United States Environmental Protection Agency
Region 8
Air Program
1595 Wynkoop Street
Denver, CO 80202

AIR POLLUTION CONTROL
TITLE V PERMIT TO OPERATE

In accordance with the provisions of Title V of the Clean Air Act and 40 CFR Part 71 and applicable rules and regulations,

Northwest Pipeline GP
La Plata B Compressor Station

is authorized to operate air emission units and to conduct other air pollutant emitting activities in accordance with the permit conditions listed in this permit.

This source is authorized to operate at the following location:

Southern Ute Indian Reservation
Section 35 and 36, Township 34 North, Range 9 West
La Plata County, Colorado

Terms not otherwise defined in this permit have the meaning assigned to them in the referenced regulations. All terms and conditions of the permit are enforceable by EPA and citizens under the Clean Air Act.

11/4/09.

Callie A.Videtich, Director
Air Program
US EPA Region 8

Date

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AIR POLLUTION CONTROL
TITLE V PERMIT TO OPERATE

Northwest Pipeline GP
La Plata B Compressor Station

Permit Number: V-SU-0029-08.01
Replaces Amended Permit No.: V-SU-0029-08.00

Issue Date: November 4, 2009
Effective Date: November 4, 2009
Expiration Date: July 15, 2014

The permit number cited above should be referenced in future correspondence regarding this facility.

Permit Revision History

DATE OF REVISION	TYPE OF REVISION	SECTION NUMBER AND TITLE	DESCRIPTION OF REVISION
November 2003	**Initial Permit Issued**		**Permit # V-SU-0029-00.00**
June 2009	**1st Renewal Issued**		**Permit # V-SU-0029-08.00**
November 2009	**Administrative Amendment**		**Permit # V-SU-0029-08.01**
		II.E.1. Monitoring Requirements	Corrected regulatory citation for origin of authority
		III.C. Alternative Operating Scenarios – Turbine Replacement /Overhaul	Added explanatory note for how/when provision can be used
		III.D. Alternative Operating Scenarios – Engine Replacement / Overhaul	Revised explanatory note to reflect that a new explanatory note was added to Section III.D.
		IV.Q. Off Permit Changes	Corrected text for consistency with applicable regulatory requirement.

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Abbreviations and Acronyms

AR	Acid Rain
ARP	Acid Rain Program
bbls	Barrels
BACT	Best Available Control Technology
CAA	Clean Air Act [42 U.S.C. Section 7401 et seq.]
CAM	Compliance Assurance Monitoring
CEMS	Continuous Emission Monitoring System
CFR	Code of Federal Regulations
CMS	Continuous Monitoring System (includes COMS, CEMS and diluent monitoring)
COMS	Continuous Opacity Monitoring System
CO	Carbon monoxide
CO_2	Carbon dioxide
DAHS	Data Acquisition and Handling System
dscf	Dry standard cubic foot
dscm	Dry standard cubic meter
EIP	Economic Incentives Programs
EPA	Environmental Protection Agency
FGD	Flue gas desulfurization
gal	Gallon
GPM	Gallons per minute
H_2S	Hydrogen sulfide
HAP	Hazardous Air Pollutant
hr	Hour
Id. No.	Identification Number
kg	Kilogram
lb	Pound
MACT	Maximum Achievable Control Technology
MVAC	Motor Vehicle Air Conditioner
Mg	Megagram
MMBtu	Million British Thermal Units
mo	Month
NESHAP	National Emission Standards for Hazardous Air Pollutants
NMHC	Non-methane hydrocarbons
NO_x	Nitrogen Oxides
NSPS	New Source Performance Standard
NSR	New Source Review
pH	Negative logarithm of effective hydrogen ion concentration (acidity)
PM	Particulate Matter
PM_{10}	Particulate matter less than 10 microns in diameter
ppm	Parts per million
PSD	Prevention of Significant Deterioration
PTE	Potential to Emit
psi	Pounds per square inch
psia	Pounds per square inch absolute
RICE	Reciprocating Internal Combustion Engine
RMP	Risk Management Plan
scfm	Standard cubic feet per minute
SNAP	Significant New Alternatives Program
SO_2	Sulfur Dioxide
tpy	Ton Per Year
US EPA	United States Environmental Protection Agency
VOC	Volatile Organic Compounds

LIST OF TABLES

I. Source Information and Emission Unit Identification

I.A. General Source Information

Parent Company name: Northwest Pipeline GP

Plant Name: La Plata B Compressor Station

Plant Location: NE ¼, SE ¼ of Section 35, T34N, R9W
Lat. 37.143669 Long. -107.787361

Region: 8 **State:** Colorado **County:** La Plata

Reservation: Southern Ute Reservation **Tribe:** Southern Ute Indian Tribe

Responsible Official: Director of Operations

SIC Code: 4922

AFS Plant Identification Number: 08-067-00081

Other Clean Air Act Permits: This is the first renewal of the part 71 permit. There are no other Clean Air Act (CAA) permits, such as PSD or minor NSR, issued to this facility.

Description of Process:

The La Plata B Compressor Station is a natural gas compression and transmission facility located in La Plata County, Colorado. Natural gas is received at the station through a single inlet line from other gas conditioning plants and then compressed at the station. The La Plata B Compressor Station uses two Solar Taurus Model T-6502S Turbines to provide compression for Northwest Pipeline's mainline natural gas pipeline system. The Solar Model Taurus T-6502S Stationary Gas Turbines have been retrofitted with SoLoNOx technology to control emissions of nitrogen oxides (NO_x). Emissions from these units are vented to individual stacks. In addition, as needed, these turbines supply waste heat to two boilers that are complementarily fired by Deltak/COEN heat recovery boilers equipped with natural gas fired duct burners to provide the supplemental heat. The turbines are each rated at a maximum 45,000,000 Btu per hour (45 MMBtu/hr) heat input and the boilers are rated at a maximum 29 MMBtu/hr. Steam production is provided for the Ignacio Gas Plant, located adjacent to the compressor station. After compression, the gas exits the facility via a single natural gas pipeline.

Auxiliary equipment at the compressor station includes metering equipment, comfort and processing heating equipment, an emergency generator, a water heater, several oil and natural gas storage tanks with their associated vents, and station pressure relief valves that vent to the atmosphere.

The source is comprised of the Ignacio Gas Plant, the La Plata A Compressor Station, and the La Plata B Compressor Station facilities and is considered one source for purposes of

Prevention of Significant Deterioration (PSD), New Source Review (NSR) construction permitting requirements, and/or any other applicable Federal requirements. The three portions of the facility have different operators; therefore, three separate title V permits have been issued for each operator.

I.B. Source Emission Points

Table 1 identifies and describes each emission unit, such as process units and control devices. Table 2 identifies and describes the insignificant activities and/or emission units at the facility.

Table 1 – Emission Units
Northwest Pipeline GP
La Plata B Compressor Station

Emission Unit ID	Description	Control Equipment
P001 P002	45 MMBtu/hr Solar Model Taurus T-6502S Turbine. Natural gas fired: Serial Number: TC92156 Installed: 11/01/1992 (engine component serial no. 0071T) Serial Number: TC92157 Installed: 11/01/1992 (replacement engine component serial no. 1184T Installed 10/12/2005)	SoLoNOx Retrofit
B001 B002	29 MMBtu/hr Deltak Waste Heat Boiler with COEN Duct Burner, Model Delta 3S6-347. Natural gas fired: Serial Number: G92001A Installed: 1993 Serial Number: G92001B Installed: 1993	None
G001	565 bhp, Caterpillar 3412 SITA Emergency Generator. Natural gas fired: Serial Number: 7DB00769 Installed: 1992	None

Table 2 - Insignificant Emission Units
Northwest Pipeline GP
La Plata B Compressor Station

Description
1 – Used Oil / Condensate Tank; 4,200 gallons
2 – Lube Oil Storage Tanks; 600 gallons each
13 – Space Heaters for Personal Comfort
1 – Catalytic Heater for Chromatograph
1 – 2.5 MMBtu/hr Sellers Water Heater
1 – Blow Down Vent
Fugitive Emissions from Valves, Flanges, Seals, etc.

II. Requirements for Specific Units

II.A. 40CFR 60, Subpart A – Standards of Performance for New Stationary Sources, General Provisions [40 CFR 60.1 – 60.19]

1. The facility is subject to the requirements of 40 CFR part 60, subpart A, including, but not limited to the sections below. Notwithstanding conditions in this permit, the permittee shall comply with all applicable requirements of 40 CFR part 60, subpart A.

2. Requirements pursuant to 40 CFR part 60, subpart A in Section II of this permit are taken from 40 CFR part 60 of the Code of Federal Regulations as published on July 1, 2007.

3. At all times, including periods of startup, shutdown, and malfunction, the permittee shall, to the extent practicable, maintain and operate any affected facility including associated air pollution control equipment in a manner consistent with good air pollution control practices for minimizing emissions. Determination of whether acceptable operating and maintenance procedures are being used will be based on information available to the Administrator which may include, but is not limited to, monitoring results, opacity observations, review of operating and maintenance procedures, and inspection of the source.

4. This source is subject to the entire text of 40 CFR, part 60, subpart A, including, but not limited to, the following sections:

Section	Description
60.1	Applicability
60.2	Definitions
60.3	Units and abbreviations
60.4(a)	Address
60.5	Determination of construction or modification
60.6	Review of plans
60.7	Notification and record keeping
60.8	Performance tests
60.9	Availability of information
60.11	Compliance with standards and maintenance requirements
60.12	Circumvention
60.14	Modification
60.15	Reconstruction
60.17	Incorporations by reference
60.19	General notification and reporting requirements

II.B. 40 CFR Subpart GG – Standards of Performance for Stationary Gas Turbines [40 CFR 60.330 – 60.335]

1. This facility is subject to the requirements of 40 CFR part 60, subpart GG. Notwithstanding conditions in this permit, the permittee shall comply with all applicable requirements of 40 CFR part 60, subpart GG.

2. Requirements pursuant to 40 CFR part 60, subpart GG in Section II of this permit are taken from 40 CFR part 60 of the Code of Federal Regulations as published on July 1, 2008.

II.C. Emission Standards and Limits [40 CFR part 60, subpart GG and 40 CFR 71.6(a)(1),71.6(a)(1)(i), and 71.6(a)(1)(iii)]

1. Emission units P001 and P002 are subject to the nitrogen oxide (NO_x) standard and the sulfur dioxide (SO_2) fuel standard listed in Table 3 below.

Table 3 - Turbine Emission Standards

Pollutant	Emission Standard	Regulatory Reference
NO_x	$STD = 0.0150\frac{(14.4)}{Y} + F = 174$ ppm where Y= 12.4 kilojoules per watt hour (manufacturer's rated heat rate at manufacturer's rated peak load) and F = 0 (NO_x emission allowance for fuel bound nitrogen) and STD = allowable NO_x emissions (percent by volume at 15 percent oxygen and on a dry basis)	40 CFR 60.332(a)(2)
SO_2	Either: (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; or	40 CFR 60.333(a)
	(b) Fuel sulfur content shall not exceed 0.8 percent by weight.*	40 CFR 60.333(b)

* The permittee has elected to demonstrate compliance with the SO_2 limit by verifying that the fuel used meets the definition of natural gas to avoid fuel sulfur monitoring. See Section II.E.1 of this permit.

II.D. Testing Requirements [40 CFR 60.8, 40 CFR 60.335, and 40 CFR 71.6(a)(3)(i)(A) - (C)]

1. The permittee shall comply with the initial performance test requirements of 40 CFR 60.8(a) – (f) for measuring NO_x emissions from replaced units P001 and P002 within 60 days after achieving maximum production rate at which the turbines will be operated, but no later than 180 days after initial startup of the turbines.

2. The permittee shall comply with the test methods and procedures of 40 CFR 60.335(a), (b), and (c) when conducting the initial performance test for NO_x for units P001 and P002.

II.E. Monitoring Requirements [40 CFR 60.334(c) and (h) and 40 CFR 71.6(a)(3)(i)(A) through (C)]

1. The permittee shall measure NO_x emissions from emission units P001 and P002 at least once every quarter to show compliance with the requirements of 40 CFR 60.332(a)(2). To meet this requirement, the permittee shall measure NO_x emissions from the turbine using a portable analyzer and a monitoring protocol approved by EPA. EPA approved the monitoring protocol in a January 24, 2008 letter (see Appendix B).

   (a) Monitoring shall begin in the first calendar quarter following EPA notification to the applicant of the approval of the monitoring protocol.

   (b) If an emission unit is inoperable for 1,500 hours or more in any calendar quarter, the permittee is exempt from conducting NO_x monitoring for the emission unit for that quarter only.

   [40 CFR 60.334(c) and 40 CFR 71.6(a)(3)(i)(B)]

2. The permittee shall comply with the requirements of 40 CFR 60.334(h) for monitoring of sulfur content and nitrogen content of the fuel being burned in units P001 and P002.

   (a) Monitoring of nitrogen content of the fuel is only required if the permittee claims an allowance for fuel-bound nitrogen. The permittee has not claimed such an allowance.

   [40 CFR 60.334(h)(2)]

   (b) The permittee may elect not to monitor the sulfur content of the gaseous fuel, if the permittee demonstrates that the gaseous fuel burned in units P001 and P002 meets the definition of natural gas in 40 CFR 60.331(u), based on information specified in §§60.334(h)(3)(i) or (ii). The permittee has elected to supply the information specified in (i), which is 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/100scf or less" (see Appendix C).

