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,

Transwestern Pipeline Company
La Plata A 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.

Callie A. Videtich — 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

Transwestern Pipeline Company
La Plata A Compressor Station

Permit Number: V-SU-0013-08.01
Replaces Amended Permit No.: V-SU-0013-08.00

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
October 2003	**Initial Permit Issued**		**Permit # V-SU-0013-00.00**
June 2009	**1st Renewal Issued**		**Permit # V-SU-0013-08.00**
November 2009	**Administrative Amendment**	II.E.1. Monitoring Requirements III.C. Alternative Operating Scenarios – Turbine Replacement /Overhaul	**Permit # V-SU-0013-08.01** Corrected regulatory citation for origin of authority Added explanatory note for how/when provision can be used

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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
gal	gallon
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
NOx	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: Transwestern Pipeline Company

Plant Name: La Plata A Compressor Station

Plant Location: NE ¼, SE ¼ of Section 35, T34N, R9W
Latitude: 37^{o} 08.26' Longitude: 107^{o} 47. 07'

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

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

Responsible Official: Senior Vice President, Operations and Engineering

SIC Code: 4922

AFS Plant Identification Number: 08-067-00109

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 A Compressor Station is a natural gas compression and transmission facility. Natural gas is received at the station through a single inlet line from other gas conditioning plants and then compressed by two inlet turbine-driven gas compressors (units T01 and T02). After compression, the gas exits the facility via a single gas pipeline.

The La Plata A Compressor Station has two storage tanks at the facility for storing lube oil and oily waste water/pipeline condensate. There is a single 2.5 MMBtu/hour gas-fired heater used for comfort heating.

The La Plata A Compressor Station uses one Solar Centaur Model 50-H Turbine (unit T01) and one Solar Taurus Model 60-T7000S turbine (unit T02) to provide compression for Transwestern Pipeline's mainline natural gas pipeline system. Both Solar stationary gas turbines are subject to the requirements of 40 CFR part 60, subparts A and GG as they apply to the emission units, emission limits, monitoring, recordkeeping, and reporting requirements, and facility-wide operating requirements. The nitrogen oxides (NOx) emissions from unit T02 are controlled using SoLoNOx Retrofit equipment manufactured by Solar Turbines, Inc., that was installed in 1997. De-ionized, pure water is combined with natural gas fuel and combustion air to boost the horsepower of turbine T01. While water injections also decreases NOx formation in the combustion zone (and NOx concentration in the unit exhaust), it is not needed for the unit to comply with the applicable NOx emission limit and was not installed to control NOx emissions;

therefore, Transwestern views water injection as an optional process enhancement that is used under normal operation and not as a required element of emissions reduction for compliance purposes.

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) and New Source Review (NSR) pre-construction permitting requirements, and/or any other applicable Federal requirements. The three portions of the facility have different owners; therefore, a separate title V permit is issued for each owner. The La Plata A Compressor Station is owned and operated by Transwestern Pipeline Company. The La Plata B Compressor Station is owned and operated by Northwest Pipeline GP. The Ignacio Gas Conditioning Plant is owned and operated by Williams Field Services.

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
Transwestern Pipeline Company
La Plata A Compressor Station

Emission Unit ID	Description	Control Equipment
T01	46 MMBtu/hr, 5,479 hp, Solar Model Centaur 50-H Turbine; Natural gas fired: Serial Number: 0154H Installed: 1991 (started up 2/12/91)	None
T02	49.2 MMBtu/hr, 6,937 hp, Solar Model Taurus 60-T7000S Turbine; Natural gas fired: Serial Number: OHB07-T0069 Installed: 1997 (started up 3/25/98)	SoLoNOx Catalytic Converter Retrofit

Table 2 - Insignificant Emission Units
Transwestern Pipeline Company
La Plata A Compressor Station

Emission Unit ID	Description
T-1	One 500 gallon horizontal pressurized (45 psi) lube oil storage tank
T-2	One 90 bbl vertical fixed-roof oily waste water/pipeline condensate tank
HEATER	2.5 MMBtu/hr natural gas fired heater for comfort heating
TRUCK	Lube oil/oily waste water truck loading point
FUG	Fugitive Emissions from piping components

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. 40CFR 60, 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 [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 T01 and T02 are subject to the nitrogen oxide (NO_x) standard and the sulfur dioxide (SO_2) fuel standards 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 (NOx emission allowance for fuel bound nitrogen) and STD = allowable NOx 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.

2. Emission units T01 and T02 shall be exempt from the NO_x emission limit in Section II.C.1. of this permit when being fired with an emergency fuel. For the purpose of this requirement, the term "emergency fuel" means "a fuel fired by a gas turbine only during circumstances, such as natural gas curtailment or breakdown of delivery system, that makes it impossible to fire natural gas in the turbine."

[40 CFR 60.332(k), 40CFR 60.331(r)]

II.D. <u>Testing Requirements</u> [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 T01 and T02 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 T01 and T02.

II.E. <u>Monitoring Requirements</u> [40 CFR 60.334 and 40 CFR 71.6(a)(3)(i)(A) through (C)]

1. The permittee shall measure NO_x emissions from emission units T01 and T02 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 February 26, 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 T01 and T02.

   (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: 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. <u>Recordkeeping Requirements</u> [40 CFR 71.6(a)(3)(ii), 40 CFR 60.7(b) and 60.7(f), and the portable analyzer monitoring protocol as approved by EPA in a letter dated February 26, 2008 (see Appendix B)]

Emission Units T01 and T02 are subject to the following recordkeeping requirements:

1. The permittee shall comply with the following recordkeeping requirements for turbine units T01 and T02:

    (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 T01 and T02:

        (i) Monitoring of fuel sulfur content shall be recorded daily while firing an emergency fuel as defined in 40 CFR 60.331(r).
        (ii) For turbines T01 and T02, 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 custom fuel monitoring schedule 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. <u>Reporting Requirements</u> [40 CFR 60.48c(a), 60.7, and 40 CFR 71.6(a)(3)(iii)]

Emission units T01 and T02 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, as specified by 40 CFR 60.7. This notification shall include:

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

    (b) The annual capacity factor at which the permittee anticipates operating the turbine 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 September 1st through the end of February. The report due on October 1st shall cover the prior six-month period from March 1st through the end of August. 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. Alternative Operating Scenarios – Turbine Replacement/Overhaul [40 CFR 1.6(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 standards, requirements, or provisions in this permit that apply to the permitted turbines shall also apply to the replacement turbines, including the initial compliance test required by 40 CFR 60.8 and subject to all other requirements of 40 CFR part 60, subpart GG.

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 T01 and T02 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. 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.E. 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	**For non-U.S. Postal Service Express mail** (FedEx, Airborne, DHL, and UPS)
U.S. Environmental Protection Agency FOIA and Miscellaneous Payments Cincinnati Finance Center P.O. Box 979078 St. Louis, MO 63197-9000	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. <u>Annual Emissions Inventory</u> [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. <u>Compliance Requirements</u> [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. **<u>Severability Clause</u>** [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. **<u>Permit Actions</u>** [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. **<u>Administrative Permit Amendments</u>** [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. <u>Minor Permit Modifications</u> [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. <u>Property Rights</u> [40 CFR 71.6(a)(6)(iv)]

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

IV.N. <u>Inspection and Entry</u> [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. <u>Emergency Provisions</u> [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 Clean Air Act;

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 an existing 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 must be provided in a written notice to EPA, contemporaneously with installation of the replacement turbine, 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) 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 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) 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) If the existing source is not a "major stationary source" as defined in §52.21(b)(1): 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. 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.

9. 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, or by replacement of multiple turbines.

IV.R. Permit Expiration and Renewal [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 Durango, Colorado Airport take Highway 172 west approximately three miles to County Road 307 and turn south driving approximately four miles. La Plata A Compressor Station is the first facility on the west side of the street at 3775 County Road 307.

2. Latitude and Longitude Coordinates

   Lat. 37.140556 (37° 08' 26") Long. -107.785278 (-107° 47' 7")

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

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

GENERAL TERMS AND CONDITIONS
(continued)

2. QUALITY

2.1 The gas stream delivered into Transporter's pipeline system by Shipper or Shipper's designee at receipt points shall conform to each of the following quality specifications:

A. shall be commercially free from objectionable odors, solid matter, dust, gums, and gum forming constituents, or any other substance which interferes with the intended purpose or 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;

B. shall contain not more than seven (7) pounds/MMcf of water at the temperature and pressure at which the gas is delivered into Transporter's pipeline system;

C. shall contain no hydrocarbons in liquid form at the temperature and pressure at which the gas is delivered into Transporter's pipeline system;

D. shall contain not more than 0.1% by volume of oxygen;

E. shall contain not more than 2.0% by volume of carbon dioxide;

F. shall contain not more than a combined total of 3.0% by volume of carbon dioxide plus nitrogen;

G. shall contain not more than one quarter (1/4) grain of hydrogen sulfide per one hundred (100) cubic feet of gas;

H. shall contain not more than 0.3 grains of mercaptan sulfur per one hundred (100) cubic feet of gas;

I. shall contain not more than 0.75 grains of total sulfur per one hundred (100) cubic feet of gas;

J. 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;

K. shall have a minimum total heating value of not less than nine hundred seventy (970) Btu's per cubic foot; and

L. shall have a temperature of not less than forty (40) degrees Fahrenheit, and not more than one hundred twenty (120) degrees Fahrenheit.

