in, deducted from, or transferred among Allowance Tracking System accounts in accordance with the Acid Rain Program.
(5) An allowance shall not be deducted in order to comply with the requirements under paragraph (1) of the sulfur dioxide requirements prior to the calendar year for which the allowance was allocated.
(6) An allowance allocated by the Administrator under the Acid Rain Program is a limited authorization to emit sulfur dioxide in accordance with the Acid Rain Program. No provision of the Acid Rain Program, the Acid Rain permit application, the Acid Rain permit, or an exemption under 40 CFR 72.7 or 72.8 and no provision of law shall be construed to limit the authority of the United States to terminate or limit such authorization.
(7) An allowance allocated by the Administrator under the Acid Rain Program does not constitute a property right.

STEP 3, Cont'd.

Nitrogen Oxides Requirements The owners and operators of the source and each affected unit at the source shall comply with the applicable Acid Rain emissions limitation for nitrogen oxides.

Excess Emissions Requirements

(1) The designated representative of an affected unit that has excess emissions in any calendar year shall submit a proposed offset plan, as required under 40 CFR part 77.
(2) The owners and operators of an affected unit that has excess emissions in any calendar year shall:
(i) Pay without demand the penalty required, and pay upon demand the interest on that penalty, as required by 40 CFR part 77; and
(ii) Comply with the terms of an approved offset plan, as required by 40 CFR part 77.

Recordkeeping and Reporting Requirements

(1) Unless otherwise provided, the owners and operators of the source and each affected unit at the source shall keep on site at the source each of the following documents for a period of 5 years from the date the document is created. This period may be extended for cause, at any time prior to the end of 5 years, in writing by the Administrator or permitting
authority:
(i) The certificate of representation for the designated representative for the source and each affected unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation, in accordance with 40 CFR 72.24; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such documents are superseded because of the submission of a new certificate of representation changing the designated representative;
(ii) All emissions monitoring information, in accordance with 40 CFR part 75, provided that to the extent that 40 CFR part 75 provides for a 3-year period for recordkeeping, the 3-year period shall apply.
(iii) Copies of all reports, compliance certifications, and other submissions and all records made or required under the Acid Rain Program; and,
(iv) Copies of all documents used to complete an Acid Rain permit application and any other submission under the Acid Rain Program or to demonstrate compliance with the requirements of the Acid Rain Program.
(2) The designated representative of an affected source and each affected unit at the source shall submit the reports and compliance certifications required under the Acid Rain Program, including those under 40 CFR part 72 subpart I and 40 CFR part 75.

Liability

(1) Any person who knowingly violates any requirement or prohibition of the Acid Rain Program, a complete Acid Rain permit application, an Acid Rain permit, or an exemption under 40 CFR 72.7 or 72.8, including any requirement for the payment of any penalty owed to the United States, shall be subject to enforcement pursuant to section 113(c) of the Act.
(2) Any person who knowingly makes a false, material statement in any record, submission, or report under the Acid Rain Program shall be subject to criminal enforcement pursuant to section 113(c) of the Act and 18 U.S.C. 1001.
(3) No permit revision shall excuse any violation of the requirements of the Acid Rain Program that occurs prior to the date that the revision takes effect.
(4) Each affected source and each affected unit shall meet the requirements of the Acid Rain Program.

Step 3, Cont'd.

Liability, Cont'd.

(5) Any provision of the Acid Rain Program that applies to an affected source (including a provision applicable to the designated representative of an affected source) shall also apply to the owners and operators of such source and of the affected units at the source.
(6) Any provision of the Acid Rain Program that applies to an affected unit (including a provision applicable to the designated representative of an affected unit) shall also apply to the owners and operators of such unit. Except as provided under 40 CFR 72.44 (Phase II repowering extension plans) and 40 CFR 76.11 (NO_x averaging plans), and except with regard to the requirements applicable to units with a common stack under 40 CFR part 75 (including 40 CFR 75.16, 75.17, and 75.18), the owners and operators and the designated representative of one affected unit shall not be liable for any violation by any other affected unit of which they are not owners or operators or the designated representative and that is located at a source of which they are not owners or operators or the designated representative.
(7) Each violation of a provision of 40 CFR parts 72, 73, 74, 75, 76, 77, and 78 by an affected source or affected unit, or by an owner or operator or designated representative of such source or unit, shall be a separate violation of the Act.

Effect on Other Authorities

No provision of the Acid Rain Program, an Acid Rain permit application, an Acid Rain permit, or an exemption under 40 CFR 72.7 or 72.8 shall be construed as:
(1) Except as expressly provided in title IV of the Act, exempting or excluding the owners and operators and, to the extent applicable, the designated representative of an affected source or affected unit from compliance with any other provision of the Act, including the provisions of title I of the Act relating to applicable National Ambient Air Quality Standards or State Implementation Plans;
(2) Limiting the number of allowances a unit can hold; *provided,* that the number of allowances held by the unit shall not affect the source's obligation to comply with any other provisions of the Act;
(3) Requiring a change of any kind in any State law regulating electric utility rates and charges, affecting any State law regarding such State regulation, or limiting such State regulation, including any prudence review requirements under such State law;
(4) Modifying the Federal Power Act or affecting the authority of the Federal Energy Regulatory Commission under the Federal Power Act; or,
(5) Interfering with or impairing any program for competitive bidding for power supply in a State in which such program is established.

STEP 4

Certification

Read the certification statement, sign, and date

I am authorized to make this submission on behalf of the owners and operators of the affected source or affected units for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.

Name Ron Bowen	
Signature	Date 3-06-07