UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 8
1595 Wynkoop Street
DENVER, CO 80202-1129
Phone 800-227-8917
http://www2.epa.gov/aboutepa/epa-region-8-mountains-and-plains

Ref: 8P-AR

MAY 15 2014

Mr. Jeffrey Stovall
Arrow Pipeline, LLC
Attn: Air Quality Team
801 Cherry Street, Suite 3800, Unit 20
Fort Worth, TX 76102

Re: Arrow Pipeline, LLC, Arrow Pipeline Station #7, Dunn County, North Dakota, Final Conditional Permit to Construct, Permit # SMNSR-TAT-000661-2013.001

Dear Mr. Stovall:

The U.S. Environmental Protection Agency Region 8 has completed its review of Arrow Pipeline, LLC's request to obtain a synthetic minor permit to construct pursuant to the Tribal Minor New Source Review Permit Program at 40 CFR Part 49 (MNSR) for the Station #7 natural gas compressor station. Based on the information submitted in your application the EPA hereby issues the enclosed final MNSR permit to construct. Please review each condition carefully and note any restrictions placed on this source.

A 30-day public comment period was held from March 20, 2014 to April 21, 2014. The EPA received comments from Arrow Pipeline, LLC on April 21, 2014. No other comments were received during the public comment period. The EPA's response to the public comments is also enclosed. The EPA made several revisions to the permit based on your comments, as well as on EPA-identified changes necessary for clarification and consistency with other EPA-issued permits. The final permit will be effective on June 15, 2014.

Pursuant to §49.159, within 30 days after the final permit decision has been issued, any person who commented on the specific terms and conditions of the draft permit, may petition the Environmental Appeals Board to review any term or condition of the permit.

Any person who failed to comment on the specific terms and conditions of this permit may petition for administrative review only to the extent that the changes from the draft to the final permit or other new grounds were not reasonably ascertainable during the public comment period.

The 30-day period within which a person may request review begins with this notice of the final permit decision. If an administrative review of the final permit is requested, the specific terms and conditions of the permit that are the subject of the request for review must be stayed.

If you have any questions concerning the enclosed final permit please contact Claudia Smith of my staff at (303) 312-6520.

Sincerely,

Debra H. Thomas
Acting Assistant Regional Administrator
Office of Partnerships and Regulatory Assistance

Enclosures

cc: Edmund Baker, Environmental Director, Three Affiliated Tribes

Enclosure - Response to Comments

Comments from Arrow Pipeline, LLC (Arrow) on Proposed Permit to Construct for the Station #7 pursuant to the Tribal Minor New Source Review Permit Program at 40 CFR Part 49 (MNSR)

1. General Comment:

   Arrow requested to remove all references to "crude oil" in the proposed permit that appear in together with references to natural gas condensate and produced water, as it was a relic from a former facility design. The current design of Station #7 does not propose that crude oil be handled in emitting equipment; rather, crude oil will remain in underground pipelines located near Station #7.

   We agree that the requested change is warranted and have removed all references to "crude oil" from permit conditions I.B., I.D.2.(d), I.D.2.(f)-(h), I.D.3., I.D.4.(b)-(c), I.D.4.(e), I.D.5.(a), I.D.5.(c), I.G.1., I.G.5-6., I.G.7.(a)-(c) , I.H.1.(a), I.H.5.(c)(i)-(ii), and I.I.3.(a)-(b).

2. Permit Condition I.A., Corporate Office Location:

   The Corporate Office Location has been changed to reflect a new office location specified by Arrow that is in Fort Worth, Texas.

3. Permit Condition I.B.:

   The following revision requested by Arrow has been made to the last paragraph of this section (indicated by underlined italic font) to accurately reflect facility design:

   "Compressed natural gas will be routed to a splitter, with most of the natural gas routed to a natural gas pipeline exiting the station and the remainder routed to a fuel gas coalescer. Natural gas from the fuel gas coalescer will be routed to and combusted by individual compressor engines and/or natural gas–fired electrical generator engines designed to provide power to the station *and/or to the flare or enclosed combustor pilot*."

4. Permit Condition I.D.2(g):

   Arrow requested to remove the requirement to install a Lease Automated Custody Transfer unit to track the volume of crude oil transferred through the facility. As previously mentioned, Arrow asserted that crude oil will not be handled by emitting equipment at Station #7. Arrow believed that the references to LACT units may be a relic from a former station design. Arrow stated understanding the need to track the volume of produced water and natural gas condensate handled on-site for compliance demonstration purposes. However, Arrow does not believe that a LACT unit is necessary to achieve this requirement; especially since there is no crude oil being stored onsite. LACT units are sophisticated measurement equipment used for precise measurements where custody transfer of hydrocarbons occurs. Arrow requested that the permit language instead specify that the volume of produced water and natural gas condensate be monitored at the tanks. Arrow believes this approach will be accurate enough to ensure compliance with throughput limitations and to calculate emissions. Moreover, measurement at the tanks is an approach allowed by Onshore Oil and Gas Order No. 4.

We agree that the requested deletion is warranted for consistency with the current facility design. We have removed the requirements to install LACT units in this section and to use them to monitor the throughput volume of produced water and natural gas condensate. We have also removed Section E. Requirements for LACT Units from the final permit and adjusted subsequent section numbering as appropriate. We have added the following condition 7(c) to Section F. Requirements for Tanks (formerly Section G. Requirements for Tanks) in order to track the volume of natural gas condensate and produced water processed at this facility:

(c) *The Permittee shall follow the instructions in the "Onshore Oil and Gas Operations; Federal and Indian Oil & Gas Leases; Onshore Oil and Gas Order No. 4; Measurement of Oil," Section III.C; "Oil Measurement by Tank Gauging," developed by the US Department of the Interior's Bureau of Land Management, to measure the volume of produced water and natural gas condensate routed to each tank to subsequently determine the volume of produced water and natural gas condensate processed through the station as required in the **Requirements for Emission Limits, Construction, and Operation** section of this permit. Other measurement methods may be used upon prior written approval by the EPA.*

[Note: EPA is incorporating by reference the measurement methodologies described in this document only. There are no other enforcement implications intended. The Onshore Oil and Gas Operations; Federal and Indian Oil & Gas Leases; Onshore Oil and Gas Order No. 4 can be found 43 CFR 3160; Federal Register/Vol. 54, No. 36 or on-line at http://www.blm.gov/pgdata/etc/medialib/blm/mt/blm_programs/energy/oil_and_gas/operations/orders.Par.92085.File.dat/ord4.pdf]

5. Permit Condition I.E.3.(e) [formerly I.F.3.(e)]:

Arrow expressed concern that the requirement to notify the EPA at least one week prior to a scheduled performance test if the test cannot be conducted may cause unavoidable noncompliance with the permit. In the event of an unavoidable and unforeseen engine malfunction or operational shut-down less than one week before a scheduled performance test that cannot be resolved in time for the test, Arrow will have failed to notify the EPA one week prior to performance testing. Arrow requested that this verbiage be changed slightly to specify, "*at least one week prior to performance testing or as soon as practicable prior to a scheduled performance test."* Arrow committed to still notify the EPA within one week prior to a scheduled performance test if possible. But when not possible, Arrow would notify EPA as soon as it is determined that the engine cannot be tested according to the timeframe established.

We are agreeable to this requested change and it has been made to the final permit. The intent of the original condition was that the EPA would be notified in advance if a test could not be performed as scheduled, so that EPA inspectors planning to observe a test could reasonably change plans accordingly. We are satisfied that it should be a rare occurrence where EPA receives a notification less than a week before a planned test is postponed.

6. Permit Condition I.E.3.(b) [formerly I.F.3.(b)] and I.E.4(g) [formerly I.F.4(g)]:

Arrow stated they understand the intent of the requirement that making adjustments to engine settings, catalytic control systems, or processes or operational parameters in order to pass a performance test is not permitted. However, Arrow asserted that operators often make these types of adjustments for reasons independent of emissions reduction. Delay of operationally necessary adjustments may affect the safe operation or functionality of the engine. As such, Arrow requested clarification be added that engine tuning and adjustments which are not made solely to pass a performance test are allowable.

We are agreeable to the requested change and have revised the condition in the final permit to read as follows: "The Permittee shall not perform engine tuning or make any adjustments to engine settings, catalytic control system settings, processes, or operational parameters on the day of or during measurements for the purpose of passing a performance test. Any such tuning or adjustments may result in a determination by the EPA that the test is invalid. The Permittee shall record the reason and result of any adjustments made on the day of or during any performance test. Artificially increasing an engine load to meet testing requirements is not considered engine tuning or adjustments."

7. Permit Condition I.F.7(b) [formerly I.G.7(b)]

Arrow stated they understand the need to visually inspect the components of closed vent systems and control devices for each storage tank. Arrow stated the requirements of permit condition I.J.2. (formerly I.K.2.) which require the development of a written leak inspection and repair protocol with inspection conducted at a minimum, semi-annually, can meet the visual inspection requirement. Arrow, therefore, requested that permit condition I.F.7(b) be removed to eliminate redundancy. As a result of such change, Arrow suggested to change the frequency of the inspections specified in permit condition I.J.2. from annually to quarterly.

Arrow asserted that by synchronizing these two permit conditions, there would be more flexibility under a written leak inspection and repair protocol in the approach used to verify that set-points are not exceeded. For example, permit condition I.F.7(b) requires visual inspections to be performed while tanks are being filled. However, if visual inspections are conducted when tanks are being filled, the minimum vacuum value will not be obtained during the inspection. Minimum vacuum values are expected to occur while the tank is being emptied.