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

2 6 2008

Sam Duletsky
Senior Environmental Engineer
711 Louisiana Street, Suite 900
Houston, Texas 77002

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

Dear Mr. Duletsky,

After reviewing the file for Transwestern's LaPlata A 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 February 19, 2008, you submitted an updated protocol. EPA approves the use of this protocol (enclosed) for use at the LaPlata A 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 WYOMING AIR QUALITY DIVISION
PORTABLE ANALYZER MONITORING PROTOCOL

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

WYOMING DEPARTMENT OF ENVIRONMENTAL QUALITY
AIR QUALITY DIVISION
122 West 25th Street
Cheyenne, Wyoming 82002

April 21, 1999
Revised January 25, 2006

Approved By: ____________________
Dan Olson
Administrator

TABLE OF CONTENTS

1. APPLICABILITY AND PRINCIPLE

1.1 Applicability. This method is applicable to the determination of nitrogen oxides (NO and NO_2), carbon monoxide (CO), and oxygen (O_2) concentrations in 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.

1.2 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 3.33 times 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. For the NO, NO_2 and CO channels, 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. For the O_2 channel, the difference, expressed as percent O_2, 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. For the NO, NO_2 and CO channels, 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. For the O_2 channel, the difference, expressed as percent O_2, 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. A schematic of an acceptable measurement system is shown in Figure 1. 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 measurement 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 Quality 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 reaccomplished. Additionally, reaccomplish the linearity check 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 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 Form 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 manditory 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 reaccomplished. Additionally, reaccomplish the stability check 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 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 Form 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. 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. 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 Form 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 Form C and monitor and record the temperature regularly (at least once each 7 minutes) during the sample collection period on Form D. 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.

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

where:		
	I_{CO}	= CO interference response (percent)
	$R_{CO\text{-}NO}$	= 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)
	$R_{CO\text{-}NO2}$	= 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.

$$I_{NO} = \left(\frac{R_{NO\text{-}NO_2}}{C_{NO_2G}}\right)\left(\frac{C_{NO_2S}}{C_{NO_XS}}\right)x100$$

where:

I_{NO} = NO interference response (percent)

$R_{NO\text{-}NO2}$ = 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 Form 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 Form 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 Form 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. For NO, NO_2 and CO, 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. For O_2, record the absolute value of the difference between the analyzer response and the O_2 calibration gas concentration. Record whether the calibration is valid by comparing the percent of span or difference between the calibration gas concentration and analyzer O_2 response, as applicable, 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.** On Form D-1, D-2, or D-3, 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 Form 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. For NO, NO_2 and CO, 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. For O_2, record the absolute value of the difference between the analyzer response and the O_2 calibration gas concentration. Record whether the calibration is valid by comparing the percent of span or difference between the calibration gas concentration and analyzer O_2 response, as applicable, 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 on Form D-1, D-2, or D-3. Sign the 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), grams per horsepower hour (gm/hp-hr), 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 Above 500 Horsepower. All reciprocating engines and combustion turbines above 500 horsepower (site-rated) should be equipped with fuel flow meters for measuring fuel consumption during the portable analyzer test.

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. Reciprocating engines above 500 horsepower which are not equipped with fuel flow meters may use the site-rated horsepower and 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 to calculate emission rates. Emissions shall be calculated using the following methods.

10.1.1.1 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. 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.

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

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

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 reciprocating engine or combustion turbine horsepower can be derived from operating conditions during the portable analyzer test, this derived horsepower should be used to calculate a gram per horsepower hour emission rate using the following equations. Information showing the derivation of the horsepower shall be provided with the test results.

$$gm/hp\text{ - }hr\ CO = \frac{(lb/hr\ CO)(454)}{(Tested\ Horsepower_{Note\ 1})}$$

$$gm/hp\text{ - }hr\ NO_X = \frac{(lb/hr\ NO_X)(454)}{(Tested\ Horsepower_{Note\ 1})}$$

Note 1 - Horsepower determined during the test.

If the reciprocating engine horsepower during the time of testing cannot determined from the operating data, the operating horsepower for the time of the test shall be calculated based on the heat input per hour during the test and the default values shown below for specific fuel consumption based on the higher heating value of the fuel. Heat input per hour (MMBtu/hr) shall be calculated based on the average hourly fuel usage during the test and the higher heating value of the fuel consumed. For 4-cycle engines (controlled and uncontrolled) and 2-cycle lean burn engines, use a default specific fuel consumption of 9,400 Btu/hp-hr. For 2-cycle uncontrolled (non-lean burn) engines, use a default specific fuel consumption of 11,000 Btu/hp-hr. Calculate the gram per horsepower hour emission rates using the following equations.

$$Engine\ Horsepower = \frac{(Heat\ Input\ Per\ Hour_{Note\ 1})(10^6)}{(Specific\ Fuel\ Consumption_{Note\ 2})}$$

$$gm/hp\text{ - }hr\ NO_X = \frac{(lb/hr\ NO_X)(454)}{(Engine\ Horsepower)}$$

$$gm/hp\text{ - }hr\ CO = \frac{(lb/hr\ CO)(454)}{(Engine\ Horsepower)}$$

Note 1 - 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.

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

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.

$$ppm\ NO_{X\ @\ 15\%\ O_2} = ppm\ NO_{X\ corrected}\left(\frac{5.9}{20.9 - O_2\%_{corrected}}\right)$$

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

10.1.1.2 Reciprocating Engines Above 500 Horsepower Not Equipped with Fuel Meters. If reciprocating engines above 500 horsepower (site-rated) are not equipped with fuel flow meters during the test, emissions shall be calculated using the site-rated horsepower and 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.

$$gm/hp\text{-}hr\ NO_X = \frac{(ppm\ NO_{X\ corrected})(1.19x10^{-7})(F\ Factor_{Note\ 1})\left(\frac{20.9}{20.9 - O_2\%_{corrected}}\right)}{(Specific\ Fuel\ Consumption_{Note\ 2})(10^{-6})(454)}$$

$$lb/hr\ NO_X = \frac{(gm/hp\text{-}hr\ NO_X)(Engine\ Horsepower_{Note\ 3})}{454}$$

$$gm/hp\text{-}hr\ CO = \frac{(ppm\ CO_{corrected})(7.27x10^{-8})(F\ Factor_{Note\ 1})\left(\frac{20.9}{20.9 - O_2\%_{corrected}}\right)}{(Specific\ Fuel\ Consumption_{Note\ 2})(10^{-6})(454)}$$

$$lb/hr\ CO = \frac{(gm/hp\text{-}hr\ CO)(Engine\ Horsepower_{Note\ 3})}{454}$$

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.

Note 3 - Site-rated engine horsepower.

10.1.2 Reciprocating Engines Below 500 Horsepower. Reciprocating engines below 500 horsepower may calculate emission rates using the derived horsepower for the operating conditions during the portable analyzer test (either from engine parameter measurements or calculated from compressor operating parameters) and the manufacturer's specific fuel consumption based on the higher heating value of the fuel consumed during the test. Information showing the derivation of the engine operating horsepower and manufacturer's specific fuel consumption shall be provided with the test results. The following equations shall be used to calculate emission rates.

$$gm/hp\text{ - }hr\ NO_x = \frac{(ppm\ NO_{x\ corrected})(1.19x10^{-7})(F\ Factor_{Note\ 1})(\frac{20.9}{20.9 - O_2\%_{corrected}})}{(Specific\ Fuel\ Consumption_{Note\ 2})(10^{-6})(454)}$$

$$gm/hp\text{ - }hr\ CO = \frac{(ppm\ CO_{corrected})(7.27x10^{-8})(F\ Factor_{Note\ 1})(\frac{20.9}{20.9 - O_2\%_{corrected}})}{(Specific\ Fuel\ Consumption_{Note\ 2})(10^{-6})(454)}$$

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

Note 2 - Use manufacturer's specific fuel consumption based on the higher heating value of the fuel and include manufacturer's data with the test results. If the manufacturer reports the specific fuel consumption based on the lower heating value of the fuel, multiply by 1.11 to obtain the specific fuel consumption based on the higher heating value of the fuel.

Pound per hour emission rates shall be calculated using the gram per horsepower hour emission rates and the engine horsepower derived from engine or compressor operating parameter data. If engine horsepower data is not available, site-rated horsepower shall be used to calculate pound

$$lb/hr\ NO_x = \frac{(gm/hp\text{ - }hr\ NO_x)(Engine\ Horsepower_{Note\ 1})}{(454)}$$

$$lb/hr\ CO = \frac{(gm/hp\text{ - }hr\ CO)(Engine\ Horsepower_{Note\ 1})}{(454)}$$

per hour emissions. The following equations shall be used to calculate emission rates.

Note 1 - Use derived operating horsepower and include derivation method/calculations with the test results. If a derived horsepower is not available or cannot be obtained, use site-rated horsepower.

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.