   [40 CFR 60.334(h)(3)(i)]

[Explanatory Note: The language in this permit from the revised NSPS subpart GG is considered by EPA Region 8 to supersede and render unnecessary the Custom Fuel Monitoring Schedule, approved by EPA Region 8 on July 22, 1993. EPA Region 8 has examined the information supplied by the permittee pursuant to §60.334(h)(3)(i) and has determined that the permittee's fuel meets the definition of natural gas in 40 CFR part 60, subpart GG.]

II.F. Recordkeeping Requirements [40 CFR 71.6(a)(3)(ii), 40 CFR 60.7(b) and 60.7(f)]

Emission Units P001, P002, B001 and B002 are subject to the following recordkeeping requirements:

1. The permittee shall comply with the following recordkeeping requirements for turbine units P001 and P002:

(a) The permittee shall maintain records of the occurrence and duration of any startup, shutdown, or malfunction in the operation of an affected facility; any malfunction of the air pollution control equipment; or any periods during which a continuous monitoring system or monitoring device is inoperative.

(b) The permittee shall maintain a file of all measurements, including performance testing measurements, monitoring device calibration checks, and other information required by the New Source Performance Standards (NSPS) conditions of this permit.

(c) The permittee shall comply with the following recordkeeping requirements when firing an emergency fuel in turbine units P001 and P002:

(i) Monitoring of fuel sulfur content shall be recorded daily while firing an emergency fuel as defined in 40 CFR 60.331(r).
(ii) Monitoring of fuel nitrogen content shall be recorded daily while firing a fuel other than pipeline-quality natural gas.
(iii) Monitoring of fuel nitrogen content shall be recorded daily while firing an emergency fuel as defined in 40 CFR 60.331(r).

2. The permittee shall keep records of all required monitoring in Section II.D. of this permit. The records shall include the following:

(a) The date, place, and time of sampling or measurements;

(b) The date(s) analyses were performed;

(c) The company or entity that performed the analyses;

(d) The analytical techniques or methods used;

(e) The results of such analyses; and

(f) The operating conditions as existing at the time of sampling or measurement.

3. Records shall be kept of off permit changes, as required by Section IV.Q. of this permit.

4. The permittee shall retain records of all required monitoring data and support information, sample analyses, fuel supplier, fuel quality, and fuel make-up, pertinent to the conditions in Section II.E. of this permit, for a period of at least five (5) years from the date of the monitoring sample, measurement, report, or application. These records shall be made available upon request by EPA Region 8. Support information includes all calibration and maintenance records, all original strip-chart recordings for continuous monitoring instrumentation, and copies of all reports required by this permit.

II.G. **Reporting Requirements** [40 CFR 60.48c(a), 60.7, and 40 CFR 71.6(a)(3)(iii)]

Emission units P001, P002, B001, and B002 are subject to the following reporting requirements:

1. The permittee shall submit notification of the date of construction or reconstruction, anticipated startup, and actual startup of each turbine or boiler, as specified by 40 CFR 60.7. This notification shall include:

   (a) The design heat input capacity of the turbine or boiler and identification of fuels to be combusted in the turbine or boiler.

   (b) The annual capacity factor at which the permittee anticipates operating the turbine or boiler based on all fuels fired and based on each individual fuel fired.

III. Facility-Wide Requirements

Conditions in this section of the permit apply to all emissions units located at the facility, including any units not specifically listed in Table 1 and Table 2 of Section I.B.

[40 CFR 71.6(a)(1)]

III.A. General Recordkeeping Requirements [40 CFR 71.6(a)(3)(ii)]

The permittee shall comply with the following generally applicable recordkeeping requirements:

1. If the permittee determines that his or her stationary source that emits (or has the potential to emit, without federally recognized controls) one or more hazardous air pollutants is not subject to a relevant standard or other requirement established under 40 CFR part 63, the permittee shall keep a record of the applicability determination on site at the source for a period of five (5) years after the determination, or until the source changes its operations to become an affected source, whichever comes first. The record of the applicability determination shall include an analysis (or other information) that demonstrates why the permittee believes the source is unaffected (e.g., because the source is an area source).

[40 CFR 63.10(b)(3)]

III.B General Reporting Requirements [40 CFR 71.6(a)(3)(iii)]

1. The permittee shall submit to EPA reports of any monitoring results and recordkeeping required under this permit semi-annually by April 1st and October 1st of each year. The report due on April 1st shall cover the prior six-month period from July 1st through the end of December. The report due on October 1st shall cover the prior six-month period from January 1st through the end of June. All instances of deviations from permit requirements must be clearly identified in such reports. All required reports must be certified by a responsible official consistent with Section IV.E.1. of this permit.

[Explanatory note: To help part 71 permittees meet reporting responsibilities, EPA has developed a form "SIXMON" for six-month monitoring reports. The form may be found on the EPA website at: http://www.epa.gov/air/oaqps/permits/p71forms.html]

2. "Deviation," means any situation in which an emissions unit fails to meet a permit term or condition. A deviation is not always a violation. A deviation can be determined by observation or through review of data obtained from any testing, monitoring, or recordkeeping established in accordance with §71.6(a)(3)(i) and (a)(3)(ii). For a situation lasting more than 24 hours which constitutes a deviation, each 24 hour period is considered a separate deviation. Included in the meaning of deviation are any of the following:

   (a) A situation where emissions exceed an emission limitation or standard;

   (b) A situation where process or emissions control device parameter values indicate that an emission limitation or standard has not been met;

(c) A situation in which observations or data collected demonstrates noncompliance with an emission limitation or standard or any work practice or operating condition required by the permit; or

(d) A situation in which an exceedance or an excursion, as defined in 40 CFR part 64 occurs.

3. The permittee shall promptly report to EPA deviations from permit requirements, including those attributable to upset conditions as defined in this permit, the probable cause of such deviations, and any corrective actions or preventive measures taken. "Prompt" is defined as follows:

(a) Any definition of "prompt" or a specific timeframe for reporting deviations provided in an underlying applicable requirement as identified in this permit;

(b) Where the underlying applicable requirement fails to address the time frame for reporting deviations, reports of deviations will be submitted based on the following schedule:

(i) For emissions of a hazardous air pollutant or a toxic air pollutant (as identified in the applicable regulation) that continue for more than an hour in excess of permit requirements, the report must be made within 24 hours of the occurrence.

(ii) For emissions of any regulated air pollutant, excluding a hazardous air pollutant or a toxic air pollutant that continue for more than two (2) hours in excess of permit requirements, the report must be made within 48 hours.

(iii) For all other deviations from permit requirements, the report shall be submitted with the semi-annual monitoring report required in III.B.1.

4. If any of the conditions in Sections III.B.3.(b)(i) - (ii) are met, the source must notify EPA by telephone (1-800-227-8917) or facsimile (303-312-6064) based on the timetables listed above. *[Notification by telephone or fax must specify that this notification is a deviation report for a part 71 permit.]* A written notice, certified consistent with Section IV.E.1. of this permit must be submitted within ten (10) working days of the occurrence. All deviations reported under this section must also be identified in the 6-month report required under permit Section III.B.1.

[Explanatory note: To help part 71 permittees meet reporting responsibilities, EPA has developed a form "PDR" for prompt deviation reporting. The form may be found on the EPA website at: http://www.epa.gov/air/oaqps/permits/p71forms.html]

III.C. <u>Alternative Operating Scenarios</u> - Turbine Replacement/Overhaul
[40 CFR 71.6(a)(9)]

1. Replacement of a permitted turbine with a turbine of the same make, model, heat input capacity rating, and configured to operate in the same manner as the turbine being replaced, shall be an allowed alternative operating scenario provided the replacement activity satisfies all of the provisions for off permit changes under this permit (Section IV.Q), including the provisions specific to turbine replacement.

2. Any emission limits, requirements, control technologies, or other provisions that apply to turbines that are replaced under this Alternative Operating Scenarios section shall also apply to the replacement turbines.

3. Replacement of a permitted turbine with a turbine subject to 40 CFR part 60, subpart KKKK is not allowed under this alternative operating scenario.

4. Replacement of a permitted turbine with a turbine subject to 40 CFR part 63, subpart YYYY is not allowed under this alternative operating scenario.

[Explanatory note: Section III.C was included to allow for off permit replacement of turbines that may have existing federally enforceable limits – in the case of this facility, the limitations in 40 CFR part 60, subpart GG. According to the definition in subpart GG and subsequent agency applicability guidance, the "affected facility" is the "Mainline Unit Package," which is comprised of a gas component that produces the high-energy exhaust gas flow (i.e. the engine section) and a reaction component that receives the exhaust gas flow and is made up of the diffuser/bladed wheel and shaft (i.e. the power turbine section). A replacement of the entire "Mainline Unit Package" shall be considered a new turbine and thus subject to the initial compliance tests required by Section II.D. and all other conditions applicable to units P001 and P002 in this permit. For replacement turbines which trigger new applicable requirements (i.e., 40 CFR part 60, subpart KKKK or 40 CFR part 63, subpart YYYY)), the minor permit modification process (Section IV.I of this permit) shall be used to maintain the permitted emission limits of the replaced turbine and/or incorporate the new applicable requirements.]

III.D. <u>Alternative Operating Scenario</u> – Natural Gas Fired Electric Generating Unit Replacement/Overhaul [40 CFR 71.6(a)(9)]

1. Replacement of a permitted generator with a generator of the same make, model, heat input capacity rating, and configured to operate in the same manner as the generator being replaced, shall be an allowed alternative operating scenario provided the replacement activity satisfies all of the provisions for off permit changes (Section IV.Q.) under this permit, including the provisions specific to engine replacement.

2. Replacement of a permitted generator with a generator subject to 40 CFR part 60, subpart JJJJ is not allowed under this alternative operating scenario.

3. Replacement of a permitted generator with a generator subject to 40 CFR part 63, subpart ZZZZ is not allowed under this alternative operating scenario.

[Explanatory note: Section III.D was included to allow for off permit replacement of engines that may have existing federally enforceable limits. For replacement engines which trigger new applicable requirements (i.e., NSPS or MACT), the minor permit modification process (Section IV.I of this permit) shall be used to maintain the permitted emission limits of the replaced engine and/or incorporate the new applicable requirements.]

III.E. Permit Shield [40 CFR 71.6(f)(3)]

Nothing in this permit shall alter or affect the following:

1. The liability of a permittee for any violation of applicable requirements prior to or at the time of permit issuance;

2. The ability of EPA to obtain information from a source pursuant to section 114 of the CAA or;

3. The provisions of section 303 of the CAA (emergency orders), including the authority of EPA under that section.

III.F. Prevention of Significant Deterioration [40 CFR 52.21]

This facility is a major stationary source (potential to emit of any pollutant regulated under the Clean Air Act (not including pollutants listed under section 112(b)) > 250 tpy) for the purposes of Prevention of Significant Deterioration (PSD) requirements. Any projects at this facility which meet the definition of "major modification" at 40 CFR 52.21(b)(2) would require that the permittee obtain a pre-construction permit pursuant to federal regulations. In the event that the permittee elects to use the method specified in 52.21(b)(41)(ii)(a) through (c) for calculating the projected actual emissions of a proposed project, the permittee shall comply with all of the requirements of 40 CFR 52.21(r)(6) that apply to the project.

IV. Part 71 Administrative Requirements

IV.A. Annual Fee Payment [40 CFR 71.6(a)(7) and 40 CFR 71.9]

1. The permittee shall pay an annual permit fee in accordance with the procedures outlined below.

[40 CFR 71.9(a)]

2. The permittee shall pay the annual permit fee each year no later than April 1st. The fee shall cover the previous calendar year.

[40 CFR 71.9(h)]

3. The fee payment shall be in United States currency and shall be paid by money order, bank draft, certified check, corporate check, or electronic funds transfer payable to the order of the U.S. Environmental Protection Agency.

[40 CFR 71.9(k)(1)]

4. The permittee shall send fee payment and a completed fee filing form to:

For regular U.S. Postal Service mail

U.S. Environmental Protection Agency
FOIA and Miscellaneous Payments
Cincinnati Finance Center
P.O. Box 979078
St. Louis, MO 63197-9000

For non-U.S. Postal Service Express mail
(FedEx, Airborne, DHL, and UPS)

U.S. Bank
Government Lockbox 979078
US EPA FOIA & Misc. Payments
1005 Convention Plaza
SL-MO-C2-GL
St. Louis, MO 63101

[40 CFR 71.9(k)(2)]

5. The permittee shall send an updated fee calculation worksheet form and a photocopy of each fee payment check (or other confirmation of actual fee paid) submitted annually by the same deadline as required for fee payment to the address listed in Submissions section of this permit.

[40 CFR 71.9(h)(1)]

[Explanatory note: The fee filing form FF and the fee calculation worksheet form FEE may be found on EPA website at: http://www.epa.gov/air/oaqps/permits/p71forms.html]

6. Basis for calculating annual fee:

   (a) The annual emissions fee shall be calculated by multiplying the total tons of actual emissions of all "regulated pollutants (for fee calculation)" emitted from the source by the presumptive emissions fee (in dollars/ton) in effect at the time of calculation.

   [40 CFR 71.9(c)(1)]

      (i) "Actual emissions" means the actual rate of emissions in tpy of any regulated pollutant (for fee calculation) emitted from a part 71 source over the preceding calendar year. Actual emissions shall be calculated using each emissions unit's actual operating hours, production rates, in-place control equipment, and types of materials processed, stored, or combusted during the preceding calendar year.