We agree that condition I.F.7(b) is redundant given the requirements for inspecting for equipment leaks from closed vent systems in Section I.J. of the permit. However, condition I.F.7(b) has not been deleted as requested in the final permit. Instead, condition I.F.7(b) has been revised as follows to refer to the equipment leaks from closed-vent systems requirements in section I.J. of the final permit:

(b) The Permittee shall perform quarterly inspections of each closed vent system and control device of each natural gas condensate storage tank as specified in the ***Requirements for Equipment Leaks from Closed-Vent Systems*** *section of this permit to ensure that the pressure and vacuum relief set-points are not being exceeded in a way that has resulted, or may result, in venting and possible damage to equipment. The inspections shall be performed when the tanks are either being filled or emptied.*

We did not remove the requirement to conduct the equipment leak inspections of the tanks when they are being filled, but rather revised the condition to require the inspections either when the tanks are being filled or emptied to include opportunities to identify problems related to maximum vacuum and possible leaks related to damage to equipment. Based on recent studies *of storage tanks at oil and natural gas well production facilities*[1]*, the largest quantity of tank leaks due to overpressuring of the tank have been measured to occur during tank filling events. We agree that tank failure (collapse) can also occur when a tank experiences high vacuum that tank structure cannot accommodate, which would likely occur when a tank is being emptied; therefore, we believe it is important to verify that the tanks can accommodate the highest pressure or vacuum they would likely encounter (we believe Arrow intended for the comment to refer to high vacuum when asserting that minimum vacuum values are expected to occur while the tank is being emptied).*

Additionally, condition I.J.2(b) [formerly I.K.2(b)] has been revised to require equipment leak inspections to be conducted quarterly at a minimum, to accommodate synchronizing the two permit conditions.

8. <u>Permit Condition I.F.8. [formerly I.G.8.]</u>

Arrow's stated assumption was that the requirements in condition I.F.7(d) require that Arrow shall calculate emissions from tanks using the parameters listed in this condition, not by direct monitoring as potentially implied by condition I.F.8(a). Arrow requested that the verbiage in condition I.F.8(a) be revised to specify that records of the parameters used to calculate working, breathing, and flashing losses for the tanks be maintained. Arrow suggested the condition be revised as: "The permittee shall maintain a record of monthly volume of produced water and natural gas condensate handled by the tanks, the most recent extended laboratory analysis, and the control efficiency of the control device being used. Such records will be used to determine compliance with throughput and emission limits associated with the produced water and natural gas condensate tanks."

Since condition I.F.8(d) states that records of VOC and HAP emission calculations for each tank must be maintained, it follows that the working breathing, and flashing losses from the tanks would be required to be kept. Therefore, Arrow asserted that the suggested changes would increase the clarity of condition I.F.8., and eliminate redundancy while fully adhering to the intent of the permit condition. Arrow committed to use EPA-approved calculation methods to calculate working, breathing, and flashing losses from the tanks as referenced in condition I.F.7(c).

We agree that condition I.F.8(a) requires clarification. Section I.D. Requirements for Emission Limits, Construction, and Operation already requires monitoring, calculation, and recordkeeping of the volume received and throughput in barrels of produced water and natural gas condensate at the station. Section I.D. also already requires extended laboratory analysis of the produced water and natural gas condensate and associated recordkeeping. Requiring the same again in Section I.F. would be redundant. To provide clarity and reduce redundancy in the final permit, the following changes have been made in Sections I.D. and I.F. (indicated by strike-through font for deletions and underlined font for additions).

[1] Final Technical Report: Vapor Control & Enclosed Flare Management Study, Prepared by Clearstone Engineering, Ltd., January 18, 2011, available online at: ftp://ft.dphe.state.co.us/apc/aqcc/PREHEARING%20STATEMENTS,%20EXHIBITS%20&%20ALTERNATIVE%20PROPOSALS/Air%20Pollution%20Control%20Division%20(APCD)/APCD-PHS%20EX-WW.pdf

Condition I.D.4(b):

*(b) The Permittee shall ~~use a LACT unit or other monitoring methods approved by the EPA that are capable of continuously~~ measure~~ing~~ the volume of produced water ~~and crude oil~~ and natural gas condensate ~~received at~~ processed through ~~at~~ the station according to the **Requirements for Tanks** section of this permit.*

Condition I.F.7(d):

*(d) The Permittee shall calculate the VOC and HAP emissions from each tank. The VOC and HAP emissions at the station shall be determined using: the measured monthly volume of produced water ~~and crude oil~~ and natural gas condensate routed to the tanks; the most recent extended laboratory analysis of the produced water and ~~crude oil and~~ natural gas condensate entering the station as required in the **Requirements for Emission Limits, Construction, and Operation** section of this permit~~,~~; E&P Tanks V2.0 and/or EPA Tanks 4.0.9d, as appropriate~~,~~; and the most recent tested control efficiency of the control device being used as required in the **Requirements for Emission Limits, Construction, and Operation** section of this permit. Other calculation ~~measurement~~ methods may be used upon prior written approval by the EPA.*

Condition I.F.8(a):

(a) The permittee shall maintain ~~a~~ records of the ~~monitored volume of working, breathing, and flashing losses from each tank~~ monthly volume of produced water and natural gas condensate handled by each tank.

9. Permit Condition I.G.2(f)(i) [formerly I.H.2.(f)(i)

Arrow stated they understand that this condition requires the enclosed combustor or utility flare to be operated as a control device. Arrow requested that the term “natural gas” be replaced with “vapors” or “emissions” for clarity.

We agree that clarification in this permit condition is warranted and have replaced the term “natural gas” with “hydrocarbon emissions,” as that term is consistently used throughout the rest of the permit to describe the emissions routed to the closed-vent system or control device. We have also checked the other such references throughout the permit and made corrections as necessary for consistency.

10. Permit Condition I.G.2(f)(vii) [formerly I.H.2(f)(vii)]:

Arrow commented that the explanation of what constitutes visible smoke emissions is included in permit condition I.G.5(a)(ii): “Visible smoke emissions are present if smoke is observed emitting from the enclosed combustor or utility flare for more than 2 minutes in any hour.” In order to add clarity, Arrow requested that this definition be added to the end of condition I.G.2(f)(vii) similar to the following: “Operated with no visible smoke emissions for more than 2 minutes in any 1 hour.”

We are agreeable to providing clarity in this condition and have revised the condition to read: “Operated with no visible smoke emissions, as defined in EPA Reference Method 22 of 40 CFR Part 60, Appendix A.”

11. Permit Condition I.G.5(a)(ii) [formerly I.H.5(a)(ii)]:

Arrow believes this condition requires the operator to make a determination whether any smoke is visible at each visit. If no smoke is present, then no further action is required because recordkeeping is required. If any smoke is present, then a 1-hour observation using EPA Reference Method 22 should be conducted. However, multiple discussions were held amongst Arrow personnel before this interpretation was reached. If this interpretation is indeed correct, Arrow requested that this condition be restructured as follows to add clarity: "Monitor for visible smoke during operation of any enclosed combustor or utility flare each time an operator is on site, at a minimum quarterly. Upon observation of visible smoke, use EPA Reference Method 22 of 40 CFR Part 60, Appendix A, to confirm that no visible smoke emissions are present for more than 2 minutes in any 1 hour. The observation period shall be 1 hour."

We agree that clarification is warranted in this condition. Arrow's interpretation of our intent for this condition is correct. The condition has been revised in the final permit as requested by Arrow.

12. Permit Condition I.I.1. [formerly I.J.1.]:

Arrow stated they intend to utilize an instrument air pneumatic pump and controller system at Station #7, but would like to retain the ability to meet the requirements of permit condition I.I.1(a) via any of the five (5) emission control techniques specified in paragraphs (i) – (vi) of the condition. However, Arrow requested that a provision be added to permit condition I.I.1 that exempts pneumatic controllers and pumps that do not emit regulated pollutants (i.e. air, solar, or electric actuated) from the maintenance, recordkeeping, and emissions tracking requirements specified in permit condition I.IJ.1(b)-(e). Arrow believes that these requirements are not necessary for equipment that does not emit regulated pollutants nor is potentially subject to the requirements of New Source Performance Standard (NSPS) Subpart OOOO.

We agree that clarification is warranted in this condition, because not all types of pneumatic pumps and controllers described result in potential emissions of permit-regulated pollutants. We have revised the condition such that only natural gas actuated pumps and controllers are subject to the maintenance, recordkeeping, and emissions tracking requirements specified in paragraphs (b)-(e) of the condition.

13. Permit Condition I.I.2(c) [formerly I.J.2(c)]:

Arrow stated they believe that the intent of this requirement is to track emissions associated with compressor blowdowns. In order to maximize accuracy and efficiency and eliminate the need for written log sheets, Arrow requested the ability to track blowdowns via a SCADA system. Arrow requested that permit condition I.I.2(c) be modified as follows: "The Permittee shall keep records of the date and time of each event, the volume of the gas emitted, calculated based on a representative emission factor, and a description of the emission estimation methods used to calculate the VOC and HAP emissions." Arrow stated they believe this approach will satisfy the intent of this requirement in tracking blowdown events and estimating emissions from these events.

We are agreeable to the requested change, as it meets the intent of the condition to track emissions associated with compressor blowdowns. We have revised the permit condition as requested.

14. Permit Condition I.J.2(e) [formerly I.K.2(e)]:

Permit condition I.J. pertains to equipment leaks from the closed vent system. However, Arrow asserted that the wording in condition I.J.2(e) could potentially be misinterpreted in the future to apply to any equipment at the facility regardless of whether it is part of a closed vent system. Therefore, Arrow requested that the condition specify that it applies to equipment that is part of a closed-vent system.