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

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

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

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

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

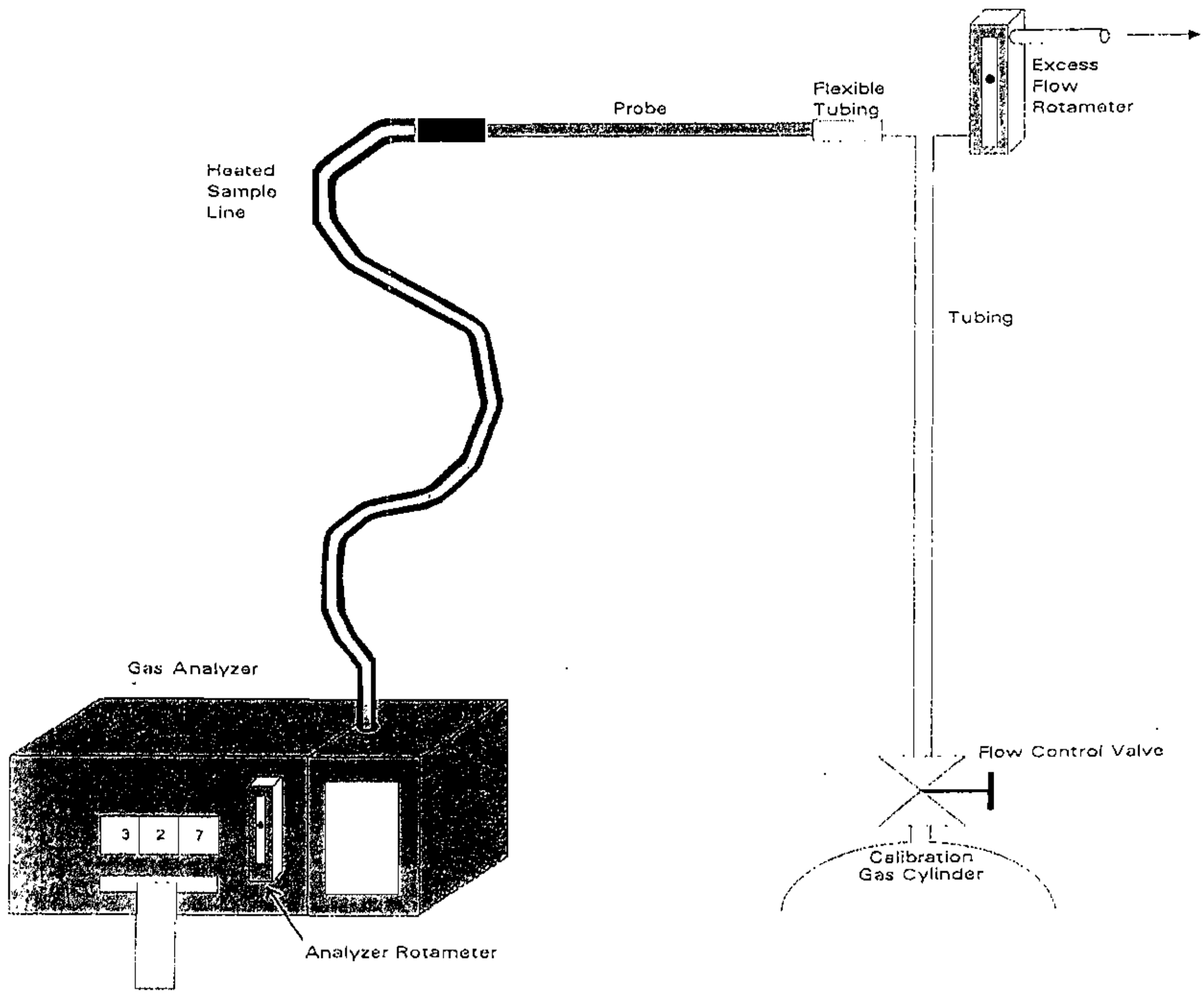
Test reports shall be submitted to the Air Quality Division within thirty (30) days of completing the test unless a specific reporting schedule is set by a condition of a permit. A separate test report shall be submitted for each emission source tested and, at a minimum, the following information shall be included:

- **Form A, Linearity Check Data Sheet,** Submit the linearity check as required by Section 6.2 for the nominal range tested.
- **Form B, Stability Check Data Sheet,** Submit the stability check as required by Section 6.4 for the nominal range tested.
- **Form C, Calibration Error Check Data Sheet**
- **Form D-1, D-2 or D-3,** Submit the appropriate test results form for type of source tested.
- If the manufacturer's specific fuel consumption is used, documentation from the manufacturer shall be submitted.
- If the horsepower is calculated during the test, information showing the derivation of the horsepower shall be included.

For sources subject to Section 30 of the Wyoming Air Quality Standards and Regulations, the submittal must be certified as truthful, accurate and complete by the facility's responsible official.

Records pertaining to the information above and supporting documentation shall be kept for five (5) years and made available upon request by this 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.

FIGURE 1.
CALIBRATION SYSTEM SCHEMATIC



Form 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								

Form 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): __________

Form 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 Note 1	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 Note 1	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

Note 1: The percent of span calculation is applicable to the NO, NO_2 and CO channels only.

Form D-1
Reciprocating Engine Test Results

Company:______________________ Facility:______________________

Source Tested:______________________ Date:______________________

Source Manufacturer/Model #:______________________

Site-rated Horsepower:______________________ Source Serial #:______________________

Type of Emission Control:______________________

Analyst:______________________ Analyzer Serial #:______________________

Analyzer Manufacturer/Model #:______________________

Operating Conditions

Source operating at 90 percent or greater site-rated horsepower during testing? yes no

Suction/ Discharge Pressures (Indicate Units)	Engine RPM	Engine Gas Throughput (Indicate Units)	Engine Fuel Consumption (Indicate Units)	Fuel Heat Content (Btu/cf)	Engine Specific Fuel Consumption (Btu/hp-hr)[1]	Engine Tested Horsepower

[1] As reported by the Manufacturer

Test Results

Test Start Time:__________ NO Cell Temperature (°F) after 1/3 (e.g., 7 minutes) of the test:__________

Test End Time:__________ NO Cell Temperature (°F) after 2/3 (e.g., 14 minutes) of the test:__________

NO_X ($NO + NO_2$)								
Avg. Tested NO ppm	$NO_{corrected}$ ppm	Avg. Tested NO_2 ppm	$NO_{2\ corrected}$ ppm	$NO_{X\ corrected}$ ppm	Tested gm/hp-hr	Tested lb/hr	Allowable gm/hp-hr	Allowable lb/hr

O_2		CO					
Avg. Tested O_2 %	$O_{2\ corrected}$ %	Avg. Tested CO ppm	$CO_{corrected}$ ppm	Tested gm/hp-hr	Tested lb/hr	Allowable gm/hp-hr	Allowable lb/hr

I certify to the best of my knowledge the test results are accurate and representative of the emissions from this source.

______________________ Print Name

______________________ Signature

Form D-2
Combustion Turbine Test Results

Company:____________________ Facility:____________________

Source Tested:____________________ Date:____________________

Source Manufacturer/Model #:____________________

Site-rated Horsepower:____________________ Source Serial #:____________________

Type of Emission Control:____________________

Analyst:____________________ Analyzer Serial #:____________________

Analyzer Manufacturer/Model #:____________________

Operating Conditions

Source operating at 90 percent or greater site-rated horsepower during testing? yes no

Suction/ Discharge Pressures (Indicate Units)	Turbine T_5 Temperature (°F)	Turbine RPM	Turbine Gas Throughput (Indicate Units)	Turbine Fuel Consumption (Indicate Units)	Fuel Heat Content (Btu/cf)	Turbine Specific Fuel Consumption (Btu/hp-hr)[1]	Turbine Tested Horsepower

[1] As reported by the Manufacturer

Test Results

Test Start Time:__________ NO Cell Temperature (°F) after 1/3 (e.g., 7 minutes) of the test:__________

Test End Time: __________ NO Cell Temperature (°F) after 2/3 (e.g., 14 minutes) of the test:__________

NO_X ($NO + NO_2$)										
Avg. Tested NO ppm	$NO_{corrected}$ ppm	Avg. Tested NO_2 ppm	$NO_{2\ corrected}$ ppm	$NO_{X\ corrected}$ ppm	Tested gm/hp-hr	Tested lb/hr	Tested ppm @ 15% O2	Allowable gm/hp-hr	Allowable lb/hr	Allowable ppm @ 15% O2

O_2		CO							
Avg. Tested O_2 %	$O_{2\ corrected}$ %	Avg. Tested CO ppm	$CO_{corrected}$ ppm	Tested gm/hp-hr	Tested lb/hr	Tested ppm @ 15% O2	Allowable gm/hp-hr	Allowable lb/hr	Allowable ppm @ 15% O2

I certify to the best of my knowledge the test results are accurate and representative of the emissions from this source.

____________________ ____________________

Print Name Signature

Form D-3
Heater/Boiler Test Results

Company:________________________ Facility:________________________

Source Tested:________________________ Date:________________________

Source Manufacturer/Model #:____

Design Firing Rate (MMBtu/hr):______________ Source Serial #:________________________

Type of Emission Control:____

Analyst:________________________ Analyzer Serial #:________________________

Analyzer Manufacturer/Model #:____

Operating Conditions

Source operating at 90 percent or greater site-rated horsepower during testing? yes no

Fuel Consumption (cf/hr)	Fuel Heat Content (Btu/cf)	Heater/Boiler Tested Firing Rate (MMBtu/hr)

Test Results

Test Start Time:____________ NO Cell Temperature (°F) after 1/3 (e.g., 7 minutes) of the test:__________

Test End Time: ____________ NO Cell Temperature (°F) after 2/3 (e.g., 14 minutes) of the test:__________

NO_X ($NO + NO_2$)								
Avg. Tested NO ppm	$NO_{corrected}$ ppm	Avg. Tested NO_2 ppm	$NO_{2\ corrected}$ ppm	$NO_{X\ corrected}$ ppm	Tested lb/MMBtu	Tested lb/hr	Allowable lb/MMBtu	Allowable lb/hr

O_2		CO					
Avg. Tested O_2 %	$O_{2\ corrected}$ %	Avg. Tested CO ppm	$CO_{corrected}$ ppm	Tested lb/MMBtu	Tested lb/hr	Allowable lb/MMBtu	Allowable lb/hr

I certify to the best of my knowledge the test results are accurate and representative of the emissions from this source.