[40 CFR 71.9(c)(6)]

(ii) Actual emissions shall be computed using methods required by the permit for determining compliance, such as monitoring or source testing data.

[40 CFR 71.9(h)(3)]

(iii) If actual emissions cannot be determined using the compliance methods in the permit, the permittee shall use other federally recognized procedures.

[40 CFR 71.9(e)(2)]

[Explanatory note: The presumptive fee amount is revised each calendar year to account for inflation, and it is available from EPA prior to the start of each calendar year.]

(b) The permittee shall exclude the following emissions from the calculation of fees:

(i) The amount of actual emissions of each regulated pollutant (for fee calculation) that the source emits in excess of 4,000 tons per year;

[40 CFR 71.9(c)(5)(i)]

(ii) Actual emissions of any regulated pollutant (for fee calculation) already included in the fee calculation; and

[40 CFR 71.9(c)(5)(ii)]

(iii) The quantity of actual emissions (for fee calculation) of insignificant activities [defined in §71.5(c)(11)(i)] or of insignificant emissions levels from emissions units identified in the permittee's application pursuant to §71.5(c)(11)(ii).

[40 CFR 71.9(c)(5)(iii)]

7. Fee calculation worksheets shall be certified as to truth, accuracy, and completeness by a responsible official.

[40 CFR 71.9(h)(2)]

[Explanatory note: The fee calculation worksheet form already incorporates a section to help you meet this responsibility.]

8. The permittee shall retain fee calculation worksheets and other emissions-related data used to determine fee payment for five (5) years following submittal of fee payment. [Emission-related data include, for example, emissions-related forms provided by EPA and used by the permittee for fee calculation purposes, emissions-related spreadsheets, and emissions-

related data, such as records of emissions monitoring data and related support information required to be kept in accordance with §71.6(a)(3)(ii).]

[40 CFR 71.9(i)]

9. Failure of the permittee to pay fees in a timely manner shall subject the permittee to assessment of penalties and interest in accordance with §71.9(l).

[40 CFR 71.9(l)]

10. When notified by EPA of underpayment of fees, the permittee shall remit full payment within 30 days of receipt of notification.

[40 CFR 71.9(j)(2)]

11. A permittee who thinks an EPA assessed fee is in error and who wishes to challenge such a fee, shall provide a written explanation of the alleged error to EPA along with full payment of the EPA assessed fee.

[40 CFR 71.9(j)(3)]

IV.B. Annual Emissions Inventory [40 CFR 71.9(h)(1)and (2)]

The permittee shall submit an annual emissions report of its actual emissions for both criteria pollutants and regulated HAPs for this facility for the preceding calendar year for fee assessment purposes. The annual emissions report shall be certified by a responsible official and shall be submitted each year to EPA by April 1st.

The annual emissions report shall be submitted to EPA at the address listed in the Submissions section of this permit.

[Explanatory note: An annual emissions report, required at the same time as the fee calculation worksheet by §71.9(h), has been incorporated into the fee calculation worksheet form as a convenience.]

IV.C. Compliance Requirements [40 CFR 71.6(a)(6)(i) and (ii), and sections 113(a) and 113(e)(1) of the Act, and 40 CFR 51.212, 52.12, 52.33, 60.11(g), and 61.12]

1. Compliance with the Permit

   (a) The permittee must comply with all conditions of this part 71 permit. Any permit noncompliance constitutes a violation of the Clean Air Act and is grounds for enforcement action; for permit termination, revocation and re-issuance, or modification; or for denial of a permit renewal application.

   [40 CFR 71.6(a)(6)(i)]

   (b) 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 in order to maintain compliance with the conditions of this permit.

   [40 CFR 71.6(a)(6)(ii)]

   (c) For the purpose of submitting compliance certifications in accordance with this permit, or establishing whether or not a person has violated or is in violation of any requirement of this permit, nothing shall preclude the use, including the exclusive use, of any credible evidence or information, relevant to whether a source would have been in compliance with applicable requirements if the appropriate performance or compliance test or procedure had been performed.

[Section 113(a) and 113(e)(1) of the Act, 40 CFR 51.212, 52.12, 52.33, 60.11(g), and 61.12]

2. Compliance Schedule

(a) For applicable requirements with which the source is in compliance, the source will continue to comply with such requirements.

[40 CFR 71.5(c)(8)(iii)(A)]

(b) For applicable requirements that will become effective during the permit term, the source shall meet such requirements on a timely basis.

[40 CFR 71.5(c)(8)(iii)(B)]

3. Compliance Certifications

The permittee shall submit to EPA a certification of compliance with permit terms and conditions, including emission limitations, standards, or work practices annually by April 1st, and shall cover the preceding calendar year.

[Explanatory note: To help part 71 permittees meet reporting responsibilities, EPA has developed a reporting form for annual compliance certifications. The form may be found on EPA website at: http://www.epa.gov/air/oaqps/permits/p71forms.html]

The compliance certification shall be certified as to truth, accuracy, and completeness by a responsible official consistent with §71.5(d).

[40 CFR 71.6(c)(5)]

(a) The certification shall include the following:

(i) Identification of each permit term or condition that is the basis of the certification;

(ii) The identification of the method(s) or other means used for determining the compliance status of each term and condition during the certification period, and whether such methods or other means provide continuous or intermittent data. Such methods and other means shall include, at a minimum, the methods and means required in this permit. If necessary, the permittee also shall identify any other material information that must be included in the certification to comply with section 113(c)(2) of the Clean Air Act, which prohibits knowingly making a false certification or omitting material information;

(iii) The status of compliance with each term and condition of the permit for the period covered by the certification based on the method or means designated in the preceding paragraph of this permit. The certification shall identify each deviation and take it into account in the compliance certification;

(iv) Such other facts as the EPA may require to determine the compliance status of the source; and

(v) Whether compliance with each permit term was continuous or intermittent.

[40 CFR 71.6(c)(5)(iii)]

IV.D. Duty to Provide and Supplement Information
[40 CFR 71.6(a)(6)(v), 71.5(a)(3), and 71.5(b)]

1. The permittee shall furnish to EPA, within a reasonable time, any information that EPA 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 shall also furnish to the EPA copies of records that are required to be kept pursuant to the terms of the permit, including information claimed to be confidential. Information claimed to be confidential must be accompanied by a claim of confidentiality according to the provisions of 40 CFR part 2, subpart B.

[40 CFR 71.6(a)(6)(v) and 40 CFR 71.5(a)(3)]

2. The permittee, upon becoming aware that any relevant facts were omitted or incorrect information was submitted in the permit application, shall promptly submit such supplementary facts or corrected information. In addition, a permittee shall provide additional information as necessary to address any requirements that become applicable after the date a complete application is filed, but prior to release of a draft permit.

[40 CFR 71.5(b)]

IV.E. Submissions [40 CFR 71.5(d), 71.6(c)(1) and 71.9(h)(2)]

1. Any document (application form, report, compliance certification, etc.) required to be submitted under this permit shall be certified by a responsible official as to truth, accuracy, and completeness. Such certifications shall state that based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete.

[Explanatory note: EPA has developed a reporting form CTAC for certifying truth, accuracy and completeness of part 71 submissions. The form may be found on EPA website at: http://www.epa.gov/air/oaqps/permits/p71forms.html]

2. Any documents required to be submitted under this permit, including reports, test data, monitoring data, notifications, compliance certifications, fee calculation worksheets, and applications for renewals and permit modifications shall be submitted to:

Part 71 Permit Contact
Air Program, 8P-AR
U.S. Environmental Protection Agency
1595 Wynkoop Street
Denver, Colorado 80202

IV.F. Severability Clause [40 CFR 71.6(a)(5)]

The provisions of this permit are severable, and in the event of any challenge to any portion of this permit, or if any portion is held invalid, the remaining permit conditions shall remain valid and in force.

IV.G. Permit Actions [40 CFR 71.6(a)(6)(iii)]

This permit may be modified, revoked, reopened, and reissued, or terminated for cause. The filing of a request by the permittee for a permit modification, revocation and reissuance, or termination, or of a notification of planned changes or anticipated noncompliance does not stay any permit condition.

IV.H. Administrative Permit Amendments [40 CFR 71.7(d)]

The permittee may request the use of administrative permit amendment procedures for a permit revision that:

1. Corrects typographical errors;

2. Identifies a change in the name, address, or phone number of any person identified in the permit, or provides a similar minor administrative change at the source;

3. Requires more frequent monitoring or reporting by the permittee;

4. Allows for a change in ownership or operational control of a source where the EPA determines that no other change in the permit is necessary, provided that a written agreement containing a specific date for transfer of permit responsibility, coverage, and liability between the current and new permittee has been submitted to the EPA;

5. Incorporates into the part 71 permit the requirements from preconstruction review permits authorized under an EPA-approved program, provided that such a program meets procedural requirements substantially equivalent to the requirements of §71.7 and §71.8 that would be applicable to the change if it were subject to review as a permit modification, and compliance requirements substantially equivalent to those contained in §71.6; or

6. Incorporates any other type of change which EPA has determined to be similar to those listed above in subparagraphs 1 through 5 above.

[Note to permittee: If subparagraphs 1 through 5 above do not apply, please contact EPA for a determination of similarity prior to submitting your request for an administrative permit amendment under this provision.]

IV.I. Minor Permit Modifications [40 CFR 71.7(e)(1)]

1. The permittee may request the use of minor permit modification procedures only for those modifications that:

   (a) Do not violate any applicable requirements;

(b) Do not involve significant changes to existing monitoring, reporting, or recordkeeping requirements in the permit;

(c) Do not require or change a case-by-case determination of an emission limitation or other standard, or a source-specific determination for temporary sources of ambient impacts, or a visibility or increment analysis;

(d) Do not seek to establish or change a permit term or condition for which there is no corresponding underlying applicable requirement and that the source has assumed to avoid an applicable requirement to which the source would otherwise be subject. Such terms and conditions include:

(i) A federally enforceable emissions cap assumed to avoid classification as a modification under any provision of title I; and
(ii) An alternative emissions limit approved pursuant to regulations promulgated under section 112(i)(5) of the Clean Air Act;

(e) Are not modifications under any provision of title I of the Clean Air Act; and

(f) Are not required to be processed as a significant modification.

[40 CFR 71.7(e)(1)(i)(A)]

2. Notwithstanding the list of changes ineligible for minor permit modification procedures in Section IV.I.1., minor permit modification procedures may be used for permit modifications involving the use of economic incentives, marketable permits, emissions trading, and other similar approaches, to the extent that such minor permit modification procedures are explicitly provided for in an applicable implementation plan or in applicable requirements promulgated by EPA.

[40 CFR 71.7(e)(1)(i)(B)]

3. An application requesting the use of minor permit modification procedures shall meet the requirements of §71.5(c) and shall include the following:

(a) A description of the change, the emissions resulting from the change, and any new applicable requirements that will apply if the change occurs;

(b) The source's suggested draft permit;

(c) Certification by a responsible official, consistent with §71.5(d), that the proposed modification meets the criteria for use of minor permit modification procedures and a request that such procedures be used; and

(d) Completed forms for the permitting authority to use to notify affected States as required under §71.8.

[40 CFR 71.7(e)(1)(ii)]

4. The source may make the change proposed in its minor permit modification application immediately after it files such application. After the source makes the change allowed by the preceding sentence, and until the permitting authority takes any of the actions authorized by §71.7(e)(1)(iv)(A) through (C), the source must comply with both the applicable requirements governing the change and the proposed permit terms and conditions. During this time period, the source need not comply with the existing permit terms and conditions it seeks to modify. However, if the source fails to comply with its proposed permit terms and conditions during this time period, the existing permit terms and conditions it seeks to modify may be enforced against it.

[40 CFR 71.7(e)(1)(v)]

5. The permit shield under §71.6(f) may not extend to minor permit modifications.

[40 CFR 71.7(e)(1)(vi)]

IV.J. <u>Group Processing of Minor Permit Modifications</u> [40 CFR 71.7(e)(2)]

1. Group processing of modifications by EPA may be used only for those permit modifications:

    (a) That meet the criteria for minor permit modification procedures under the Minor Permit Modifications section of this permit; and

    (b) That collectively are below the threshold level of 10 percent of the emissions allowed by the permit for the emissions unit for which the change is requested, 20 percent of the applicable definition of major source in §71.2, or 5 tons per year, whichever is least.

[40 CFR 71.7(e)(2)(i)]

2. An application requesting the use of group processing procedures shall be submitted to EPA, shall meet the requirements of §71.5(c), and shall include the following:

    (a) A description of the change, the emissions resulting from the change, and any new applicable requirements that will apply if the change occurs;

    (b) The source's suggested draft permit;

    (c) Certification by a responsible official, consistent with §71.5(d), that the proposed modification meets the criteria for use of group processing procedures and a request that such procedures be used;

    (d) A list of the source's other pending applications awaiting group processing, and a determination of whether the requested modification, aggregated with these other applications, equals or exceeds the threshold set under this section of this permit; and

    (e) Completed forms for the permitting authority to use to notify affected States as required under §71.8.

[40 CFR 71.7(e)(2)(ii)]

3. The source may make the change proposed in its minor permit modification application immediately after it files such application. After the source makes the change allowed by the preceding sentence, and until the permitting authority takes any of the actions authorized by §71.7(e)(1)(iv)(A) through (C), the source must comply with both the applicable requirements governing the change and the proposed permit terms and conditions. During this time period, the source need not comply with the existing permit terms and conditions it seeks to modify. However, if the source fails to comply with its proposed permit terms and conditions during this time period, the existing permit terms and conditions it seeks to modify may be enforced against it.