We agree that clarification is warranted and have revised the condition to specify that it applies to equipment that is part of a closed-vent system.

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

Air Pollution Control
Synthetic Minor Source Permit to Construct

40 CFR 49.151

#SMNSR-TAT-000661-2013.001

Permit to Construct to establish legally and practically enforceable limitations and requirements on sources at a new facility.

Permittee:

Arrow Pipeline, LLC

Permitted Facility/Source:

Arrow Pipeline Station #7
Natural Gas Gathering and Transmission
Fort Berthold Operations
Dunn County, North Dakota

Summary

On May 6, 2013, the EPA received an application from Arrow Pipeline, LLC (Arrow) requesting approval to construct a new natural gas gathering and transmission station on the Fort Berthold Indian Reservation in accordance with the requirements of the Tribal Minor New Source Review Permit Program at 40 CFR Part 49 (MNSR). The operation will consist of natural gas gathering from several customers in the region and transmission to a central delivery point (CDP) located outside the exterior boundaries of the Fort Berthold Indian Reservation.

The natural gas gathering will be conducted via pipelines from production wells in the area. Upon delivery to the station, the hydrocarbons will be separated into natural gas, natural gas condensate, and produced water. The natural gas condensate and produced water will be transported off-site via trucks. The natural gas will be compressed using engine driven compressors and transmitted via pipeline to the CDP.

This permit authorizes the construction of new emission sources. Based on EPA's review of Arrow's Air Quality Impact Analysis and other available data, EPA determined that this approval will not cause or contribute to any NAAQS violations, or have potentially adverse effects on ambient air.

Table of Contents

I. Conditional Permit to Construct 4
A. General Information 4
B. Construction Proposal 4
C. Applicability 5
D. Requirements for Emission Limits, Construction and Operation 5
E. Requirements for Engines 8
F. Requirements for Tanks 15
G. Requirements for Control Systems for Hydrocarbon Emissions 18
H. Requirements for Truck Loading Operations 22
I. Requirements for Pneumatic Pumps, Pneumatic Controllers, Compressor Blowdowns 23
J. Requirements for Equipment Leaks from Closed-Vent Systems 24
K. Requirements for Minimizing Fugitive Dust 24
L. Requirements for Records Retention 25
M. Requirements for Reporting 25

II. General Provisions 26
A. Conditional Approval 26
B. Authorization 29

I. Conditional Permit to Construct

A. General Information

Facility/source:	Arrow Pipeline Station #7 Natural Gas Gathering and Transmission
Permit number:	SMNSR-TAT-000661-2013.001
SIC Code and SIC Description:	4922 – Pipeline Transportation of Natural Gas

Site Location:
Fort Berthold Indian Reservation
Dunn County, ND

Corporate Office Location:
Arrow Pipeline LLC
801 Cherry Street,
Suite 3800, Unit 20
Attn: Air Quality Team
Fort Worth, TX 76102

The equipment listed in this permit may only be operated by Arrow Pipeline, LLC, at the following location:

County	Township	Range	Section	Quarter Section	Latitude	Longitude
Dunn	148 N	92 W	4	NE¼	47.672167 N	-102.401833 W

The location indicated above is approximate and the final location may be within 1,200 feet of these coordinates. Any adjustment to the station location must comply with the Endangered Species Act and National Historic Preservation Act.

B. Construction

The gathering and transmission operations will consist of the following primary equipment:

Two Natural Gas Condensate Storage Tanks
One Produced Water Storage Tank
Two Truck Loading Racks
Eight Natural Gas-Fired Reciprocating Internal Combustion Engines
Hydrocarbon Emission Controls

The primary function of the station is to gather natural gas via pipeline from the various production wells in the area and transport it to a central delivery point located outside of the external boundaries of the Fort Berthold Indian Reservation. The station will not be processing natural gas or refining crude oil and natural gas condensate into end products.

Natural gas condensate and produced water removed from the natural gas via the slug catcher and filter separator(s) will be pumped to individual storage tanks. Truck load out racks will be used to truck the natural gas condensate and produced water from the station.

Compressed natural gas will be routed to a splitter, with most of the natural gas routed to a natural gas pipeline exiting the station and the remainder routed to a fuel gas coalescer. Natural gas from the fuel gas coalescer will be routed to and combusted by individual compressor engines and/or natural gas–fired electrical generator engines designed to provide power to the station and/or to the flare or enclosed combustor pilot.

C. Applicability

1. This Conditional Permit to Construct is being issued under the authority of the Tribal Minor New Source Review Program at 40 CFR Part 49 (MNSR).

2. The requirements in this permit have been created, at the Permittee's request, to establish legally and practically enforceable requirements for limiting emissions of volatile organic compounds (VOCs), nitrogen oxide (NO_X), carbon monoxide (CO), and individual and total hazardous air pollutants (HAPs).

3. Any conditions established for this facility or any specific units at this facility pursuant to any Conditional Permit to Construct issued under the authority of the Prevention of Significant Deterioration Permit Program at 40 CFR Part 52 (PSD) or MNSR shall continue to apply.

4. By issuing this permit, the EPA does not assume any risk of loss which may occur as a result of the operation of the permitted facility by the Permittee, Owner, and/or Operator, if the conditions of this permit are not met by the Permittee, Owner, and/or Operator.

D. Requirements for Emission Limits, Construction, and Operation

1. Emission Limits

   (a) VOC emissions shall not exceed 92 tons during any consecutive 12 months.

   (b) NO_X emissions shall not exceed 92 tons during any consecutive 12 months.

   (c) CO emissions shall not exceed 92 tons during any consecutive 12 months.

   (d) Individual HAP emissions shall not exceed 9.8 tons during any consecutive 12 months.

   (e) Total HAP emissions shall not exceed 24.5 tons during any consecutive 12 months.

   (f) Emission limits specified in this permit shall apply at all times.

2. Construction and Operational Limits

   (a) The Permittee shall limit the total maximum engine capacity at the station to 7,000 horsepower (hp).

   (b) All engine capacities shall be based on the manufacturer's maximum site rated hp of each engine.

   (c) The follow reciprocating internal combustion engines (engines) have been approved for installation and operation:

      (i) One 4-stroke lean-burn engine, with a maximum rating of 530 hp;
      (ii) One, 4-stroke lean-burn engine, with a maximum rating of 400 hp;

(iii) Three 4-stroke rich-burn engines, with a maximum rating of 1,480 hp each;
(iv) One 4-stroke rich-burn engine, with a maximum rating of 740 hp;
(v) One 4-stroke rich-burn engine, with a maximum rating of 435 hp; and
(vi) One 4-stroke rich-burn engine, with a maximum rating of 326 hp.

(d) The Permittee shall only install 2 - 400 barrel natural gas condensate tanks operated and controlled as specified in the **Requirements for Tanks** section of this permit.

(e) The Permittee shall only install 1 - 400 barrel produced water storage tank operated and controlled as specified in the **Requirements for Tanks** section of this permit.

(f) The Permittee shall limit the combined produced water and natural gas condensate throughput to 80,500 barrels in any given consecutive 12-month period.

(g) All produced water and natural gas collection, storage, and handling operations, regardless of size, shall be designed, operated and maintained by the Permittee so as to minimize leakage of hydrocarbon emissions to the atmosphere.

3. <u>Testing Requirements:</u>

Within 1 year of the first day that operations begin, the Permittee shall obtain an extended laboratory analysis of the produced water and natural gas condensate entering the station to confirm the accuracy of the emissions estimates provided in the application for this permit. Thereafter, the Permittee shall obtain an extended laboratory analysis of the produced water and natural gas condensates received at the station every 5 years and use the new data for emissions calculations required in this permit.

4. <u>Monitoring Requirements</u>

(a) The Permittee shall monitor the total maximum engine capacity at the station upon commencement of operations, at the end of each calendar year, and anytime an engine is installed, moved or replaced. All engine capacities shall be based on the maximum site rated hp of each engine.

(b) The Permittee shall measure the throughput volume of produced water and natural gas condensate processed through the station according to the **Requirements for Tanks** section of this permit.

(c) The Permittee shall calculate, at the end of each calendar month, the produced water and natural gas condensate throughput at the station, in barrels, beginning with the first calendar month that permitted operations commence. Prior to 12 full months of operation, the Permittee shall, at the end of each calendar month, add the produced water and natural gas condensate throughput for that calendar month to the calculated produced water and condensate throughput for all previous calendar months since operations commenced and record the total. Thereafter, the Permittee shall, at the end of each calendar month add the produced water and natural gas condensate throughput for that calendar month to the calculated produced water and natural gas condensate throughput for the preceding 11 calendar months and calculate a new 12-month total.

(d) The Permittee shall calculate, at the end of each calendar month, the VOC, NO_X, CO, and HAP emissions beginning with the first calendar month that permitted operations commence. Prior to 12 full months of operation, the Permittee shall, at the end of each month, add the emissions for that month to the calculated emissions for all previous months since operations commenced and record the total. Thereafter, the Permittee shall, at the end of each month add the emissions for that month to the calculated emissions for the preceding 11 months and calculate a new 12-month total.

(e) Emissions from all controlled and uncontrolled emission sources shall be included in the monthly and consecutive 12-month calculations, including, but not limited to: the natural gas condensate tanks; produced water storage tanks; truck load-out operations; produced water and natural gas system receivers; fuel gas coalescesers; slug catchers; filter separators; pig launchers and receivers; pneumatic pumps; pneumatic controls; compressor blow-downs; engines; equipment leaks; enclosed combustors; utility flares; or other EPA approved control device.