________________________ ________________________

Print Name Signature

Air Pollution Control
Title V Permit to Operate
Statement of Basis for Permit No. V-SU-0013-08.01
Administrative Amendment

Transwestern Pipeline Company
La Plata A Compressor Station
Southern Ute Indian Reservation
La Plata County, Colorado

1. Facility Information

a. Location

The Transwestern Pipeline Company (Transwestern) La Plata A Compressor Station is located within the exterior boundaries of the Southern Ute Indian Reservation in La Plata County, Colorado. It is sited approximately 14 miles southeast of Durango, Colorado at 3775 County Road 307. It is located at the following latitude and longitude: N 37^{o} 08' 26", W -107^{o} 45' 07". The mailing address is:

Transwestern Pipeline Company
La Plata A Compressor Station
4001 Indian School Road, NE
Albuquerque, New Mexico 87110

b. Contacts

Facility Contact:
George Friend
Senior Technical Specialist
Transwestern Pipeline Company
4001 Indian School Road, NE
Albuquerque, New Mexico 87110
505-260-4013

Responsible Official:
Jeff Whippo
Area Director
Transwestern Pipeline Company
711 Louisiana Street, Suite 900
Houston, Texas 77002
281-714-2000
281-714-2173 (fax)

Alternate Responsible Official:
Mike Spears
Senior Vice President, Operations & Engineering
Transwestern Pipeline Company
711 Louisiana Street, Suite 900
Houston, Texas 77002

Alternate Responsible Official:
Clint Cowan
Environmental Director
Transwestern Pipeline Company
711 Louisiana Street, Suite 900
Houston, Texas 77002

Tribal Contact:
James Temte
Air Program Director
Southern Ute Indian Tribe
970-563-4705

c. Description of operations

The La Plata A Compressor Station is a natural gas compression and transmission facility. Natural gas is received at the station through a single inlet line from other gas conditioning plants and then compressed by two inlet turbine-driven gas compressors (units T01 and T02). After compression, the gas exits the facility via a single gas pipeline.

The La Plata A Compressor Station has two storage tanks at the facility for storing lube oil and oily waste water/pipeline condensate. There is a single 2.5 MMBtu/hour gas-fired heater used for comfort heating.

The La Plata A Compressor Station uses one Solar Centaur Model 50-H Turbine (unit T01) and one Solar Taurus Model 60-T7000S turbine (unit T02) to provide compression for Transwestern Pipeline's mainline natural gas pipeline system. Both Solar stationary gas turbines are subject to the New Source Performance Standards (NSPS) for Stationary Gas Turbines, found at 40 CFR part 60, subparts A and GG as they apply to the emission units, emission limits, monitoring, recordkeeping, and reporting requirements, and facility-wide operating requirements. The nitrogen oxides (NO_x) emissions from unit T02 are controlled using SoLoNOx Retrofit equipment manufactured by Solar Turbines, Inc., that was installed in 1997. Unit T01 is equipped with a water injection system, where de-ionized, pure water is combined with natural gas fuel and combustion air to boost the horsepower of the turbine.

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) and New Source Review (NSR) pre-construction permitting requirements, and any other applicable Federal requirements. The three portions of the facility have been issued separate title V permits.

2. Description of Permit Amendment

EPA discovered that the citation identifying the origin of EPA's authority for the condition in Section II.E.1. of the currently effective permit (#V-SU-0013-08.00) was incorrect. The citation for the condition in the effective permit is currently identified as 40 CFR 60.334(c), from the Standards of Performance for Stationary Gas Turbines, found in part 60, subpart GG, which is only partially correct. 40 CFR 60.334(c) provides EPA the authority to allow Transwestern to demonstrate compliance with the applicable NO_x emission limit under §60.332 by using a previously approved procedure for monitoring--in this case, the Portable Analyzer Monitoring Protocol, the current protocol of which was approved by EPA on February 26, 2008.

Prior to promulgation of amendments to subpart GG in July 2004 (69 FR 41360), 40 CFR part 60, subpart GG required only a one-time compliance test and no periodic monitoring to assure compliance with the applicable NO_x limit for turbines in §60.332. In the initial operating permit, issued in November 2003, EPA required quarterly portable analyzer monitoring under the authority governed by 40 CFR 71.6(a)(3)(i)(B). This authority authorizes a sufficiency review of monitoring and testing in an existing emissions standard, and enhancement of that monitoring or testing through the permit, when the standard requires no periodic testing or instrumental or noninstrumental monitoring, specifies no frequency, or requires only a one-time test. The July 2004 amendments to subpart GG added requirements to periodically monitor NO_x emissions in order to assure compliance with the limits, but provided options for demonstrating that compliance in order to make it easier for sources that may have already had an approved periodic monitoring program in place. The origin of authority for the condition in Section II.E.1 should have been identified as both 40 CFR 60.334(c) *and* the enhanced periodic monitoring provisions in 40 CFR 71.6(a)(3)(i)(B). The operating permit for the La Plata A Compressor Station was re-opened for cause pursuant to 40 CFR 71.7(f) to correct the citation.

While the permit was open, EPA also took the opportunity to add clarification to some existing permit conditions and to correct an additional typo identified in the semi-annual reporting requirements. EPA provided clarification of the turbine replacement language in Section III.C. Alternative Operating Scenarios – Turbine Replacement / Overhaul to ensure that Transwestern understands when and how those provisions may be used. Additionally, the renewal permit indicated that the report due April 1st shall cover the prior six-month period from July 1st through the end of December and the report due October 1st shall cover the prior six-month period from January 1st through the end of June. These coverage periods differed from the schedule that had previously been established in the initial permit and that Transwestern had already set up for their reporting system. Therefore, the permit has been corrected to correspond to the established reporting schedule, requiring that the report due April 1st shall cover the prior six-month period from September 1st through the end of February and the report due October 1st shall cover the prior six-month period from March 1st through the end of August.

The following modifications have been made to this permit:

- Permit Issuance Cover Page
    1. Permit Revision History was updated.
- Section II.E.1. Monitoring Requirements
    1. Citation for the origin of authority was revised from "40 CFR 60.334(c)" to "40 CFR 334(c) and 40 CFR 71.6(a)(3)(i)(B)".
- Section III.B.1. General Reporting Requirements
    1. The semi-annual reporting period timeframes were revised **from** "July 1st through the end of December" and "January 1st through the end of June," **to** "September 1st through the end of February" and "March 1st through the end of August."

- Section III.C. Alternative Operating Scenarios – Turbine Replacement/Overhaul
    1. Added an explanatory note for clarification of when and how the provision may be used.

The permit modifications described above are administrative in nature and do not alter any existing enforceable requirements of the permit; therefore, the modifications qualify as administrative amendments, according to 40 CFR 71.7(d), and EPA has amended the permit in accordance with the requirements of permit Section IV.H. The permit will be reissued as permit number V-SU-0013-08.01.

For specific applicability information regarding the part 71 permit for this facility, please see the Statement of Basis for permit number V-SU-0013-08.00.

Air Pollution Control
Title V Permit to Operate
Statement of Basis for Final Permit No. V-SU-0013-08.00
First Permit Renewal
June 2009

Transwestern Pipeline Company
La Plata A Compressor Station
Southern Ute Indian Reservation
La Plata County, Colorado

1. Facility Information

a. Location

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281-714-2000
281-714-2173 (fax)

Alternate Responsible Official:
Mike Spears
Senior Vice President, Operations & Engineering
Transwestern Pipeline Company
711 Louisiana Street, Suite 900
Houston, Texas 77002

Alternate Responsible Official:
Clint Cowan
Environmental Director
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James Temte
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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) and New Source Review (NSR) pre-construction permitting requirements, and/or any other applicable Federal requirements. The three portions of the facility have been issued separate title V permits.

d. List of all units and emission-generating activities

Transwestern provided the information contained in Tables 1 and 2 in its renewal application for the La Plata A Compressor Station. Table 1 lists emission units and emission generating activities, including any air pollution control devices. Emission units identified as "insignificant" are listed separately in Table 2.

Part 71 allows sources to separately list in the permit application units or activities that qualify as "insignificant" based on potential emissions below 2 tons per year (tpy) for all regulated pollutants that are not listed as a hazardous air pollutant (HAP) under Clean Air Act (CAA) section 112(b) and below 1000 lbs/year or the de minimis level established under section 112(g), whichever is lower, for HAPs. However, the application may not omit information needed to determine the applicability of, or to impose, any applicable requirement, or to calculate the fee. Units that qualify as insignificant for the purposes of the part 71 application are in no way exempt from applicable requirements or any requirements of the part 71 permit.

Table 1 – Emission Units
Transwestern Pipeline Company
La Plata A Compressor Station

Emission Unit ID	Description	Control Equipment
T01	46 MMBtu/hr, 5,479 hp, Solar Model Centaur 50-H Turbine; Natural gas fired: Serial Number: 0154H Installed: 1991 (started up 2/12/91)	None
T02	49.2 MMBtu/hr, 6,937 hp, Solar Model Taurus 60-T7000S Turbine; Natural gas fired: Serial Number: OHB07-T0069 Installed: 1997 (started up 3/25/98)	SoLoNOx Catalytic Converter Retrofit

Table 2 - Insignificant Emission Units
Transwestern Pipeline Company
La Plata A Compressor Station

Emission Unit ID	Description
T-1	One 500 gallon horizontal pressurized (45 psi) lube oil storage tank
T-2	One 90 bbl vertical fixed-roof oily waste water/pipeline condensate tank
HEATER	2.5 MMBtu/hr natural gas fired heater for comfort heating
TRUCK	Lube oil/oily waste water truck loading point
FUG	Fugitive Emissions from piping components

e. Construction, permitting, and compliance history

Prior to the promulgation of the part 71 operating permit requirements, the source had not been required to obtain any Federal air quality permits. The State of Colorado issued emission permits 97-LP-0885 (previous permit 90-LP-050) and 97-LP-0653. However, it was determined that the compressor station is within the exterior boundaries of the Southern Ute Indian Reservation, and therefore, subject to part 71 title V operating permit requirements. The primary emission points are the Solar Turbines, Inc. Centaur 50-H and Taurus 60-T7000S natural gas compressor turbines.

EPA received the initial part 71 operating permit application for the La Plata A Compressor Station on October 11, 1999. Based on their heat input capacity and construction date, the two turbines at the facility were determined to be subject to the requirements of NSPS subparts A and GG. EPA issued the initial part 71 permit on November 19, 2003, with conditions making the water injection system on T01 and the SoLoNox control on T02 enforceable as a means to achieve the NOx emission limits required by NSPS subpart GG. The initial permit has never been modified.