[40 CFR 71.7(e)(2)(v)]

4. The permit shield under §71.6(f) may not extend to group processing of minor permit modifications.

[40 CFR 71.7(e)(2)(vi)]

IV.K. <u>Significant Permit Modifications</u> [40 CFR 71.7(e)(3)]

1. The permittee must request the use of significant permit modification procedures for those modifications that:

   (a) Do not qualify as minor permit modifications or as administrative amendments;

   (b) Are significant changes in existing monitoring permit terms or conditions; or

   (c) Are relaxations of reporting or recordkeeping permit terms or conditions.

[40 CFR 71.7(e)(3)(i)]

2. Nothing herein shall be construed to preclude the permittee from making changes consistent with part 71 that would render existing permit compliance terms and conditions irrelevant.

[40 CFR 71.7(e)(3)(i)]

3. Permittees must meet all requirements of part 71 for applications, public participation, and review by affected states and tribes for significant permit modifications. For the application to be determined complete, the permittee must supply all information that is required by §71.5(c) for permit issuance and renewal, but only that information that is related to the proposed change.

[40 CFR 71.7(e)(3)(ii), 71.8(d), and 71.5(a)(2)]

IV.L. <u>Reopening for Cause</u> [40 CFR 71.7(f)]

The permit may be reopened and revised prior to expiration under any of the following circumstances:

1. Additional applicable requirements under the Act become applicable to a major part 71 source with a remaining permit term of 3 or more years. Such a reopening shall be completed not later than 18 months after promulgation of the applicable requirement. No

such reopening is required if the effective date of the requirement is later than the date on which the permit is due to expire, unless the original permit or any of its terms and conditions have been extended pursuant to §71.7 (c)(3);

2. Additional requirements (including excess emissions requirements) become applicable to an affected source under the acid rain program. Upon approval by the Administrator, excess emissions offset plans shall be deemed to be incorporated into the permit;

3. EPA determines that the permit contains a material mistake or that inaccurate statements were made in establishing the emissions standards or other terms or conditions of the permit; or

4. EPA determines that the permit must be revised or revoked to assure compliance with the applicable requirements.

IV.M. Property Rights [40 CFR 71.6(a)(6)(iv)]

This permit does not convey any property rights of any sort, or any exclusive privilege.

IV.N. Inspection and Entry [40 CFR 71.6(c)(2)]

Upon presentation of credentials and other documents as may be required by law, the permittee shall allow EPA or an authorized representative to perform the following:

1. Enter upon the permittee's premises where a part 71 source is located or emissions-related activity is conducted, or where records must be kept under the conditions of the permit;

2. Have access to and copy, at reasonable times, any records that must be kept under the conditions of the permit;

3. Inspect at reasonable times any facilities, equipment (including monitoring and air pollution control equipment), practices, or operations regulated or required under the permit; and

4. As authorized by the Clean Air Act, sample or monitor at reasonable times substances or parameters for the purpose of assuring compliance with the permit or applicable requirements.

IV.O. Emergency Provisions [40 CFR 71.6(g)]

1. In addition to any emergency or upset provision contained in any applicable requirement, the permittee may seek to establish that noncompliance with a technology-based emission limitation under this permit was due to an emergency. To do so, the permittee shall demonstrate the affirmative defense of emergency through properly signed, contemporaneous operating logs, or other relevant evidence that:

    (a) An emergency occurred and that the permittee can identify the cause(s) of the emergency;

(b) The permitted facility was at the time being properly operated;

(c) During the period of the emergency the permittee took all reasonable steps to minimize levels of emissions that exceeded the emissions standards, or other requirements in this permit; and

(d) The permittee submitted notice of the emergency to EPA within 2 working days of the time when emission limitations were exceeded due to the emergency. This notice must contain a description of the emergency, any steps taken to mitigate emissions, and corrective actions taken. This notice fulfills the requirements for prompt notification of deviations.

2. In any enforcement proceeding the permittee attempting to establish the occurrence of an emergency has the burden of proof.

3. An emergency means any situation arising from sudden and reasonably unforeseeable events beyond the control of the source, including acts of God, which situation requires immediate corrective action to restore normal operation, and that causes the source to exceed a technology-based emission limitation under the permit due to unavoidable increases in emissions attributable to the emergency. An emergency shall not include noncompliance to the extent caused by improperly designed equipment, lack of preventive maintenance, careless or improper operation, or operator error.

IV.P. <u>Transfer of Ownership or Operation</u> [40 CFR 71.7(d)(1)(iv)]

A change in ownership or operational control of this facility may be treated as an administrative permit amendment if the EPA determines no other change in this permit is necessary and provided that a written agreement containing a specific date for transfer of permit responsibility, coverage, and liability between the current and new permittee has been submitted to EPA.

IV.Q. <u>Off Permit Changes</u> [40 CFR 71.6(a)(12) and 40 CFR 71.6(a)(3)(ii)]

The permittee is allowed to make certain changes without a permit revision, provided that the following requirements are met, and that all records required by this section are kept on site at the source for a period of five (5) years:

1. Each change is not addressed or prohibited by this permit;

2. Each change shall meet all applicable requirements and shall not violate any existing permit term or condition;

3. Changes under this provision may not include changes subject to any requirement of 40 CFR parts 72 through 78 or modifications under any provision of title I of the CAA;

4. The permittee must provide contemporaneous written notice to EPA of each change, except for changes that qualify as insignificant activities under §71.5(c)(11). The written notice must describe each change, the date of the change, any change in emissions, pollutants emitted, and any applicable requirements that would apply as a result of the change;

5. The permit shield does not apply to changes made under this provision;

6. The permittee must keep a record describing all changes that result in emissions of any regulated air pollutant subject to any applicable requirement not otherwise regulated under this permit, and the emissions resulting from those changes; and

7. Replacement of a permitted turbine with a new or overhauled turbine of the same make, model, MMBtu/hr, and configured to operate in the same manner as the turbine being replaced, in addition to satisfying all other provisions for off permit changes, shall satisfy the following provisions:

    (a) The replacement turbine must employ air emissions control devices, monitoring, record keeping and reporting that are equivalent to those employed by the turbine being replaced;

    (b) The replacement of the existing turbine must not constitute a major modification or major new source as defined in Federal PSD regulations (40 CFR 52.21);

    (c) No new applicable requirements, as defined in 40 CFR 71.2, are triggered by the replacement; and

    (d) The following information is provided in a written notice to EPA in addition to the standard information listed above for contemporaneous written notices for off permit changes:

        (i) Make, model number, serial number, MMBtu/hr, and configuration of the permitted turbine and the replacement turbine;
        (ii) Manufacture date, commence construction date <u>(as defined in 40 CFR 60.2, 60.4230(a), and 63.2)</u>, and installation date of the replacement turbine at the facility;
        (iii) If applicable, documentation of the cost to rebuild a replacement turbine versus the cost to purchase a new turbine in order to support claims that a turbine is not "reconstructed," as defined in 40 CFR 60.15 and 63.2;
        (iv) 40 CFR part 60, subpart KKKK (New Turbine NSPS) non-applicability documentation;
        (v) 40 CFR part 63, subpart YYYY (Turbine MACT) non-applicability documentation; and
        (vi) Documentation to demonstrate that the replacement does not constitute a major new source or major modification, as defined in Federal PSD rules (40 CFR 52.21), as follows:

            (A) If the replacement will not constitute a "physical change or change in the method of operation" as described in §52.21(b)(2)(i), an explanation of how that conclusion was reached shall be provided.

            (B) If the replacement will constitute a "physical change or change in the method of operation" as described §52.21(b)(2)(i), the following information shall be provided:

(1) <u>If the existing source is a "major stationary source" as defined in §52.21(b)(1)</u>: For each "regulated NSR pollutant" as defined in §52.21(b)(50), a demonstration (including all calculations) that the replacement will not be a "major modification" as defined in §52.21(b)(2). A modification is major only if it causes a "significant emissions increase" as defined in §52.21(b)(40), and also causes a "significant net emissions increase" as defined in §§52.21(b)(3) and (b)(23).

The procedures of §52.21(a)(2)(iv) shall be used to calculate whether or not there will be a significant emissions increase. If there will be a significant emissions increase, then calculations shall be provided to demonstrate there will not be a significant <u>net</u> emissions increase. These latter calculations shall include all sourcewide contemporaneous and creditable emission increases and decreases, as defined in §52.21(b)(3), summed with the PTE of the replacement unit(s).

If netting is used to demonstrate that the replacement will not constitute a "major modification," verification shall be provided that the replacement engine(s) or turbine(s) employ emission controls at least equivalent in control effectiveness to those employed by the engine(s) or turbine(s) being replaced.

PTE of replacement unit(s) shall be determined based on the definition of PTE in §52.21(b)(4). For each "regulated NSR pollutant" for which the PTE is not "significant," calculations used to reach that conclusion shall be provided.

(2) <u>If the existing source is not a "major stationary source" as defined in §52.21(b)(1)</u>: For each "regulated NSR pollutant," a demonstration (including all calculations) that the replacement turbine(s), by itself, will not constitute a "major stationary source" as defined in §52.21(b)(1)(i).

8. For replacement of a permitted engine with an engine of the same make, model, horsepower rating, and configured to operate in the same manner as the engine being replaced, in addition to satisfying all other provisions for off permit changes, the permittee satisfies the following provisions:

(a) The replacement engine employs air emissions control devices, monitoring, record keeping and reporting that are equivalent to those employed by the engine being replaced;

(b) The replacement of the permitted engine does not constitute a major modification or major new source as defined in Federal PSD regulations (40 CFR 52.21);

(c) No new applicable requirements, as defined in 40 CFR 71.2, are triggered by the replacement; and

(d) The following information is provided in a written notice to EPA, contemporaneously with installation of the replacement engine, in addition to the standard information listed above for contemporaneous written notices for off permit changes:

(i) Make, model number, serial number, horsepower rating and configuration of the permitted engine and the replacement engine;
(ii) Manufacturer date, commence construction date (per the definitions in 40 CFR 60.2, 60.4230(a), and 63.2), and installation date of the replacement engine at the facility;
(iii) If applicable, documentation of the cost to rebuild a replacement engine versus the cost to purchase a new engine in order to support claims that an engine is not "reconstructed," as defined in 40 CFR 60.15 and 63.2;
(iv) 40 CFR part 60, subpart JJJJ (SI Engine NSPS) non-applicability documentation;
(v) 40 CFR part 63, subpart ZZZZ (RICE MACT) non-applicability documentation for major HAP sources;
(vi) 40 CFR part 63, subpart ZZZZ (RICE MACT) non-applicability documentation for area sources; and
(vii) Documentation to demonstrate that the replacement does not constitute a major new source or major modification, as defined in Federal PSD rules (40 CFR 52.21), as follows:

(A) If the replacement will not constitute a "physical change or change in the method of operation" as described in §52.21(b)(2)(i), an explanation of how that conclusion was reached shall be provided.

(B) If the replacement will constitute a "physical change or change in the method of operation" as described §52.21(b)(2)(i), the following information shall be provided:

(1) If the existing source is a "major stationary source" as defined in §52.21(b)(1): For each "regulated NSR pollutant" as defined in §52.21(b)(50), a demonstration (including all calculations) that the replacement will not be a "major modification" as defined in §52.21(b)(2). A modification is major only if it causes a "significant emissions increase" as defined in §52.21(b)(40), and also causes a "significant net emissions increase" as defined in §§52.21(b)(3) and (b)(23).

The procedures of §52.21(a)(2)(iv) shall be used to calculate whether or not there will be a significant emissions increase. If there will be a significant emissions increase, then calculations shall be provided to demonstrate there will not be a significant net emissions increase. These latter calculations shall include all sourcewide contemporaneous and creditable emission increases and decreases, as defined in §52.21(b)(3), summed with the PTE of the replacement unit(s).

If netting is used to demonstrate that the replacement will not constitute a "major modification," verification shall be provided that the replacement engine(s) or turbine(s) employ emission controls at least equivalent in control effectiveness to those employed by the engine(s) or turbine(s) being replaced.

PTE of replacement unit(s) shall be determined based on the definition of PTE in §52.21(b)(4). For each "regulated NSR pollutant" for which the PTE is not "significant," calculations used to reach that conclusion shall be provided.

(2) <u>If the existing source is not a "major stationary source" as defined in §52.21(b)(1)</u>: For each "regulated NSR pollutant," a demonstration (including all calculations) that the replacement engine(s), by itself, will not constitute a "major stationary source" as defined in §52.21(b)(1)(i).

9. The notice shall be kept on site at the source and made available to EPA on request, in accordance with the general recordkeeping provision of this permit.

10. Submittal of the written notice required above shall not constitute a waiver, exemption, or shield from applicability of any applicable standard or PSD permitting requirements under 40 CFR 52.21 that would be triggered by the replacement of any one turbine, by replacement of multiple turbines, by the replacement of any one engine, or by the replacement of multiple engines.

IV.R. <u>Permit Expiration and Renewal</u> [40 CFR 71.5(a)(1)(iii), 71.5(a)(2), 71.5(c)(5), 71.6(a)(11), 71.7(b), 71.7(c)(1), and 71.7(c)(3)]

1. This permit shall expire upon the earlier occurrence of the following events:

   (a) Five (5) years elapses from the date of issuance; or

   (b) The source is issued a part 70 or part 71 permit under an EPA approved or delegated permit program.