(f) Emissions from each approved emitting unit shall be calculated by the Permittee as specified in this permit.

(g) Where sufficient to meet the monitoring requirements of this permit, the Permittee may use a Supervisory Control and Data Acquisition (SCADA) system to monitor the needed data in this permit.

(h) Alternative monitoring methods may be used by the Permittee upon EPA approval.

5. Recordkeeping Requirements

(a) The Permittee shall maintain a record of the monthly and consecutive 12-month barrels of produced water and natural gas condensate received at the station.

(b) The Permittee shall maintain a record of the monthly and consecutive 12-month VOC, NO_X, CO, and HAP emissions, in tons per year (tpy) from the station.

(c) The Permittee shall maintain a record of the results of each extended laboratory analysis of the produced water and natural gas condensate received at the station.

(d) The Permittee shall maintain a record of all input parameters and calculations used to determine the monthly emissions from all controlled and uncontrolled emission sources.

(e) The Permittee shall maintain a record of all deviations from the requirements of this permit.

(f) Where sufficient to meet all the recordkeeping requirements of this permit, the Permittee may use a SCADA system to record the needed data in this permit.

(g) Alternative methods of recordkeeping may be used by the Permittee upon EPA approval.

E. Requirements for Engines

1. <u>Emission Limits</u>

(a) Emissions from the one (1) natural gas-fired, 530 hp, 4-stroke lean-burn engine shall not exceed the following:

(i) NO_X: 2.0 grams/horse power-hour (g/hp-hr);
(ii) CO: 1.3 g/hp-hr;
(iii) VOC: 0.75 g/hp-hr; and
(iv) Formaldehyde (CH_2O): 0.2 g/hp-hr.

(b) Emissions from the one (1) natural gas-fired, 400 hp, 4-stroke lean-burn engine shall not exceed the following:

(i) NO_X: 2.0 grams/horse power-hour (g/hp-hr);
(ii) CO: 1.3 g/hp-hr;
(iii) VOC: 0.75 g/hp-hr; and
(iv) CH_2O: 0.2 g/hp-hr.

(c) Emissions from each of the three (3) natural gas-fired, 1,480 hp, 4-stroke rich-burn engines shall not exceed the following:

(i) NO_X: 1.0 g/hp-hr;
(ii) CO: 2.0 g/hp-hr;
(iii) VOC: 0.7 g/hp-hr; and
(iv) CH_2O: 0.1 g/hp-hr.

(d) Emissions from the one (1) natural gas-fired, 740 hp, 4-stroke rich-burn engine shall not exceed the following:

(i) NO_X: 1.0 g/hp-hr;
(ii) CO: 2.0 g/hp-hr;
(iii) VOC: 0.7 g/hp-hr; and
(iv) CH_2O: 0.1 g/hp-hr.

(e) Emissions from the one (1) natural gas-fired, 435 hp, 4-stroke rich-burn engine shall not exceed the following:

(i) NO_X: 1.0 g/hp-hr;
(ii) CO: 2.0 g/hp-hr;
(iii) VOC: 0.7 g/hp-hr; and
(iv) CH_2O: 0.1 g/hp-hr.

(f) Emissions from the one (1) natural gas-fired, 326 hp, 4-stroke rich-burn engines shall not exceed the following:

(i) NO_X: 1.0 g/hp-hr;
(ii) CO: 2.0 g/hp-hr;
(iii) VOC: 0.7 g/hp-hr; and

(iv) CH_2O: 0.1 g/hp-hr.

2. Control and Operational Requirements

(a) The Permittee shall equip each 4-stroke lean-burn engine with an air-to-fuel ratio (AFR) controller to ensure that the engine continues to operate as a lean-burn engine. The oxygen sensor associated with each AFR controller must be replaced after every 2,190 hours of engine run time.

(b) The Permittee shall equip and operate each 4-stroke rich-burn engine with an AFR controller to ensure that the engine continues to operate as a rich-burn engine. The oxygen sensor associated with each AFR controller must be replaced after every 2,190 hours of engine run time.

(c) The Permittee shall equip and operate each 4-stroke rich-burn engine with a non-selective catalytic reduction (NSCR) control system capable of reducing the uncontrolled emissions of NO_X, CO, VOC, and CH_2O to meet the emission limits specified in this permit.

(d) The Permittee shall install, operate, and maintain temperature sensing devices (i.e., thermocouple or resistance temperature detectors) before the NSCR control system on each engine in order to continuously monitor the exhaust temperature at the inlet of the catalyst bed. Each temperature sensing device shall be calibrated and operated by the Permittee according to manufacturer and/or vendor specifications or equivalent specifications developed by the Permittee or vendor.

(e) Except during startups, which shall not exceed 30 minutes, the engine exhaust temperature of each engine, at the inlet to the catalyst bed, shall be maintained at all times the engines operate with an inlet temperature of at least 450° F and no more than 1,350°F.

(f) During operation, the pressure drop across the catalyst bed on each engine shall be maintained to within ±2 inches of water from the baseline pressure drop measured during the most recent performance test. The baseline pressure drop for the catalyst bed shall be determined at 100% ± 10% of the engine load measured during the most recent performance test.

(g) The Permittee shall only fire each engine with natural gas.

(h) The Permittee shall follow, for each engine and its respective catalytic control system, the manufacturer and/or vendor recommended maintenance schedule and procedures or equivalent maintenance schedule and procedures developed by the Permittee or vendor to ensure optimum performance of each engine and its respective catalytic control system.

(i) The Permittee may rebuild an existing permitted engine or replace an existing permitted engine with an engine of the same horsepower rating, and configured to operate in the same manner as the engine being rebuilt or replaced. Any emission limits, requirements, control technologies, testing or other provisions that apply to the permitted engines that are replaced shall also apply to the rebuilt and replaced engines.

(j) The Permittee may resume operation without the catalytic control system during an engine break-in period, not to exceed 200 operating hours, for rebuilt and replaced engines.

3. Performance Testing Requirements

(a) Performance tests shall be conducted on each engine for measuring NO_X, CO, VOC, and CH_2O emissions to demonstrate compliance with each emission limitation in this permit. The performance tests shall be conducted in accordance with appropriate reference methods specified in 40 CFR Part 63, Appendix A and 40 CFR Part 60, Appendix A, or an EPA approved American Society for Testing and Materials (ASTM) method. The Permittee may submit to the EPA a written request for approval of an alternate test method, but shall only use that alternate test method after obtaining approval from the EPA.

(i) The initial performance test for each engine shall be conducted within 90 calendar days of startup of a new engine.
(ii) Subsequent performance tests for VOC and CH_2O emissions shall be conducted within 12 months of the most recent performance test.
(iii) Performance tests shall be conducted within 90 calendar days of each catalyst replacement.
(iv) Performance tests shall be conducted within 90 calendar days of startup of all rebuilt and replaced engines.

(b) The Permittee shall not perform engine tuning or make any adjustments to engine settings, catalytic control system settings, or processes or operational parameters the day of the engine testing or during the engine testing for the purpose of passing a performance test. Any such tuning or adjustments may result in a determination by the EPA that the test is invalid. The Permittee shall record the reason for and result of any adjustments made on the day of or during any performance test. Artificially increasing an engine load to meet testing requirements is not considered engine tuning or adjustments.

(c) The Permittee shall not abort any engine tests that demonstrate non-compliance with the emission limits in this permit.

(d) All performance tests conducted on each engine shall meet the following requirements:

(i) The pressure drop across each catalyst bed and the inlet temperature to each catalyst bed shall be measured and recorded at least once during each performance test.

(ii) All tests for CO and NO_X emissions shall be performed simultaneously.

(iii) All tests shall be performed at a maximum operating rate (90% to 110% of the maximum achievable engine load available on the day of the test). The Permittee may submit to the EPA a written request for approval of an alternate load level for testing, but shall only test at that alternate load level after obtaining approval from the EPA.

(iv) During each test run, data shall be collected on all parameters necessary to document how emissions were measured and calculated (such as test run length, minimum sample volume, volumetric flow rate, moisture and oxygen corrections, etc.).

(v) Each test shall consist of at least three 1-hour or longer valid test runs. Emission results shall be reported as the arithmetic average of all valid test runs and shall be in terms of the emission limits in this permit.

(vi) Performance test plans shall be submitted to the EPA for approval 60 calendar days prior to the date the test is planned.

Performance test plans that have already been approved by the EPA for the emission units approved in this permit may be used in lieu of new test plans unless the EPA requires the submittal and approval of new test plans. The Permittee may submit new plans for EPA approval at any time.

(vii) The test plans shall include and address the following elements:

(A) Purpose of the test;
(B) Engines and catalytic control systems to be tested;
(C) Expected engine operating rate(s) during the test;
(D) Sampling and analysis procedures (sampling locations, test methods, laboratory identification);
(E) Quality assurance plan (calibration procedures and frequency, sample recovery and field documentation, chain of custody procedures); and
(F) Data processing and reporting (description of data handling and quality control procedures, report content).

(e) The Permittee shall notify the EPA at least 30 calendar days prior to scheduled performance testing. The Permittee shall notify the EPA at least 1 week prior to scheduled performance testing, or as soon as practicable prior to a scheduled performance test, if the testing cannot be performed.