On May 13, 2005, EPA received a request for an administrative amendment to the initial permit to change the responsible official from Mr. Danny Pribble to Mr. Don Hawkins, Senior Vice President of Operations and Engineering. This amendment was never processed. On January 14, 2008, EPA received an application for renewal of the part 71 permit for the Transwestern La Plata A Compressor Station.

The La Plata A Compressor Station receives de-ionized water for water injection primarily from the Ignacio Gas Conditioning Plant across the road. Circumstances outside of Transwestern's control, such as drought, or a recent fire at the plant, can interrupt the supply of water from Williams, in which case, Transwestern must either import water by truck from New Mexico at a high cost or, under the current operating permit, shut down the turbine. The water pump is also shut down periodically to perform monthly routine maintenance and occasional repairs due to pump failure. Under the current part 71 permit, Transwestern has reported any interruption to water injection as a "deviation" from the permit. Although Transwestern has installed a back-up water pump to eliminate deviations, there may be periods when both pumps are temporarily inoperable, making water injection economically restrictive or operationally impossible.

In its part 71 renewal application, Transwestern described water injection as the normal operating mode to increase power output from the turbine. While water injection also decreases NOx formation in the combustion zone (and NOx concentration in the unit exhaust), it is not neccessary for the unit to comply with the applicable NOx emission limit in NSPS GG and was not installed to control NOx emissions; therefore, Transwestern views water injection as an optional process enhancement that is used under normal operation and not as a required element of emissions reduction for compliance purposes.

Upon review of the requirements of NSPS GG, EPA noted that NSPS GG requires owners or operators to take particular monitoring measures if they have chosen to meet the specified emission limits using certain control technologies, but it does not specifically require owners/operators to use control devices to meet the emission limits. Transwestern provided test results to demonstrate that unit T01 is capable of complying with the NSPS subpart GG NOx emission limit without water injection. The test results show that the Centaur 50-H gas turbine emits an average of less than 75 parts per million (ppm) of NO_x without water injection, which is less than half of the 174 ppm NSPS subpart GG emission limit.

Based on the information provided by Transwestern, which was certified for truth, accuracy, and completeness, EPA agrees with Transwestern that water injection is not necessary for unit T01 to meet the NOx emission limits in NSPS subpart GG. EPA removed the water injection system from Table 1 of the permit identifying it as emission control equipment for unit T01. Subsequently, EPA replaced the NSPS GG monitoring requirements specific to sources that use water injection to control NOx with the monitoring requirements for sources not using water injection to control NO_x. This action will allow for

Transwestern to disrupt water injection for the occasional necessary reasons described above, without the interruptions being considered a deviation of the permit requiring notification to EPA.

In addition to the changes described above for renewal of the part 71 permit, the following changes have been made as part of the final permit renewal. In an effort to streamline the title V permits and reduce the number of administrative permit amendments requested, EPA is modifying the structure of the permit, including removing specific non-enforceable facility information, such as the names and phone numbers of the Responsible Official, Facility Contact, and Tribal Contact, and the parent company mailing address. Part 71 does not require this information to be in the permit and changes to such information are the most often requested administrative permit amendments. This information will be maintained in the Statement of Basis for each permit action. EPA requests from this point forward that Transwestern continue to send notification in writing of changes to such facility information; however, the changes will no longer require administrative permit amendments. The notifications will be kept on file, similar to off permit change notifications, and the most current information will be updated in the Statement of Basis as part of the next permit modification or renewal.

On November 8, 2007, EPA sent a letter to inform Transwestern of a new mailing address, effective December 17, 2007, for the submittal of annual fee payments required pursuant to 40 CFR part 71 and the title V permits issued by EPA's Air Program. EPA is amending the permit to correct the fee payment address. The new addresses are:

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

On February 26, 2009, EPA received a notification from Transwestern that the Responsible Official for the La Plata A Compressor Station had changed from Mr. Don Hawkins, Senior Vice President of Operations and Engineering to Mr. Jeff Whippo, Area Director. This change has been reflected in this Statement of Basis.

f. Potential to emit

Potential to emit (PTE) means the maximum capacity of Transwestern's La Plata A Compressor Station to emit any air pollutant under its physical and operational design. Any physical or operational limitation on the capacity of the La Plata A Compressor Station to emit an air pollutant, including air pollution control equipment and restrictions on hours of operation or on the type or amount of material combusted, stored, or processed, may be treated as part of its design if the limitation is enforceable by EPA. PTE is meant to be a worse case emissions calculation. Actual emissions may be much lower.

Table 3 includes PTE data provided by Transwestern for the La Plata A Compressor Station. Transwestern calculated the PTE of NO_x for each turbine based on the permit limit of 174 ppm in the stack gas.

Table 3 – PTE of Regulated Air Pollutants
Transwestern Pipeline Company
La Plata A Compressor Station

Emission Unit ID	**Regulated Air Pollutants**							
	NOx (tpy)	VOC (tpy)	SO_2 (tpy)	PM_{10} & $PM_{2.5}$ (tpy)	CO (tpy)	Lead (tpy)	HAP (tpy)	CH_2O (tpy)
T01	138.4	0.42	0.69	1.33	6.45	0.0	0.20	0.14
T02	149.8	0.45	0.73	1.42	17.6	0.0	0.21	0.15
IEUs	1.06	2.16*	0.01	0.08	0.9	0.0	0.00	0.00
TOTAL	288.3	3.0	1.4	2.8	25.0	0.0	0.4	0.3

NO_x - oxides of nitrogen
VOC - volatile organic compounds
SO_2 - sulfur dioxide
PM_{10} & $PM_{2.5}$ - particulate matter with a diameter 10 & 2.5 microns or less, respectively
CO - carbon monoxide
HAP - hazardous air pollutants (see Clean Air Act Section 112(b))
* Based on additional documentation of tank emissions provided by Transwestern.

The facility-wide PTE are as follows:

Nitrogen Oxides (NOx) – 288.3 tpy
Carbon Monoxide (CO) – 25.0 tpy
Volatile Organic Compounds (VOC) – 3.0 tpy
Small Particulates (PM_{10} & $PM_{2.5}$) – 2.8 tpy
Sulfur Dioxide (SO_2) – 1.4 tpy
Total Hazardous Air Pollutants (HAPs) – 0.4 tpy
Largest Single HAP (formaldehyde, CH_2O) – 0.3 tpy

2. Tribe Information

a. <u>Indian country</u>:

The Transwestern La Plata A Compressor Station is located within the exterior boundaries of the Southern Ute Indian Reservation and is thus within Indian country as defined at 18 U.S.C. §1151. The Southern Ute Tribe does not have a federally-approved Clean Air Act (CAA) title V operating permits program nor does EPA's approval of the State of Colorado's title V program extend to Indian country. Thus, EPA is the appropriate governmental entity to issue the title V permit to this facility.

b. <u>The Reservation</u>:

The Southern Ute Indian Reservation is located in Southwestern Colorado adjacent to the New Mexico boundary. Ignacio is the headquarters of the Southern Ute Tribe, and Durango is the closest major city, just 5 miles outside of the north boundary of the Reservation. Current information indicates that the population of the Tribe is about 1,450 people with approximately 410 Tribal members living off the Reservation. In addition to Tribal members, there are over 30,000 non-Indians living within the exterior boundaries of the Southern Ute Reservation.

c. Tribal government:

The Southern Ute Indian Tribe is governed by the Constitution of the Southern Ute Indian Tribe of the Southern Ute Indian Reservation, Colorado adopted on November 4, 1936 and subsequently amended and approved on October 1, 1975. The Southern Ute Indian Tribe is a federally recognized Tribe pursuant to section 16 of the Indian Reorganization Act of June 18, 1934 (48 Stat.984), as amended by the Act of
June 15, 1935 (49 Stat. 378). The governing body of the Southern Ute Indian Tribe is a seven member Tribal Council, with its members elected from the general membership of the Tribe through a yearly election process. Terms of the Tribal Council are 3 years and are staggered so in any given year 2 members are up for reelection. The Tribal Council officers consist of a Chairman, Vice-Chairman, and Treasurer.

d. Local air quality:

The Tribe maintains an air monitoring network consisting of two stations equipped to measure ambient concentrations of oxides of nitrogen (NO, NO_2, and NO_x), ozone (O_3), and carbon monoxide (CO), and to collect meteorological data. The Tribe has collected NO_2 and O_3 data at the Ignacio, Colorado station (also known as the Ute 1 station, with AQS identification number 08-067-7001) and the Bondad, Colorado station (also known as Ute 3, with AQS identification number 08-067-7003) since June 1, 1982, and April 1, 1997, respectively. The CO channel at the Ignacio station has been reporting to AQS since January 1, 2000, and both stations began reporting NO and NO_x data to AQS on the same day. Also in 2000, both stations initiated meteorological monitors measuring wind speed, wind direction, vertical wind speed, outdoor temperature, relative humidity, solar radiation, and rain/snowmelt precipitation. Reporting of vertical wind speed data from both stations terminated on July 1, 2007. Particulate data (PM_{10}) was collected from December 1, 1981 to September 30, 2006 at the Ignacio station and from April 1, 1997 to September 30, 2006 at the Bondad station. The Tribe reports hourly data to AQS for the criteria pollutants being monitored (NO_2, O_3, and CO), allowing AQS users to retrieve data that can be compared to any of the National Ambient Air Quality Standards for these pollutants.

3. Applicable Requirements

a. Applicable requirement review

The following discussions address applicable requirements, and requirements that may appear to be applicable, but are not. All applicable and non-applicable requirements addressed here are included in the Code of Federal Regulations (CFR) at title 40.