[40 CFR 71.6(a)(11)]

2. Expiration of this permit terminates the permittee's right to operate unless a timely and complete permit renewal application has been submitted at least 6 months but not more than 18 months prior to the date of expiration of this permit.

[40 CFR 71.5(a)(1)(iii)]

3. If the permittee submits a timely and complete permit application for renewal, consistent with §71.5(a)(2), but EPA has failed to issue or deny the renewal permit, then all the terms and conditions of the permit, including any permit shield granted pursuant to §71.6(f) shall remain in effect until the renewal permit has been issued or denied.

[40 CFR 71.7(c)(3)]

4. The permittee's failure to have a part 71 permit is not a violation of this part until EPA takes final action on the permit renewal application. This protection shall cease to apply if, subsequent to the completeness determination, the permittee fails to submit any additional information identified as being needed to process the application by the deadline specified in writing by EPA.

[40 CFR 71.7(b)]

5. Renewal of this permit is subject to the same procedural requirements that apply to initial permit issuance, including those for public participation, affected State, and tribal review.

[40 CFR 71.7(c)(1)]

6. The application for renewal shall include the current permit number, description of permit revisions and off permit changes that occurred during the permit term, any applicable requirements that were promulgated and not incorporated into the permit during the permit term, and other information required by the application form.

[40 CFR 71.5(a)(2) and 71.5(c)(5)]

V. Appendix

V.A. <u>Inspection Information</u>

1. Directions to compressor station:

   From the City of Durango, Colorado go southeast approximately 7 miles on U.S. Highway 160 towards Bayfield. Turn right at stop light onto State Highway 172. Travel south 2.3 miles towards Ignacio. Proceed 0.3 miles after the highway curves to the east, then take a right on County Road 307. Go south 4 miles. The Ignacio Receipt Meter Station is on the left-hand side of the road at the northwest corner of the Williams Ignacio Gas Processing Plant. The La Plata B Compressor Station is the second compressor station on the right just past a power substation. Pavement turns to gravel just after the compressor station.

2. Latitude and Longitude Coordinates

   Lat. 37.143669 Long. -107.787361

V.B. <u>Portable Analyzer Monitoring Protocol and Approval</u> - Attached

V.C. <u>Tariff Sheet for Gaseous Turbine Fuel</u> – Attached

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 8
1595 Wynkoop Street
DENVER, CO 80202-1129
Phone 800-227-8917
http://www.epa.gov/region08

Ref: 8ENF-AT

JAN 24 2008

Matt Armstrong
Environmental Specialist
Williams Gas Pipeline - Northwest
295 Chipeta Way MS 3P1
Salt Lake City, UT 84158

Re: Approval of Portable Analyzer Testing Protocol for LaPlata B Compressor Station

Dear Mr. Armstrong,

After reviewing the file for Northwestern's LaPlata B Compressor Station, the Environmental Protection Agency Region 8 (EPA) discovered that a portable analyzer protocol has not been approved and put in place for the facility. EPA contacted you to get an up to date protocol, as the protocol that was in the file was out of date. On January 15, 2008 you submitted an updated protocol. EPA approves the use of this protocol (enclosed) for use at the LaPlata B Compressor Station. If you have any questions concerning our response, please contact Joshua Rickard of my staff at 303-312-6460.

Sincerely,

Cynthia J. Reynolds

Cynthia J. Reynolds, Director
Technical Enforcement Program

STATE OF COLORADO
PORTABLE ANALYZER MONITORING PROTOCOL

Colorado Department of Public Health and Environment

Determination of Nitrogen Oxides, Carbon Monoxide and Oxygen Emissions from Natural Gas-Fired Reciprocating Engines, Combustion Turbines, Boilers, and Process Heaters Using Portable Analyzers

Version - March 2006

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1. APPLICABILITY AND PRINCIPLE

1.1 Background. This protocol is based on the Gas Research Institute Method GRI-96/0008, EMC Conditional Test Method (CTM-030). The original version of this method can be found on the EPA Website at: http://www.epa.gov/ttn/emc/ctm.html. The State of Colorado adopted this method into the State of Colorado Portable Analyzer Monitoring Protocol to ensure quality data is captured while performing periodic monitoring.

1.2 Applicability. This method is applicable for the determination of nitrogen oxides (NO and NO_2), carbon monoxide (CO), and oxygen (O_2) concentrations of controlled and uncontrolled emissions from natural gas-fired reciprocating engines, combustion turbines, boilers, and process heaters using portable analyzers with electrochemical cells. The use of reference method equivalent analyzers is acceptable provided the appropriate reference method procedures in 40 CFR 60, Appendix A are used. Due to the inherent cross sensitivities of the electrochemical cells, this method is not applicable to other pollutants.

1.3 Principle. A gas sample is continuously extracted from a stack and conveyed to a portable analyzer for determination of NO, NO_2, CO, and O_2 gas concentrations using electrochemical cells. Analyzer design specifications, performance specifications, and test procedures are provided to ensure reliable data. Additions to or modifications of vendor-supplied analyzers (e.g. heated sample line, flow meters, etc.) may be required to meet the design specifications of this test method.

2. RANGE AND SENSITIVITY

2.1 Analytical Range. The analytical range for each gas component is determined by the electrochemical cell design. A portion of the analytical range is selected to be the nominal range by choosing a span gas concentration near the flue gas concentrations or permitted emission level in accordance with Sections 2.1.1, 2.1.2 and 2.1.3.

2.1.1 **CO and NO Span Gases.** Choose a span gas concentration such that the average stack gas reading for each test is greater than 25 percent of the span gas concentration. Alternatively, choose the span gas such that it is not greater than twice the concentration equivalent to the emission standard. If concentration results exceed 125 percent of the span gas at any time during the test, then the test for that pollutant is invalid.

2.1.2 **NO_2 Span Gas.** Choose a span gas concentration such that the average stack gas reading for each test is greater than 25 percent of the span gas concentration. Alternatively, choose the span gas concentration such that it is not greater than the ppm concentration value of the NO span gas. The tester should be aware NO_2 cells are generally designed to measure much lower concentrations than NO cells and the span gas should be chosen accordingly. If concentration results exceed 125 percent of the span gas at any time during the test, then the test for that pollutant is invalid.

2.1.3 **O_2 Span Gas.** The O_2 span gas shall be dry ambient air at 20.9% O_2.

3. DEFINITIONS

3.1 **Measurement System.** The total equipment required for the determination of gas concentration. The measurement system consists of the following major subsystems:

3.1.1 **Sample Interface.** That portion of a system used for one or more of the following: sample acquisition, sample transport, sample conditioning, or protection of the electrochemical cells from particulate matter and condensed moisture.

3.1.2 **External Interference Gas Scrubber.** A tube filled with scrubbing agent used to remove interfering compounds upstream of some electrochemical cells.

3.1.3 **Electrochemical (EC) Cell.** That portion of the system that senses the gas to be measured and generates an output proportional to its concentration. Any cell that uses diffusion-limited oxidation and reduction reactions to produce an electrical potential between a sensing electrode and a counter electrode.

3.1.4 **Data Recorder.** It is recommended that the analyzers be equipped with a strip chart recorder, computer, or digital recorder for recording measurement data. However, the operator may record the test results manually in accordance with the requirements of Section 7.5.

3.2 **Nominal Range.** The range of concentrations over which each cell is operated (25 to 125 percent of span gas value). Several nominal ranges may be used for any given cell as long as the linearity and stability check results remain within specification.

3.3 **Span Gas.** The high level concentration gas chosen for each nominal range.

3.4 **Zero Calibration Error.** The absolute value of the difference, expressed as a percent of the span gas, between the gas concentration exhibited by the gas analyzer when a zero level calibration gas is introduced to the analyzer and the known concentration of the zero level calibration gas.

3.5 **Span Calibration Error.** The absolute value of the difference, expressed as a percent of the span gas, between the gas concentration exhibited by the gas analyzer when a span gas is introduced to the analyzer and the known concentration of the span gas.

3.6 **Response Time.** The amount of time required for the measurement system to display 95 percent of a step change in the NO or CO gas concentration on the data recorder (90 percent of a step change for NO_2).

3.7 **Interference Check.** A method of quantifying analytical interferences from components in the stack gas other than the analyte.

3.8 **Linearity Check.** A method of demonstrating the ability of a gas analyzer to respond consistently over a range of gas concentrations.

3.9 **Stability Check.** A method of demonstrating an electrochemical cell operated over a given nominal range provides a stable response and is not significantly affected by prolonged exposure to the analyte.

3.10 **Stability Time.** As determined during the stability check; the elapsed time from the start of the gas injection until a stable reading has been achieved.

3.11 **Initial NO Cell Temperature.** The temperature of the NO cell during the pretest calibration error check. Since the NO cell can experience significant zero drift with cell temperature changes in some situations, the cell temperature must be monitored if the analyzer does not display negative concentration results. Alternatively, manufacturer's documentation may be submitted showing the analyzer incorporates a NO cell temperature control and temperature exceedance warning system.

3.12 **Test.** The collection of emissions data from a source for an equal amount of time at each sample point and for a minimum of 21 minutes total.

4. MEASUREMENT SYSTEM PERFORMANCE SPECIFICATIONS

4.1 **Zero Calibration Error.** Less than or equal to ±3 percent of the span gas value for NO, NO_2, and CO channels and less than or equal to ±0.3 percent O_2 for the O_2 channel.

4.2 **Span Calibration Error.** Less than or equal to ±5 percent of the span gas value for NO, NO_2, and CO channels and less than or equal to ±0.5 percent O_2 for the O_2 channel.

4.3 **Interference Response.** The CO and NO interference responses must be less than or equal to 5 percent as calculated in accordance with Section 7.7.

4.4 **Linearity.** For the zero, mid-level, and span gases, the absolute value of the difference, expressed as a percent of the span gas, between the gas value and the analyzer response shall not be greater than 2.5 percent for NO, CO and O_2 cells and not greater than 3.0 percent for NO_2 cells.

4.5 **Stability Check Response.** The analyzer responses to CO, NO, and NO_2 span gases shall not vary more than 3.0 percent of span gas value over a 30-minute period or more than 2.0 percent of the span gas value over a 15-minute period.

4.6 **CO Measurement, Hydrogen (H_2) Compensation.** It is recommended that CO measurements be performed using a hydrogen-compensated EC cell since CO-measuring EC cells can experience significant reaction to the presence of H_2 in the gas stream. Sampling systems equipped with a scrubbing agent prior to the CO cell to remove H_2 interferent gases may also be used.

5. APPARATUS AND REAGENTS

5.1 **Measurement System.** Use any measurement system that meets the performance and design specifications in Sections 4 and 5 of this method. The sampling system shall maintain the gas sample at a temperature above the dew point up to the moisture removal system. The sample conditioning system shall be designed so there are no entrained water droplets in the gas sample when it contacts the electrochemical cells. The essential components of the measurement system are described below:

5.1.1 **Sample Probe.** Glass, stainless steel, or other nonreactive material, of sufficient length to sample per the requirements of Section 7. If necessary to prevent condensation, the sampling probe shall be heated.

5.1.2 **Heated Sample Line.** Heated (sufficient to prevent condensation) nonreactive tubing such as teflon, stainless steel, glass, etc. to transport the sample gas to the moisture removal system. (Includes any particulate filters prior to the moisture removal system.)

5.1.3 **Sample Transport Lines.** Nonreactive tubing such as teflon, stainless steel, glass, etc. to transport the sample from the moisture removal system to the sample pump, sample flow rate control, and electrochemical cells.

5.1.4 **Calibration Assembly.** A tee fitting to attach to the probe tip or where the probe attaches to the sample line for introducing calibration gases at ambient pressure during the calibration error checks. The vented end of the tee should have a flow indicator to ensure sufficient calibration gas flow. Alternatively, use any other method that introduces calibration gases at the probe at atmospheric pressure.

5.1.5 **Moisture Removal System.** A chilled condenser or similar device (e.g., permeation dryer) to remove condensate continuously from the sample gas while maintaining minimal contact between the condensate and the sample gas.

5.1.6 **Particulate Filter.** Filters at the probe or the inlet or outlet of the moisture removal system and inlet of the analyzer may be used to prevent accumulation of particulate material in the measurement system and extend the useful life of the components. All filters shall be fabricated of materials that are nonreactive to the gas being sampled.

5.1.7 **Sample Pump.** A leak-free pump to pull the sample gas through the system at a flow rate sufficient to minimize the response time of the measurement system. The pump may be constructed of any material that is nonreactive to the gas being sampled.

5.1.8 **Sample Flow Rate Control.** A sample flow rate control valve and rotameter, or equivalent, to maintain a constant sampling rate within 10 percent during sampling and calibration error checks. The components shall be fabricated of materials that are nonreactive to the gas being sampled.

5.1.9 **Gas Analyzer.** A device containing electrochemical cells to determine the NO, NO_2, CO, and O_2 concentrations in the sample gas stream and, if necessary, to correct for interference effects. The analyzer shall meet the applicable performance specifications of Section 4. A means of controlling the analyzer flow rate and a device for determining proper sample flow rate (e.g., precision rotameter, pressure gauge downstream of all flow controls, etc.) shall be provided at the analyzer. (Note: Housing the analyzer in a clean, thermally-stable, vibration-free environment will minimize drift in the analyzer calibration, but this is not a requirement of the method.)

5.1.10 **Data Recorder.** A strip chart recorder, computer, or digital recorder, for recording data. The data recorder resolution (i.e., readability) shall be at least 1 ppm for CO, NO, and NO_2; 0.1 percent O_2 for O_2; and one degree (C or F) for temperature.