(f) If the results of a performance test of the emissions from any permitted engine demonstrate noncompliance with the emission limits in this permit, the engine shall be shut down as soon as safely possible, and appropriate corrective action shall be taken (e.g., repairs, catalyst cleaning, catalyst replacement). The engine must be retested within 7 days of being restarted and the emissions must meet the applicable limits in this permit. If the retest shows that the emissions continue to exceed the limits in this permit, the engine shall again be shut down as soon as safely possible, and the engine may not operate, except for purposes of startup and testing, until the Permittee demonstrates through testing that the emissions do not exceed the emission limits in this permit.

(g) If the permitted engine is not operating, the Permittee does not need to start up the engine solely to conduct a performance test. The Permittee may conduct the performance test when the engine is started up again.

4. <u>Monitoring Requirements</u>

(a) The Permittee shall continuously monitor the engine exhaust temperature of each engine at the inlet to the catalyst bed.

(b) Except during startups, which shall not exceed 30 minutes, if the engine's exhaust temperature at the inlet to the catalyst bed deviates from the acceptable ranges specified in this permit then the following actions shall be taken. The Permittee's completion of any or all of these actions shall not constitute, nor qualify as, an exemption from any other emission limits in this permit.

(i) Within 24 hours of determining a deviation of the engine exhaust temperature at the inlet to the catalyst bed, the Permittee shall investigate. The investigation shall include testing the temperature sensing device, inspecting the engine for performance problems and assessing the catalytic control system for possible damage that could affect catalytic system effectiveness (including, but not limited to, catalyst housing damage, and fouled, destroyed or poisoned catalyst).

(ii) If the engine exhaust temperature at the inlet to the catalyst bed can be corrected by following the engine manufacturer and/or vendor recommended procedures or equivalent procedures developed by the Permittee or vendor, and the catalytic control system has not been damaged, then the Permittee shall correct the engine exhaust temperature at the inlet to the catalyst bed within 24 hours of inspecting the engine and catalytic control system.

(iii) If the engine exhaust temperature at the inlet to the catalyst bed cannot be corrected using the engine manufacturer and/or vendor recommended procedures or equivalent procedures developed by the Permittee or vendor, or the catalytic control system has been damaged, then the affected engine shall cease operating immediately and shall not be returned to routine service until the following has been met:

(A) The engine exhaust temperature at the inlet to the catalyst bed is measured and found to be within the acceptable temperature range for that engine; and

(B) The catalytic control system has been repaired or replaced, if necessary.

(c) The Permittee shall monitor the pressure drop across the catalyst bed on each engine every 30 days using pressure sensing devices before and after the catalyst bed to obtain a direct reading of the pressure drop (also referred to as the differential pressure). *[Note to Permittee: Differential pressure measurements, in general, are used to show the pressure across the filter elements. This information will determine when the elements of the catalyst bed are fouling, blocked or blown out and thus require cleaning or replacement.]*

(d) The Permittee shall perform the first measurement of the pressure drop across the catalyst bed on each engine no more than 30 days from the date of the initial performance test. Thereafter, the Permittee shall measure the pressure drop across the catalyst bed, at a minimum, every 30 days. Subsequent performance tests, as required in this permit, can be used to meet the periodic pressure drop monitoring requirements provided it occurs within the 30-day window. The pressure drop reading can be a one-time measurement on that day, the average of performance test runs conducted on that day, or an average of all the measurements taken on that day if continuous readings are taken.

(e) The Permittee shall measure NO_X and CO emissions from each engine at least quarterly to demonstrate compliance with each engine's emission limits in this permit. To meet this requirement, the Permittee shall:

(i) Measure NO_X and CO emissions at the normal operating load using a portable analyzer and a monitoring protocol approved by the EPA or conduct a performance test as specified in this permit;
(ii) Measure the NO_X and CO emissions simultaneously; and
(iii) Commence monitoring for NO_X and CO emissions within 6 months of the Permittee's submittal of the initial performance test results for NO_X and CO emissions to the EPA.

(f) The Permittee shall not perform engine tuning or make any adjustments to engine settings, catalytic control system settings, or processes or operational parameters on the day of or during measurements for the purpose of meeting the emission limits in this permit. Any such tuning or adjustments may result in a determination by the EPA that the result is invalid. The Permittee shall record the reason for and result of any adjustments made on the day of or during any measurements. Artificially increasing an engine load to meet the testing requirements is not considered engine tuning or adjustments.

(g) If the pressure drop reading exceeds ± 2 inches of water from the baseline pressure drop established during the most recent performance test, or if the results of any quarterly emissions monitoring demonstrate non-compliance with the emission limits in this permit, then the following actions shall be taken. The Permittee's completion of any or all of these actions shall not constitute, nor qualify as, an exemption from any other emission limits in this permit:

(i) Within 24 hours of determining a deviation of the pressure drop across the catalyst bed or the emission limits in this permit, the Permittee shall investigate. The investigation shall include testing the pressure transducers and assessing the catalytic control system for possible damage that could affect catalytic system effectiveness (including, but not limited to, catalyst housing damage, and plugged, fouled, destroyed or poisoned catalyst).

(ii) If the pressure drop across the catalyst bed, or the elevated emission rates, can be corrected by following the catalytic control system manufacturer and/or vendor recommended procedures or equivalent procedures developed by the Permittee or vendor, and the catalytic control system has not been damaged, then the Permittee shall correct the problem within 24 hours of inspecting the catalytic control system.

(iii) If the pressure drop across the catalyst bed, or the elevated emission rates, cannot be corrected using the catalytic control system manufacturer and/or vendor recommended procedures or equivalent procedures developed by the Permittee or vendor, or the catalytic control system is damaged, then the Permittee shall do one of the following:

(A) Conduct a performance test within 90 calendar days, as specified in this permit, to ensure that the NO_X, CO, VOC, and CH_2O emission limits are being met and to re-establish the pressure drop across the catalyst bed. The Permittee shall perform a portable analyzer test for CO and NO_X emissions and establish a new temporary pressure drop baseline until a performance test can be scheduled and completed; or

(B) Cease operating the affected engine immediately. The engine shall not be returned to routine service until the pressure drop is measured and found to be within the acceptable pressure range for that engine as determined from the most recent performance test and the emission rates are found to be in compliance with the emission limits in this permit. Corrective action may include removal and cleaning of the catalyst or replacement of the catalyst.

(h) For any one (1) engine: If the results of 2 consecutive quarterly portable analyzer measurements demonstrate compliance with the NO_X and CO emission limits, the required monitoring frequency may change from quarterly to semi-annually.

(i) For any one (1) engine: If the results of any subsequent portable analyzer measurements demonstrate non-compliance with the NO_X or CO emission limits, required monitoring frequency shall change from semi-annually to quarterly.

(j) The Permittee shall submit portable analyzer specifications and monitoring protocols for NO_X and CO to the EPA at the following address for approval at least 45 calendar days prior to the date of initial portable analyzer monitoring:

U.S. Environmental Protection Agency, Region 8
Office of Enforcement, Compliance & Environmental Justice
Air Toxics and Technical Enforcement Program, 8ENF-AT
1595 Wynkoop Street
Denver, Colorado 80202

(k) Portable analyzer specifications and monitoring protocols that have already been approved by the EPA for the emission units approved in this permit may be used in lieu of new protocols unless the EPA requires the submittal and approval of a new protocol. The Permittee may submit a new protocol for EPA approval at any time.

(l) The Permittee is not required to conduct emissions monitoring of NO_X, CO, VOC, and CH_2O emissions, and parametric monitoring of exhaust temperature and catalyst differential pressure on engines that have not operated during the monitoring period. The Permittee shall certify that the engine(s) did not operate during the monitoring period in the annual report specified in this permit.

5. Recordkeeping Requirements

(a) Records shall be kept of manufacturer and/or vendor specifications or equivalent specifications developed by the Permittee or vendor, and maintenance requirements for each engine, AFR controller, NSCR control system, temperature sensing device, and pressure measuring device.

(b) Records shall be kept of all calibration and maintenance conducted for each engine, AFR controller, NSCR control system, temperature sensing device, and pressure measuring device.

(c) Records shall be kept of all temperature measurements required in this permit, as well as a description of any corrective actions taken pursuant to this permit.

(d) Records shall be kept of all pressure drop measurements required in this permit, as well as a description of any corrective actions taken pursuant to this permit.

(e) Records shall be kept of all required testing and monitoring in this permit. The records shall include the following:

(i) The date, place, and time of sampling or measurements;
(ii) The date(s) analyses were performed;
(iii) The company or entity that performed the analyses;
(iv) The analytical techniques or methods used;
(v) The results of such analyses or measurements; and
(vi) The operating conditions as existing at the time of sampling or measurement.

(f) Records shall be kept of all AFR controller, oxygen sensor, and NSCR control system replacements or repairs, engine rebuilds and engine replacements.

(g) Records shall be kept of each rebuilt or replaced engine break-in period, pursuant to the requirements of this permit, where an existing engine that has been rebuilt or replaced resumes operation without the catalyst control system, for a period not to exceed 200 operating hours.

(h) Records shall be kept of each time any engine is shut-down due to a deviation of the inlet temperature to the catalyst bed or pressure drop across the catalyst bed. The Permittee shall include in the record the cause of the problem, the corrective action taken, and the timeframe for bringing the pressure drop and inlet temperature range into compliance.

F. Requirements for Tanks

1. All natural gas condensate tanks and produced water storage tanks are subject to the requirements of this permit.

2. The Permittee shall follow, for each tank, the manufacturer’s recommended maintenance schedule and procedures or equivalent procedures developed by the Permittee or vendor to ensure good air pollution control practices for minimizing hydrocarbon emissions.