Prevention of Significant Deterioration (PSD)

PSD is a preconstruction review requirement of the CAA that applies to proposed projects that are sufficiently large (in terms of emissions) to be a "major" new stationary source or "major" modification of an existing stationary source. The PSD regulations are found at 40 CFR 52.21. Source size is defined in terms of "potential to emit," which is its capability at maximum design capacity to emit a pollutant, except as constrained by existing federally and practically enforceable conditions applicable to the source. A new stationary source or a modification to an existing minor stationary source is major if the proposed project has the potential to emit any pollutant regulated under the CAA in amounts equal to or exceeding specified major source thresholds (100 tpy for 28 listed industrial source categories and 250 tpy for all other sources). PSD also applies to modifications at existing major sources that cause a "significant net emissions increase" at that source. A modification is a physical change or change in the method of operation. Significance levels for each pollutant are defined in the PSD regulations at 40 CFR 52.21.

The La Plata A Compressor Station does not belong to any of the 28 listed source categories. Therefore, the potential to emit threshold for determining PSD applicability for this source is 250 tpy. The La Plata A Compressor Station is a major source of NOx emissions for the purposes of PSD requirements. The La Plata A Compressor Station, the La Plata B Compressor Station (owned by Northwest Pipeline GP), and the Ignacio Gas Plant (owned by Williams Field Services) are considered to be a single source for PSD and title V permitting purposes, and other applicable requirements including, but not limited to, section 112 National Emission Standards for Hazardous Air Pollutants. EPA made this single source applicability determination in response to an April 19, 1999 letter from Mr. Larry Campbell of Transwestern Pipeline Company in which he contended that the La Plata A Compressor Station was not a major source on its own, and therefore, was not subject to the 40 CFR part 71 federal operating permit provisions. EPA disagreed with Mr. Campbell's contention in a letter dated August 17, 1999, from Mr. Richard R. Long, Director of the EPA Region 8 Air and Radiation Program, to Mr. Larry Campbell of Transwestern Pipeline Company, and provided a rationale for asserting that La Plata A Compressor Station is part of a single source with the La Plata B Compressor Station and Ignacio Gas Plant,.

The single source determination requires that the potential emissions from all components of the source be aggregated when evaluating applicability of both PSD and title V. In addition, emissions netting calculations must include emission increases and decreases from the entire source. However, this does not mean that all the components of the source must necessarily obtain a PSD permit for a modification at one of the components. A PSD permit applies to the new construction, not the entire source. As always, the applicability of PSD and the required permitting must be evaluated on a case-by-case basis.

Although the La Plata A Compressor Station is a major PSD source (PTE of any one criteria pollutant is greater than 250 tons per year) as a result of the single source determination, a PSD review was not triggered at the La Plata A Compressor Station for the 1984, 1991, and 1992 PSD modifications that Williams Field Service implemented at the Ignacio Gas Plant. <u>Hence, Transwestern was not required to obtain a PSD permit.</u>

In regards to applicability determinations with respect to PSD and title V, Transwestern's La Plata A Compressor Station is considered a major stationary source. Therefore, any future proposed modifications at the facility must evaluate PSD applicability based on significance levels. Furthermore, any netting calculations must take into consideration increases and decrease facility-wide, which includes Williams Field Services Ignacio Gas Plant, Northwest Pipeline GP La Plata B Compressor Station, and Transwestern La Plata A Compressor Station.

New Source Performance Standard (NSPS)

<u>40 CFR Part 60, Subpart A</u>: General Provisions. This subpart applies to the owner or operator of any stationary source which contains an affected facility, the construction or modification of which is commenced after the date of publication of any standard in part 60. The general provisions under subpart A apply to sources that are subject to the specific subparts of part 60.

As explained below, the La Plata A Compressor Station is subject to the provisions of 40 CFR part 60, subpart GG. Therefore, the general provisions of 40 CFR part 60 also apply.

<u>40 CFR Part 60, Subpart K</u>: Standards of Performance for Storage Vessels for Petroleum Liquids for which Construction, Reconstruction, or Modification Commenced After June 11, 1973, and Prior to May 19, 1978. This rule applies to storage vessels for petroleum liquids with a storage capacity greater than 40,000 gallons. 40 CFR part 60, subpart K does not apply to storage vessels for petroleum or condensate stored, processed, and/or treated at a drilling and production facility prior to custody transfer.

Subpart K does not apply to the storage vessels at the La Plata A Compressor Station because all of the tanks at the facility have a capacity less than 40,000 gallons.

<u>40 CFR Part 60, Subpart Ka</u>: Standards of Performance for Storage Vessels for Petroleum Liquids for which Construction, Reconstruction, or Modification Commenced After May 18, 1978, and Prior to June 23, 1984. This rule applies to storage vessels for petroleum liquids with a storage capacity greater than 40,000 gallons. Subpart Ka does not apply to petroleum storage vessels with a capacity of less than 420,000 gallons used for petroleum or condensate stored, processed, or treated prior to custody transfer.

Subpart Ka does not apply to the storage vessels at the La Plata A Compressor Station because all of the tanks at the facility have a capacity less than 40,000 gallons.

<u>40 CFR Part 60, Subpart Kb</u>: Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for which Construction, Reconstruction, or Modification Commenced After July 23, 1984. This rule applies to storage vessels with a capacity greater

than or equal to 75 cubic meters.

The subpart does not apply to the storage vessels at the La Plata A Compressor Station because the facility has no tanks with a capacity greater than or equal to 75 cubic meters (approximately 19,813 gallons) that store volatile organic liquids.

40 CFR Part 60, Subpart GG**:** Standards of Performance for Stationary Gas Turbines. This rule applies to stationary gas turbines, with a heat input at peak load equal to or greater than 10.7 gigajoules per hour (10 MMBtu/hr), that commenced construction, modification, or reconstruction after October 3, 1977.

Turbine units T01 and T02 were constructed after October 3, 1977. Each turbine also has a heat input at peak loads greater than10 MMBtu/hr and each is, therefore, subject to subpart GG. Units T01 and T02 are subject to the NO_x standard at 40 CFR 60.332(a)(2), the sulfur in fuel standard at 40 CFR 60.333(b), and the appropriate testing and monitoring requirements at 40 CFR 60.334 and 60.335.

The installation of existing units T01 and T02 occurred in 1991 and 1997, respectively. The units were subject to the initial performance tests for NO_x required by 40 CFR 60.8 in order to determine if the units met the NO_x emission standard at 40 CFR 60.332(a)(2). Units T01 and T02 were also subject to the test methods and procedures for NO_x specified in 40 CFR 60.335(a), (b), (c), and (f).

Periodic Monitoring

The requirements of 40 CFR 60.334(c) for monitoring of NO_x emissions state:

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

Turbine units T01 and T02 commenced construction in 1991 and 1997, respectively, and do not use steam or water injection to control NO_x emissions. Unit T01 is not controlled and unit T02 was retrofitted with SoLoNOx technology to control NO_x emissions. EPA approved Transwestern's Portable Analyzer and Monitoring Protocol for measuring NO_x emissions at the facility on February 26, 2008. Therefore, Transwestern may continue to use the approved monitoring protocol to demonstrate compliance with the applicable NO_x emission limit under §60.332(a).

Transwestern shall comply with the requirements of 40 CFR 60.334(h) for monitoring of nitrogen content and sulfur content of the fuel being burned in units T01 and T02.

Under §60.334(h)(2), 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.

Under §60.334(h)(3), the permittee may elect not to monitor the sulfur content of the gaseous fuel, if the fuel is demonstrated by the permittee to meet the definition of natural gas in §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:

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

The SO_2 standard in 40 CFR 60.333(b) is:

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

Because the permittee has elected to demonstrate that the fuel meets the definition of natural gas in §60.331(u), by supplying a valid tariff sheet, as allowed in §60.334(h)(3)(i), there is no monitoring required to demonstrate compliance with the SO_2 standard in 40 CFR 60.333(b).

<u>40 CFR part 60, Subpart JJJJ</u>: Standards of Performance for Stationary Spark Ignition Internal Combustion Engines. This subpart establishes emission standards and compliance requirements for the control of emissions from stationary spark ignition (SI) internal combustion engines (ICE) that commenced construction, modification or reconstruction after June 12, 2006, where the SI ICE are manufactured on or after specified manufacture trigger dates. The manufacture trigger dates are based on the engine type, fuel used, and maximum engine horsepower.

For the purposes of this subpart, the date that construction commences is the date the engine is ordered by the owner or operator (See 40 CFR 60.4230(a)).

According to the information provided by Transwestern in the renewal application, there are no stationary SI ICE operated at the La Plata A Compressor Station. Therefore, this subpart does not apply.

<u>40 CFR Part 60, Subpart KKK</u>: Standards of Performance for Equipment Leaks of VOC from Onshore Natural Gas Processing Plants. This rule applies to compressors and other equipment at onshore natural gas processing facilities. As defined in this subpart, a natural gas processing plant is any processing site engaged in the extraction of natural gas liquids from field gas, fractionation of mixed natural gas liquids (NGLs) to natural gas products, or both. Natural gas liquids are defined as the hydrocarbons, such as ethane, propane, butane, and pentane that are extracted from field gas.

The La Plata A Compressor Station does not extract natural gas liquids from field gas, nor does it fractionate mixed NGLs to natural gas products; therefore, the facility does not meet the definition of a natural gas processing plant under this subpart and this rule does not apply.

<u>40 CFR Part 60, Subpart LLL</u>: Standards of Performance for Onshore Natural Gas Processing;

SO_2 Emissions. This rule applies to sweetening units and sulfur recovery units at onshore natural gas processing facilities. As defined in this subpart, sweetening units are process devices that separate hydrogen sulfide (H_2S) and carbon dioxide (CO_2) from a sour natural gas stream. Sulfur recovery units are defined as process devices that recover sulfur from the acid gas (consisting of H_2S and CO_2) removed by a sweetening unit.

The La Plata A Compressor Station does not perform sweetening or sulfur recovery at the facility. Therefore, this rule does not apply.

40 CFR part 60, Subpart KKKK: Standards of Performance for Stationary Combustion Turbines. The rule applies to stationary combustion turbines with a heat input at peak load equal to or greater than 10.7 gigajoules (10 MMBtu) per hour. This subpart establishes emission standards and compliance schedules for the control of emissions from stationary combustion turbines that commenced construction, modification or reconstruction after February 18, 2005.