5.1.11 **External Interference Gas Scrubber.** Used by some analyzers to remove interfering compounds upstream of a CO electrochemical cell. The scrubbing agent should be visible and should have a means of determining when the agent is exhausted (e.g., color indication).

5.1.12 **NO Cell Temperature Indicator.** A thermocouple, thermistor, or other device must be used to monitor the temperature of the NO electrochemical cell. The temperature may be monitored at the surface of the cell, within the cell or in the cell compartment. Alternatively, manufacturer's documentation may be submitted showing the analyzer incorporates a NO cell temperature control and temperature exceedance warning system.

5.1.13 **Dilution Systems.** The use of dilution systems will be allowed with prior approval of the Air Pollution Control Division.

5.2 **Calibration Gases.** The CO, NO, and NO_2 calibration gases for the gas analyzer shall be CO in nitrogen or CO in nitrogen and O_2, NO in nitrogen, and NO_2 in air or nitrogen. The mid-level O_2 gas shall be O_2 in nitrogen.

5.2.1 **Span Gases.** Used for calibration error, linearity, and interference checks of each nominal range of each cell. Select concentrations according to procedures in Section 2.1. Clean dry air may be used as the span gas for the O_2 cell as specified in Section 2.1.3.

5.2.2 **Mid-Level Gases.** Select concentrations that are 40-60 percent of the span gas concentrations.

5.2.3 **Zero Gas.** Concentration of less than 0.25 percent of the span gas for each component. Ambient air may be used in a well ventilated area for the CO, NO, and NO_2 zero gases.

6. **MEASUREMENT SYSTEM PERFORMANCE CHECK PROCEDURES.** Perform the following procedures before the measurement of emissions under Section 7.

6.1 **Calibration Gas Concentration Certification.** For the mid-level and span cylinder gases, use calibration gases certified according to EPA Protocol 1 procedures. Calibration gases must meet the criteria under 40 CFR 60, Appendix F, Section 5.1.2 (3). Expired Protocol 1 gases may be recertified using the applicable reference methods.

6.2 **Linearity Check.** Conduct the following procedure once for each nominal range to be used on each electrochemical cell (NO, NO_2, CO, and O_2). After a linearity check is completed, it remains valid for five consecutive calendar days. After the five calendar day period has elapsed, the linearity check must be performed again. Additionally, perform the linearity check again if the cell is replaced. (If the stack NO_2 concentration is less than 5% of the stack NO concentration as determined using the emission test procedures under Section 7, the NO_2 linearity check is not required. However, the NO_2 cell shall be calibrated in accordance with the manufacturer's instructions, the pretest calibration error check and post test calibration error check shall be conducted in accordance with Section 7, and the test results shall be added to the NO test values to obtain a total NO_X concentration.)

6.2.1 **Linearity Check Gases.** For each cell obtain the following gases: zero (0-0.25 percent of nominal range), mid-level (40-60 percent of span gas concentration), and span gas (selected according to Section 2.1).

6.2.2 Linearity Check Procedure. If the analyzer uses an external interference gas scrubber with a color indicator, using the analyzer manufacturer's recommended procedure, verify the scrubbing agent is not depleted. After calibrating the analyzer with zero and span gases, inject the zero, mid-level, and span gases appropriate for each nominal range to be used on each cell. Gases need not be injected through the entire sample handling system. Purge the analyzer briefly with ambient air between gas injections. For each gas injection, verify the flow rate is constant and the analyzer responses have stabilized before recording the responses on a data sheet similar to that in Appendix A.

6.3 Interference Check. A CO cell response to the NO and NO_2 span gases or an NO cell response to the NO_2 span gas during the linearity check may indicate interferences. If these cell responses are observed during the linearity check, it may be desirable to quantify the CO cell response to the NO and NO_2 span gases and the NO cell response to the NO_2 span gas during the linearity check and use estimated stack gas CO, NO and NO_2 concentrations to evaluate whether or not the portable analyzer will meet the post test interference check requirements of Section 7.7. This evaluation using the linearity check data is optional. However, the interference checks under Section 7.7 are mandatory for each test.

6.4 Stability Check. Conduct the following procedure once for the maximum nominal range to be used on each electrochemical cell (NO, NO_2 and CO). After a stability check is completed, it remains valid for five consecutive calendar days. After the five calendar day period has elapsed, the stability check must be performed again. Additionally, perform the stability check again if the cell is replaced or if a cell is exposed to gas concentrations greater than 125 percent of the highest span gas concentration. (If the stack NO_2 concentration is less than 5% of the stack NO concentration as determined using the emission test procedures under Section 7, the NO_2 stability check is not required. However, the NO_2 cell shall be calibrated in accordance with the manufacturer's instructions, the pretest calibration error check and post test calibration error check shall be conducted in accordance with Section 7, and the test results shall be added to the NO test values to obtain a total NO_X concentration.)

6.4.1 **Stability Check Procedure.** Inject the span gas for the maximum nominal range to be used during the emission testing into the analyzer and record the analyzer response at least once per minute until the conclusion of the stability check. One-minute average values may be used instead of instantaneous readings. After the analyzer response has stabilized, continue to flow the span gas for at least a 30-minute stability check period. Make no adjustments to the analyzer during the stability check except to maintain constant flow. Record the stability time as the number of minutes elapsed between the start of the gas injection and the start of the 30-minute stability check period. As an alternative, if the concentration reaches a peak value within five minutes, you may choose to record the data for at least a 15-minute stability check period following the peak.

6.4.2 **Stability Check Calculations.** Determine the highest and lowest concentrations recorded during the 30-minute period and record the results on a data sheet similar to that in Appendix B. The absolute value of the difference between the maximum and minimum values recorded during the 30-minute period must be less than 3.0 percent of the span gas concentration. Alternatively, record stability check data in the same manner for the 15-minute period following the peak concentration. The difference between the maximum and minimum values for the 15-minute period must be less than 2.0 percent of the span gas concentration.

7. **EMISSION TEST PROCEDURES.** Prior to performing the following emission test procedures, calibrate/challenge all electrochemical cells in the analyzer in accordance with the manufacturer's instructions.

7.1 **Selection of Sampling Site and Sampling Points.**

7.1.1 **Reciprocating Engines.** Select a sampling site located at least two stack diameters downstream of any disturbance (e.g., turbocharger exhaust, crossover junction, or recirculation take-offs) and one half stack diameter upstream of the gas discharge to the atmosphere or any disturbance. Use a sampling location at a single point near the center of the duct.

7.1.2 **Combustion Turbines.** Select a sampling site and sample points according to the procedures in 40 CFR 60, Appendix A, Method 20. Alternatively, the tester may choose an alternative sampling location and/or sample from a single point in the center of the duct if previous test data demonstrate the stack gas concentrations of CO, NO_X, and O_2 do not vary significantly across the duct diameter.

7.1.3 **Boilers/Process Heaters.** Select a sampling site located at least two stack diameters downstream of any disturbance and one half stack diameter upstream of the gas discharge to the atmosphere or any disturbance. Use a sampling location at a single point near the center of the duct.

7.2 **Warm Up Period.** Assemble the sampling system and allow the analyzer and sample interface to warm up and adjust to ambient temperature at the location where the stack measurements will take place.

7.3 **Pretest Calibration Error Check.** Conduct a zero and span calibration error check before testing each new source. Conduct the calibration error check near the sampling location just prior to the start of an emissions test. Keep the analyzer in the same location until the post test calibration error check is conducted.

7.3.1 **Scrubber Inspection.** For analyzers that use an external interference gas scrubber tube, inspect the condition of the scrubbing agent and ensure it will not be exhausted during sampling. If scrubbing agents are recommended by the manufacturer, they should be in place during all sampling, calibration and performance checks.

7.3.2 **Zero and Span Procedures.** Inject the zero and span gases using the calibration assembly. Ensure the calibration gases flow through all parts of the sample interface. During this check, make no adjustments to the system except those necessary to achieve the correct calibration gas flow rate at the analyzer. Set the analyzer flow rate to the value recommended by the analyzer manufacturer. Allow each reading to stabilize before recording the result on a data sheet similar to that in Appendix C. The time allowed for the span gas to stabilize shall be no less than the stability time noted during the stability check. After achieving a stable response, disconnect the gas and briefly purge with ambient air.

7.3.3 **Response Time Determination.** Determine the NO and CO response times by observing the time required to respond to 95 percent of a step change in the analyzer response for both the zero and span gases. Note the longer of the two times as the response time. For the NO_2 span gas record the time required to respond to 90 percent of a step change.

7.3.4 **Failed Pretest Calibration Error Check.** If the zero and span calibration error check results are not within the specifications in Section 4, take corrective action and repeat the calibration error check until acceptable performance is achieved.

7.4 **NO Cell Temperature Monitoring.** Record the initial NO cell temperature during the pretest calibration error check on a data sheet similar to that in Appendix C and monitor and record the temperature regularly (at least once each 7 minutes) during the sample collection period. If at any time during sampling, the NO cell temperature is 85 degrees F or greater and has increased or decreased by more than 5 degrees F since the pretest calibration, stop sampling immediately and conduct a post test calibration error check per Section 7.6, re-zero the analyzer, and then conduct another pretest calibration error check per Section 7.3 before continuing. (It is recommended that testing be discontinued if the NO cell exceeds 85 degrees F since the design characteristics of the NO cell indicate a significant measurement error can occur as the temperature of the NO cell increases above this temperature. From a review of available data, these errors appear to result in a positive bias of the test results.)

Alternatively, manufacturer's documentation may be submitted showing the analyzer is configured with an automatic temperature control system to maintain the cell temperature below

85 degrees F (30 degrees centigrade) and provides automatic temperature reporting any time this temperature is exceeded. If automatic temperature control/exceedance reporting is used, test data collected when the NO cell temperature exceeds 85 degrees F is invalid.

7.5 **Sample Collection.** Position the sampling probe at the first sample point and begin sampling at the same rate used during the calibration error check. Maintain constant rate sampling (± 10 percent of the analyzer flow rate value used in Section 7.3.2) during the entire test. Sample for an equal period of time at each sample point. Sample the stack gas for at least twice the response time or the period of the stability time, whichever is greater, before collecting test data at each sample point. A 21 minute period shall be considered a test for each source. When sampling combustion turbines per Section 7.1.2, collect test data as required to meet the requirements of 40 CFR 60, Appendix A, Method 20. Data collection should be performed for an equal amount of time at each sample point and for a minimum of 21 minutes total. The concentration data must be recorded either (1) at least once each minute, or (2) as a block average for the test using values sampled at least once each minute. Do not break any seals in the sample handling system until after the post test calibration error check (this includes opening the moisture removal system to drain condensate).

7.6 **Post Test Calibration Error Check.** Immediately after the test, conduct a zero and span calibration error check using the procedure in Section 7.3. Conduct the calibration error check at the sampling location. Make no changes to the sampling system or analyzer calibration until all of the calibration error check results have been recorded. If the zero or span calibration error exceeds the specifications in Section 4, then all test data collected since the previous calibration error check are invalid. If the sampling system is disassembled or the analyzer calibration is adjusted, repeat the pretest calibration error check before conducting the next test.

7.7 **Interference Check.** Use the post test calibration error check results and average emission concentrations for the test to calculate interference responses (I_{NO} and I_{CO}) for the CO and NO cells. If an interference response exceeds 5 percent, all emission test results since the last successful interference test for that compound are invalid.

7.7.1 CO Interference Response.

$$I_{CO} = [(\frac{R_{CO-NO}}{C_{NOG}})(\frac{C_{NOS}}{C_{COS}}) + (\frac{R_{CO-NO_2}}{C_{NO_2G}})(\frac{C_{NO_2S}}{C_{COS}})]x100$$

where:

	I_{CO}	= CO interference response (percent)
	R_{CO-NO}	= CO response to NO span gas (ppm CO)
	C_{NOG}	= concentration of NO span gas (ppm NO)
	C_{NOS}	= concentration of NO in stack gas (ppm NO)
	C_{COS}	= concentration of CO in stack gas (ppm CO)
	R_{CO-NO2}	= CO response to NO_2 span gas (ppm CO)
	C_{NO2G}	= concentration of NO_2 span gas (ppm NO_2)
	C_{NO2S}	= concentration of NO_2 in stack gas (ppm NO_2)

7.7.2 NO Interference Response.

$$I_{NO} = (\frac{R_{NO-NO_2}}{C_{NO_2G}})(\frac{C_{NO_2S}}{C_{NO_xS}})x100$$

where:

	I_{NO}	= NO interference response (percent)
	R_{NO-NO2}	= NO response to NO_2 span gas (ppm NO)
	C_{NO2G}	= concentration of NO_2 span gas (ppm NO_2)
	C_{NO2S}	= concentration of NO_2 in stack gas (ppm NO_2)
	C_{NOxS}	= concentration of NO_X in stack gas (ppm NO_X)

7.8 Re-Zero. At least once every three hours, recalibrate the analyzer at the zero level according to the manufacturer's instructions and conduct a pretest calibration error check before resuming sampling. If the analyzer is capable of reporting negative concentration data (at least 5 percent of the span gas below zero), then the tester is not required to re-zero the analyzer.

8. **DATA COLLECTION.** This section summarizes the data collection requirements for this protocol.

8.1 **Linearity Check Data.** Using a data sheet similar to that in Appendix A, record the analyzer responses in ppm NO, NO_2, and CO, and percent O_2 for the zero, mid-level, and span gases injected during the linearity check under Section 6.2.2. To evaluate any interferences, record the analyzer responses in ppm CO to the NO and NO_2 span gases and the analyzer response in ppm NO to the NO_2 span gas. Calculate the CO and NO interference responses using the equations under Sections 7.7.1 and 7.7.2, respectively, and estimated stack gas CO, NO and NO_2 concentrations.