3. The Permittee shall install, maintain and operate each tank such that all the emission limits in this permit will be met.

4. The Permittee shall ensure that the produced water storage tank is an enclosed tank.

5. The Permittee shall limit the hydrocarbon emissions from handling natural gas condensate using one or more of the following techniques:

   (a) Route all hydrocarbon emissions through a closed-vent system to an operating system designed to recover and inject the emissions into a natural gas gathering pipeline system for sale or other beneficial purpose; and/or

   (b) Route all hydrocarbon emissions through a closed-vent system to a control device as specified in the **Requirements for Control Systems for Hydrocarbon Emissions** section of this permit.

6. Covers: The Permittee shall equip all openings on each natural gas condensate tank with a cover to ensure that all hydrocarbon emissions are efficiently being routed through a closed-vent system to a natural gas pipeline system for sale or other beneficial purpose and/or a control device as specified in the **Requirements for Control Systems for Hydrocarbon Emissions** section of this permit.

   (a) The Permittee shall ensure that each cover and all openings on the cover (e.g., access hatches, sampling ports, pressure relief valves, and gauge wells) form a continuous impermeable barrier over the entire surface area of the tanks.

   (b) Each cover opening shall be secured in a closed, sealed position (e.g., covered by a gasketed lid or cap) whenever material is in a tank on which the cover is installed except during those times when it is necessary to use an opening as follows:

      (i) To add material to, or remove material from the tank (this includes openings necessary to equalize or balance the internal pressure of the tank following changes in the level of the material in the tank);
      (ii) To inspect or sample the material in the tank; or
      (iii) To inspect, maintain, repair, or replace equipment located inside the tank.

   (c) Each thief hatch cover shall be weighted and properly seated.

   (d) Pressure relief valves shall be set to release at a pressure that will ensure that all hydrocarbon emissions are routed through the closed-vent system to a natural gas pipeline system for sale or other beneficial purpose and/or a control device as specified in the **Requirements for Control Systems for Hydrocarbon Emissions** section of this permit under normal operating conditions.

7. Monitoring Requirements

   (a) The Permittee shall perform quarterly visual inspections of the natural gas condensate tank covers, thief hatches, seals, pressure relief valves, and closed-vent systems to ensure proper condition and functioning and repair any damaged equipment. The quarterly inspections shall be performed while the tanks are being filled.

   (b) The Permittee shall perform quarterly inspections of each closed-vent system and control device of each natural gas condensate storage tank as specified in the **Requirements for Equipment Leaks from Closed-Vent Systems** section of this permit to ensure that the pressure and vacuum relief set-points are not being exceeded in a way that has resulted, or may result, in venting of hydrocarbon emissions and possible damage to equipment.

(c) The Permittee shall follow the instructions in the “Onshore Oil and Gas Operations; Federal and Indian Oil & Gas Leases; Onshore Oil and Gas Order No. 4; Measurement of Oil,” Section III.C; “Oil Measurement by Tank Gauging,” developed by the US Department of the Interior’s Bureau of Land Management, to measure the volume of produced water and natural gas condensate routed to each tank to use in subsequently determining the volume of produced water and natural gas condensate processed through the station as required in the **Requirements for Emission Limits, Construction, and Operation** section of this permit. Other measurement methods may be used upon prior written approval by the EPA.

[Note: EPA is incorporating by reference the measurement methodologies described in this document only. There are no other enforcement implications intended. The Onshore Oil and Gas Operations; Federal and Indian Oil & Gas Leases; Onshore Oil and Gas Order No. 4 can be found 43 CFR 3160; Federal Register/Vol. 54, No. 36 or *on-line at http://www.blm.gov/pgdata/etc/medialib/blm/mt/blm_programs/energy/oil_and_gas/operations/orders.Par.92085.File.dat/ord4.pdf]*

(d) The Permittee shall calculate the VOC and HAP emissions from each tank. The VOC and HAP emissions at the station shall be determined using: the measured monthly volume of produced water and natural gas condensate routed to the tanks; the most recent extended laboratory analysis of the produced water and natural gas condensate entering the station as required in the **Requirements for Emission Limits, Construction, and Operation** section of this permit; E&P Tanks V2.0 and/or EPA Tanks 4.0.9d, as appropriate; and the most recent tested control efficiency of the control device being used, as required in the **Requirements for Emission Limits, Construction, and Operation** section of this permit. Other calculation methods may be used upon prior written approval by the EPA.

8. Record Keeping Requirements

(a) The Permittee shall maintain records of the monthly volume of produced water and natural gas condensate handled by each tank.

(b) The Permittee shall maintain a record of all quarterly inspections. All inspection records shall include, at a minimum, the following information:

(i) The date of the inspection;
(ii) The findings of the inspection;
(iii) Any required repairs; and
(iv) The inspector's name and signature.

(c) The Permittee shall maintain records of the date of installation of each tank, the manufacturer’s recommended maintenance schedule and procedures or equivalent procedures developed by the Permittee or vendor and all scheduled maintenance and repairs.

(d) The Permittee shall maintain records of the VOC and HAP emission calculations for each tank.

G. Requirements for Control Systems for Hydrocarbon Emissions

1. Closed-Vent Systems: The Permittee shall meet the following requirements for closed-vent systems:

(a) Each closed-vent system shall route all hydrocarbon emissions from the natural gas condensate tanks to a natural gas pipeline system for sale or other beneficial purpose and/or a control device as specified in this section of the permit.

(b) All vent lines, connections, fittings, valves, pressure relief valves, or any other appurtenance employed to contain and collect hydrocarbon emissions from the natural gas condensate tanks to transport them to a natural gas pipeline system for sale or other beneficial purpose and/or a control device as specified in this section of the permit shall be maintained and operated properly at all times.

(c) Each closed-vent system shall be designed to operate with no detectable hydrocarbon emissions, as required in the **Requirements for Equipment Leaks from Closed-Vent Systems** section of this permit.

(d) If any closed-vent system contains one or more bypass devices that could be used to divert all or a portion of the hydrocarbon emissions, from entering a natural gas pipeline system for sale or other beneficial purpose and/or a control device as specified in this section of the permit, the Permittee shall meet one of following requirements for each bypass device:

(i) At the inlet to the bypass device that could divert the hydrocarbon emissions away from a natural gas pipeline or a control device and into the atmosphere, properly install, calibrate, maintain, and operate a flow indicator that is capable of taking continuous readings and sounding an alarm when the bypass device is open such that hydrocarbon emissions are being, or could be, diverted away from a natural gas pipeline or a control device and into the atmosphere; or

(ii) Secure the bypass device valve installed at the inlet in the non-diverting position using a car-seal or a lock-and-key type configuration.

(e) Low leg drains, high point bleeds, analyzer vents, open-ended valves or lines, and safety devices are not subject to the requirements applicable to bypass devices.

2. Enclosed Combustors and Utility Flares: The Permittee shall meet the following requirements for enclosed combustors and utility flares:

(a) Follow, for each enclosed combustor or utility flare, manufacturer and/or vendor written operating instructions, procedures and maintenance schedules or equivalent operating instructions, procedures, and maintenance schedules developed by the Permittee or vendor to ensure good air pollution control practices for minimizing hydrocarbon emissions;

(b) Ensure, for each enclosed combustor or utility flare, that there is sufficient capacity to reduce the mass content of VOCs in the hydrocarbon emissions routed to it by at least 95% for the minimum and maximum volumetric flow rate and BTU content routed to the device;

(c) Operate each enclosed combustor or utility flare such that the mass content of VOCs in the hydrocarbon emissions routed to it are reduced by at least 95%; and

(d) Ensure that each utility flare is designed and operated in accordance with requirements of the General Provisions for the New Source Performance Standards (NSPS A) at §60.18(b), for such flares except for §§60.18(c)(2) and 60.18(f)(2) for those utility flares operated with an auto ignition system.

(e) The Permittee shall ensure that each enclosed combustor is:

  (i) A model demonstrated by a manufacturer to the meet the 95% VOC destruction efficiency requirements of the New Source Performance Standards for Natural Gas Production, Transmission and Distribution at 40 CFR Part 60, Subpart OOOO (NSPS OOOO), using the procedure specified in §60.5413(d), by the due date of the first annual report; or
  (ii) Demonstrated to meet the 95% VOC destruction efficiency requirements of NSPS OOOO using EPA approved performance test methods specified in §60.5413(b).

(f) The Permittee shall ensure that each enclosed combustor and utility flare is:

  (i) Operated properly at all times that hydrocarbon emissions are routed to it;

  (ii) Operated with a liquid knock-out system to collect any condensable vapors (to prevent liquids from going through the control device);

  (iii) Equipped with a flash-back flame arrestor;

  (iv) Equipped with one of the following:

    (A) A continuous burning pilot flame, a thermocouple, and a malfunction alarm and notification system if the pilot flame fails; or
    (B) An electronically controlled auto-ignition system with a malfunction alarm and notification system if the flame fails while hydrocarbon gas emissions are flowing to the enclosed combustor or utility flare.

  (v) Equipped with a continuous recording device, such as a chart recorder, data logger or similar device, or connected to a SCADA system, to monitor and document proper operation of the enclosed combustor or utility flare;

  (vi) Maintained in a leak-free condition; and

  (vii) Operated with no visible smoke emissions, as defined in EPA Reference Method 22 of 40 CFR Part 60, Appendix A.