The turbines operating at La Plata A Compressor Station (T01 and T02) are affected units under subpart KKKK; however, the requirements do not apply, because the turbines were constructed prior to February 18, 2005 (installed at the facility in 1991 and 1997) and EPA has no information that indicates that the turbines have been replaced with new units or have been modified or reconstructed after February 18, 2005. Therefore, based on the information provided by Transwestern, this rule does not apply.

National Emissions Standards for Hazardous Air Pollutants (NESHAP)

40 CFR Part 63, Subpart A: General Provisions. This subpart contains national emissions standards for HAPs that regulate specific categories of sources that emit one or more HAP regulated pollutants under the CAA. The general provisions under subpart A apply to sources that are subject to the specific subparts of part 63.

As explained below, the La Plata A Compressor Station is not subject to any specific subpart of part 63; however, the facility emits at least one HAP regulated under the CAA and has equipment in relevant source categories (i.e., turbine units T01 and T02) which are not subject to relevant standards (i.e., 40 CFR part 63, subpart YYYY). A record of the applicability determinations demonstrating that this source is not subject to the relevant part 63 standards must be kept in accordance with §63.1(b)(3). This applicability determination must be kept on-site for a period of 5 years after the determinations or until a source changes its operations to become an affected source. There are no other general provisions under subpart A that apply to this facility.

40 CFR Part 63, Subpart HH: National Emission Standards for Hazardous Air Pollutants from Oil and Natural Gas Production Facilities. This subpart applies to the owners and operators of affected units located at natural gas production facilities that are major sources of HAPs, and that process, upgrade, or store natural gas prior to the point of custody transfer, or that process, upgrade, or store natural gas prior to the point at which natural gas enters the natural gas transmission and storage source category or is delivered to a final end user. The affected units are glycol dehydration units, storage vessels with the potential for flash emissions, and the group of ancillary equipment, and compressors intended to operate

in volatile hazardous air pollutant service, which are located at natural gas processing plants.

Throughput Exemption

Those sources whose maximum natural gas throughput, as appropriately calculated in §63.760(a)(1)(i) through (a)(1)(iii), is less than 18,400 standard cubic meters per day are exempt from the requirements of this subpart.

Source Aggregation

Major source, as used in this subpart, has the same meaning as in §63.2, except that:

1) Emissions from any oil and gas production well with its associated equipment and emissions from any pipeline compressor station or pump station shall not be aggregated with emissions from other similar units.

2) Emissions from processes, operations, or equipment that are not part of the same facility shall not be aggregated.

3) For facilities that are production field facilities, only HAP emissions from glycol dehydration units and storage tanks with flash emission potential shall be aggregated for a major source determination.

Facility

For the purpose of a major source determination, facility means oil and natural gas production and processing equipment that is located within the boundaries of an individual surface site as defined in subpart HH. Examples of facilities in the oil and natural gas production category include, but are not limited to: well sites, satellite tank batteries, central tank batteries, a compressor station that transports natural gas to a natural gas processing plant, and natural gas processing plants.

Production Field Facility

Production field facilities are those located prior to the point of custody transfer. The definition of custody transfer (40 CFR 63.761) means the point of transfer after the processing/treating in the producing operation, except for the case of a natural gas processing plant, in which case the point of custody transfer is the inlet to the plant.

Natural Gas Processing Plant

A natural gas processing plant is defined in 40 CFR 63.761 as any processing site engaged in the extraction of NGLs from field gas, or the fractionation of mixed NGLs to natural gas products, or a combination of both. A treating plant or compression facility that does not engage in these activities is considered to be a production field facility.

Major Source Determination for Production Field Facilities

The definition of major source in this subpart (at 40 CFR §63.761) states, in part, that only emissions from the dehydration units and storage vessels with a potential for flash emissions at production field facilities are to be aggregated when comparing to the major source thresholds. For facilities that are not production field facilities, HAP emissions from all HAP emission units shall be aggregated.

Area Source Applicability

40 CFR part 63, subpart HH applies to area sources of HAPs. An area source is a HAP source whose total HAP emissions are less than 10 tpy of any single HAP or 25 tpy for all HAPs in aggregate. This subpart requires different emission reduction requirements for triethylene glycol dehydration units found at oil and gas production facilities based on their geographical location. Units located in densely populated areas (determined by the Bureau of Census) and known as urbanized areas with an added 2-mile offset and urban clusters of 10,000 people or more, are required to have emission controls. Units located outside these areas will be required to have the glycol circulation pump rate optimized or operators can document that PTE of benzene is less than 1 tpy.

Applicability of Subpart HH to the La Plata A Compressor Station

The La Plata A Compressor Station is a production field facility, not a natural gas processing plant. Furthermore, the facility does not have dehydration units and the HAP emissions from the tanks at the facility with potential for flash emissions alone are below the major source thresholds of 10 tpy of a single HAP and 25 tpy of aggregated HAPs. Therefore, subpart HH does not apply to this facility.

<u>40 CFR Part 63, Subpart HHH</u>: National Emission Standards for Hazardous Air Pollutants from Natural Gas Transmission and Storage Facilities. This rule applies to natural gas transmission and storage facilities that transport or store natural gas prior to entering the pipeline to a local distribution company or to a final end user, and that are major sources of hazardous air pollutant (HAP) emissions. Natural gas transmission means the pipelines used for long distance transport and storage vessel is a tank or other vessel designed to contain an accumulation of crude oil, condensate, intermediate hydrocarbon, liquids, produced water or other liquid and is constructed of wood, concrete, steel or plastic structural support. A compressor station that transports natural gas prior to the point of custody transfer or to a natural gas processing plant (if present) is not considered a part of the natural gas transmission and storage source category.

The La Plata A Compressor Station is a natural gas transmission and storage facility, but does not have HAP emissions in excess of the major source thresholds of 10 tpy of a single HAP or 25 tpy of HAPs in aggregate. Therefore, subpart HHH does not apply to this facility.

40 CFR Part 63, Subpart YYYY: National Emission Standards for Hazardous Air Pollutants from Stationary Combustion Turbines. This rule establishes national emission limitations and work practice standards for HAPs emitted from Stationary Combustion Turbines. The affected source includes the stationary combustion turbine located at a major source of HAP emissions.

Stationary Combustion Turbine

Stationary combustion turbines are defined in §63.6175 as all equipment, including but not limited to the turbine, the fuel, air, lubrication and exhaust gas systems, control systems (except emissions control equipment), and any ancillary components and sub-components comprising any simple cycle stationary combustion turbine, any regenerative/recuperative cycle stationary combustion turbine, the combustion turbine portion of any stationary cogeneration cycle combustion system, or the combustion turbine portion of any stationary combined cycle steam/electric generating system. Stationary means that the combustion turbine is not self propelled or intended to be propelled while performing its function. Stationary combustion turbines do not include turbines located at a research or laboratory facility, if research is conducted on the turbine itself and the turbine is not being used to power other applications at the research or laboratory facility.

Major Source

Major source for purposes of this subpart has the same meaning as provided in 40 CFR 63.2 with the exception that emissions from any oil or gas exploration or production well (with its associated equipment) and emissions from any pipeline compressor station or pump station shall not be aggregated with emissions from other similar units, to determine whether such emission points or stations are major sources, even when emission points are contiguous are or are under common control.

Applicability to the La Plata A Compressor Station

The La Plata A Compressor Station is not subject to this subpart because it is not a major source of HAPs as determined from the requirements of this rule.

Compliance Assurance Monitoring (CAM) Rule

40 CFR Part 64: Compliance Assurance Monitoring Provisions. According to 40 CFR 64.2(a), the CAM rule applies to each Pollutant Specific Emission Unit (PSEU) that meets the following three criteria: 1) is subject to an emission limitation or standard, and 2) uses a control device to achieve compliance, and 3) has pre-control emissions that exceed or are equivalent to the major source title V threshold of 100 tpy.

The turbines at the La Plata A Compressor Station are subject to limitations on emissions of NO_x and SO_2. PSEU turbine T01 does not use add-on control devices to achieve either pollutant emission limit. PSEU turbine T02 uses add-on control devices to achieve compliance with the NO_x limit, but it does not have the uncontrolled potential to emit NO_x greater than the major source threshold of 100 tpy. Because the La Plata A Compressor station gas turbines do not meet all of criteria, Transwestern is not required to submit a CAM plan. Therefore, turbines T01 and T02 are not subject to the CAM requirements.

Chemical Accident Prevention

40 CFR Part 68: Chemical Accident Prevention Provisions. Based on Transwestern's application, the La Plata A Compressor Station does not use or store any regulated substances listed in 112(r) of the CAA that is above the threshold quantity. Transwestern is not, therefore, subject to the requirement to develop and submit a risk management plan (RMP). However, Transwestern has an ongoing responsibility to submit a RMP if a substance is listed that the La Plata A Compressor Station has in quantities over the threshold amount or if the La Plata A Compressor Station ever increases the amount of any regulated substance above the threshold quantity.

Periodic Monitoring

The monitoring requirements contained in 40 CFR part 60, subpart GG only require that a one time performance test for NOx be conducted to demonstrate initial compliance with the requirements of 40 CFR 60.332. No additional testing or monitoring of NOx emissions is required under this NSPS.

The *Appalachian Power* court held that 40 CFR 71.6(a)(3)(i) authorizes a sufficiency review of monitoring and testing in an existing emissions standard, and enhancement of that monitoring or testing through the permit, when the standard requires no periodic testing or instrumental or non-instrumental monitoring, specifies no frequency, or requires only a one-time test. Thus, EPA has authority in the federal operating permit regulation to specify additional testing or monitoring for a source to assure compliance, when existing applicable regulations do not require periodic monitoring or only require a one-time emissions test.