8.2 **Stability Check Data.** Record the analyzer response at least once per minute during the stability check under Section 6.4.1. Use a data sheet similar to that in Appendix B for each pollutant (NO, NO_2, and CO). One-minute average values may be used instead of instantaneous readings. Record the stability time as the number of minutes elapsed between the start of the gas injection and the start of the 30-minute stability check period. If the concentration reaches a peak value within five minutes of the gas injection, you may choose to record the data for at least a 15-minute stability check period following the peak. Use the information recorded to determine the analyzer stability under Section 6.4.2.

8.3 **Pretest Calibration Error Check Data.** On a data sheet similar to that in Appendix C, record the analyzer responses to the zero and span gases for NO, NO_2, CO, and O_2 injected prior to testing each new source. Record the calibration zero and span gas concentrations for NO, NO_2, CO, and O_2. Record the absolute difference between the analyzer response and the calibration gas concentration, divide by the span gas concentration, and multiply by 100 to obtain the percent of span. Record whether the calibration is valid by comparing the percent of span with the specifications under Section 4.1 for the zero calibrations and Section 4.2 for the span calibrations. Record the response times for the NO, CO, and NO_2 zero and span gases as described under Section 7.3.3. Select the longer of the two times for each pollutant as the response time for that pollutant. Record the NO cell temperature during the pretest calibration.

8.4 **Test Data.** Record the source operating parameters during the test. Record the test start and end times. Record the NO cell temperature after one third of the test (e.g., after seven minutes) and after two thirds of the test (e.g., after 14 minutes). From the analyzer responses recorded each minute during the test, obtain the average flue gas concentration of each pollutant. These are the uncorrected test results.

8.5 **Post Test Calibration Error Check Data.** On a data sheet similar to that in Appendix C, record the analyzer responses to the zero and span gases for NO, NO_2, CO, and O_2 injected immediately after the test. To evaluate any interferences, record the analyzer responses in ppm CO to the NO and NO_2 span gases and the analyzer response in ppm NO to the NO_2 span gas. Record the calibration zero and span gas concentrations for NO, NO_2, CO, and O_2. Record the absolute difference between the analyzer response and the calibration gas concentration, divide by the span gas concentration, and multiply by 100 to obtain the percent of span. Record whether the calibration is valid by comparing the percent of span with the specifications under Section 4.1 for the zero calibrations and Section 4.2 for the span calibrations. (If the pretest and post test calibration error check results are not within the limits specified in Sections 4.1 and 4.2, data collected during the test is invalid and the test must be repeated.) Record the NO cell temperature during the post test calibration. Calculate the average of the monitor readings during the pretest and post test calibration error checks for the zero and span gases for NO, NO_2, CO, and O_2. The pretest and post test calibration error check results are used to make the calibration corrections under Section 9.1. Calculate the CO and NO interference responses using the equations under Sections 7.7.1 and 7.7.2, respectively and measured stack gas CO, NO and NO_2 concentrations.

8.6 **Corrected Test Results.** Correct the test results using the equation under Section 9.1. Add the corrected NO and NO_2 concentrations together to obtain the corrected NO_X concentration. Calculate the emission rates using the equations under Section 10 for comparison with the emission limits. Record the results and sign a certification regarding the accuracy and representation of the emissions from the source.

9. CALIBRATION CORRECTIONS

9.1 Emission Data Corrections. Emissions data shall be corrected for a test using the following equation. (Note: If the pretest and post test calibration error check results are not within the limits specified in Sections 4.1 and 4.2, the test results are invalid and the test must be repeated.)

$$C_{Corrected} = (C_R - C_O)\frac{C_{MA}}{C_M - C_O}$$

where: $C_{Corrected}$ = corrected flue gas concentration (ppm)
C_R = flue gas concentration indicated by gas analyzer (ppm)
C_o = average of pretest and post test analyzer readings during the zero checks (ppm)
C_M = average of pretest and post test analyzer readings during the span checks (ppm)
C_{MA} = actual concentration of span gas (ppm)

10. EMISSION CALCULATIONS

10.1 Emission Calculations for Reciprocating Engines and Combustion Turbines. Emissions shall be calculated and reported in units of the allowable emission limit as specified in the permit. The allowable may be stated in pounds per hour (lb/hr) or tons per year (ton/yr), or both. EPA Reference Method 19 shall be used as the basis for calculating the emissions. As an alternative, EPA Reference Methods 1-4 may be used to obtain a stack volumetric flow rate.

10.1.1 Reciprocating Engines and Combustion Turbines Equipped with Fuel Meters. EPA Reference Method 19 and heat input per hour (MMBtu/hr) shall be used to calculate a pound per hour emission rate. A ton per year emission rate shall be calculated by multiplying the pound per hour emission rate by 8760 hours, divided by 2000 pounds per ton. If the hours of operation of the unit are limited by a permit limit, the tons per year shall be calculated using the number of hours the unit is limited to. Heat input per hour shall be based on the average hourly fuel usage rate during the test and the higher heating value of the fuel consumed. The emission rates shall be calculated using the following equations.

$$lb/hr\,CO = (ppm\,CO_{corrected})(7.27x10^{-8})(F\,Factor_{Note1})(\frac{20.9}{20.9 - O_2\%_{corrected}})(Heat\,Input\,Per\,Hour_{Note2})$$

$$lb/hr\,NO_X = (ppm\,NO_{X_{corrected}})(1.19x10^{-7})(F\,Factor_{Note1})(\frac{20.9}{20.9 - O_2\%_{corrected}})(Heat\,Input\,Per\,Hour_{Note2})$$

$$ton/yr\,CO = \frac{(lb/hr\,CO)(8760\,hours/year)}{2000\,lb/ton}$$

$$ton/yr\,NOx = \frac{(lb/hr\,NOx)(8760\,hours/year)}{2000\,lb/ton}$$

Note 1 - Use 8710 dscf/MMBtu unless calculated based on actual fuel gas composition and higher heating value of the fuel.

Note 2 - Heat input per hour (MMBtu/hr) shall be based on the average hourly fuel usage during the test and the higher heating value of the fuel consumed.

If the combustion turbine horsepower cannot be calculated during the testing, the emissions shall be reported in terms of concentration (ppm by volume, dry basis) corrected to 15 percent O_2. Compliance with the concentrations corrected to 15 percent O_2 as submitted in the air quality permit application and/or set as an allowable in the permit will demonstrate compliance with the gm/hp-hr allowable. Use the following equations to correct the concentrations to 15 percent O_2.

$$ppm\,CO_{@15\%O_2} = ppm\,CO_{corrected}(\frac{5.9}{20.9 - O_2\%_{corrected}})$$

$$ppm\,NO_{X_{@15\%O_2}} = ppm\,NO_{X_{corrected}}(\frac{5.9}{20.9 - O_2\%_{corrected}})$$

10.1.2 Reciprocating Engines Not Equipped with Fuel Meters. If reciprocating engines are not equipped with fuel flow meters during the test, emissions shall be calculated using the default specific fuel consumption factors, based on the higher heating value of the fuel, of 9,400 Btu/hp-hr for 4-cycle engines (controlled and uncontrolled) and 2-cycle lean burn engines and 11,000 Btu/hp-hr for 2-cycle uncontrolled (non-lean burn) engines. The following equations shall be used to calculate emissions.

$$lb/MMBtu\ NO_X = (ppm\ NO_{X\ corrected})(1.19x10^{-7})(F\ Factor_{Note\ 1})(\frac{20.9}{20.9 - O_2\%_{corrected}})$$

$$lb/MMBtu\ CO = (ppm\ CO_{corrected})(7.27x10^{-8})(F\ Factor_{Note\ 1})(\frac{20.9}{20.9 - O_2\%_{corrected}})$$

$$lb/hr\ NO_X = (lb/MMBtu\ NO_X)(Heat\ Input_{Note\ 2})$$

$$lb/hr\ CO = (lb/MMBtu\ CO)(Heat\ Input_{Note\ 2})$$

$$ton/yrNOx = \frac{(lb/hrNOx)(8760hours/year)}{2000lb/ton}$$

$$ton/yrCO = \frac{(lb/hrCO)(8760hours/year)}{2000lb/ton}$$

Note 1 - Use 8710 dscf/MMBtu unless calculated based on actual fuel gas composition and higher heating value of the fuel.

Note 2 - Default Specific Fuel Consumption (Btu/hp-hr) shall be as defined above for the particular type of engine tested.

10.2 Emission Calculations for Heaters/Boilers. For heaters and boilers, pound per million Btu (lb/MMBtu) emission rates shall be calculated based on EPA Reference Method 19. The pound per million Btu emission rates shall be converted to pound per hour emission rates using heat input per hour (MMBtu/hr). The heat input per hour shall be calculated using the average hourly fuel usage rate during test and the higher heating value of the fuel consumed or the permitted maximum heat input per hour for the boiler or heater. If a fuel meter is used to obtain heat input per hour data, the fuel meter shall be maintained and calibrated according to the manufacturer's recommendations. Records of all maintenance and calibrations shall be kept for five years. As an alternative, EPA Reference Methods 1-4 may be used to obtain a stack volumetric flow rate. The following equations shall be used to calculate emission rates.

$$lb/MMBtu\ NO_X = (ppm\ NO_{X\ corrected})(1.19x10^{-7})(F\ Factor_{Note\ 1})(\frac{20.9}{20.9 - O_2\%_{corrected}})$$

$$lb/MMBtu\ CO = (ppm\ CO_{corrected})(7.27x10^{-8})(F\ Factor_{Note\ 1})(\frac{20.9}{20.9 - O_2\%_{corrected}})$$

$$lb/hr\ NO_X = (lb/MMBtu\ NO_X)(Heat\ Input_{Note\ 2})$$

$$lb/hr\ CO = (lb/MMBtu\ CO)(Heat\ Input_{Note\ 2})$$

$$ton/yrCO = \frac{(lb/hrCO)(8760hours/year)}{2000lb/ton}$$

$$ton/yrNOx = \frac{(lb/hrNOx)(8760hours/year)}{2000lb/ton}$$

Note 1 - Use 8710 dscf/MMBtu unless calculated based on actual fuel gas composition and the higher heating value of the fuel.

Note 2 - Heat input shall be based on the average hourly fuel usage rate during the test and the higher heating value of the fuel consumed if the boiler/heater is equipped with a fuel meter or the permitted maximum heat input if a fuel meter is not available.

11. REPORTING REQUIREMENTS AND RECORD KEEPING REQUIREMENTS

Test reports shall be kept onsite for five (5) years and made available upon request by the Division. Test reports shall include the following:

- **Appendix A, Linearity Check Data Sheet,**
- **Appendix B, Stability Check Data Sheet,**
- **Appendix C, Calibration Error Check Data Sheet**
- Results of the test shall be reported in the unit of standard as written in applicable permit.
- Operating parameters at which the unit was operating at during the test.
- If the manufacturer's specific fuel consumption is used, documentation from the manufacturer shall be included in the report.

Records pertaining to the information above and supporting documentation shall be kept for five (5) years and made available upon request by the Division. Additionally, if the source is equipped with a fuel meter, records of all maintenance and calibrations of the fuel meter shall be kept for five (5) years from the date of the last maintenance or calibration.

Appendix A

Linearity Check Data Sheet

Date:______________

Analyst:___________________________________

Analyzer Manufacturer/Model #:____

Analyzer Serial #:____

LINEARITY CHECK									
Pollutant		Calibration Gas Concentration (Indicate Units)	Analyzer Response ppm NO	Analyzer Response ppm NO_2	Analyzer Response ppm CO	Analyzer Response % O_2	Absolute Difference (Indicate Units)	Percent of Span	Linearity Valid (Yes or No)
NO	Zero								
	Mid								
	Span								
NO_2	Zero								
	Mid								
	Span								
CO	Zero								
	Mid								
	Span								
O_2	Zero								
	Mid								
	Span								

Appendix B
Stability Check Data Sheet

Date:__________ Analyst:____________________

Analyzer Manufacturer/Model #:____________________

Analyzer Serial #:____________________

Pollutant: NO, NO_2, CO (Circle One) Span Gas Concentration (ppm):__________

STABILITY CHECK					
Elapsed Time (Minutes)	Analyzer Response	Elapsed Time (Continued)	Analyzer Response	Elapsed Time (Continued)	Analyzer Response
1		17		33	
2		18		34	
3		19		35	
4		20		36	
5		21		37	
6		22		38	
7		23		39	
8		24		40	
9		25		41	
10		26		42	
11		27		43	
12		28		44	
13		29		45	
14		30		46	
15		31		47	
16		32		48	

For 30-minute Stability Check Period:

Maximum Concentration (ppm): __________ Minimum Concentration (ppm): __________

For 15-minute Stability Check Period:

Maximum Concentration (ppm): __________ Minimum Concentration (ppm): __________

Maximum Deviation = 100*(Max. Conc. - Min. Conc.)/Span Gas Conc. = __________ percent