3. Other Control Devices: Upon written approval by the EPA, the Permittee may use control devices other than those listed above that are capable of reducing the mass content of VOCs in the hydrocarbon emissions routed to it by at least 95%, provided that:

(a) In operating such control devices, the Permittee shall follow the manufacturer's written operating instructions, procedures and maintenance schedules or equivalent operating instructions, procedures, and maintenance schedules developed by the Permittee or vendor to ensure good air pollution control practices for minimizing hydrocarbon emissions;

(b) The Permittee shall ensure there is sufficient capacity to reduce the mass content of VOCs in the hydrocarbon emissions routed to such other control devices by at least 95% for the minimum and maximum natural gas volumetric flow rate and BTU content routed to each device; and

(c) The Permittee shall operate such a control device to reduce the mass content of VOCs in the hydrocarbon emissions routed to it by at least 95%.

4. Testing Requirements:

Within 180 days after initial startup at each station, and every 5 years thereafter, the Permittee shall conduct a performance test of the closed-vent system to demonstrate that it is operating in a leak free condition, and a performance test of the control device to which hydrocarbon emissions are routed, to demonstrate 95% destruction efficiency.

(a) Testing of the closed-vent system shall be conducted in accordance with EPA Reference Method 21, listed in 40 CFR Part 60, Appendix A.

(b) Testing of the enclosed combustor VOC destruction efficiency shall be conducted in accordance with EPA Reference Method 25A, listed in 40 CFR Part 60, Appendix A.

(c) A 95% VOC destruction efficiency can be assumed for utility flares provide they are designed and operated in accordance with §60.18(b) of NSPS A.

(d) The Permittee may submit a written request to the EPA for an alternate testing method, but shall only use that test method upon receipt of written approval by the EPA.

5. Monitoring Requirements:

(a) The Permittee shall monitor the operation of each enclosed combustor and utility flare to confirm proper operation as follows:

(i) Continuously monitor the enclosed combustor and utility flare operation, using a malfunction alarm and notification system for failures, and checking the alarm and notification system for proper operation whenever an operator is on site, at a minimum quarterly;

(ii) Monitor for visible smoke during operation of any enclosed combustor or utility flare each time an operator is on site, at a minimum quarterly. Upon observation of visible smoke, use EPA Reference Method 22 of 40 CFR Part 60, Appendix A, to confirm that no visible smoke emissions are present for more than 2 minutes in any hour. The observation period shall be 1 hour; and

(iii) Respond to any observation of improper monitoring equipment operation or any malfunction and notification alarm system to ensure the monitoring equipment is returned to proper operation as soon as practicable and safely possible after an observation or an alarm sounds.

(b) Where sufficient to meet the monitoring requirements the Permittee may use a SCADA system to monitor and record the required data.

(c) The Permittee shall calculate VOC, NO_X, CO and HAP emissions from each enclosed combustor and utility flare using the following:

(i) The monitored volume of hydrocarbon emissions from the produced water storage tank and natural gas condensate tanks, as required in the **Requirements for Tanks** section of this permit;

(ii) The most recent extended laboratory analysis of the produced water and natural gas condensate received at each station;

(iii) The most recent performance test results of the closed-vent system and control device; and

(iv) The emission factors in AP-42 Chapter 1.4, Natural Gas Combustion.

6. Recordkeeping Requirements

The Permittee shall keep records of the following:

(a) The site-specific design input parameters provided by the manufacturer or vendor and used to properly size the control device to assure the minimum 95% reduction requirements;

(b) All required monitoring of the control device operations;

(c) Any deviations from the operating parameters specified in the manufacturer or vendor site-specific designs. The records shall include the control's total operating time during the calendar month in which the exceedance occurred, the date, time and length of time that the parameters were exceeded, and the corrective actions taken and any preventative measures adopted to operate the controls within that operating parameter;

(d) Any instances in which any closed-vent system or control device was bypassed or down in each calendar month, the reason for each incident, its duration, and the corrective actions taken and any preventative measures adopted to avoid such bypasses or downtimes;

(e) Any instances in which the pilot flame is not present in an enclosed combustor or the utility flare while hydrocarbon emissions are vented to it, the date and times that the pilot was not present and the corrective actions taken or any preventative measures adopted to improve the operation of the pilot flame;

(f) Any instances in which the thermocouple (or other heat sensing monitoring device) installed to detect the presence of a flame in an enclosed combustor or engineered flare while hydrocarbon emissions are vented to it is not operational, the time period during which it was not operational, and the corrective measures taken;

(g) Any instances in which the recording device installed to record data from the thermocouple is not operational;

(h) Any time periods in which visible emissions are observed emanating from a control system; and

(i) The VOC, NO_X, CO, and HAP emissions calculations included in the consecutive 12-month total for all units covered by this permit.

H. Requirements for Truck Loading Operations

1. The Permittee shall operate truck loading operations such that the emission limits in this permit are met.

2. The Permittee shall install, operate and maintain a piping system designed for submerged loading by either bottom loading or loading through a submerged fill pipe. The submerged fill pipe shall be no more than 12 inches from the bottom of the truck tank. The Permittee shall not conduct truck loading operations unless submerged loading is used.

3. Monitoring Requirements: VOC and HAP emissions from the truck loading operations for each calendar month shall be calculated by the Permittee using the following:

(a) The total measured volume of produced water and natural gas condensate, in barrels, loaded for the month;

(b) The actual physical and chemical properties of the produced water and natural gas condensate and its associated vapors from the most recent semiannual extended laboratory analysis of the produced water and natural gas condensate received at the station; and

(c) The procedures outlined in AP-42 Chapter 5.2, Transportation and Marketing of Petroleum Liquids for the actual method of truck loading for VOC, and HAP emissions.

4. Recordkeeping Requirements

(a) Records shall be kept by the Permittee of the manufacturer and/or vendor specifications or equivalent specifications developed by the Permittee or vendor, and all scheduled maintenance and repairs on the truck loading equipment.

(b) Records shall be kept of the VOC and HAP emissions calculations included in the consecutive 12-month total for all units covered by this permit.

I. Requirements for Pneumatic Pumps, Pneumatic Controllers, Compressor Blowdowns

1. Pneumatic Pumps and Controllers

(a) The Permittee shall install, maintain, and operate any pneumatic pumps and controllers such that the consecutive 12-month emission limit requirements in this permit will be met. This shall be achieved by meeting one or more of the following emission control techniques:

(i) Operate air actuated controllers and pneumatic pumps;
(ii) Operate solar or electric actuated controllers and pneumatic pumps;
(iii) Operate low-bleed natural gas actuated controllers (6 standard cubic feet per hour);
(iv) Operate no-bleed natural gas actuated controllers;
(v) Route any natural gas emissions discharge streams to an operating system designed to recover and inject the emissions into a natural gas gathering pipeline system for sale or other beneficial purpose, such as fuel supply; and/or
(vi) Route any natural gas emissions discharge stream to a control device as specified in the **Requirements for Control Systems for Hydrocarbon Emissions** section of this permit.

(b) Each natural gas actuated pneumatic pump and controller shall be operated and maintained according to the manufacturer or vendor specifications or equivalent specifications developed by the Permittee or vendor.

(c) Records shall be kept of the date of installation of each natural gas actuated pneumatic pump and controller.

(d) Records shall be kept of a description of the steps taken to minimize the emissions from any natural gas actuated pneumatic pump and controller, and a description of emission estimation methods used to calculate VOC and HAP emissions.

(e) Emissions from all natural gas actuated pneumatic pumps and controllers shall be included in the entire gathering and transmission operation's consecutive 12-month total.

2. Compressor Blowdowns

(a) During manual and automated blow down episodes associated with maintenance or repair, hydrate clearing, emergency operations, equipment depressurization, etc., the Permittee shall limit emissions such that the emission limits in this permit are met.

(b) The Permittee's personnel shall remain on site during manual blow downs.

(c) The Permittee shall keep records of the date and time of each compressor blowdown event, the volume of gas released during the episode, calculated based on a representative emission factor, and a description of emission estimation methods used to calculate the VOC and HAP emissions.

(d) Compressor blowdown emissions shall be included in the consecutive 12-month total of all units covered by this permit.

J. Requirements for Equipment Leaks from Closed-Vent Systems

1. The Permittee shall minimize leaks of hydrocarbon gases from each vent line, connection, fitting, valve, pressure relief device, or any other appurtenance employed to contain and collect hydrocarbon emissions to transport them such that the emission limits in this permit are met.

2. The Permittee shall develop a written leak inspection and repair protocol that, at a minimum, specifies the following:

   (a) A detailed description of the procedures to be used for leak detection, which may include, but is not limited to, audio, visual, and/or or olfactory techniques;

   (b) A schedule of inspections to be conducted, at a minimum, quarterly;

   (c) A definition of when a "leak" is detected;

   (d) A repair schedule for leaking equipment (including delay of repair); and

   (e) A log book that contains a list, summary description, and diagram showing the location of all equipment that is part of a closed-vent system at the facility, and a record of type of inspections performed, the date of inspections, the results of the inspections, and the date of repairs performed on leaking equipment.

3. In the event that the EPA determines that the protocol on record is not meeting its intended goals, the Permittee shall develop a revised protocol upon request by the EPA.

4. Total emissions from equipment leaks shall be determined by assuming 8,760 hours of operation in a year and with maximum leakage of all components from equipment in hydrocarbon service.