Because 40 CFR part 60, subpart GG only requires that a one-time compliance test for NOx emissions be conducted for a subject turbine, additional monitoring of the turbines for assuring compliance with the NO_x emission limit has been included in the permit. Appropriate periodic monitoring for the gas-fired turbines was determined to be quarterly monitoring of NOx emissions using a portable analyzer.

Stratospheric Ozone and Climate Protection

40 CFR Part 82, Subpart F: Air Conditioning Units. Based on Transwestern's application, the La Plata A Compressor Station does not currently operate affected units at the facility. However, should the La Plata A Compressor Station perform any maintenance, service, repair, or disposal of any equipment, including window air conditioners, containing chlorofluorocarbons (CFCs), or contracts with someone to do this work, Transwestern must comply with the standards of 40 CFR subpart F, specifically, §82.156, §82.158, §82.161, and §82.166(i), and request a minor modification to this part 71 permit.

40 CFR Part 82, Subpart H: Halon Fire Extinguishers. Based on Transwestern's application, the La Plata A Compressor Station does not have fire extinguishers on site that use halon, so subpart H for halon emissions reduction does not apply. If Transwestern ever decides to use fire extinguishers that use halon and use its personnel to service, maintain, test, repair, or dispose of equipment that contains halons or use such equipment during technician training, then it must comply with the standards of 40 CFR part 82, subpart H for halon emissions reduction and request a minor to this part 71 permit.

b. Conclusion

Since the La Plata A Compressor Station is located in Indian country, the State of Colorado's implementation plan does not apply to this source. In addition, no tribal implementation plan (TIP) has been submitted and approved for the Southern Ute Tribe, and EPA has not promulgated a federal implementation plan (FIP) for the area of jurisdiction governing the Southern Ute Indian Reservation. Therefore, the La Plata A Compressor Station is not subject to any implementation plan.

EPA recognizes that, in some cases, sources of air pollution located in Indian country are subject to fewer requirements than similar sources located on land under the jurisdiction of a state or local air pollution control agency. To address this regulatory gap, EPA is in the process of developing national regulatory programs for preconstruction review of major sources in nonattainment areas and of minor sources in both attainment and nonattainment areas. These programs will establish, where appropriate, control requirements for sources that would be incorporated into part 71 permits. To establish additional applicable, federally-enforceable emission limits, EPA Regional Offices will, as necessary and appropriate, promulgate FIPs that will establish federal requirements for sources in specific areas. EPA will establish priorities for its direct federal implementation activities by addressing as its highest priority the most serious threats to public health and the environment in Indian country that are not otherwise being adequately addressed. Further, EPA encourages and will work closely with all tribes wishing to develop TIPs for approval under the Tribal Authority Rule. EPA intends that its federal regulations created through a FIP will apply only in those situations in which a tribe does not have an approved TIP.

4. EPA Authority

a. General authority to issue part 71 permits

Title V of the Clean Air Act requires that EPA promulgate, administer, and enforce a federal operating permits program when a state does not submit an approvable program within the time frame set by title V or does not adequately administer and enforce its EPA-approved program. On July 1, 1996 (61 FR 34202), EPA adopted regulations codified at 40 CFR part 71 setting forth the procedures and terms under which the Agency would administer a federal operating permits program. These regulations were updated on February 19, 1999 (64 FR 8247) to incorporate EPA's approach for issuing federal operating permits to stationary sources in Indian country.

As described in 40 CFR 71.4(a), EPA will implement a part 71 program in areas where a state, local, or tribal agency has not developed an approved part 70 program. Unlike states, Indian tribes are not required to develop operating permits programs, though EPA encourages tribes to do so. See, e.g., Indian Tribes: Air Quality Planning and Management (63 FR 7253, February 12, 1998) (also known as the

"Tribal Authority Rule"). Therefore, within Indian country, EPA will administer and enforce a part 71 federal operating permits program for stationary sources until a tribe receives approval to administer their own operating permits program.

5. Use of All Credible Evidence

Determinations of deviations, continuous or intermittent compliance status, or violations of the permit are not limited to the testing or monitoring methods required by the underlying regulations or this permit; other credible evidence (including any evidence admissible under the Federal Rules of Evidence) must be considered by the source and EPA in such determinations.

6. Public Participation

a. Public notice

There was a 30-day public comment period for actions pertaining to the draft permit. Public notice was given for the draft permit by mailing a copy of the notice to the permit applicant, the affected state, tribal and local air pollution control agencies, the city and county executives, the state and federal land managers, and the local emergency planning authorities which have jurisdiction over the area where the source is located. A copy of the notice was also provided to all persons who have submitted a written request to be included on the mailing list. If you would like to be added to our mailing list to be informed of future actions on these or other Clean Air Act permits issued in Indian country, please send your name and address to:

Claudia Smith, Part 71 Permit Contact
U.S. Environmental Protection Agency, Region 8
1595 Wynkoop Street (8P-AR)
Denver, Colorado 80202-1129

Public notice was published in the Durango Herald on April 10, 2009, giving opportunity for public comment on the draft permit and the opportunity to request a public hearing.

b. Opportunity for comment

Members of the public were given the opportunity to review a copy of the draft permit prepared by EPA, the application, the Statement of Basis for the draft permit, and all supporting materials for the draft permit. Copies of these documents were available at:

La Plata County Clerk's Office
1060 East 2nd Avenue
Durango, Colorado 81302

and

Southern Ute Indian Tribe
Environmental Programs Office
116 Mouache Drive
Ignacio, Colorado 81137

and

US EPA Region 8
Air Program Office
1595 Wynkoop Street (8P-AR)
Denver, Colorado 80202-1129

All documents were available for review at the U.S. EPA Region 8 office Monday through Friday from 8:00 a.m. to 4:00 p.m. (excluding federal holidays).

Any interested person could submit written comments on the draft part 71 operating permit during the public comment period to the Part 71 Permit Contact at the address listed above. EPA keeps a record of the commenters and of the issues raised during the public participation process. All comments have been considered and answered by EPA in making the final decision on the permit.

Anyone, including the applicant, who believed any condition of the draft permit was inappropriate could raise all reasonable ascertainable issues and submit all arguments supporting their position by the close of the public comment period. Any supporting materials submitted must have been included in full and may not have been incorporated by reference, unless the material was already submitted as part of the administrative record in the same proceeding or consisted of state or federal statutes and regulations, EPA documents of general applicability, or other generally available reference material.

No comments on the draft permit or Statement of Basis were received during the public comment period.

c. Opportunity to request a hearing

A person could submit a written request for a public hearing to the Part 71 Permit Contact, at the address listed in section 6.a above, by stating the nature of the issues to be raised at the public hearing. EPA did not receive any requests for a public hearing during the public comment period.

d. Appeal of permits

Within 30 days after the issuance of a final permit decision, any person who filed comments on the draft permit or participated in the public hearing may petition to the Environmental Appeals Board to review any condition of the permit decision. Any person who failed to file comments or participate in the public hearing may petition for administrative review, only if the changes from the draft to the final permit decision or other new grounds were not reasonably foreseeable during the public comment period. The 30-day period to appeal a permit begins with EPA's service of the notice of the final permit decision.

The petition to appeal a permit must include a statement of the reasons supporting the review, a demonstration that any issues were raised during the public comment period, a demonstration that it was impracticable to raise the objections within the public comment period, or that the grounds for such objections arose after such a period. When appropriate, the petition may include a showing that the condition in question is based on a finding of fact or conclusion of law which is clearly erroneous; or, an exercise of discretion, or an important policy consideration that the Environmental Appeals Board should review.

The Environmental Appeals Board will issue an order either granting or denying the petition for review, within a reasonable time following the filing of the petition. Public notice of the grant of review will establish a briefing schedule for the appeal and state that any interested person may file an amicus brief. Notice of denial of review will be sent only to the permit applicant and to the person requesting the review. To the extent review is denied, the conditions of the final permit decision become final agency action.

A motion to reconsider a final order shall be filed within 10 days after the service of the final order. Every motion must set forth the matters claimed to have been erroneously decided and the nature of the alleged errors. Motions for reconsideration shall be directed to the Administrator rather than the Environmental Appeals Board. A motion for reconsideration shall not stay the effective date of the final order unless it is specifically ordered by the Board.

e. Petition to reopen a permit for cause

Any interested person may petition EPA to reopen a permit for cause, and EPA may commence a permit reopening on its own initiative. EPA will only revise, revoke and reissue, or terminate a permit for the reasons specified in 40 CFR 71.7(f) or 71.6(a)(6)(i). All requests must be in writing and must contain facts or reasons supporting the request. If EPA decides the request is not justified, it will send the requester a brief written response giving a reason for the decision. Denial of these requests is not subject to public notice, comment, or hearings. Denials can be informally appealed to the Environmental Appeals Board by a letter briefly setting forth the relevant facts.

f. Notice to affected states/tribes

As described in 40 CFR 71.11(d)(3)(i), public notice was given by mailing a copy of the notice to the air pollution control agencies of affected states, tribal and local air pollution control agencies that have jurisdiction over the area in which the source is located, the chief executives of the city and county where the source is located, any comprehensive regional land use planning agency and any state or Federal land manager whose lands may be affected by emissions from the source. The following entities were notified:

- State of Colorado, Department of Public Health and Environment
- State of New Mexico, Environment Department
- Southern Ute Indian Tribe, Environmental Programs Office
- Ute Mountain Ute Tribe, Environmental Programs
- Navajo Tribe, Navajo Nation EPA
- Jicarilla Tribe, Environmental Protection Office
- La Plata County, County Clerk
- Town of Ignacio, Mayor
- National Park Service, Air, Denver, CO
- U.S. Department of Agriculture, Forest Service, Rocky Mountain Region
- Carl Weston
- San Juan Citizen Alliance
- Wild Earth Guardians (formerly Rocky Mountain Clean Air Action)