Stability Time (minutes): __________

Appendix C
Calibration Error Check Data Sheet

Company:______________________ Facility:______________

Source Tested:______________________ Date:______________

Analyst:______________________ Analyzer Serial #:______________

Analyzer Manufacturer/Model #:______________________

PRETEST CALIBRATION ERROR CHECK								
			A	B	|A-B|	|A-B|/SG*100		
		Pump Flow Rate (Indicate Units)	Analyzer Reading (Indicate Units)	Calibration Gas Concentration (Indicate Units)	Absolute Difference (Indicate Units)	Percent of Span	Calibration Valid (Yes or No)	Response Time (Minutes)
NO	Zero							
	Span							
NO_2	Zero							
	Span							
CO	Zero							
	Span							
O_2	Zero							
	Span							
		Pretest Calibration NO Cell Temperature (°F):						

SG = Span Gas

POST TEST CALIBRATION ERROR CHECK										
			A	B	|A-B|	|A-B|/SG*100			Interference Check	
		Pump Flow Rate (Indicate Units)	Analyzer Reading (Indicate Units)	Calibration Gas Concentration (Indicate Units)	Absolute Difference (Indicate Units)	Percent of Span	Calibration Valid (Yes or No)	Average of Pretest and Post Test Analyzer Readings (Indicate Units)	NO Monitor Response (ppm)	CO Monitor Response (ppm)
NO	Zero									
	Span									
NO_2	Zero									
	Span									
CO	Zero									
	Span									
O_2	Zero									
	Span									
		Post Test Calibration NO Cell Temperature (°F):								
		CO Interference Response (I_{CO}, %):				NO Interference Response (I_{NO}, %):				

SG = Span Gas

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FERC GAS TARIFF

FOURTH REVISED VOLUME NO. 1

(Superseding Third Revised Volume No. 1 and
First Revised Volume No. 1-A)

Of

NORTHWEST PIPELINE GP

Filed with

FEDERAL ENERGY REGULATORY COMMISSION

Communications concerning this Tariff should be sent to:

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GENERAL TERMS AND CONDITIONS
(Continued)

3. QUALITY

3.1 Gas Quality at Receipt Points. All Gas delivered by Shipper to Transporter shall conform to the applicable specifications in either Section 3.1(a) or Section 3.1(b). As used in this section, the La Plata Facilities are defined as those facilities commencing at a measurement facility downstream of the discharge side of Northwest's La Plata B compressor station southward to the Blanco Hub, including the La Plata A compressor station and certain plant interconnects, all located in southern Colorado and northern New Mexico.

(a) All Gas delivered by Shipper to Transporter at Receipt Points not connected to the La Plata Facilities shall conform to the following specifications:

(1) Hydrocarbon Liquids and Liquefiables: The hydrocarbon dew point of the gas delivered shall not exceed fifteen degrees Fahrenheit at any pressure between 100 psia and 1,000 psia as calculated from the gas composition and shall be free from hydrocarbons in the liquid state. At all times, any and all liquid or liquefiable hydrocarbons, or any other constituent or by-product, recovered from the gas by Transporter, after delivery of gas to Transporter shall be and remain the exclusive property of Transporter, except as specified in Section 20 of the General Terms and Conditions.

(2) Hydrogen Sulfide and Total Sulfur: The gas shall contain not more than one quarter grain of hydrogen sulfide per one hundred cubic feet and not more than five grains total sulfur per one hundred cubic feet.

(3) Carbon Dioxide and Total Nonhydrocarbons: The gas shall contain not more than two percent by volume of carbon dioxide and shall contain not more than three percent by volume of combined nonhydrocarbon gases including, but not limited to, carbon dioxide, nitrogen and oxygen, except as otherwise provided in Section 3.5.

GENERAL TERMS AND CONDITIONS
Continued)

3. QUALITY (Continued)

(4) Dust, Gums, etc.: The gas shall be commercially free from objectionable odors (excluding odorant added to natural gas for safety reasons or to comply with federal and/or state regulations), solid matter, dust, gums, and gum forming constituents, or any other substance which interferes with the intended purpose of merchantability of the gas, or causes interference with the proper and safe operation of the lines, meters, regulators, or other appliances through which it may flow.

(5) Heating Value: The total gross heating value of the gas deliverable hereunder shall not be less than 985 Btu.

(6) Oxygen: The gas shall not contain in excess of two-tenths of one percent by volume of oxygen, and the parties agree to exercise every reasonable effort to keep the gas completely free of oxygen.

(7) Temperature: The temperature of the gas at the point of delivery shall not exceed one hundred twenty degrees Fahrenheit.

(8) Water: The gas delivered shall be free from liquid water and shall not contain more than seven pounds of water in vapor phase per million cubic feet.

(9) Mercury: The gas shall be free from any detectable mercury.

(10) Toxic or Hazardous Substance: The gas shall not contain any toxic or hazardous substance in concentrations which, in the normal use of the gas, may be hazardous to health, injurious to pipeline facilities, or be a limit to merchantability or be contrary to applicable government standards.

GENERAL TERMS AND CONDITIONS
(Continued)

3. QUALITY (Continued)

(11) Bacteria: The gas, including any associated liquids, shall not contain any microbiological organism, active bacteria or bacterial agent capable of causing or contributing to: (i) injury to Transporter's pipelines, meters, regulators, or other facilities and appliances through which such gas flows or (ii) interference with the proper operation of the Transporter's facilities. Microbiological organisms, include, but are not limited to, sulfate reducing bacteria (SRB) and acid producing bacteria (ACB). When bacteria or microbiological organisms are considered a possibility, Shipper(s) desiring to Nominate such gas, upon Transporter's request, shall cause such gas to be tested for bacteria or bacterial agents utilizing the American Petroleum Institute test method API-RP38 or other acceptable test method as determined by both parties.

(b) All Gas delivered by Shipper to Transporter at Receipt Points connected to the La Plata Facilities shall conform to the following specifications:

(1) Hydrocarbon Liquids and Liquefiables: The hydrocarbon dew point of the gas delivered shall not exceed fifteen degrees Fahrenheit at any pressure between 100 psia and 1,000 psia as calculated from the gas composition and shall be free from hydrocarbons in the liquid state. At all times, any and all liquid or liquefiable hydrocarbons, or any other constituent or by-product, recovered from the gas by Transporter, after delivery of gas to Transporter shall be and remain the exclusive property of Transporter, except as specified in Section 20 of the General Terms and Conditions.

(2) Hydrogen Sulfide and Total Sulfur: The gas shall contain not more than one quarter grain of hydrogen sulfide per one hundred cubic feet of gas. The gas shall contain not more than 0.3 grains of mercaptan sulfur per one hundred cubic feet of gas. The gas shall contain not more than 0.75 grains of total sulfur per one hundred cubic feet of gas.

GENERAL TERMS AND CONDITIONS
(Continued)

3. QUALITY (Continued)

(3) Carbon Dioxide and Total Nonhydrocarbons: The gas shall contain not more than two percent by volume of carbon dioxide and shall contain not more than three percent by volume of combined nonhydrocarbon gases including, but not limited to, carbon dioxide, nitrogen and oxygen, except as otherwise provided in Section 3.5.

(4) Dust, Gums, etc.: The gas shall be commercially free from objectionable odors (excluding odorant added to natural gas for safety reasons or to comply with federal and/or state regulations), solid matter, dust, gums, and gum forming constituents, or any other substance which interferes with the intended purpose of merchantability of the gas, or causes interference with the proper and safe operation of the lines, meters, regulators, or other appliances through which it may flow.

(5) Heating Value: The total gross heating value of the gas deliverable hereunder shall not be less than 985 Btu.

(6) Oxygen: The gas shall not contain in excess of two-tenths of one percent by volume of oxygen, and the parties agree to exercise every reasonable effort to keep the gas completely free of oxygen.

(7) Temperature: The temperature of the gas at the point of delivery shall not exceed one hundred twenty degrees Fahrenheit.

(8) Water: The gas delivered shall be free from liquid water and shall not contain more than seven pounds of water in vapor phase per million cubic feet.

(9) Mercury: The gas shall be free from any detectable mercury.

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GENERAL TERMS AND CONDITIONS
(Continued)

3. QUALITY (Continued)

(10) Toxic or Hazardous Substance: The gas shall not contain any toxic or hazardous substance in concentrations which, in the normal use of the gas, may be hazardous to health, injurious to pipeline facilities, or be a limit to merchantability or be contrary to applicable government standards.

(11) Bacteria: The gas, including any associated liquids, shall not contain any microbiological organism, active bacteria or bacterial agent capable of causing or contributing to: (i) injury to Transporter's pipelines, meters, regulators, or other facilities and appliances through which such gas flows or (ii) interference with the proper operation of the Transporter's facilities. Microbiological organisms, include, but are not limited to, sulfate reducing bacteria (SRB) and acid producing bacteria (ACB). When bacteria or microbiological organisms are considered a possibility, Shipper(s) desiring to Nominate such gas, upon Transporter's request, shall cause such gas to be tested for bacteria or bacterial agents utilizing the American Petroleum Institute test method API-RP38 or other acceptable test method as determined by both parties.

GENERAL TERMS AND CONDITIONS
(Continued)

3. QUALITY (Continued)

3.2 Gas Quality at Delivery Point(s). The gas delivered by Transporter to Shipper at the Delivery Point shall be natural gas containing a gross heating value of at least 985 Btus. Such gas shall be commercially free of dust, gums, dirt, impurities and other solid matter and shall not contain more than one-quarter grain hydrogen sulfide per one hundred cubic feet as determined by using commercially available on-line analyses and/or such analytical methods that are generally accepted in industry practice; provided that Transporter may install and utilize a recording hydrogen sulfide analyzer to monitor the gas at points at which it deems such continuous monitoring to be desirable. The gas to be delivered shall not contain more than twenty grains of total sulfur per one hundred cubic feet.

The gas shall be free of water and hydrocarbons in liquid form at the temperature and pressure at which the gas is delivered and in no event shall have a water content in excess of seven pounds in vapor phase per million cubic feet.

3.3 Determination of Gross Heating Value and Component Analysis. The party operating the measurement equipment shall determine the gross heating value of the gas delivered and its component analysis at reasonable intervals. Such determination shall be made using either an on-line chromatograph or by chromatographic analysis of a representative sample of gas taken with a continuous sampler. Transporter may at its option allow the use of spot samples. If at any time and for any reason Shipper or Transporter should question the results of any spot sampling, a redetermination shall be made and the redetermination mutually acceptable to the parties shall be used; provided, however, if neither party questions such results within a period of sixty (60) days following the determination thereof, then such results shall be deemed conclusive and binding upon the parties. Btu measuring equipment shall be installed at a location or locations where the gross heating value of the gas received or delivered hereunder may be reasonably determined.

3.4 Failure to Meet Specifications. Transporter or Shipper shall have the right, exercisable by the giving of written or oral notice to the other party, to require the remedy of any failure to deliver or redeliver gas in accordance with the quality specifications set forth in Sections 3.1 and 3.2. In the event gas delivered by either party fails to conform to such specifications, as evidenced by the latest chromatograph analysis derived from an on-line chromatograph or from a sample taken manually and analyzed by a chromatograph, or from any other verifiable evidence, the receiving party may refuse to accept all or any portion of such gas.

GENERAL TERMS AND CONDITIONS
(Continued)

3. QUALITY (Continued)

3.5 Accepting Gas Which Fails to Meet Specifications. To the extent Transporter can accept gas that does not meet quality specifications without jeopardizing Transporter's ability to meet its obligations to deliver gas to downstream interconnecting pipelines or markets, it will do so on a non-discriminatory basis to all similarly situated Shippers. When such ability is jeopardized by gas not meeting the quality specifications as set forth in Section 3.1, Transporter will implement the following steps in the following order:

(a) Transporter will identify the receipt point(s) from which gas is flowing that contain more than 2% by volume of carbon dioxide and/or more than 3% by volume of total nonhydrocarbon gases and which are contributing to the gas quality problem.

(b) Transporter will then rank these receipt points according to the highest percentage by volume of carbon dioxide and/or nonhydrocarbon gas entering the system (depending on which violation of quality specifications is impacting or may impact Transporter's ability to deliver). Transporter will make reasonable efforts to notify receipt point operators by telephone and via Transporter's Designated Site at the earliest time possible as to the action required and the time within which compliance is required, depending on the operational situation existing at the time. Transporter will notify the receipt point operators in the order of the ranking starting with the receipt point with the highest percentage of applicable contaminant until the problem is resolved. The required action may include any alternative that will alleviate the gas quality problem.

(c) Within two business days after resolving a gas quality problem, Transporter will post to its Designated Site: a description of the problem, the receipt point, the receipt point operator, the action required, the action taken, and the date and time that the problem was resolved.

GENERAL TERMS AND CONDITIONS
(Continued)

3. QUALITY (Continued)

3.6 Gas Analysis Equipment. If Transporter, in its reasonable judgment, determines that any additional or modified Gas analysis or control equipment is needed to accurately monitor the quality of Gas received at an existing Receipt Point and control the receipt of Gas failing to conform to the applicable quality specifications, then the Shipper(s) desiring to nominate at such Receipt Point will cause the interconnecting party at such Receipt Point to install such necessary additional or modified equipment.

Unless otherwise mutually agreed, if Transporter installs such additional or modified Gas analysis or control equipment, the interconnecting party will provide a contribution in aid of construction to Transporter for all actual costs incurred by Transporter, and reimburse Transporter for any related income taxes. The related income taxes will be the difference between Transporter's current federal and state income tax liability resulting from the contribution in aid of construction and the present value of Transporter's future tax benefits resulting from tax depreciation on such facilities, grossed-up for income taxes. The cash flow discount factor for the present value calculation will be the most recent weighted cost of capital percentage specifically approved by the Commission for deriving Transporter's Recourse Rates.