K. Requirements for Minimizing Fugitive Dust

1. <u>Work Practice and Operational Requirements</u>

   (a) The Permittee shall take all reasonable precautions to prevent fugitive dust emissions at each station and shall construct, maintain, and operate each station to minimize fugitive dust emissions. Reasonable precautions include, but are not limited to the following:

      (i) Use, where possible, of water or chemicals for control of dust during construction and operations, grading of roads, or clearing of land;
      (ii) Application of asphalt, water, or other suitable chemicals on unpaved roads, materials stockpiles, and other surfaces, located at the facilities, that can create airborne dust;
      (iii) The prompt removal from paved surfaces, located at the station, of earth or other material that does or may become airborne; or
      (iv) Restricting vehicle speeds.

   (b) The Permittee shall prepare and implement a written fugitive dust emission prevention plan, approved by EPA, that specifies the reasonable precautions to be taken and the procedures to be followed to prevent fugitive dust emissions.

2. Monitoring Requirements

(a) The Permittee shall survey the station during construction and operation to determine if there are obvious visible dust plumes. This survey must be done at a minimum once per week in all active areas and during daylight hours.

(b) The Permittee shall document the results of the survey, including the date and time of the survey, identification of the cause of any visible dust plumes observed, and the precautions taken to prevent continued fugitive dust emissions.

3. Recordkeeping Requirements

The Permittee shall maintain records for 5 years that document the fugitive dust prevention plan, the periodic surveys and the reasonable precautions that were taken to prevent fugitive dust emissions.

L. Requirements for Records Retention

1. The Permittee shall retain all records required by this permit for a period of at least 5 years from the date the record was created.

2. Records shall be kept in the vicinity of the facility, such as at the facility, the location that has day-to-day operational control over the facility, or the location that has day-to-day responsibility for compliance of the facility.

M. Requirements for Reporting

1. Annual Emission Reports

(a) The Permittee shall submit a written annual report of the actual annual emissions from all emission units at the facility covered under this permit, including emissions from start-ups, shutdowns, and malfunctions, each year no later than April 1st. The annual report shall cover the period for the previous calendar year. All reports shall be certified to truth and accuracy by the person primarily responsible for Clean Air Act compliance for the Permittee.

(b) The report shall include facility-wide emission of NO_X, CO, VOC, each individual HAP and total HAP emissions.

(c) The report shall be submitted to:

U.S. Environmental Protection Agency, Region 8
Office of Partnerships and Regulatory Assistance
Tribal Air Permitting Program, 8P-AR
1595 Wynkoop Street
Denver, Colorado 80202

The report may be submitted via electronic mail to r8AirPermitting@epa.gov.

2. All other documents required to be submitted under this permit, with the exception of the Annual Emission Reports, shall be submitted to:

   U.S. Environmental Protection Agency, Region 8
   Office of Enforcement, Compliance & Environmental Justice
   Air Toxics and Technical Enforcement Program, 8ENF-AT
   1595 Wynkoop Street
   Denver, Colorado 80202

   All documents may be submitted electronically to r8airreportenforcement@epa.gov.

3. The Permittee shall promptly submit to the EPA a written report of any deviations of permit requirements and a description of the probable cause of such deviations and any corrective actions or preventative measures taken. A "prompt" deviation report is one that is post marked or submitted via electronic mail to r8airreportenforcement@epa.gov as follows:

   (a) Within 30 days from the discovery of any deviation of the emission or operational limits that is left un-corrected for more than 5 days after discovering the deviation; and

   (b) By April 1st for the discovery of a deviation of recordkeeping or other permit conditions during the preceding calendar year that do not affect the Permittee's ability to meet the emission limits.

4. The Permittee shall submit a written report for any required performance tests to the EPA Regional Office within 60 days after completing the tests.

5. The Permittee shall submit any record or report required by this permit upon EPA request.

II. General Provisions

A. Conditional Approval

Pursuant to the authority of 40 CFR 49.151, the EPA hereby conditionally grants this permit to construct.

This authorization is expressly conditioned as follows:

1. *Document Retention and Availability:* This permit and any required attachments shall be retained and made available for inspection upon request at the location set forth herein.

2. *Permit Application:* The Permittee shall abide by all representations, statements of intent and agreements contained in the application submitted by the Permittee. The EPA shall be notified 10 days in advance of any significant deviation from this permit application as well as any plans, specifications or supporting data furnished.

3. *Permit Deviations:* The issuance of this permit may be suspended or revoked if the EPA determines that a significant deviation from the permit application, specifications, and supporting data furnished has been or is to be made. If the proposed source is constructed, operated, or modified not in accordance with the terms of this permit, the Permittee will be subject to appropriate enforcement action.

4. *Compliance with Permit:* The Permittee shall comply with all conditions of this permit, including emission limitations that apply to the affected emissions units at the permitted facility/source. Noncompliance with any permit term or condition is a violation of this permit and may constitute a violation of the Clean Air Act and is grounds for enforcement action and for a permit termination or revocation.

5. *Fugitive Emissions:* The Permittee shall take all reasonable precautions to prevent and/or minimize fugitive emissions during the construction period.

6. *National Ambient Air Quality Standard and PSD Increment:* The permitted source shall not cause or contribute to a National Ambient Air Quality Standard violation or a PSD increment violation.

7. *Compliance with Federal and Tribal Rules, Regulations, and Orders:* Issuance of this permit does not relieve the Permittee of the responsibility to comply fully with all other applicable federal and tribal rules, regulations, and orders now or hereafter in effect.

8. *Enforcement:* It is not a defense, for the Permittee, in an enforcement action, to claim that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of this permit.

9. *Modifications of Existing Permitted Emission Units/Limits:* For proposed modifications, as defined at §49.152(d), that would increase an emissions unit's allowable emissions of pollutants above its existing permitted annual allowable emissions limit, the Permittee shall first obtain a permit modification pursuant to the MNSR regulations approving the increase. For a proposed modification that is not otherwise subject to review under the PSD or MNSR regulations, such proposed increase in the annual allowable emissions limit shall be approved through an administrative permit revision as provided at §49.159(f).

10. *Relaxation of Legally and Practically Enforceable Limits:* At such time that a new or modified source within this permitted facility/source or modification of this permitted facility/source becomes a major stationary source or major modification solely by virtue of a relaxation in any legally and practically enforceable limitation which was established after August 7, 1980, on the capacity of the permitted facility/source to otherwise emit a pollutant, such as a restriction on hours of operation, then the requirements of the PSD regulations shall apply to the source or modification as though construction had not yet commenced on the source or modification.

11. *Revise, Reopen, Revoke and Reissue, or Terminate for Cause:* This permit may be revised, reopened, revoked and reissued, or terminated for cause. The filing of a request by the Permittee, for a permit revision, revocation and reissuance, or termination, or of a notification of planned changes or anticipated noncompliance does not stay any permit condition. The EPA may reopen this permit for a cause on its own initiative, e.g., if this permit contains a material mistake or the Permittee fails to assure compliance with the applicable requirements.

12. *Severability Clause:* 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.

13. *Property Rights:* This permit does not convey any property rights of any sort or any exclusive privilege.

14. *Information Requests:* The Permittee shall furnish to the EPA, within a reasonable time, any information that the EPA may request in writing to determine whether cause exists for revising, revoking and reissuing, or terminating this permit or to determine compliance with this permit. For any such information claimed to be confidential, you shall also submit a claim of confidentiality in accordance with 40 CFR Part 2, Subpart B.

15. *Inspection and Entry:* The EPA or its authorized representatives may inspect this permitted facility/source during normal business hours for the purpose of ascertaining compliance with all conditions of this permit. Upon presentation of proper credentials, the Permittee shall allow the EPA or its authorized representative to:

    (a) Enter upon the premises where this permitted facility/source is located or emissions-related activity is conducted, or where records are required to be kept under the conditions of this permit;

    (b) Have access to and copy, at reasonable times, any records that are required to be kept under the conditions of this permit;

    (c) Inspect, during normal business hours or while this permitted facility/source is in operation, any facilities, equipment (including monitoring and air pollution control equipment), practices, or operations regulated or required under this permit;

    (d) Sample or monitor, at reasonable times, substances or parameters for the purpose of assuring compliance with this permit or other applicable requirements; and

    (e) Record any inspection by use of written, electronic, magnetic and photographic media.

16. *Permit Effective Date:* This permit is effective immediately upon issuance unless comments resulted in a change in the proposed permit, in which case the permit is effective 30 days after issuance. The Permittee may notify the EPA, in writing, that this permit or a term or condition of it is rejected. Such notice should be made within 30 days of receipt of this permit and should include the reason or reasons for rejection.

17. *Permit Transfers:* Permit transfers shall be made in accordance with 40 CFR 49.159(f). The Air Program Director shall be notified in writing at the address shown below if the company is sold or changes its name.

    U.S. Environmental Protection Agency, Region 8
    Office of Partnerships and Regulatory Assistance
    Tribal Air Permitting Program, 8P-AR
    1595 Wynkoop Street
    Denver, Colorado 80202

18. *Invalidation of Permit:* This permit becomes invalid if construction is not commenced within 18 months after the effective date of this permit, construction is discontinued for 18 months or more, or construction is not completed within a reasonable time. The EPA may extend the 18-month period upon a satisfactory showing that an extension is justified. This provision does not apply to the time period between the construction of the approved phases of a phased

construction project. The Permittee shall commence construction of each such phase within 18 months of the projected and approved commencement date.

19. *Notification of Start-Up:* The Permittee shall submit a notification of the anticipated date of initial start-up of this permitted source to the EPA within 60 days of such date, unless this permitted source is an existing source.

B. Authorization:

Authorized by the United States Environmental Protection Agency, Region 8

5-15-14

Debra H. Thomas
Acting Assistant Regional Administrator
Office of Partnerships and Regulatory Assistance

Date